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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 POST-HEARING BRIEF**

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I. INTRODUCTION

Rocky Mountain Power ("RMP" or "the Company") seeks a rate increase in this case of $74.5 million, or approximately 5.5% on an overall basis. The case has been distilled to only the Company's most basic and essential costs and return necessary to provide safe and reliable energy for an ever-increasing number of customers. Most notably:

- *The requested rate of return is modest given that corporate interest rates and credit spreads are as high as they have been for many years;*
- *Net power costs are rising at such a pace that the Company's costs will be significantly understated even with its full $1.044 billion NPC request reflected in rates;*
- *The labor costs included in this case are significantly decreased despite upward pressures on medical cost and a demanding infrastructure build cycle; and*
- *Overall O&M costs are being held flat.*

The Company's business and regulatory environment has demanded that it operate effectively and efficiently on a budget that is stripped down to the bone, as reflected by the costs included in this case. The Company needs recovery of these basic and essential costs to serve its existing customers and to make the investments necessary to meet Utah's burgeoning load growth.

II. ARGUMENT

A. Cost of Capital

The Company presented the following cost of capital recommendations in this case:[1]

Table 1

Rocky Mountain Power
Weighted Average Cost of Capital

(a) Component	(b) Percent of Total	(c) Nominal Cost (%)	(d) Weighted Average Cost
Long Term Debt	49.2%	6.30%	3.10%
Preferred Stock	0.4%	5.41%	0.02%
Common Stock Equity	50.4%	10.75%	5.42%
Total	100.0%		8.54%

[1] Williams Supplemental Direct/3, ll. 42-49.

Column (b) in Table 1 above demonstrates the Company's proposed capital structure. As a result of the Test Period Order, the equity component is now 1% lower than in the Company's original filing.[2] No party has contested the reasonableness of the Company's proposed capital structure. *ROR Tr. 66, ll. 14-15 (DPU); ROR Tr. 137, ll. 15-19 (CCS).*[3]

a. Cost of Equity

Parties have challenged the Company's proposed return of equity of 10.75%, with DPU recommending 10.10% and CCS recommending 9.85%. The Commission should accept the Company's recommendation for the following reasons:

1. DPU and CCS state or imply in their testimony that RMP's cost of equity should be decreased to reflect current low interest rates. While the yields on U.S. Treasury securities have declined, in fact, the yield required by the market on *corporate* securities with RMP's credit rating have been increasing. Single-A utility bond rates were 6.29% in April 2008.[4] This is higher than the 5.81% long-term yield that the market required in December 2006 when the Commission approved the stipulated 10.25% return on equity in Docket No. 06-035-21 and considerably higher than the 5.61% yield that the market required in February 2005 when the Commission approved the stipulated 10.50% return on equity in Docket No. 04-035-42.[5]

2. Corporate spreads, which primarily reflect investors' *credit* risk perceptions, have also widened significantly.[6] The spread above 10-year U.S. Treasury securities for single-A public utility bonds of similar maturity was 261 basis points (*i.e.* 2.61%) in April 2008; this same spread was only 125 basis points (1.25%) in December 2006 and 144 basis points (1.44%) in February 2005.[7] The Commission has previously recognized that no mechanical relationship exists between interest rates and cost of capital because of the interplay of variables such as

[2] *Id*. at 1, ll. 17-18.

[3] References to the Transcript of Proceeding for the Rate of Return portion of the hearing held on May 20, 2008, are designated as ROR Tr. References to the Transcript of Proceeding for the Revenue Requirement portion of the hearing held on June 2, 2008 through June 5, 2008 are designated simply as Tr.

[4] Exhibit RMP-1(ROR).

[5] *Id.*

[6] Hadaway Rebuttal/6, ll. 98-99.

[7] Exhibit RMP-1(ROR).

investor perceptions about risk and inflation.[8] However, Company witness Dr. Hadaway has clearly demonstrated that in fact the *equity* risk premium for public utility common equity[9] is inversely related to the market required yield on long-term public utility debt. Thus, as the market-required cost of long-term public utility debt increases (decreases), the equity risk premium declines (increases). Two dynamics are taking place in the financial markets. While credit spreads are widening and the market required yield on public utility debt is rising, the equity risk premium is narrowing. These concepts are illustrated in Dr. Hadaway's Exhibit RMP SCH-6 and RMP SCH-8R. These exhibits incorporate both the expansion of the corporate *credit* spreads *and* the compression of the *equity* risk premium spread. They explain why the Company's cost of equity capital is now increasing, in the face of declines in government interest rates.

3. Dr. Hadaway's updated DCF results, set forth in rebuttal exhibit SCH-R-7, support his return on equity recommendation without reliance on forecast data or controversial growth rates. *ROR Tr. 33.* The constant growth model using analysts' growth rates, a model that "is about as traditional as you can get," produces a range of 10.4 % to 10.8%.[10] *ROR Tr. 35, ll. 3-4*. Dr. Hadaway's constant growth model using long-term GDP reflects a growth rate (6.5%) that is only slightly higher than current analyst growth rates (6.18%).[11] This model produces returns in the range of 11.2% to 11.3%. Dr. Hadaway's two-stage DCF model produces a range of 10.90% to 11.0%.[12] Finally, and most importantly, 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.

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[8] *Re Questar Gas Co.,* Docket 99-057-20, at 15 (Aug. 11, 2000).

[9] The equity risk premium equals the market required cost of equity minus the market required cost of debt. As such, the market required cost of equity equals the the market required cost of long-term debt plus the equity risk premium.

[10] 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.

[11] Hadaway Rebuttal, Exhibit SCH-7R, at 2-3.

[12] *Id.* p. 4

4. DPU witness Mr. Peterson's DCF results support a return on equity higher than his 10.10% recommendation. To support his DCF framework, Mr. Peterson cites the Commission's 2002 Questar decision as adopting a DCF model using a weighted average growth rate composed of 75% earnings per share ("EPS") and 25% dividend growth. In fact, that case used the weighted average as the bottom of the DCF range only and applied a 100% EPS approach to set the top end of the range.[13] The result of this was to give dividend growth *less* weight than the Commission previously permitted.[14] From a policy perspective, reliance on dividend growth instead of earnings growth is problematic because, over the long-term horizon measured by the DCF model, earnings growth drives dividend growth, not the opposite.

5. DPU Exhibit 2.5 contains a summary of Mr. Peterson's DCF results. The summary of weighted average growth and EPS growth rate results shows a range of 10.03% to 10.69%, with a midpoint of approximately 10.36%.[15] *ROR Tr. 86, ll. 11-18*. However, DPU Exhibit 2.7(b) contains a calculation error for the weighted average growth using one month prices, resulting in an understatement of these numbers.[16] *ROR Tr. 91, l. 9-92, l. 25*. Correcting this error, as set forth in RMP Cross Exhibit 3 (ROR), raises the weighted average growth results from 10.03% to 10.10%. *ROR Tr. 92, ll. 22-25.* This, in turn, increases Mr. Peterson's DCF range from 10.10% to 10.69%, with a mid-point of approximately 10.40%. *ROR Tr. 93, ll. 1-15*. Mr. Peterson's Exhibit 2.7(a) also contained an error, a missing column of numbers, which Mr., Peterson corrected on the day of hearing. *Tr. 69, ll. 1-12.* Collectively, these errors should reduce the weight given to Mr. Peterson's analysis.

