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BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of: the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of Its Proposed Electric Service Schedules and Electric Service Regulations, Consisting of a General Rate Increase of Approximately $161.2 Million Per Year, and for Approval of a New Large Load Surcharge	Docket No. 07-035-93 **ROCKY MOUNTAIN POWER'S** **PETITION FOR RECONSIDERATION**

Pursuant to Utah Code § 63G-4-3-1, Utah Code § 54-7-15 and Utah Administrative Rule 746-100-11.F, Rocky Mountain Power (the "Company") submits to the Public Service Commission of Utah ("the Commission") this Petition for Reconsideration of the Public Service Commission's August 11, 2008, Report and Order on Revenue Requirement and subsequently issued August 21, 2008, Erratum Report and Order on Revenue Requirement ("the Order"). In the Petition, the Company asks that the Commission review, reconsider, and grant a new hearing, revising the portions of the Order and the Commission's oral rulings which addressed following issues: (1) Net Power Costs, (2) Return on Equity ("ROE"), (3) Generation Overhaul Expenses, (4) Property Taxes, (5) Test Year, (6) ETO Funding of the Goodnoe Hills Wind Project, and (7) Commission's Exclusion of the Company's Sur-surrebuttal Evidence. The record in this case, properly reviewed under applicable standards, dictates an overall revenue requirement increase substantially higher than that allowed in the Order.

NET POWER COSTS

A. The Commission Erred in Failing to Analyze Whether Its Approved Net Power Cost Adjustments Produced A Reasonable Overall Net Power Costs Result.

Utah law indicates that if the Commission establishes a test period that is not determined exclusively on the basis of future projections (as was ordered in this case), the Commission must at a minimum consider changes that are known in nature and are measurable in amount in order to determine a level of rates that is just and reasonable.[1] The policy prescribed by the Legislature reflects a sound principle of ratemaking that pre-dates even *Bonbright*[2]; that is, rates for public utilities should reflect as much as possible conditions that will exist during the rate-effective period.[3] For this reason, it is incumbent on the Commission to review the effect of

[1] *See* Utah Code § 54-4-4(3)(c).

[2] James C. Bonbright, Albert L. Danielson, David R. Kamerschen, *Principles of Public Utility Rates* 150 n. 7 (1961).

[3] *See* Utah Code § 54-4-4(3)(c).

cumulative adjustments to ensure that the result is fair and reasonable. This is particularly true in the area of power costs – which make up the lion's share of the Company's costs that are addressed in rate cases before this Commission and which are commonly the subject of a myriad of proposed adjustments.

In fact, in past rate cases this is precisely how the Commission has operated: after sorting through numerous adjustments proposed by the parties, the Commission has performed a "reasonableness check" by comparing its resulting net power costs to actual cost benchmarks to ensure the validity of its overall net power cost results.[4] In this case the Commission failed to perform a reasonableness check on its allowed power costs of approximately $1.006 billion. Had it done so, it would have concluded that the cumulative effect of its allowed adjustments produced an unreasonable and unfair result.

In presenting its case, the Company produced actual cost benchmarks in its testimony to demonstrate the reasonableness of its proposed system net power costs baseline of $1.044 billion.[5] Specifically, among other evidence, the Company demonstrated that while its system net power costs for 2007 were $975 million, actual system net power costs for the 12 months ending March 2008 were $1.024 billion.[6] In addition, the Company provided uncontroverted evidence of the known and measurable costs that would serve to increase rates in the Test Period. In short, the Company provided uncontroverted evidence demonstrating that its net power costs are rising at the pace of $40-$50 million every 6 months (a fact corroborated by the Test Period Order in this case which backed the test year up by six months and reduced net power costs by $40 million, from $1.091 billion to $1.051 billion).

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[4] *See, e.g, Re PacifiCorp, dba Utah Power & Light Co.,* Docket 01-035-01, Order at 244-245 (Sept. 10, 2001) (Commission compared its ordered power cost expenses with the Company's actual power costs over a period of years).

[5] Duvall Rebuttal/4, 1. 83. While the Company could have used aggressive projections in support of its net power costs, the evidence shows that it chose conservative ones instead.

[6] Exhibit GND-3R-RR.

By way of contrast, the Commission's allowed net power cost of approximately $1.006 billion for a forward-looking test period through December 2008 was less than the Company's most recent March 2008 actual historical net power costs $1.024 billion. Combined with the system net power costs now in rates in Utah of $813 million, in place for more than 7/12 of 2008, the result from the Order produces system net power costs in Utah rates for 2008 of approximately $895 million, *$80 million less than actual system net power costs for 2007 ($975 million).*

Past Commission precedent and Utah law dictate the Commission reconsider its overall net power cost decision. This is particularly critical when, in this case, the Commission used the same known and measurable standard in its analysis and decision to approve certain parties' downward adjustments to net power costs.[7]

B. The Commission Erred in its Adjustments to the Net Power Costs Related to the Sacramento Municipal Utility District ("SMUD") Contract

1. <u>The Commission Erred in Imputing a Price of $58.46 per MWh Related to the SMUD Contract</u>

In its Order, the Commission adopted a new and much higher imputed price related to a wholesale sales contract between the Company and SMUD—$58.46 per megawatt hour ("MWh"). In two prior cases, the 1999 and 2001 PacifiCorp rate cases, the Commission imputed a price of $37 MWh related to this contract. Importantly, in originally setting this imputed price, the Commission focused on the overall reasonableness of the price when PacifiCorp entered into the contract as compared to other, contemporaneous wholesale contracts, not the level of imputed revenues embedded in the imputed price.

PacifiCorp filed this case using the $37 per MWh imputed price previously set by the Commission. The effect of the Commission's adjustment increasing the imputed price to $58.46

[7] *See Re Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah*, Docket No. 07-035-93, Phase I Order on Revenue Requirement at 44 (Aug. 11, 2008) (emphasis added) [hereinafter "Order"].

per MWh was to reduce system net power costs by $7.52 million and the Company's Utah revenue requirement by $3.287 million.[8]

a. The Commission should correct its computational error.

The Company recognizes that the Commission's adjustment may be simply the result of a calculation error, where the Commission added the current contract price of $21.46 per MWh to the historic $37 per MWh imputed price, instead of recognizing that $21.46 per MWh price was already reflected in the $37 per MWh imputed price. The Commission's prior orders make clear that the $37 per MWh imputed price reflects the actual contract price (now $21.46 per MWh), effectively supplemented by imputed revenues. In this case, the Commission should correct its error by recognizing that it was a mistake to add the current contract price to the $37 per MWh imputed price and eliminate the adjustment.

b. If the Commission's adjustment was not a computational error, the adjustment should be reversed as arbitrary, unsupported by the evidence and asymmetric.

Some history on this issue is instructive. The original imputation for the SMUD contract was made in the 1999 rate case (Docket No. 99-035-10) and was based primarily on three factors: (1) that the price SMUD paid the Company was below the then-current market price, (2) that the Company had received a $94 million up-front payment from SMUD as part of the contract, and (3) that a similar contract with Southern California Edison ("SCE") provided for a higher price per MWh. Other commissions have adopted the $37 MWh as the reasonable imputed revenue value for the contract. No other commission has increased the imputation beyond that level.

In the 1999 rate case, the Commission approved an imputed price of $37 per MWh. In reaching that conclusion, the Commission was clear that an imputation decision (which is essentially the same thing as a prudence decision) "should be made *in light of circumstances existing at the time*. This view continues to be appropriate and we will apply it in this Docket. Since the contract was below-market when signed, the task before us is to find the rate,

[8] Order at 24-28.

contemporaneous with the date of the contract, to use as the basis for revenue imputation."[9] The Commission accepted the $37 per MWh price from the SCE contract as a proxy for the price that would have been prudent under the SMUD contract.[10]

In the revenue requirement order in the 2001 rate case (Docket No. 01-035-01), the Commission reaffirmed the $37 per MWh imputed price.[11] In the current docket, the Commission set an imputed price of $58.46 per MWh, effectively converting the original imputed *price* of $37 per MWh into an imputed *revenue* adjustment of $37 per MWh, to which the Commission then added the current contract price of $21.46 per MWh. Whether this outcome was the result of a calculation error or was an intentional change in the Commission's approach to the SMUD contract, the result is unsupported by the record and by applicable law and precedent.

First, no party ever suggested that the Commission should convert the historic imputed price of $37 per MWh into a revenue imputation of $37 per MWh to be added to the actual contract price.