6. CCS witness Mr. Lawton's DCF analysis supports a higher return on equity than his 9.85% recommendation. His surrebuttal "updates" to Dr. Hadaway's DCF analyst growth rate

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[13] *Re Questar Gas Company*, Docket No. 02-057-02 at 34-35 (Dec. 30, 2002).

[14] *Id*. at 32.

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

[16] This same error in calculations under the column for 75% EPS and 25% DPS weighted cost of equity is embedded in DPU Exhibits 2.7(a) & (b), 2.8(a) & (b), and 2.9(a) &(b).

and GDP growth rate models produce returns of 10.17% and 10.22%, respectively.[17]

7. 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.[18] This analysis, however, assumed a single-A corporate bond yield of 5.5%. *ROR Tr. 130, ll. 12-15*. 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. *ROR Tr. 129, ll. 14-24*. 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—would produce a return of 10.72%. *ROR Tr. 131, l. 13-132, l. 2*.

Mr. Lawton claimed that "nobody would do" such an analysis because it relies upon a one-month spot price. *ROR Tr. 132, ll. 1-2*. Instead, he indicated that use of a three-month historical average would be more reasonable. *ROR Tr. 143, ll. 2-5*. The three-month historical average for single-A bond yields is 6.24%.[19] Because this value is only 5 basis points lower than April 2008 yield, it would produce only a small reduction in the 10.72% return to which Mr. Lawton testified.

8. Mr. Lawton relies upon the CAPM model to justify his low return on equity recommendation. His "updates" to Dr. Hadaway's CAPM analysis show a range of 8.00% to 9.30% and uses a 1.42% short-term Treasury bill yield as one of the inputs in a calculation intended to estimate the investor required cost of equity—a security with a perpetual life and certainly with an investor holding period in excess of a short-term (90-day) Treasury bill. *ROR Tr. 126, l. 2-127, l. 5*. Removing these low CAPM results, Mr. Lawton's updated surrebuttal analysis produces a range of 10.02% to 10.30%, with a mid-point of 10.17%. *ROR Tr. 128, ll. 7-25*.

9. Dr. Hadaway testified that he removed the CAPM model from his analysis in rebuttal

[17] CCS Exhibit 3.3 SR at 1.
[18] *Id.*
[19] Exhibit RMP-1(ROR) (indicating Single-A rates for February, March and April 2008 of 6.22%, 6.21% and 6.29%, respectively.)

because, under current market conditions, it did not produce reliable results. *ROR Tr. 39, l. 15-38, l. 21*. Similarly, Mr. Peterson disregarded the lower half of his CAPM results (from 8.00% to 9.1%) as outside the range of reasonableness. *ROR Tr. 79, ll. 17-21*.

This Commission has previously rejected the CAPM to set return on equity.[20] *ROR Tr. 80, ll. 3-7*. In the 2002 Questar case, the Commission stated flatly: "[W]e cannot rely on the CAPM."[21] While Mr. Peterson asks the Commission to reconsider this point, he admits that the Commission's previously expressed skepticism of the model was "justified" and that the "practical implementation of the model has resulted in much controversy and consternation."[22] This case clearly demonstrates the limitations of the CAPM model, in that the model cannot accurately reflect current market conditions, which combine low government interest rates, high corporate interest rates, and wide corporate credit spreads.

10. The Commission has historically included a qualitative assessment of business risk as a part of its return on equity determinations.[23] In this case, the Company's business risk supports Dr. Hadaway's 10.75% recommendation. The Company's load growth in Utah and Wyoming, especially in the industrial sector, has resulted in the need for a 10-year, $20 billion capital investment program. *ROR Tr. 153, l. 13-154, l. 25*. Managing an investment program of this scale at a time of increasing costs, constrained resource choices and environmental and regulatory complexity has created new and unprecedented business challenges for the Company. *ROR Tr. 169, ll. 19-23; 153, ll. 13-20; 154, ll. 18-25*. The Company's most recent ratings report from Standard & Poor's notes the importance of strong regulatory support given the business

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[20] *See* DPU Exhibit 2, Peterson Direct/4, ll. 76-77 ("The Commission appears to largely reject consideration of CAPM.")

[21] *Re Questar Gas Company*, Docket No. 02-057-02 at 34 (Dec. 30, 2002) ("[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.")

[22] DPU Exhibit 2, Peterson Direct/4, l. 76; Direct/20, ll. 447-448.

[23] *Re Questar Gas Company*, Docket No. 02-057-02 at 24 (Dec 30, 2002) (Defining business risk as "uncertainty about the rate of return investors expect the Company to earn, and the possibility that actual return will deviate from it," and noting that the qualitative consideration of business risk factors is instructive for rate of return purposes.)

risks now faced by the Company.[24]

b. Cost of Debt

Parties have controverted the Company's proposed 6.30% cost of debt, focusing on the cost of the Company's $700 million debt issuance scheduled for November 2008. This issuance is required to fund the Company's major capital investment program. *ROR Tr. 25, ll. 16-19*. The Company's estimated interest rate for this new debt is 6.52%.[25] DPU recommends an overall cost of debt of 6.28%, assuming that the interest rate on the new debt will be 21 basis points lower;[26] CCS recommends a 6.27% cost of debt, assuming that the interest rate on the new debt will be 45 basis points lower.[27]

The Company testified in rebuttal that recent decreases in Treasury rates have been fully offset by increases in the corporate credit spread, resulting in no change in the projected 6.52% interest rate for new debt.[28] At hearing, Mr. Peterson supported his lower projected interest rate on the erroneous basis that corporate credit spreads are narrowing and cited Dr. Hadaway's rebuttal testimony in support of this position. *ROR Tr. 66, l. 13-67, l. 7*. Mr. Peterson later withdrew this comment. *ROR Tr. 72, l. 3*.

In light of current market turmoil and some of the widest corporate credit spreads in recent history, it is unreasonable to assume that the Company's debt costs will reflect declines in government interest rates. At the hearing, Mr. Peterson acknowledged that, as a result of recent market turmoil, he supported as reasonable the 7.20% rate for Questar's March 2008 debt issuance and Questar's overall 6.72% cost of debt.[29] In this case, RMP is projecting new debt costs and an overall debt level well below these figures.