In this case, CCS witness Hayet proposed a much smaller increase in the imputed price from $37.00 per MWh to $43.80 per MWh (an increase of 18% per MWh).[12] Yet, somewhere between Mr. Hayet's proposed adjustment and the Order, the imputed price jumped $14.66 per MWh to $58.46. What happened cannot be explained by the record. Mr. Falkenberg adopted Mr. Hayet's testimony. In Mr. Falkenberg's direct testimony, he stated that he had incorporated Mr. Hayet's SMUD pricing proposal into his summary Table 1.[13]

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[9] *Re PacifiCorp*, Utah PSC Docket No. 99-035-10, 201 P.U.R. 467, 498 (May 24, 2000). (emphasis added).

[10] Coincidentally, the $15.46 per MWh imputed revenue resulting from the SCE contract price was also a fair approximation of taking the $94 million upfront payment and amortizing it over the life of the contract. *See* Exhibit DPU-SR, Dalton Surrebuttal/3, l. 41-4, l. 44.

[11] In the revenue requirement order in 2001 rate case, the Commission erroneously left the door open for an increase in the imputation level and thus backed off from its unequivocal 1999 ruling that its role in an imputation issues was to determine the proper amount *as of the date of the contract*. Although this language in the 2001 ruling was incorrect, it was not appealable by the Company because the Company was not harmed by the "dicta," and the issue was not ripe.

[12] Exhibit CCS-5D, Hayet Direct/16 ll. 314, 320.

[13] Exhibit CCS 4D, Falkenberg Direct/42, ll. 993-97.

In Mr. Dalton's rebuttal testimony for the DPU, he originally proposed an increase in the imputed price for the SMUD contract to $54.16 per MWh. In Mr. Dalton's surrebuttal, however, he withdrew this adjustment and recommended that the imputed price of the SMUD contract remain at $37 per MWh. Notably, Mr. Dalton concluded that it would be "erroneous to add the 2008 contract price" to the $37 per MWh imputed price.[14]

The adjustment adopted by the Commission is not based on any evidence, let alone the "substantial evidence" that must support an order of a Utah administrative agency.[15] The amount of the Commission's adjustment far exceeds the proposed adjustment of CCS—the only party that ultimately proposed an adjustment on this issue. The Commission erred in adopting an imputed price at a level not proposed by any party and unsupported by the record in this case.

Second, in adopting its SMUD adjustment, the Commission appears to have relied upon Mr. Dalton's observations in his surrebuttal testimony that the $37 per MWh imputed price reflected the approximate levelized value of the $94 million up-front payment from SMUD to the Company.[16] Unfortunately, Mr. Dalton's observation was incorrectly calculated, resulting in it being substantially overstated. Properly calculated, the real levelized value of the $94 million is closer to $20. per MWh than $37 per MWh. Because the Company was improperly denied sur-surrebuttal testimony, the Company never had an opportunity to correct this analytical error in the record.[17]

Moreover, the underlying theory of the analysis adopted by the Commission—which is that the imputed price of $37 per MWh was designed to impute revenues at a level tied to return the $94 million lump sum payment to customers—is incorrect. A review of the Commission's earlier orders on the SMUD contract demonstrates that the Commission set the imputed price for

[14] Exhibit DPU-SR, Dalton Surrebuttal/3, l. 41-4, l. 44.

[15] Utah Code Ann. § 63G-4-403(4)(g) (agency actions must be supported by "substantial evidence when viewed in light of the whole record").

[16] Order at 57-60.

[17] The Company reasonably elected not to cross-examine Mr. Dalton on this issue, given the fact that he had withdrawn his SMUD adjustment.

the contract at a level that approximated market prices at the time of the contract. While the $94 million lump sum payment may have supported the Commission's decision to impute a higher than actual price to the contract, the imputed price was never explained to be tied to "cashing out" the lump sum payment.

Third, the Commission has long recognized that the prudence of a utility decision is to be judged based on the facts and circumstances known or that should reasonably have been known to the utility at the time it made its decision. It is inappropriate to judge the decision based on hindsight or new information. This standard is codified in Utah Code § 54-4-4(a)(ii) & (iii).

In its 2006 Gas Management Cost Application Order, the Commission clearly articulated its prudence standard:

> In conducting a prudence review, we must analyze the decision-making process in light of the circumstance and the facts that the utility knew or reasonably should have known at the time of the decision. We do not substitute our judgment in hindsight for the reasonable decisions made by management, nor do we determine that a reasonable decision is imprudent merely because we conclude that a better, reasonable alternative was available for consideration or action. [18]

When the Commission reviewed the SMUD pricing issue in 1999 and determined that an imputed price of $37 per MWh was appropriate, it necessarily determined that based on information known to or that should have been known to the Company when it entered into the SMUD contract in 1987, $37 per MWh was the appropriate imputed price. That imputation cannot change based on new information or circumstances in 2008 that could not have been known to the utility in 1987 when it entered into the SMUD contract. Accordingly, increasing the imputation violates the well-established prudence standard.

Taking into consideration new information or circumstances to increase the SMUD imputation and decrease the Company's net power costs also results in asymmetrical ratemaking. The Commission has not considered new information or circumstances demonstrating the

[18] *Re Questar Gas* Co., Docket Nos. 04-057-04 *et al*., Order at 27 (Jan. 6, 2006); *See also Re Mountain Fuel Supply Co*., Docket Nos. 91-057-11 and 91-057-17, 1993 WL 217073 Report and Order (Sept. 10, 1993).

increased value to customers of various other Company contracts, such as the BPA peaking contract or the Hermiston gas contract.

Fourth, as just noted, the purpose of the original 1999 imputation was to "find the rate, *contemporaneous with the date of the contract*, to use as the basis for revenue imputation."[19] The Commission did so in that case, and the amount it found appropriate was $37 per MWh. The Commission's decision in this case to dramatically increase the imputed amount is a direct contradiction of its ruling in the 1999 case. Yet the Commission has provided no reasoned basis for a change of position on this issue as required by law. This violates the principles that some aspects of Commission orders in rate cases have the effect of stare decisis[20] and that the Commission may not depart from past practice without enunciating a reasonable basis for doing so and following proper procedures.[21]

Relatedly, the CCS's recommended adjustment is barred by res judicata. Res judicata prevents the relitigation of the same issues by the same parties. Res judicata has no application to ratemaking per se.[22] However, the Utah Supreme Court has recognized that res judicata does have application in administrative proceedings "to enforce repose when an administrative agency has acted in a judicial capacity in an adversary proceeding to resolve a controversy over legal rights and to apply a remedy."[23] This is such an issue.

The appropriate imputed price for the SMUD contract based on what the Company knew or should have known in 1987 is a specific factual determination that was fully litigated in 1999

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[19] *Re PacifiCorp*, Utah PSC Docket No. 99-035-10, 201 P.U.R. 467, 498 (May 24, 2000) (emphasis added).

[20] *Salt Lake Citizens Congress v. Mountain States Tel. & Tel. Co.*, 846 P.2d 1245, 1252 (Utah 1992) ("[T]he Commission's 1969 ruling [in a general rate case] had a binding legal effect under the doctrine of stare decisis.")

[21] *See Williams v. Pub. Serv. Comm'n*, 720 P.2d 773, 777 (Utah 1986) ("[T]he Commission cannot reverse its long-settled position ... and announce a fundamental policy change without following the requirements of the Utah Administrative Rulemaking Act.")

[22] *See Salt Lake Citizens Congress*, 846 P.2d at 1251 ("[R]es judicata has only limited applicability to some agency proceedings such as rate cases where the predominant issue is what constitutes a just and reasonable rate for a future period."); *Utah Dept. of Admin. Services v. Pub. Serv. Comm'n*, 658 P.2d 601, 621 (Utah 1983) (contrasting rulings determining property rights to which res judicata applies "to the lack of finality that exists as to orders fixing public utility rates").

[23] *Id.* (quoting *Utah Dept. of Admin. Services*, 658 P.2d at 621).

based on such past information. It is no more subject to continued litigation and revisiting than would be a decision to approve the transfer of properties from a utility and a corresponding finding that the compensation and benefits received by the utility were fair, just and reasonable. Such decisions are final and are not subject to being revisited when circumstances change in the future as they inevitably will.[24]

For the reasons set forth above, the Commission should reverse its decision substantially increasing the amount of the SMUD imputation and adopt the positions of the Company and DPU maintaining the $37 per MWh imputed price.

2. <u>The Commission Erred in Adopting CCS' Adjustments to GRID to Determine the Four-Year Historical Monthly Sales for the SMUD Contract</u>

The Commission adopted a CCS-proposed adjustment that reduces net power costs by $2.594 million and revenue requirement by $1.137 million related to actual versus modeled revenues from the SMUD contract based on the Commission's acceptance of CCS' assertion that Mr. Falkenberg's use of monthly sales for modeling purposes was more reasonable.[25]

Mr. Falkenberg outlined his rationale for this adjustment to GRID in his Direct Testimony.[26] Mr. Duvall, the Company witness, responded with two fundamental points. First, and most important, Mr. Duvall noted that Mr. Falkenberg's decision to adjust SMUD on the basis of actual data, while completely ignoring the numerous other purchase and sale contracts that are modeled by GRID (in other words allowing the values of *seventy* other contracts – some of which would likely be revenue positive to the Company – to continue to be determined by GRID[27]) is one-sided and unfair. In Mr. Duvall's words, Mr. Falkenberg's method amounts to the "selective deoptimization" of the "GRID commitment logic."[28] Mr. Duvall's second point is consistent with his first: for ratemaking purposes, purchase and sale contracts should either be

[24] *Utah Dept. of Admin. Services*, 658 P.2d at 621.

[25] Order at 23-24.

[26] Exhibit CCS 4D, Falkenberg Direct/39-41, ll. 913-66.

[27] Mr. Falkenberg acknowledges in his surrebuttal testimony that there are more than seventy contract line items in GRID. Exhibit CCS 4SR, Falkenberg Surrebuttal/44, ll. 1162-63).

[28] Duvall Rebuttal/27, ll. 599-603.

modeled on a consistent normalized basis, as GRID does, or all should be based on actual results, but it is inappropriate and unfair to selectively model one contract differently than the others.[29]

Accuracy and fairness demand that if one class of inputs (in this case, the analysis of impact on net power costs of third-party contracts) are determined using a consistent model, then *all* such contracts should be consistently analyzed, otherwise the aggregate results will be unfair, unbalanced and misleading. The Commission's acceptance of CCS' one-off treatment of the SMUD contract is a classic example adopting a single one-sided exception to a standard regulatory practice.[30]

C. The Commission Erred in Excluding Electric Swaps and Indexed Gas Transactions from the Company's Net Power Cost Study

In his reply testimony, Mr. Duvall noted that in the Company's net power cost study filing the Company included gas swaps and indexed electric transactions, but that the Company had inadvertently omitted electric swaps and indexed gas transactions. He noted that the Company conducts these transactions as a hedge against market risk. He also noted that no party had challenged other swaps and indexed transactions that are already in the filing, and that inclusion of these omitted transactions increases system net power costs by approximately $3.2 million.[31]

Mr. Falkenberg opposed the inclusion of these costs, claiming that they were not a correction but an update and that they should not be accepted in the study because the parties lacked time to investigate the transactions and determine their proper regulatory treatment. He

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[29] *Id.* at lines 597-98. Mr. Falkenberg's response to Mr. Duvall was disingenuous at best. First, he avoided the fundamental point of Mr. Duvall's testimony (which was that we should either model it consistently or use actual data for all contracts). Falkenberg suggested that because he used four years of actual data what he was really doing was normalization. But he certainly was not using GRID, which was the means by which the seventy other contract line items were normalized. He claimed that there is "nothing wrong" with the "normalization technique he used." It may well be that Mr. Falkenberg used an acceptable methodology for the SMUD contract, but if indeed it is an acceptable methodology it should be consistently applied. If his technique is accurate, then the same technique should be applied to analyze all similar contracts. The point here is quite simple: it is unfair and inconsistent to arbitrarily pick one large third-party contract from a much larger group of third-party contracts and treat it for regulatory purposes differently than all others are treated.

[30] And incidentally, the contract CCS selectively chose to analyze different than the broader class of contracts just happens to lower the revenue requirement by more than $1 million.

[31] Duvall Rebuttal/11, ll. 226-31.

also criticized the Company for not including these costs in its Supplemental filing after the Commission's test year decision.[32]

The Commission accepted CCS' position on this issue. The Commission should reconsider this issue for the following reasons:

First, the statutory policy of Utah is to allow a utility to establish rates that best reflect the conditions in the rate-effective period, a standard that implies that items omitted by mistake should be given due consideration. That is precisely what was done with many other corrections and post-filing updates that the Commission accepted to reflect information as it became available and allowed the quantification of the most accurate 2008 net power costs[33]—the vast majority of these lowered net power costs.[34] Making such updates is particularly critical, even if it occurs somewhat late in the case, if the statutory policy of reflecting conditions in the rate-effective period is to be achieved. On the other hand, selectively recognizing some updates and corrections while refusing to consider others is directly counter to this clear legislative policy. Given the many corrections and updates whose effect was to decrease net power costs, the public interest in accuracy and fundamental fairness dictates that the Company should be able to make a correction that goes the other direction.

Second, DPU testified at hearing that it had reviewed the gas swaps and indexed electric transactions and found them valid.[35] While the swaps and indexed transactions omitted from the Company's original study dealt with different transactions, they were of precisely the same type DPU found to be reasonable. There is every reason to either accept them as appropriate or to require regulators to engage in an analysis of them.

Finally, Utah law is clear that all reasonable efforts should be made to develop a well-

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[32] Exhibit CCS 4SR, Falkenberg Surrebuttal/38, l. 975-39, l. 94.

[33] *See e.g.*, Order at 44.

[34] *See* RMP Cross Exhibit 14.

[35] *See* Transcript of Proceedings June 2 through 5 of Revenue Requirement Hearing, ("Tr.") 471, ll. 7-13.

matched test period.[36] When numerous updates and corrections going one direction are proposed and considered, it becomes incumbent from a fairness perspective to assure that *all* similar updates and corrections be considered.

In failing to consider the electric swaps and indexed gas transactions, the Commission erred in its duty to make all reasonable efforts to assure a well matched test period that reflects conditions during the rate-effective period.

D. The Commission Erred in Refusing to Allow the Net Power Calculation to Be Updated to Reflect the March 2008 Forward Price Curve

In its rebuttal testimony the Company proposed that the Commission replace its September 30, 2007 official forward price curve with more recent information, *i.e*. its March 31, 2008 official forward price curve. The effect, given rising energy costs, would have increased net power costs by $7.5 million.[37] The Commission, however, rejected the Company's updates stating that they were "untimely" and "not well supported."[38] The Commission's rejection of the updated price curve was erroneous for the following reasons.

Originally the Company filed its case using net power costs information from its September 30, 2007 official forward price curve (Alternative 1). Subsequently, the Company provided updated information using the March 31, 2008 forward price curve (Alternative 2) on May 9, 2008, in keeping with other parties' handling of proposed post-filing updates and corrections reflecting the most recently available information, For example, the CCS proposed an adjustment based on the Commission's April 3, 2008 approval of the Fourth Amendment to the Sunnyside contract which changed the basis for pricing the purchase of power from Sunnyside. Such update reduced net power costs by $3.642 million.[39] The Commission

[36] *Utah Dep't of Bus. Reg. v. Pub. Serv. Comm'n,* 614 P.2d 1242, 1246 (Utah 1980) (Rejecting a single-item rate case based solely on a wage increase: "when *Mountain Fuel* embarked on a new test year, projecting one item of expense, it was impossible to determine whether the rates were just and reasonable without consideration of the other factors involved in making such a determination.").

[37] *Tr. 417, 1. 25-418, l. 3.*

[38] Order at 51.

[39] Order at 44.

accepted the adjustment even though it was based on information that was introduced to the case long after the original case was filed.

The Company introduced its own updates to net power costs in Alternative 2 on May 9, 2008. CCS argued that the Commission should reject the Company's updated information because the Company did not also adjust net power costs related to changes to hydro shaping, which would reduce net power costs by approximately $500,000.[40] The Company conceded that adjustment and other adjustments introduced by other parties (as shown in its Alternative 2 position) contingent on the Commission treating all updates, including its updated forward price curve, symmetrically. However, it appears that the Commission accepted most if not all of the updates that reduced net power costs, irrespective of when they were introduced in the case, and rejected the forward price curve update the Company introduced in Alternative 2, which increased net power costs. The Commission applied the "untimely" standard inequitably to the parties. If parties made adjustments based on evidence introduced after the original filing of the case and those adjustments reduced net power costs, they were accepted. However if the Company proposed adjustment based on evidence introduced after the original filing of the case and those adjustments increased net power costs, they were rejected. In other words, the Commission failed to make symmetrical adjustments to the case, in contravention of established precedent under Utah law where the Utah Supreme Court has stated, "[t]he commission may adjust all figures, revenue, expense, and investment for anticipated changes, but it may not adjust one side or part of the equation without adjusting the other … "[41]

CCS's claim that the Company should have included Alternative 2 updates in the March 2008 test year compliance filing is disingenuous: a compliance filing, by its nature, does not give the compliant company the discretion to make fundamental changes in the filing. The Company believed that including the 2008 forward price curve in the compliance filing would be

[40] Order at 50. Exhibit CCS-4SR, Falkenberg Surrebuttal/41, ll. 1042-1051.