[24] Walje Revenue Requirement Rebuttal, Exhibit ARW-1R-RR at 2.
[25] Williams Rebuttal/2, l. 40.
[26] DPU Exhibit 2, Peterson Direct/10, ll. 205-09.
[27] CCS Exhibit 3, Lawton Direct/29, l. 705-30, l. 710.
[28] Williams Rebuttal/2, ll. 34-40.
[29] Cross Exhibit RMP-1(ROR) (DPU Exhibit 2 in Docket No. 07-057-13 at 9-10.)

B. Net Power Costs

a. Overview of Positions

The Company requests approval of system net power costs ("NPC") of $1.044 billion. Only CCS has testified against the Company's current NPC recommendation, proposing adjustments of $42 million, for a reduced system NPC of $1.002 billion.[30]

Mr. Duvall's Rebuttal Exhibit GND-1R-RR shows the Company's current NPC recommendation under two alternative approaches. Alternative 1 is based on the DPU adjustments along with three corrections. Alternative 2 reflects the Company's comprehensively modeled rebuttal NPC, which totals $1.047 billion and, as of the date of the Company's rebuttal filing, provided a $3 million "cushion" to lower the result to the same level as Alternative 1.[31]

The Company included Alternative 1 to minimize controversy in the case, but made clear that further updates or corrections should work off the Company's modeled base case, Alternative 2.[32] If the Commission wishes to review individual adjustments or use a single alternative to analyze this case, it should use Alternative 2, but cap the Company's NPC at $1.044 billion to recognize the concession in Alternative 1.

In its surrebuttal and at hearing, CCS ignored the Company's Alternative 2, accused the Company of not making adjustments it had conceded, and proposed reductions to Alternative 1. *Tr. 482, l. 12- 483, l. 9*. Because CCS continues to contest specific adjustments, as well as the overall level of proposed NPC, the Company's rebuttal testimony was clear that CCS' adjustments should be directed to Alternative 2. CCS' proposal to instead adjust Alternative 1 punishes the Company for its attempt to compromise and represents an attempt to double-count adjustments, because Alternative 2 models all conceded adjustments.

As detailed in Exhibit GND-1R-RR, Alternative 2 starts with the Company's Supplemental Net Power Costs of $1.051 billion and makes the following adjustments:

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[30] Exhibit CCS-4SR Falkenberg Surrebuttal/2, ll. 70-72.
[31] Duvall Rebuttal/3, ll. 52-55.
[32] *Id.*

- Lines 1-3 of Alternative 2 are the same corrections as shown in Alternative 1.[33]

- Line 4 reflects updates based upon new information presented by other parties,[34] along with an update for the latest official forward price curve from March 2008.

- Lines 5 and 6 correct for the commitment logic error in GRID, fully addressing the uneconomic dispatch of Lake Side, Currant Creek, and West Valley.

- Line 7 adjusts the planned maintenance schedule by moving *all* coal plant maintenance out of January and February and into March and April.

- Line 8 reflects an adjustment to forced outages to remove both monthly and weekly modeling. This recognizes that "unplanned outages are quite random by nature" as asserted in CCS witness Mr. Falkenberg's Direct Testimony.[35]

- Line 9 removes the ramping adjustment on Gadsby 1, 2, and 3 so the ramping adjustment now only applies to coal units.

- At hearing, the Company agreed to three additional adjustments to Alternative 2 totaling less than $1 million: (1) UAE's call option adjustment; (2) CCS' adjustment to reshape hydro to reflect the updated forward price curves; and (3) CCS' adjustment to exclude self-supply generation in the West control area. *Tr. 412, l. 13-413, l. 5.*

Updated for adjustments conceded at hearing, Alternative 2 results in NPC of approximately $1.046 billion, still leaving a $2 million cushion/concession for the Company's recommended NPC of $1.044 billion.

b. NPC Benchmarks

As a check on the parties' NPC positions in this case, the Company provided NPC benchmarks in its rebuttal testimony,[36] which are updated and set forth below:

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[33] The corrections are CCS 4.8 (SMUD Leap Year); CCS 4.21 (Currant Creek Outage Rates) and CCS 4.26 (Self-Supply Non-Owned Reserves), along with the Company's inadvertently omitted electric swaps and indexed gas transactions.

[34] The updating adjustments 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).

[35] Exhibit CCS 4D Falkenberg Direct/74, l. 1777.

[36] Duvall Rebuttal/4, l. 83.

NPC Benchmarks		
NPC now in rates	$813 million	Exhibit GND-2R-RR
2008 NPC @ $1.044 billion effective 9/1/08	$890 million	Duvall Rebuttal/4, ll. 71-73
NPC in rates updated for loads in case	$854 million	CCS-4SR Falkenberg/14, ll. 352-54
2008 NPC @ $1.044 billion effective 9/1/08 with NPC in rates updated for loads in case	$927 million	Tr. 422, ll. 18-24.
Actual NPC CY 2007	$975 million	Exhibit GND-2R-RR
Actual power costs 12 months ending March 2008	$1.024 billion	Exhibit GND-3R-RR
Oregon TAM updated for Utah loads	$1.032 billion	Exhibit 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 GND-5R-RR

CCS argues against consideration of such NPC benchmarks. First, CCS claims that the Company's NPC under-recovery is largely due to its under-forecasting of loads.[37] But, as can be seen from the third benchmark above provided by CCS, adjusting NPC in rates for loads in the current case only closes $40 million of the $162 million gap between NPC now in rates and actual 2007 NPC.

Second, CCS claims that the Company's benchmarks are overstated and irrelevant because they reflect actual NPC before auditing and without normalizing adjustments.[38] The Company's benchmarks include results from the Oregon TAM, an annual regulatory NPC update. The TAM for the 2008 test period, adjusted only to reflect filed and actual loads, is $1.032 billion and $1.060 billion, respectively. *Tr. 411, ll. 15-24.* This benchmark reflects a fully normalized NPC forecast with many of Mr. Falkenberg's proposed adjustments, including GRID commitment logic and call options. *Tr. 463, l. 16- 464, l. 4*.

Third, while CCS claims that the Company's citations to actual results are an irrelevant distraction, *Tr. 514, ll. 10-16*, CCS used actual results in the Company's 2001 rate case, the last time the Company litigated NPC in Utah. *Tr. 515, l. 6- 517, l. 16.*[39] Similarly, while CCS claims that the Commission ignored comparisons to actual results in the 2001 case, *Tr. 518, ll. 4-14*, the

[37] Exhibit CCS-4SR Falkenberg, Surrebuttal/12, ll. 308-311.
[38] *Id.* at 4, ll. 106-108.
[39] *See also* RMP Cross Exhibit 16.

Commission in fact included a full section comparing actual results to NPC in rates in its decision. *Tr. 519, ll. 13-17*.[40]

CCS' arguments cannot dispel what the benchmarks reveal: (1) NPC are rising at the pace of $40-$50 million every 6 months (a fact also correlated by the Test Period Order in this case which reduced system NPC from $1.091 billion to $1.051 billion); (2) the Company is significantly under-recovering NPC in Utah rates and this situation will continue even if the Company's recommended NPC are approved; and (3) CCS' NPC proposal of $1.002 billion is unreasonably low and should be rejected as an outlier. *Tr. 411, l. 25- 412, l. 11*.

Mr. Falkenberg's testimony states that "I expect the Company makes every effort to achieve the least cost operation of the power system, subject to applicable constraints."[41] In view of this testimony, it is difficult to understand or believe the magnitude of CCS' proposed adjustments. When asked what kind of "sanity check" he applied to his overall NPC recommendation, Mr. Falkenberg replied that none was required because the difference between his recommendation and the Company's—currently $42 million—was not "substantial." *Tr. 541, l. 12-542, l. 2*. From the Company's standpoint, CCS' adjustments are very substantial and wrongly imply that NPC are flat or declining when they are increasing dramatically.

c. Individual Adjustments—Updates and Corrections

In their direct testimony, parties proposed numerous corrections and post-filing updates to reflect the most recently available information about 2008 NPC.[42] On the same basis, in rebuttal the Company proposed to add electric swaps and indexed gas transactions inadvertently omitted from the original filing, increasing system NPC by approximately $3.2 million.[43]

The Company included companion transactions (gas swaps and indexed electric transactions) in the original filing and no party has challenged these. At hearing, DPU witness Mr. Dalton testified that the DPU reviewed and approved of these hedges. *Tr. 471, ll. 7-13*.

[40] *See also* RMP Cross Exhibit 14.
[41] Exhibit CCS 4D, Falkenberg Direct/14-15, ll. 391-393.
[42] Duvall Rebuttal/9, ll. 187-195 and 11, ll. 219-224.
[43] *Id.* at 11, ll. 225-231.

While CCS objected to a Company correction in rebuttal that increases NPC, it has not questioned the appropriateness of the underlying transactions. Given the many proposed corrections and updates that decrease NPC, fairness should permit the Company a single correction that increases NPC, especially given the absence of surprise or prejudice.

Similarly, the Commission should permit the Company to update its NPC to reflect the March 2008 forward price curve. This case was filed using a September 2007 forward price curve. Updating the case for the March 2008 forward price curves increases NPC by approximately $7.5 million. *Tr. 417, l. 25-418, l. 3*. This update is required to ensure that NPC in the case accurately reflect conditions in the 2008 test period, which include rapidly increasing forward price curves. As of May 23, 2008, forward price curves were up 10% from the prices used in the March 2008 update, which would cause NPC to increase by another $10 million. *Tr. 418, ll. 6-10.* This demonstrates both the need for and the reasonableness of the March 2008 forward price curve update.

CCS objects to the Company's proposal to update the forward price curve because it does not reflect changes to hydro shaping that accompany the new curve, which could reduce NPC by approximately $500,000.[44] The Company accepted this adjustment at hearing in Alternative 2. *Tr. 412, ll. 17-25.* CCS also objects to this update claiming that the Company should have included it in the Test Period Order compliance filing in March 2008.[45] The Company approached the compliance filing as just that, a filing that did not give it discretion to update items such as the forward price curve. In any event, CCS cannot claim prejudice associated with increasing forward prices because the Company used a forward price curve dating back to the month of the compliance filing—March 2008.

d. Individual Adjustments—Partially Accepted Adjustments

1. Planned Outage Schedule - In his direct testimony, Mr. Falkenberg challenged the Company's planned outage schedule because it included coal plant outages in January and

[44] Exhibit CCS-4SR, Falkenberg Surrebuttal/41, ll. 1042-1051.
[45] *Id.* at 39, ll. 990-994.

February.[46] In rebuttal, the Company acknowledged its mistake in including outages in these months, proposed a corrected schedule, and included this adjustment in Alternative 2.[47] 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.[48]

At hearing, Mr. Falkenberg testified that the Commission should reject any proposed schedule that included coal plant outages in January and February. *Tr. 486, ll. 5-10*. He also criticized DPU's proposed outage schedule, claiming that while he had removed all coal plant outages from January, DPU still had outages in January. *Tr. 484, l. 19- 485, l. 3.*

In fact, Mr. Falkenberg's planned outage schedule includes two outages for a total of 19 days in January for the Hayden 1 and 2 coal plants. *Tr. 488, l. 15- 490, l. 3.* Mr. Falkenberg also admitted that correcting this mistake would require preparation of a new schedule to move the outages from January to another month. *Tr. 490, ll. 11-20*. The record in this case—now closed for this phase—contains only Mr. Falkenberg's planned outage schedule with January outages, which according to his own testimony, the Commission should reject.[49]

Even if Mr. Falkenberg's schedule did not contain this fatal flaw, the Commission should still reject his planned outage adjustment. While Mr. Falkenberg claims to have adhered to historical schedules, normalized modeling makes this impossible. *Tr. 414, ll. 13-23*. 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. *Tr. 414, l. 24- 416, l. 5*. Historical schedules do provide a general guide that maintenance should occur in the spring and the fall, a practice now fully reflected in the Company's filing. *Tr. 414, ll. 20-23*.

[46] Exhibit CCS 4D, Falkenberg Direct/54, l. 1331-1333.

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

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

[49] During the hearing, the Commission served a data request asking for NPC 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 from January to another month. This correction was clearly outside the scope of the Commission's data request and constitutes an indirect and improper attempt to supplement the closed record in this case. The Company objects to the Commission giving any evidentiary weight to this aspect of the CCS response to the Commission's data request for NPC workpapers.

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."[50] These exact concerns are presented by Mr. Falkenberg's adjustment in this case, warranting a similar outcome.

2. Call Options - There are two issues raised by the call option adjustment. The first is potential uneconomic dispatch. The Company conceded this aspect of the adjustment, agreed with UAE's quantification of the adjustment in surrebuttal and included it in Alternative 2. *Tr. 412, ll. 17-20*. The second, which represents most of CCS' adjustment, is removal of the call premiums for months in which the call options do not dispatch. This adjustment is akin to not paying insurance premiums in months when one does not make a claim. *Tr. 416, ll. 2-9.* The Company executed the call options to meet demand and ensure reliable service into the Utah load area during periods of increased demand and/or transmission constraints and high prices. Mr. Falkenberg's adjustment improperly seeks to disallow prudent costs.[51]

3. Monthly and Weekly Outage Modeling - In his direct testimony, Mr. Falkenberg argued against monthly modeling of forced outages because such outages are by definition random events.[52] In rebuttal, the Company accepted this adjustment and, using the same rationale, proposed to also eliminate weekday/weekend modeling of forced outages.[53] Mr. Falkenberg protested in surrebuttal, this time arguing that forced outages are not random but instead have a discernable weekday/weekend pattern.[54]

On cross-examination, Mr. Falkenberg admitted that the weekday/weekend difference only "amounts to around 1%." *Tr. 509, ll. 4-6.* Because this difference is so small, it is not discernable in a monthly comparison of historical outage rates by unit, such as that set forth in Cross Exhibit RMP 15. If the Company reverts to more general, annual modeling of forced

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[50] RMP Cross Exhibit 14 at 14.
[51] Duvall Rebuttal/22, ll. 473-477.
[52] Exhibit CCS 4D, Falkenberg Direct/74, l. 1777.
[53] Duvall Rebuttal/19, ll. 411-415.
[54] Exhibit CCS-4SR, Falkenberg Surrebuttal/32, ll. 823-824.

outages as proposed by Mr. Falkenberg, there is no justification for retention of the weekday/weekend split.