[41] *Utah Dep't of Bus. Reg.*, 614 P.2d at 1248.

inappropriate given that it was directed simply to update its exhibits on the basis of the test period ordered by the Commission.

The conclusion that the new forward price curve is not well-supported is also incorrect. The Company scrupulously developed that price curve using the accepted methodology that it has used for several years for ratemaking, avoided costs, integrated resource planning and resource evaluation as well as financial accounting. Recently the Commission granted pre-approval of the costs of the Chehalis plant based on analysis that incorporated the Company's most recent official forward price curve at the time of the evaluation. The Commission did not find in that case that the forward price curve was "not well-supported." The methodology is discussed in the 2007 Integrated Resource Plan which clearly indicates that the first six years of the electricity and gas forward price curves are from the market. [42]

Finally, the policy enunciated by the Legislature is to see that rates for public utilities reflect, as much as possible, conditions that will exist during the rate-effective period (a period that is much closer in time to March 2008 than to September 2007). And, as noted in the Company's Post Hearing Brief, price curve information (the May 23, 2008 price curve)[43] demonstrates that the March 2008 price curve will be a conservative estimate for the rate-effective period.

The Company, therefore, respectfully requests that the Commission reconsider its decision to reject the 2008 forward price curve, include it in the calculation of net power costs, and set rates based upon it.

E. The Commission Erred in Adopting CCS' Planned Outage Schedule

The Commission's Order adopted, in its entirety, the outage schedule propounded by CCS' Mr. Falkenberg. The Commission stated:

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[42] See *PacifiCorp's 2007 Integrated Resource Plan*, Technical Appendices at 16 (Docket No. 07-2035-01). The Company's forward price curve methodology is so well supported and understood in Utah that it is used for all of the applications cited above with little to no questions, which is consistent with the fact that the market price is the price at which the Company could buy or sell power or natural gas and is not derived from a computer model.

[43] Tr. 418, ll. 6-10.

> We are persuaded by CCS, its planned outage schedule best normalizes planned outages to reflect both actual historic practice and planned outages, while taking into consideration other factors important to scheduling outages. CCS' data shows both the Company and Division proposals schedule fewer outages in May and June than is historically the practice. We are additionally persuaded by CCS' analysis that its planned outage schedule better reflects the costs incurred, on average, in the four years, 2003 through 2007, than DPU or Company proposed schedules. This adjustment reduces total Company net power costs by $10.933 million and Utah revenue requirement by $4.796 million.[44]

In his direct testimony, Mr. Falkenberg challenged the Company's planned outage schedule because it included coal plant outages in the months of January and February.[45] In rebuttal, the Company acknowledged its mistake in including outages in these months, proposed a corrected schedule, and included this adjustment in Alternative 2.[46] In surrebuttal, Mr. Falkenberg continued to press his $11 million outage adjustment on the basis that the Company set outages in early spring and the fall instead of in May and June.[47] At hearing, Mr. Falkenberg testified that the Commission should flatly reject any proposed schedule that included coal plant outages in January and February.[48] He also criticized DPU's proposed outage schedule, claiming that while it had removed all coal plant outages from January, DPU still had outages in February.[49]

In fact, CCS' planned outage schedule submitted by Mr. Falkenberg and adopted by the Commission includes two outages for a total of 19 days in January for the Hayden 1 and 2 coal plants.[50] Mr. Falkenberg admitted that correcting this mistake would require preparation of a new schedule to move the outages from January to another month.[51] The record in this case

[44] Order at 33.

[45] Exhibit CCS-4D, Falkenberg Direct/54, ll. 1331-1333.

[46] Duvall Rebuttal/18, ll. 391-402.

[47] Exhibit CCS-4SR, Falkenberg Surrebuttal/22, ll. 556-568.

[48] Tr. 486, ll. 5-10.

[49] Tr. 484, l. 19- 485, l. 3.

[50] Tr. 488, l. 15- 490, l. 3.

[51] Tr. 490, ll. 11-20.

contains only Mr. Falkenberg's planned outage schedule with January outages.[52] The Commission adopted CCS' schedule which, according to CCS' own testimony, it should have rejected on its face because it contained outages in January.

Even if the record before the Commission did not contain this fatal flaw, the Commission erred in adopting Mr. Falkenberg's planned outage adjustment. While Mr. Falkenberg claims to have adhered to historical schedules, normalized modeling makes this impossible.[53] Attempts to adhere to historical schedules also limit the Company's flexibility to respond to changes in the fleet, plant additions, and changing maintenance demands.[54] Historical schedules do provide a general guide that maintenance should occur in the spring and the fall, a practice that was fully reflected in the Company's revised outage schedule.[55]

Finally, in the Company's 2001 rate case, the Commission rejected an adjustment to change the schedule of planned maintenance because of the "potential to influence future performance of maintenance and the resulting reliability of the system in a manner adverse to ratepayers."[56] These exact concerns are presented by Mr. Falkenberg's adjustment in this case, and the Commission ignored its own precedent by adopting Mr. Falkenberg's recommendation.

RETURN ON EQUITY

F. The Commission Erred in Setting the Company's ROE at 10.25%.

1. The Commission erred in failing to provide the basis for its decision on ROE.

[52] During the hearing, the Commission served a data request asking for net power cost workpapers before the close of the hearing. While the Company responded to this request in a timely manner, CCS delayed its response to this data request until Monday, June 10, 2008. In its response, CCS included a proposed correction to the mistake in its planned outage schedule moving the outages proposed by Mr. Falkenberg from January to another month. This correction was clearly outside the scope of the Commission's data request and constituted an indirect and improper attempt to supplement the closed record in this case. The Commission properly ignored this untimely and improper submission from CCS.

[53] Tr. 414, ll. 13-23.

[54] Tr. 414, l. 24- 416, l. 5.

[55] Tr. 414, ll. 20-23.

[56] RMP Cross Exhibit 14 at 14.

The Utah Supreme Court grants substantial deference in reviewing the Commission's factual findings.[57] That deference, however, is not unbounded. As explained by the Supreme Court in *Mountain States Legal Foundation v. Public Service Comm'n of Utah*, it is the responsibility of the Court to determine whether the Commission acted outside of its jurisdiction, in excess of its lawful powers, or in a manner that is arbitrary and capricious.[58] Accordingly, the Court found that "the Commission must make findings of fact which are sufficiently detailed to apprise the parties and the Court of the basis for the Commission's decision."[59]

In *Milne Truck Lines, Inc. v. Public Service Comm'n of Utah,* [60] the Utah Supreme Court provided the Commission with clear direction as to the level of detail required to support its findings. First, the Court explained that the Commission must make findings of fact on all necessary ultimate issues under the governing statutory standards.[61] In addition, the Court emphasized the critical necessity of subsidiary findings, stating:

> It is also essential that the Commission make subsidiary findings in sufficient detail that the critical subordinate factual issues are highlighted and resolved in such a fashion as to demonstrate that there is a logical and legal basis for the ultimate conclusions. The importance of complete, accurate, and consistent findings of fact is essential to a proper determination by an administrative agency. To that end, findings should be sufficiently detailed to disclose the steps by which the ultimate factual conclusions, or conclusions of mixed fact and law, are reached.[62]

The Commission's order on ROE fails to fulfill these requirements. In this case the Commission was presented with a full record detailing the parties' competing positions on ROE. The parties presented divergent views on the appropriate models to be employed to produce ROE, as well as the inputs to and results of the modeling. In all, the parties provided the Commission with 266 pages of testimony on ROE, and supported by 37 pages of exhibits. In

[57] *Williams v. Mountain States Tel. & Tel. Co.*, 763 P.2d 796, 798–99 (Utah 1988).

[58] *Mountain States Legal Found. v. Pub. Serv. Comm'n of Utah*, 636 P.2d. 1047, 1051 (Utah 1981).

[59] *Milne Truck Lines, Inc. v. Pub. Serv. Comm'n of Utah*, 720 P.2d. 1373, 1378 (Utah 1986).