4. Ramping - In its rebuttal testimony, the Company agreed to remove gas plants from its ramping adjustment to ensure against inadvertently covering a gas plant being held for reserves. In surrebuttal, Mr. Falkenberg offered a new analysis to demonstrate that the Company's ramping costs remain overstated.[55] Mr. Falkenberg's analysis relies upon in-applicable operating ramping rates, however, which are used when a plant is actually running and it is "hot." *Tr. 416, l. 22-417, l. 2.* The Company's ramping costs are designed to cover cold starts, a process which can take six to ten hours. *Tr. 417, ll. 9-11*. The problems in Mr. Falkenberg's data are apparent as his analysis reduces start-up time to an hour and suggests that a coal plant can ramp up faster than a gas plant. *Tr. 417, ll. 8-13*.

e. Individual Adjustments—Fully Contested Adjustments

1. Heat Rate Modeling / Minimum loading - For his combined $4.7 million heat rate modeling/minimum loading adjustment, Mr. Falkenberg assumes that (i) plants will run at their highest efficiency level during forced outages, (ii) plants can run at levels below their physical minimum, and (iii) there are no partial forced outages. These assumptions are completely unrealistic and do not represent normal system operations. *Tr. 415, ll. 14-22.*

The Company has used its current de-rating method for over 25 years without the adjustments proposed by Mr. Falkenberg. Indeed, Mr. Falkenberg proposed these adjustments for the first time earlier this year. *Tr. 522, ll. 12-16*. Mr. Falkenberg alleges in conclusory fashion that his adjustment is "industry standard," but his testimony cites just one utility, Portland General Electric ("PGE"), that does anything remotely similar to his adjustment. *Tr. 520, l. 21-521, l. 4.*

2. Wind Integration Charges - The Company proposed a wind integration charge of $1.14 per MWh plus a 5% reserve. Mr. Falkenberg proposed an adjustment to lower this

[55] *Id*. at 35, ll. 903-906.

charge to $0.22 plus the 5% reserve. PGE, Mr. Falkenberg's industry standard-setting utility for heat rate modeling, proposes to charge $4.39 MWh for its wind integration charge. *Tr. 527, ll. 5-7.* This charge is influenced by BPA's wind integration charge of $2.82 MWh, a charge which also impacts the Company. *Tr. 528, ll. 18-24; Tr. 105, ll.1-10.* Compared to the wind integration charges of PGE and BPA, the Company's proposed charge appears reasonable, while Mr. Falkenberg's is far too low.

3. SMUD Pricing/Shaping - In the SMUD pricing adjustment, Mr. Falkenberg seeks to relitigate the prudence of the SMUD contract, which was executed 20 years ago. *Tr. 413, ll. 15-20.* For many years, Mr. Falkenberg has regularly and unsuccessfully litigated this issue. Other commissions have followed the pricing approach set by the Utah Commission, and there is no reason to change it in this case.[56]

Mr. Falkenberg also proposes to deoptimize the SMUD contract, substituting actual data for the normalized modeling of this contract.[57] This adjustment is inconsistent with both CCS' objection to review of actual NPC benchmarks and its GRID commitment issue, where the adjustment is based upon the expectation that the Company will optimize its power system. It is also a selective adjustment, with CCS proposing to deoptimize only one of the Company's many purchase and sale contracts. *Tr. 413, l. 22-414, l. 2.*

C. Labor

The Company's filing includes approximately $503 million in labor costs—approximately *thirty million dollars less* than those presented by the Company in its 2006 rate case. This decrease occurs during a significant build cycle and when the Company is confronting steep rises in medical costs and union-negotiated wage increases. Overall, on a cents per kWh basis, wages and benefits have declined by 9% since the last filing, even while the Company is subject to external business pressures that should be driving labor costs higher.[58]

[56] Duvall Rebuttal/26, ll. 570-575.
[57] Duvall Rebutta/27, l. 591.
[58] Wilson Rebuttal/3, l. 66-4, l. 73.

The Company's success in holding the line on labor costs is a direct result of the emphasis on cost control brought to the Company by MidAmerican Energy Holdings Company's ("MEHC") acquisition. Consistent with this emphasis, the Company has implemented a workforce restructuring program that has allowed the Company to reduce staffing in key areas without compromising critical goals of safety, reliability, and customer service. In addition, the Company has continued to re-design its health, welfare, and retirement plans to shift more responsibility from the Company to its employees.[59]

However, the Company can cut costs only so far without sacrificing service. Indeed, if the Company is forced to cut labor costs even further, it will be unable to attract the qualified personnel necessary to maintain the Company's high performance standards. *Tr. 201, ll. 5-16*.

a. Incentive Compensation

At the hearing, Director of Human Resources, Erich Wilson, explained the two fundamental principles underlying the Company's compensation philosophy. First, the Company's primary goal is to provide employees with compensation at the market average. Market level compensation is critical in order to attract qualified employees in an increasingly competitive environment. *Tr. 193, ll. 10-14*. Second, in order to encourage superior performance, compensation is structured such that some portion is "at risk." *Tr. 193, ll. 14-17*. Employee compensation, therefore, consists of base pay and an incentive element. Combined, base pay and the "target" level incentive element equal the market average for the employee's position. When performance is below expected levels, the employee will receive incentive below target level or no incentive pay and therefore below-average pay.[60]

To determine the amount of incentive pay awarded to an employee, the employee's performance is compared against individual and group goals that are set for each employee at the beginning of the year. *Tr. 194, ll. 5-9; 267, ll. 5-11*. All goals promote the efficient operations of the Company, and focus on safety, reliability, and customer service, therefore providing direct

[59] *Id.* at 4, ll. 74-84.
[60] Tr. 193, l. 24-194, l. 4; Wilson Rebuttal/14, ll. 307-311.

benefits to the Company's customers. *Tr. 194, ll. 9-12*. No goals relate to financial results, except for those applicable to the executive incentive plan for which the Company has not requested recovery. *Tr. 225, ll. 6-10.*

DPU was initially critical of the incentive plan, and proposed an adjustment through its witness Mark E. Garrett. After hearing Mr. Wilson's live testimony on the incentive plan, however, DPU withdrew its adjustment. *Tr. 282, l. 21-283, l. 9.* Therefore, the only remaining adjustment before the Commission is that of CCS witness, Helmuth W. Schultz III, who argues that incentive compensation be reduced by $3.4 million on a Utah basis.[61]

Mr. Schultz makes three basic arguments against the incentive plan, none of them valid. First, Mr. Schultz argues that because the Company budgets for and disburses a set amount of incentive pay each year (the aggregate of all employees' target incentive pay) incentive pay is not truly "at risk."[62] However, the purpose of the plan is not to place compensation for the Company as a whole "at risk." Rather the point is to place a portion of each *individual employee's* compensation at risk[63]—which, as Mr. Schultz himself concedes, creates the more powerful motivator for the employee. *Tr. 372, l. 25-373, l. 8.*

Second, pointing to one employee's goal of meeting the OMAG budget, Mr. Schultz argues that a portion of the Company's requested incentive pay should be disallowed because it is impermissibly tied to the financial performance of the Company.[64] Mr. Schultz is incorrect. When employees keep costs down, customers benefit in the form of lower rates. Accordingly, such goals—distinguishable from goals purely based on the profits of the Company—should be encouraged, not discouraged.[65]

Finally, Mr. Schultz contends that employees should receive incentive pay only for

[61] Exhibit CCS-6, Schultz Direct/16, l. 364-17, ll. 364-367.
[62] Exhibit CCS-6SR, Schultz Surrebuttal/15, ll. 325-330; Tr. 265, ll. 14-18.
[63] Tr. 221, ll. 13-17.
[64] Exhibit CCS-6SR, Schultz Surrebuttal/17, l. 356-18, l. 376.
[65] It is worth noting that although the Commission will not allow costs associated with an incentive plan whose goals are driven primarily by financial goals of the Company, it will not disallow a plan simply because the plan includes financial goals. On the contrary, if the Commission concludes that an incentive plan includes financial goals, the Commission will look further to determine whether customers benefit from such goals. *Re PacifiCorp dba Utah Power and Light Co.*, Docket No. 97-035-01, 192 P.U.R. 4th 289, 304 (Mar. 4, 1999).

superior performance. *Tr. 373, ll. 15-21.* In his view, then, base compensation on its own—without any incentive component—must be set at market average for total average compensation.[66] Mr. Schultz's system would weaken the current program by depriving it of the negative incentive created by the potential for employees to earn less than market average for below-average performance. And even Mr. Schultz agrees that the potential penalty for below average performance can serve to motivate employee behavior. *Tr. 375, ll. 4-8.*

The Commission previously addressed CCS' criticisms of the structure of the Company's incentive plan in the 1997 rate case. The Commission found that the plan's goals benefited ratepayers and did not constitute financial goals.[67] The Commission should make the same finding in this case and reject CCS' adjustment.

b. Merit Increases

In calculating base pay, the Company began with base compensation for the June 2006-June 2007 Base Period, and escalated that amount with across-the-board merit increases in January 2007 and January 2008.[68] For non-union employees, the merit increase for 2007 was based upon the 2.25% granted non-union employees in January 2007; the merit increase for 2008 was based upon the 3.5% merit increase granted non-union employees in January 2008.[69] Merit increases for union employees were based upon negotiated raises. Both the 2007 and 2008 merit increases for non-union employees were based upon the Company's evaluation of market compensation and the merit increases planned by those companies with which the Company competes for employees.[70] CCS and DPU recommend two different adjustments.

CCS Adjustment: CCS recommends that the 3.5% non-union merit increase for 2008 be reduced to the 3.0% level given to the Company's union workforce in that year, resulting in a reduction in labor costs of $281,711 on a Utah basis. Mr. Schultz argues that the Company has

[66] At hearing, Mr. Schultz agreed that employees should receive market average pay for "normal" or expected performance. *Tr. 378, l. 19-379, l. 4.*

[67] 192 P.U.R. at 303.

[68] Exhibit RMP SRM-1R-RR at 4.10.2.

[69] These increases were actually granted in late December of each previous year. Exhibit RMP SRM-1R-RR at 4.10.3 and 4.10.4.

[70] Wilson Rebuttal/9, ll. 177-186; Tr. 196, ll. 13-16; Tr. 219, ll. 10-21.

not sufficiently supported its merit pay calculation and also opines that the Company's overall base pay is just generally too high.[71] Neither position is supported by the evidence.

First, the Company provided substantial and undisputed evidence demonstrating the reasonableness of its 2008 merit increase. In particular, Mr. Wilson testified that in order to remain competitive, the Company bases its annual merit increases on those granted by its competitors for employees. To this point, Mr. Wilson offered an exhibit showing the Company research on which it based its 2008 merit increase. The exhibit shows that the 3.5% included in the filing is, if anything, conservative.[72]

Moreover, Mr. Schultz's analysis of the Company's compensation does not support his argument that the Company's base pay is above market average. In his first evaluation, Mr. Schultz attempted to compare compensation received by Company employees to studies of market compensation for various types of positions. However, on cross examination Mr. Schultz admitted that in doing so, he did not use Company job descriptions and was attempting to compare jobs by titles only.[73] When questioned further on this point, Mr. Schultz conceded that job descriptions are generally necessary to determine the appropriate market pay for a particular job. *Tr. 379, ll. 5-11*. Moreover, Mr. Schultz relied on only one compensation survey to perform his research—despite the fact that the Company provided Mr. Schultz with a number of studies it uses to set compensation. Had Mr. Schultz referred to more than one study, he would have found Company compensation to be at the market average.[74]

Mr. Schultz' second evaluation was equally flawed. Here, Mr. Schultz compared the Company's "midpoint" for each position with the actual salaries earned by the employees in those positions.[75] Based upon his review, Mr. Schultz concluded that Company salaries are "on the higher end." However, his conclusion is undermined by his own findings. As explained by

[71] Exhibit CCS-6, Schultz Direct/7, ll. 148-149 and 157-158; Schultz Surrebuttal/11, ll. 232-242.

[72] RMP EDW-3R-RR.

[73] Wilson Rebuttal/12, ll. 253-259.

[74] Mr. Wilson stated: "If Mr. Schultz' analyses were to include surveys of not just one, and if he were to look at more than a handful of positions, he would find that the Company pay for some positions would be slightly above market, and for some individuals' pay, it would be slightly below." *Tr. 197, ll. 3-15.*

[75] Exhibit CCS-6SR, Schultz Surrebuttal/11, l. 247-12, l. 261.

Mr. Wilson, the midpoint is designed to approximate market average. *Tr. 196 l. 25-197 l. 2*. Accordingly, Mr. Schultz' finding "the Company's average wage level exceeded the midpoint in 5 of 12 job codes" [76] means that wage levels in 7 out of 12 job codes were below market average. In sum, there is no credible evidence in the record to suggest that the Company's pay is above market.