[60] *Id.*

[61] *Id.*

[62] *Id.*

addition, the witnesses provided substantial live testimony at hearing, much of it on cross-examination. Nevertheless, despite the full and contested record, the Commission's Order on ROE consists of brief summaries of the parties' positions, and then the following statement:

> Through our consideration of the financial models *as we deem appropriate*, with the inputs or components and weighting *we believe reasonable*, and weighing all of the expert financial testimony and other witness testimony received, we find and conclude that a rate of return on common equity of 10.25 percent is reasonable.[63]

The Order does not explain the Commission's reasoning or how the Commission exercised its expert judgment. There is no rationale as to (i) why a higher or lower number would be unreasonable; (ii) what model or formula was employed; (iii) why a particular model or models were employed; (iv) what inputs were accepted or rejected; (v) whether and how the Commission considered other elements of its Order and the Order in its totality in determining the number; and (vi) how the Commission arrived at 10.25%.[64] Rather, in this case the Commission merely alludes to undisclosed models that it deems appropriate and unspecified inputs, components and weightings that it believes reasonable and, without any further explanation, reaches what appears to be the arbitrary conclusion that 10.25% is reasonable. The Order is insufficient to inform the parties[65]—or a reviewing court—as to the basis for the Commission's finding, and is therefore arbitrary and capricious.[66] Properly and fairly analyzed, the record in this case, particularly in light of the cost recovery risk the Commission creates by its order, supports a higher ROE for the Company. The Commission should therefore reconsider

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[63] Order at 18.

[64] This failure to explain its decision is in stark contrast to the detailed explanations of ROE decisions that the Commission has included in past orders. *See, e.g., Re Questar Gas Company,* Docket No. 02-057-02, Order at 34 (Dec. 30, 2002).

[65] The Commission's failure to provide any real explanation for its ROE ruling makes it extremely difficult for the courts to evaluate the decision on review. It also provides the parties with no guidance for future rate cases. This issue is best understood in light of the controversy between the parties as to which companies should be considered proxies for RMP for the purposes of their DCF analyses. DPU specifically requested that the Commission "specify what companies it accepts as proxies." DPU Exhibit 2.0 SR, Peterson Surrebuttal/7, ll. 119-20.

[66] *See also, Mountain States Legal Found.*, 636 P.2d. at 1051 (Commission expertise alone is not an adequate basis upon which ultimate findings as to reasonableness of rates and classifications of customers may be based).

its Order, provide a clear justification for its decision and increase the ROE awarded in this case to 10.75% as requested by the Company.

2. The Commission's Decision Conflicts with Its Own Policies without Explanation.

Section 63G-4-403 of the Utah Code provides relief from an agency decision when the agency action is "contrary to the agency's prior practice, unless the agency justifies the inconsistency by giving facts and reasons that demonstrate a fair and rational basis for the inconsistency." Consistent with this statute, the Courts will set aside a Commission order that departs from past policy without providing an explanation. In this case the Commission provided no explanation whatsoever as to how it arrived at its decision to award a 10.25% ROE. Nevertheless, a review of the evidence demonstrates that it could not have followed its past policy.

Over the past decade the Commission has developed a consistent approach to determining ROE for Utah's regulated utilities. This approach was comprehensively described in the 2002 Questar rate case order[67] where the Commission provided clear guidance as to its method for determining ROE. In particular, the Commission stated that, "…among financial models, we continue to favor . . . the DCF [Discounted Cash Flow] model."[68] The Commission explained: "The theory on which [the DCF] model is based is widely accepted, and the information required for the model inputs is readily and publicly available."[69] The Commission then carefully explained how that model was used to produce a range of results using various metrics for companies determined to be proxies,[70] and the method by which the Commission

[67] *Re Questar Gas Company*, Docket No. 02-057-02, Order (Dec. 30, 2002) [hereinafter "Questar Order").

[68] In the present case, there were several versions of the DCF model sponsored by the parties, *i.e*., single stage constant growth models and two stage non-constant growth models. Thus, even if the Commission continues to "favor" the DCF model, a question left unaddressed in the present case is which form of the DCF model does the Commission "favor" and why.

[69] *Id*. at 20.

[70] *Id*. at 21.

determines the midpoint of the accepted range, which in turn serves as the presumptive basis for the adopted ROE, absent risk factors.[71]

On the other hand, in the Questar Order the Commission was equally clear in its rejection of the Capital Asset Pricing Model ("CAPM"). The Commission explained that "CAPM has always been particularly problematic for this Commission because of both theoretical and practical shortcomings."[72] In the end, the Commission flatly concluded: "We cannot rely on CAPM."[73]

The witnesses in this docket provided three basic types of models to support their respective ROE recommendations: DCF, CAPM, and equity risk premium analyses. Overall, the DCF evidence and the equity risk premium evidence supported an ROE significantly higher than that adopted by the Commission.

First, Company witness, Dr. Hadaway's updated DCF results, set forth in rebuttal exhibit SCH-R-7, support a range (Group Average to Group Median) of ROE outcomes, from 10.4 to 11.3%. The constant growth model using analysts' growth rates, a model that "is about as traditional as you can get," produces a range of 10.0% to 10.8%.[74] Dr. Hadaway's constant growth model using long-term GDP produces returns in the range of 11.2% to 11.3%. Dr. Hadaway's two-stage DCF model produces a range of 10.9% to 11.0%.[75]

DPU DCF results sponsored by Mr. Peterson and shown on DPU Exhibit 2.5 discloses a range of 10.03% to 10.69%, with a midpoint of approximately 10.36%.[76] However, DPU

[71] *Id*. at 25, 34-35.

[72] *Id*. at 33.

[73] Questar Order at 34 ("[W]e cannot rely on the CAPM. In addition to this Commission's previous concerns with this model, which are not successfully addressed on the present record, we now have the unrebutted assertion that the estimates of the variable beta are of no statistical significance.").

[74] The Transcript of Proceedings of the May 20, 2008 Rate of Return Hearing ("ROR Tr."). 35, ll. 3-4. Even if PPL Corporation was excluded from Dr. Hadaway's comparable group as an outlier as suggested in DPU's cross-examination, Dr. Hadaway's DCF results would be only slightly lower (*i.e.*, a range of 10.2% to 11.1%), and still support Dr. Hadaway's recommendation. PPL Corporation has no impact on Dr. Hadaway's equity risk premium results.

[75] *Id.* at 4.

[76] ROR Tr. 86, ll. 11-18. While this summary also includes results using a 10-year historical growth rate, Mr. Peterson excluded these results from consideration. ROR Tr. 86; ll. 3-6. This summary also includes DCF

Exhibit 2.7(b) contains a calculation error[77] for the weighted average growth using one month prices, resulting in an understatement of these numbers.[78] Correcting this error, as set forth in RMP Cross Exhibit 3 (ROR), raises the weighted average growth results from 10.03% to 10.10%.[79] This, in turn, increases Mr. Peterson's DCF range from 10.1% to 10.69%, with a mid-point of approximately 10.4%.[80] CCS witness Mr. Lawton's DCF analysis did produce a lower range. His surrebuttal "updates" to Dr. Hadaway's DCF analyst growth rate and GDP growth rate models produce returns of 10.17% and 10.22%, respectively.[81] However, the Commission did not express that CCS' DCF analysis was superior to that of the Company or DPU. Thus, while Mr. Lawton's DCF numbers might define the very bottom of the DCF range, they could not be used to explain a 10.25% result in the face of the significantly higher numbers produced by all of the other DCF analyses presented.

Dr. Hadaway, Mr. Peterson and Mr. Lawton also performed equity risk premium analyses. Dr. Hadaway's equity risk premium analysis, that incorporates the current market required yield on single-A public utility debt, indicates a cost of common equity of 10.73% is required in the current environment. Mr. Lawton's risk premium analysis also supports a higher return on equity than his 9.85% recommendation. His surrebuttal "update" to Dr. Hadaway's risk premium analysis produces a 10.30% return. This analysis, however, assumed a single-A corporate bond yield of 5.5%. At hearing, Mr. Lawton admitted that his Exhibit CCS 3.1 SR, entitled Long Term Interest Rate Trends, reflected no annual yield as low as 5.5% at any point between 1993 through 2007. Mr. Lawton also admitted that using the most current single-A rate of 6.29% from April 2008—which would address his concerns about use of forecast data—

results using dividend growth rates only, an approach that this Commission has never used. ROR Tr. 87, l. 23-Tr. 88, l. 2.

[77] The errors in DPU's exhibits make reliance on this analysis questionable.

[78] ROR Tr. 91, l. 9-92, l. 25.

[79] ROR Tr. 92, ll. 22-25.