DPU Adjustment: DPU proposes a reduction to labor costs of $1,159,117 on a Utah basis related to the 2.25% merit increase for non-union employees granted in 2007.[77] In support of this adjustment, Mr. Garrett points to a re-calculation by Mr. McDougal of one of Mr. Garrett's previous adjustments. That re-calculation showed (a) the pay of employees over the July through December period *preceding* the date of the 2.25% merit increase; (b) the pay of employees over the January through June period *after* the merit increase; and (c) the resulting difference between the wages over these two time periods—1.67%. Based on this, Mr. Garrett argued that the Company should be allowed to recover only 1.67% for the 2007 merit increase.[78] Mr. Garrett's adjustment is flawed and should be disregarded. As Mr. McDougal pointed out at the time of the hearing, Mr. Garrett is comparing labor costs between mismatched time periods—July through December in 2006 and January through June in 2007. Due to labor fluctuations over the course of the year, the comparison should be between the same months. *Tr. 55, ll. 9-18*. If Mr. Garrett's calculation is revised to compare July through December in 2006 to July through December in 2007, the increase is 2.16%[79]—virtually identical to the 2.25% increase in the Company's filing. *Tr. 55, ll. 16-18.*

In sum, the evidence demonstrates that the Company's proposed merit increases are conservative relative to those granted by its competitors.[80]

c. Productivity Adjustment

The labor costs included in the Company's filing reflect significant productivity savings

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[76] RMP Cross 10.
[77] DPU Exhibit 5.0SR, Garrett Surrebuttal/8, ll. 124-127.
[78] DPU Exhibit 5.0SR, Garrett Surrebuttal/7, ll. 114-121.
[79] McDougal Rebuttal at 41, ll. 892-899; Exhibit RMP SRM-1-R-RR. at 11.5.9; Tr. 55, ll. 11-18.
[80] Tr. 219, l. 22-Tr. 220, l. 1*; see* Exhibit EDW-3R-RR.

on the part of the Company. As discussed above, the $503 million requested by the Company represents a $30 million decrease in costs since 2006. Moreover, when taking into account increased loads, these savings reflect a *9% savings over the same time period*.[81] These savings come as a result of two specific initiatives included in the filing—automated meter reading and savings resulting from the MEHC transition.[82]

Despite the significant productivity savings built into the case, DPU recommends that the Commission apply an additional 1% productivity adjustment that would further reduce labor costs $2,404,135 on a Utah basis.[83] DPU's recommendation would overstate future increases in productivity and would double-count productivity increases the Company has already included in its filing.[84] In addition, Mr. Garrett admitted that he knows of no litigated case in which a commission has included a productivity factor. *Tr. 350, ll. 21-22.* Given that the Company has presented specific and measurable ways in which it has included productivity in its labor expense calculations and that applying a productivity factor is not an established policy in this or any other jurisdiction, the Commission should reject this adjustment.

d. Overtime Adjustment

As a result of its efficiency efforts, the Company has been able to decrease its employee complement during a time of increasing loads and significant construction initiatives—all without sacrificing safety, reliability, or customer service. *Tr. 198, ll. 16-20.* However, while producing overall savings, operating with a leaner workforce means that the Company will more frequently need additional staffing to respond to specific increases in work. *Tr. 198, l. 18-199, l. 6.* As explained by Mr. Wilson, rather than spend funds hiring new full time workers, or pay a premium for contract labor, the Company has chosen to increase overtime for certain workers. *Tr. 245, l. 14-246, l. 3*. As a result, the Company has forecast a 4.8% increase in the amount of overtime incurred in 2007 for a total of $25,022,587 on a Utah basis.[85]

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[81] *Id.* at 4, ll. 71-72.
[82] *Id.* at 27, ll. 593-595.
[83] Tr. 336, ll. 9-11; DPU Exhibit No. 5.0SR, Garrett Surrebuttal/10, ll. 161-163.
[84] Wilson Rebuttal/27, ll. 592-600.
[85] Exhibit RMP-SRM-1R-RR at 4.10.2; 4.10.15.

CCS argues that the overtime incurred by the Company has increased significantly over the past two years, and recommends a reduction to the Company's overtime expense to the 2003-2005 level, allowing for 3% inflation. This proposal would result in a $1,939,292 decrease in labor expenses.[86] Mr. Schultz argues that during the 2003-2004 period overtime increased very slightly at the same time as the number of employees increased.[87] However, the comparison is inapt. Many factors combine to produce a need for overtime, and the Company did *not* take the position that a reduction in the number of employees *always* results in increased overtime. Rather, the Company has explained that the reduction in force *in combination with the substantial construction initiatives* has resulted in the need for increased overtime. *Tr. 198, ll. 20-22.* This combination of forces has and will continue to require the Company to incur increased overtime expenses. The Commission should therefore reject CCS' adjustment.

e. Medical Costs

The Company included medical costs reflecting a 9.8% increase over those actually incurred in 2007.[88] Mr. Wilson explained that this forecast was based on the analysis of its long-term consultants, Hewittt & Associates, after a full review of extensive and company-specific data.[89] Mr. Wilson also explained that the forecast incorporates the savings resulting from significant steps taken by the Company to reduce its medical expenses, so its projected increase is on the lower end of the Hewitt scale. *Tr. 208, ll. 10-19.* Nevertheless, both DPU and CCS recommend reductions to the Company's medical expenses.

DPU Adjustment: DPU argues that a 9.8% increase is too high and instead recommends an increase of 5.06%, resulting in a downward adjustment to medical expenses of $984,164 on a Utah basis.[90] In support of this adjustment, Mr. Garrett relies on a Tower Perrin study that predicts that health care costs for U.S. companies will increase by 6% in 2008, while expenses

[86] Exhibit CCS-6SR, Schultz Surrebuttal/14, ll. 309-311.
[87] *Id.* at 13, l. 280-14, l. 292.
[88] Wilson Rebuttal/21, ll. 460-461; Tr. 199, ll. 19-22..
[89] Tr. 200, ll. 19-24; Wilson Rebuttal/22, ll. 477-483.
[90] DPU Exhibit 5.0SR, Garrett Surrebuttal/12, ll. 193-196.

for "high performing companies" will increase by 5% or less.[91]

The Commission should reject DPU's adjustment. First, the Towers Perrin study is just one of many such generic studies and has no particular applicability to the medical costs that the Company can expect to incur. The Towers Perrin Study is based on data from 500 companies across all sectors. *Tr. 322, ll. 14-16.* Of the 250 companies specified, only two were comparatively sized utilities. *Tr. 322, ll. 17-22.*

Moreover, at hearing, DPU produced additional evidence suggesting that generic studies are of limited use in forecasting medical expenses. Specifically, DPU introduced an article published by Hewitt & Associates offering its own predictions about the increases in medical expenses U.S. companies should expect in 2008. This article is based on data provided by 1800 companies, and predicts that medical expenses in 2008 will increase for U.S. companies in general by 8.7%.[92] The contrast between the predictions offered by two respected labor consulting companies further demonstrates the limitations of generic studies.