[80] ROR Tr. 93, ll. 1-15.

[81] CCS Exhibit 3.3 SR Lawton Surrebuttal Rate of Return/1.

would produce an equity risk premium return estimate of 10.72%. Again, this evidence supports a higher result than the 10.25% ROE in the Commission's Order.

In making this argument, the Company is hindered by the Commission's failure to provide *any* rationale for its ROE determination—let alone an indication upon which models it relied. That said, there does not appear to be any combination of DCF or equity risk premium inputs included in the record by any party that will yield a 10.25% ROE point estimate. Because all of the valid DCF and equity risk premium modeling presented to the Commission produce significantly higher ROEs than 10.25%, the parties must conclude that the Commission had to be relying on the CAPM in order to somehow reach the 10.25% found in its ruling. This created two errors: (1) The Commission failed to explain why it has rejected its prior policy against CAPM; and (2) the Commission failed to explain which CAPM model it used, what weight it gave to the model and how it combined the results of that model with the results of other models in the record.

3. <u>The Commission's Decision on ROE is Inconsistent with Commission Precedent on Risk Factors.</u>

Under *Hope*[82] and *Bluefield*[83], the Commission must allow utilities a rate of return that provides investors an opportunity to earn a return on an investment devoted to public service comparable to the return the investor might earn in other investments of similar risk.[84] Thus, an analysis of the risk to which a utility is subject is central to the Commission's inquiry on ROE.[85] In the Questar Order, described above, the Commission explicitly addressed the role that business and regulatory risk play in its evaluation of ROE.[86] In so doing, the Commission made clear its view that mechanisms that reduce regulatory risk, such as Questar's "pass-through treatment of gas costs, acceptance of gas supply risk-hedging techniques [and] a weather

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[82] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

[83] *Bluefield Water Works v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923).

[84] *Hope*, 320 U.S. at 603; *Bluefield Water Works*, 262 U.S. at 692-93.

[85] *See* Questar Order at 19.

[86] *Id*. at 22-26.

normalization clause . . ."[87] all reduce the overall amount of risk facing utilities which have such mechanisms,[88] all other things being equal.[89] The Commission affirmed this view in its order in the 2007 Questar rate case, stating that "We continue to believe that the CET [conservation enabling tariff] affects the Company's operations through a reduction of business risk."[90]

In light of this precedent, as well as a comparison of the relative regulatory and business risks facing Questar and RMP, the Commission erred in failing to give weight to the business risk testimony of Mr. Richard Walje corroborating RMP's proposed 10.75% ROE. The Commission incorrectly concluded that the business risks to which Mr. Walje testified were not unique to RMP. A decision to award RMP an ROE just 25 basis points above that awarded to Questar in its 2007 rate case[91] suggests a one-sided application of business risk factors to arbitrarily reduce Questar's ROE, but not to support an ROE for RMP of at least at the mid-point of recognized DCF and equity risk premium model results or higher.

RMP faces production and transmission business risk and it operates without a fuel adjustment clause or revenue decoupling mechanism. Thus, compared to Questar (and most electric utilities in the comparable group), RMP faces very significant recovery risks for power costs—which constitute its single largest business expense item. Indeed, in addition to the fundamental differences between an integrated electric utility and a distribution-only gas utility, as well as the unique risks described by Mr. Walje, the degree of regulatory risk faced by the Company is heightened by the Commission's decision in this case setting the Company's power costs in rates at a level far lower than its actual costs—thereby disallowing a substantial percentage of these expenses. Given this fact and the other business risks faced uniquely by RMP (and not by other Utah utilities), the Commission's decision to set the Company's ROE at

[87] *Id* at 24.

[88] *Id*. at 22-26.

[89] There are many facets to a public utility's business/regulatory risk. While the existence of the pass through items mentioned here may tend to reduce a utility's business/regulatory risk, there may be other considerations that restore the utility's fundamental risk/return relationship to its previous level.

[90] *Re Questar Gas Company, Docket* 07-057-13, Order at 14 (June 27, 2008).

[91] *Id.*

10.25% was in error. RMP has been substantially prejudiced by the Commission's ROE decision. For this reason, the Commission should reconsider and increase the ROE awarded to RMP and explain the rationale employed to reach that award consistent with the Commission's past precedent.

GENERATION OVERHAUL EXPENSES

G. The Commission Erred in Failing to Account for Inflation in Determining the Generation Overhaul Expenses.

In setting rates, the Commission must determine amounts the Company will expend during the period the rates will be in effect.[92] Thus, the Commission's failure to account for inflation by escalating four-year-old expenses to current dollars in determining generation overhaul expenses was arbitrary and capricious and unsupported by substantial evidence.

In its rebuttal case, the Company sought generation overhaul expenses of $34.92 million.[93] This amount has two components: (1) $31.04 million calculated using the overhaul expenses of the four-year historical period adjusted for inflation (or "escalated" to current dollars), and (2) $4.53 million in generation overhaul expenses for the Currant Creek and Lake Side generating plants (less $0.65 million for the Lake Side generating plant which amount was contained in the Incremental Generation O&M adjustment).[94]

In its Order, the Commission approved an amount for generation overhaul in the test period of $32.8 million.[95] To arrive at this amount the Commission used a four-year historical average of generation overhaul expenses,[96] and also approved the generation overhaul expenses associated with the Currant Creek and Lake Side generating plants. However, the Commission

[92] *Mountain Fuel Supply Co v Pub. Serv. Comm'n.* 861 P.2d 414, 422 (Utah 1993); Utah Code § 54-4-4(3)(a).

[93] Order at 80.

[94] *Id.*

[95] Order at 82.

[96] Order at 81-82.

refused to accept the any adjustment of historical expenses to account for inflation.[97] In doing so the Commission clearly erred.

The Company provided substantial evidence to support this methodology and there is no reasonable basis to exclude inflation from the overhaul expenses. Company witness Steven McDougal testified that costs incurred in previous years must be escalated to account for inflation because the value of the dollar in the test period will be greater than the value of the dollar in the year the expense was actually incurred.[98] In other words, if the Company incurred an expense four years ago it would cost more in test-year dollars to pay the same expense. Failing to account for inflation understates the amount of overhaul expenses the Company can expect to incur in the future.[99] Thus, the escalation sought by the Company addressed solely the issue of inflation. This is a separate and distinct issue from the variance in the overhaul costs for each of the four years in the historical analysis.

The only evidence presented in opposition to the Company's position was from CCS witness DeRonne, who testified that escalation was inappropriate because of the year-to-year variations in the overhaul expenses.[100] However, this analysis is faulty because it addresses the normalization issue and not the escalation issue. Ms. DeRonne offers no evidence as to why the escalation should not be used other than simply stating that the overhaul expenses vary from year-to-year.[101] However, Mr. McDougal testified that utilization of the four-year historical average was intended to address this variation issue because the average normalized the annual expenses over the four-year period. This effectively accounted for the annual variations in overhaul expenses.

[97] Order at 82.

[98] McDougal Rebuttal/6, ll. 117-119.

[99] McDougal Rebuttal/6, ll, 120-127, l. 122.

[100] Tr. 609, l. 23-610, l. 4.

[101] *Id.*

Ms. DeRonne also testified that escalation is normally considered specifically to address the fact that the value of the dollar generally declines each year because of inflation.[102] Ms. DeRonne even acknowledged that during the historical period inflation had indeed occurred.[103] However, again, she provided no evidence as to why escalation is inappropriate in this case other than arguing that the year-to-year expenses differ.

The historical average is used to account for variations in overhaul expenses from year-to-year. Escalation, on the other hand, is not intended to address the year-to-year variance in the expenses incurred nor does it do so. Escalation accounts for the fact that maintenance performed four years ago would cost more if performed today because the value of the dollar has decreased in the ensuing four-year period. On cross examination, Ms. DeRonne conceded this distinction.[104] Therefore, in analyzing costs which were incurred four years ago and comparing those costs to costs incurred in the most recent year in the historical period or the test year, an escalation factor must be used to address the fact that inflation has decreased the value of the dollar over time. Mr. McDougal's testimony outlines the difference between the escalation and the historical average and argues persuasively that if an historical average is used then an escalation factor must also be used.

The Commission should reconsider its decision to not utilize an escalation factor to account for inflation because the Company provided substantial evidence in support of its position and no evidence was provided to rebut that Company evidence. Therefore, there is no reasonable basis for the Commission to exclude inflation from its calculation of the generation overhaul expenses.

PROPERTY TAXES

H. The Commission Erred in Accepting CCS' Property Tax Recommendation.

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[102] Tr. 603, ll. 23-24 and Tr. 610, l. 14.

[103] Tr. 611, ll. 1-2.

[104] Tr. 611, ll. 1-2; Tr. 609 ll. 23-24.

In its Order, the Commission accepted CCS' recommendation and accordingly reduced the total Company property tax expense by $6.929 million and Utah revenue requirement by $2.988 million.[105] This decision is unsupported by the evidence in the case and is therefore arbitrary and capricious.[106]

The Company's rate filing included a property tax estimate of $79.7 million.[107] This estimate represented an approximate $10.6 million increase over the Company's actual 2007 property tax expense.[108] The Company based this estimate on the significant increase in the value of the Company's operating property and earnings that taxing jurisdictions consider when calculating the market value on which the Companies tax liability is determined.[109] The Company's unrebutted evidence showed that it received 2008 property tax assessments in four of the ten states in which the Company operates that equaled a $901 million increase in assessed property over the 2007 level.[110]

CCS countered with a recommended a property tax expense of $70.7 million.[111] As explained in her written testimony, CCS witness Donna DeRonne arrived at this estimate using a rather unorthodox method. Instead of estimating the value of the Company's property subject to taxes and multiplying that value by the applicable tax rates—the method taxation experts use—Ms. DeRonne simply looked at the Company's property tax increase from 2006 to 2007 (2.36%) and applied that increase to the Company's actual 2007 property tax expense.[112] As explained by Company witness Norman Ross, this method bears no relationship to how states actually assess property taxes[113] and incorrectly ignores the substantial increase in the Company's property

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[105] Order at 78.

[106] *See Milne Truck Lines, Inc.*, 720 P.2d. at 1378.

[107] Tr. 161, ll. 13-19.

[108] Tr. 161, ll. 20-24.

[109] Order at 77.

[110] Tr. 166, l. 21-167, l. 4; Tr. 599, ll. 1-18.

[111] Exhibit CCS-2SR, DeRonne Surrebuttal/27, ll. 600-602.

[112] Exhibit CCS-2D, DeRonne Direct/34, ll. 750-756.

[113] Tr. 162, ll. 16-22. Tr. 162, l. 19-163, l.1.

values and earnings that are subject to tax.[114] As a result, taking into account the unrebutted evidence of the substantial increase in the Company's property subject to the tax, Ms. DeRonne's method assumes a tax rate of only .18%—which even Ms. DeRonne appeared to agree was unreasonable.[115]

Despite the weakness in the CCS evidence, the Commission stated that it found CCS' position on property taxes "persuasive,"[116] and reduced the total recommended property tax to $70.736. This finding is without substantial evidence to support it.

First, it should be noted that the Commission seemed to accept the fact that the Company's property subject to taxes had increased by approximately $900 million. However, the Commission stated that "some of these investments, such as those related to the installation of pollution control equipment, *could be* subject to either property tax exemptions or special taxing situations."[117] Based on this speculation, the Commission implicitly found that the Company's increase in property value over 2007 would be taxed at the rate of .18%—a number even Ms. DeRonne could not endorse.

Based upon the record, the Commission's property tax estimate appears to be based on pure speculation. Accordingly there is no support for the Commission's property tax estimate. The Commission should therefore reconsider its decision.

TEST YEAR DECISION

I. The Commission Erred in Selecting a Test Period that Does Not Best Reflect the Conditions the Company Will Encounter During the Rate-Effective Period.

Utah Code Ann. § 54-4-4(3)(a) states that in determining just and reasonable rates, the Commission "shall select a test period that, on the basis of evidence, the commission finds best reflects the conditions that a public utility will encounter during the period when the rates determined by the commission will be in effect." In addition, in the Company's 2004 rate case,

[114] Tr. 164, ll. 4-11.

[115] Tr. 604, ll. 7-20.

[116] Order at 77.

[117] *Id*.

the Commission identified nine factors that should be considered in order to meet this standard: "the general level of inflation, changes in the utilities investment, revenues or expenses, changes in utility services, availability and accuracy of data to the parties, ability to synchronize the utility's investment, revenues and expenses, whether the utility is in a cost increasing or costs declining status, incentives to efficient management and operation, and the length of time the new rates are expected to be in effect."[118]

In support of its proposal for a 12 month test period ending on June 30, 2009, the Company offered a comprehensive analysis of the evidence in light of the statutory mandate and of the above factors. Had the Commission properly considered the Company's evidence in light of these criteria, as well as the statutory mandate, the Commission would have accepted the Company's proposed test period.

On February 14, 2008, the Commission issued its order on the test period ("Test Period Order") rejecting the Company's proposed and adopting the 2008 calendar-year test period proposed by the UAE Intervention Group ("UAE"). In so doing the Commission explicitly stated that its decision was based upon "an evaluation and balancing" of the factors discussed in the 2004 rate case order.[119] However, while noting that "[t]hese factors are employed by DPU and UAE in the formation of their positions . . .."[120] the Test Period Order makes no reference whatsoever to any testimony presented by the Company.[121]

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[118] *Re* PacifiCorp, 2004 WL 2656541 (Utah P.S.C. October 20, 2004)

[119] *Re Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah*, Docket No. 07-035-93, Order on Test Period at 2 (February 14, 2008).

[120] *Id.*

[121] The Commission did state: "With respect to the nine factors, witnesses support use of a forecasted test year based primarily on changes in the utility's investment, revenues or expenses; the ability to synchronize the utility's investment, revenues and expenses; and the belief the Company is in a cost increasing status. Company testimony provides evidence of changes in utility investment, the bulk of which is projected to occur prior to year-end 2008." *Id*. at 2-3. It is unclear which witnesses in support of a forecasted test year the Order on Test Period refers to, and the Company would note that this treatment, even if the Commission is referring to Company witnesses, is in stark contrast to the analysis the Order on Test Period provides of UAE and UIEC witness testimony, and further supports the Company's argument that its testimony was not properly considered by the Commission.

In fact, the testimony of Company witnesses Rich Walje and Steven McDougal provide strong support for the Company's proposal on each of the criteria. In particular, their testimony established that the Company's proposed test period:

1. Satisfies the matching principle (Criteria 1);[122]
2. Allows for the synchronization of the utilities revenues, investments and expenses (Criteria 6);
3. Is most appropriate given that the Company is in a growth cycle during a period of rising costs (Criteria 2 and 7);[123]
4. Is most appropriate given the fact that the Company is in an expansion period, and that its growth forecasts are corroborated by government data (Criteria 3 and 5);[124]
5. Accounts for changes in utility service (Criteria 4);[125]
6. Will provide incentives to efficient management (Criteria 8);[126]
7. Is most appropriate for the length rates are expected to be in effect—in particular given the dramatic growth in new investments (Criteria 9).[127]

The evidence presented by the Company in the Test Period hearing clearly supports the selection of a test period ending June 30, 2009 because it "best reflects the conditions [the Company] will encounter during the period when the rates determined by the commission will be in effect." Notably, DPU and CCS both agreed with the Company's position on which test period most accurately reflected the conditions the Company will encounter during the rate effective period. The Commission's selection of a calendar year 2008 Test Period, without considering the testimony the Company presented on each of the nine factors that should be considered in selecting a test period, denies the Company the due process guaranteed to it by

[122] McDougal Direct/6, l. 125-8, 1. 182.

[123] McDougal Direct/22, l. 508-25, l. 566; Walje Direct/4, l. 69-10, l. 212.

[124] Walje Direct/8, l. 167-9, l. 195.

[125] McDougal Direct/33, l. 744-36, l. 799.

[126] Zenger Test Period Direct/17, ll. 335-47; Higgins Test Period.Direct/17, l. 7-18, l. 21.

[127] McDougal Direct/6, l. 125-8, l. 182..

Utah Code § 54-4-4(3)(a).[128] The Commission should reconsider its decision to require a 2008 calendar year test period and grant rate relief based on costs that the Company will incur during the rate-effective period commencing August 13, 2008.

ETO FUNDING OF GOODNOE HILLS

J. The Company Interprets the Commission's Silence in Regard to the Energy Trust of Oregon ("ETO") Funding of Goodnoe As Rejecting Renewable Energy Credits from Goodnoe

The Commission failed to state whether or not the State of Utah will elect to keep its allocated share of renewable energy credits ("RECs") from the Goodnoe Hills wind plant ("Goodnoe"). ETO has pledged approximately $4.5 million in exchange for Goodnoe RECs being allocated to Oregon customers after the first five years of Goodnoe operations. The State of Utah has the option to keep its allocated share of RECs from Goodnoe if it pays $1.9 million for Utah's portion of the amount pledged by ETO, part of which was included in this case as an offset to Utah's revenue requirement. As described in the Company's rebuttal testimony,[129] the Company reduced Utah's revenue requirement by $359,000 in this rate case to reflect ETO credits. Since the Commission did not add the $359,000 to the Company's revenue requirement associated with Goodnoe, the implication is that the Commission has elected not to displace the ETO funding to keep Utah's allocated share of the RECs from Goodnoe after the first five years

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[128] The evidence presented by UAE on which the Commission relied did not go to the issue of whether the 2008 test period better reflected conditions in the rate-effective period than the test period proposed by the Company and accepted by DPU and CCS. The evidence presented by UAE witness Higgins was simply that a forecast closer in time is more reliable. However, Mr. Higgins' testimony did not analyze whether the Company's forecasts for a test period ending June 30, 2009 were unreliable, let alone demonstrate that they were.

UAE and UIEC also argued that the Commission should not move immediately to a test period ending 20 months after the date of the rate application to balance ratepayer and shareholder interests and in the interests of gradualism. Ratepayer and shareholder interests are appropriately balanced when the utility is permitted to recover its reasonable costs of providing service, not when its rates are set below its reasonable costs because they are based on a period prior to the rate-effective period. The concept of gradualism may have application to cost of service and rate spread issues, but it has no application to revenue requirement. The purpose of the amendment to section 54-4-4 to allow the use of fully forecast test periods was to allow utilities a reasonable opportunity to earn a reasonable rate of return rather than constantly earning less than a reasonable rate of return because rates were set based on historic costs.

[129] Tallman Rebuttal/19, ll. 398–481.

of operation. Because the Commission failed to expressly state as much, the Company requests that the Commission clarify its intent on this issue.

EXCLUSION OF SUR-SURREBUTTAL EVIDENCE

K. The Commission Erred in Excluding the Company's Live Sur-surrebuttal Testimony and Exhibits.

Due process, and the Commission's own rules, requires the Commission to allow the Company a fair opportunity to rebut evidence presented against it. Accordingly, the Commission erred in refusing to allow the Company to make *even an offer of proof* of its sur-surrebuttal evidence.

First, and foremost, in *Mountain Fuel Supply Co. v. Public Service Comm'n of Utah*, the Utah Supreme Court made clear that the Commission must consider all relevant evidence offered by the utility. In that case, Mountain Fuel requested that it be allowed to introduce evidence related to a future test year. While in that case the court upheld the Commission's rejection of the evidence on the grounds that Mountain Fuel was unable to establish relevance, in so doing, it enunciated a clear principle: "[I]f a utility makes a sufficient proffer [of the evidence], the Commission [is] obligated to accept the evidence and make the necessary factual findings."[130]

The Commission's rule on the order of the presentation of evidence also implies that the applying party (in the instant case the Company) is entitled to present sur-surrebuttal evidence when the intervening parties submit surrebuttal testimony. Utah Administrative Rule R746-100-10.J allows for the applicant or petitioner to present its case in chief and rebut any evidence submitted by the intervening parties. Although the rule appears to contemplate just one response and one rebuttal, it is reasonable to assume that in a case where the intervening parties are allowed to submit surrebuttal testimony the rule allows for the Company to rebut that surrebuttal testimony with sur-surrebuttal testimony.

In addition to the administrative rule implicitly authorizing sur-surrebuttal testimony, Utah statutes also expressly state that in an administrative hearing "[t]he presiding officer shall

[130] *Mountain Fuel Supply Co.*, 861 P.2d at 424.

afford to all parties the opportunity to present evidence, argue, respond, conduct cross-examination, and submit rebuttal evidence."[131] Indeed, the Commission has a long-established practice of allowing parties to present live rebuttal to any new material in the last round of written testimony filed in a case.[132]

In this case, the Company's sur-surrebuttal testimony and exhibits should have been admitted into the record because they were relevant and notice was provided prior to the hearing of the intent to present the evidence. Specifically, all parties had ample notice of the Company's intent to provide sur-surrebuttal. At the December 20, 2007, Scheduling Conference the parties agreed that the Company would be allowed to present live sur-surrebutal testimony because the deadline for filing the surrebuttal testimony was only five business days before the hearing of June 2, 2008.[133] Moreover, the Company filed notice of its intent to present live sur-surrebuttal testimony on May 27, 2008—just two business days after receiving the parties' May 23 surrebuttal testimony. In addition, on May 30, 2008, the Company provided every party to the docket with a list of the live sur-surrebuttal witnesses and the exhibits that would accompany the live testimony. This witness list and exhibits were also provided to the Commission on June 2, along with the response to objections to the sur-surrebuttal filed by CCS. In that response, the Company explained that the sur-surrebuttal exhibits and testimony were necessary in order to rebut new evidence raised on surrebuttal.[134]

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[131] Utah Code § 63G-4-206(1)(d).

[132] For example, in the May 20, 2008 hearing on rate of return in this case, the Commission allowed live sur-surrebuttal testimony.

[133] Tr. 24, ll. 1-5. In addition to the agreement to allow live sur-surrebuttal testimony at the June 2, 2008, hearing, the parties also agreed to a similar allowance for the rate of return phase of the hearing. This hearing was held on May 20, 2008, and no party objected to the presentation of live sur-surrebuttal testimony. That hearing also included the offer and receipt of sur-surrebuttal exhibits. The allowance of live sur-surrebuttal evidence at the May 20, 2008, hearing was the product of the same agreement that applied to the June 2, 2008, hearing. The December 27, 2007, Scheduling Order contained identical language for the May 20th and June 2nd hearing dates with respect to the filing of surrebuttal testimony and the order lacked explicit permission to present sur-surrebuttal testimony for both hearings. But, the Commission allowed live sur-surrebuttal testimony at the May 20th hearing and refused to allow live sur-surrebuttal testimony at the June 2nd hearing.

[134] *Re Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah*, Docket No. 07-035-93, Rocky Mountain Power's Response to Objection to Sur-Surrebuttal Testimony and Exhibits at 3-4 (June 2, 2008).

Furthermore, the evidence the Company sought to introduce was highly relevant. In this case, CCS submitted over one hundred pages of surrebuttal testimony and eight new exhibits on May 24, 2008. Part of the surrebuttal testimony was fifty-five pages and seven exhibits from CCS witness Falkenberg. His testimony—as well as the testimony of CCS and DPU witnesses, Jamie Dalton, Helmuth Schmidt and Donna DeRonne—raised new issues and arguments which the Company had the right to rebut through sur-surrebuttal testimony.

Despite the ample notice and the clear relevance of the materials of the Company's planned testimony and exhibits, the Commission upheld CCS' objections and refused to allow the Company to submit any sur-surrebuttal testimony or exhibits.[135] The Commission also refused to allow the Company to proffer the proposed sur-surrebuttal testimony and exhibits into the record or otherwise make an offer of proof.[136] Indeed, the Commission went so far as to remove from the Commission website the witness list and exhibits which had been filed by the Company with its June 2nd response.[137] The Commission only allowed the cover letter to remain.[138] As a result, there is no evidence in the record upon which a court could determine whether or not the Commission should have considered the sur-surrebuttal evidence.

The decision to limit the Company's ability to present live sur-surrebuttal testimony is particularly unjust given that the other parties' surrebuttal testimony created new issues which the Company has not had a previous opportunity to address.[139] In reviewing the Commission's order there are several instances where the Commission makes reference to a failure by the Company to rebut a piece of evidence or counter an argument by CCS. The Company's sur-surrebuttal testimony and exhibits very well may have addressed these alleged deficiencies; however, an offer of proof was not allowed so the record is incomplete. For this reason, the only

[135] Tr. 2 8, ll. 7-10.

[136] Tr. 31, ll. 20-23.

[137] *Id.*

[138] *Id.*

[139] Tr. 20, l. 4.

cure for the Commission's error is to reopen the record and allow for a rehearing in order to allow the rejected exhibits and live testimony into the record

III. CONCLUSION

For all of the above reasons, the Commission should grant review, reconsideration and rehearing on the above issues, as described herein.

RESPECTFULLY SUBMITTED: September 2, 2008.

Mark Moench
Sr. Vice President and General Counsel
Rocky Mountain Power

CERTIFICATE OF SERVICE

I hereby certify that on this 2nd day of September, 2008, I caused to be mailed overnight, postage prepaid, a true and correct copy of a CD containing the Petition For Reconsideration of Rocky Mountain Power in Docket No. 07-035-93 to the following:

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