On the other hand, Hewitt's advice to the Company's is more accurate because it is based not only on its extensive knowledge of medical plans and expenses but also on the Company's own demographics and claims experience. *Tr. 200, ll. 19-24.* The company-specific nature of the Hewitt study is important because utility workforces are different from those in other industries. Most notably, the Company's workforce is 60% union and has a higher percentage of its workforce within 10 years of retirement age. Both of these elements can drive up healthcare costs.[93]

<u>CCS Adjustment</u>: CCS proposes a reduction in medical expenses of $2,403,260 on a Utah basis. Mr Schulz argues that because the Company's actual 2007 costs were less than forecasted, the 2008 forecast should be reduced by the amount by which the Company over

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[91] DPU Exhibit 5.0, Garrett Direct/17, ll. 314-318 and 330-331.

[92] DPU Cross Exhibit 1.

[93] Wilson Rebuttal/22, ll. 473-476; Tr. 200, ll. 14-18. Mr. Garrett claims that the Towers Perrin study addressed older workers, so the Commission should discount the fact that the Company has an aging workforce. *Tr. 289, ll. 16-21.* This statement is inaccurate. The Towers Perrin study addressed older retirees, not employees. *Tr. 329, l. 23-Tr. 330, l. 4.*

estimated 2007 medical costs.[94] This proposal is based on Mr. Schultz's mistaken belief that the Company used its 2007 forecasted medical expenses to create its 2008 forecast. However, because the Company did *not* use the 2007 forecast as the basis for its 2008 forecast, Mr. Schultz's adjustment must be rejected.[95]

More importantly, a review of the actual expenses in the first part of 2008 shows that the Company's 2008 forecast is in reality conservative.[96] In fact, if the Company's actual expenses from January through March of 2008 are annualized for the entire year, the result is $2 million higher than forecast.[97] Mr. Schultz attempts to discredit the validity of these actual expenses by stating that the claims for the first six months of 2007 "would have had to be" significantly higher than the last months.[98] Mr. Schultz does not, however, support this statement or explain why the Company's actual results for the first three months of 2008 are not indicative of the accuracy of its forecast.

f. Relocation Expense Adjustment

The Company offers a relocation program, designed and administered by a third party consultant, to attract skilled employees and compete with other employers in the marketplace. The costs of the program have increased in recent years due to changes in the economy, the housing market downturn, and a shortage of employees with required skill sets. The Company has restructured its relocation benefits in order to contain these costs, but it cannot reduce them any further without compromising its ability to attract a qualified workforce.[99] Accordingly, the costs included in this case, which are based on Base Year costs, reflect these increases.

CCS proposes that instead of using Base Year costs, the Company should set relocation expenses based on a five-year historical average, resulting in a reduction of $218,519 on a Utah

[94] Exhibit CCS-6, Schultz Direct/21, ll. 468-470, 476-478.
[95] The fact that the Company's forecast for 2008 is actually *lower* than its 2007 forecast shows that the Company did not use the 2007 forecast to predict medical expenses in 2008. *See* Exhibit CCS 6.7.
[96] Wilson Rebuttal/23, ll. 496-497.
[97] *Id.* at 23, ll. 497-500.
[98] Exhibit CCS-6SR, Schultz Surrebuttal/20, ll. 439-445.
[99] Wilson Rebuttal/25, l. 563-26, l. 573.

basis.[100] This recommendation ignores entirely the fact that relocation costs have been increasing steadily over the past several years and there is no indication that the factors driving these increases will turn around. Moreover, Mr. Schultz' recommendation to use a five-year average appears to be completely results-driven given that he recommends this method only with respect to a few select cost categories where it serves to reduce expense. Mr. Schultz has not presented a persuasive reason why the Commission should depart from the uniform methodology of using base year costs to set labor expenses.

g. Capitalization

DPU recommends that the Company's capitalization ratio be increased from 26.61% to 28.08%. *Tr. 290, ll. 12-20.* The resulting adjustment to expenses will depend on the Commission's decision on other adjustments, but Mr. Garrett expects this adjustment to be approximately $3 million. *Tr. 292, ll. 2-10*.

First, the Commission should be aware that DPU introduced this adjustment for the first time in its surrebuttal testimony. Therefore, the Company had no opportunity before the hearing to prepare a written response to this proposal.[101]

Second, and more importantly, the method by which Mr. Garrett arrived at this adjustment is completely arbitrary. As Mr. McDougal explained at the hearing, Mr. Garrett took his capitalization rate from 2007 data—the year during which the Company incurred unique costs related to the MEHC transition.[102] Mr. Garrett then applied this capitalization rate to forecasted 2008 labor costs in this case, but did so without adjusting for the MEHC transition costs that are a component of the base costs used to develop the 2008 forecasted labor. *Tr. 58, l. 18-59, l. 13.* Essentially, Mr. Garrett used a capitalization rate that includes unusually high, non-recurring labor items and applied it to a normalized test period with no such items. However, as can be seen in Appendix A, if the capitalization rate proposed by the Company in this case is

[100] Exhibit CCS-6SR, Schultz Surrebuttal/24, ll. 533-537.
[101] The Company offered to introduce a sur-surrebuttal exhibit illustrating the problems with Mr. Garrett's proposal. However, the Commission ruled the exhibit inadmissible.
[102] Tr. 58, ll. 5-17; RMP Cross 6.

adjusted for the transition changes, the 26.61% rate becomes 28.17%—which is even higher than the rate proposed by Mr. Garrett. One can either apply a lower percentage to a higher, unadjusted total labor cost, or a higher percentage to a lower, adjusted total labor cost with the same result. Either approach would be the same in the Company's case and would not change the amount expensed or capitalized. However, if Mr. Garrett's proposal were applied correctly, it may actually increase the revenue requirement in this case because the amount of labor capitalized would decrease from the comparable calculations of 28.17% to 28.08%. *Tr. 59, ll. 6-13.* DPU's adjustment is based on an inaccurate and unreasonable calculation method and should be rejected.

h. Other Labor Issues

In addition, the Commission should allow the following labor costs for the reasons stated in the testimony of Messrs. McDougal and Wilson:[103]

- **Pension, Post-retirement, and Post-employment Expenses**: $33,571,791 in pension, post-retirement, and post-employment expenses on a Utah basis.[104]

- **Other Employee Benefits**: $708,793 in additional costs associated with a new random drug and alcohol testing policy, a more detailed fitness-for-duty examination driven by an aging workforce, and a change to the annual benefits open enrollment program on a Utah basis.[105]

- **Pension Administration Expenses:** $410,777 to cover increased pension administration costs resulting from federally mandated changes to the Company's pension plan on a Utah basis.[106]

- **Injuries and Damages Adjustment:** $1,631,951 in expenses on a Utah basis for injuries and damages.[107]

D. General Revenue Requirement

a. Cash Working Capital

Cash working capital ("CWC") is a rate base component that measures the amount of cash that a utility's investors must advance to fund the utility's day-to-day operations. The

[103] Wilson Rebuttal/23, l. 503-25, l. 549; McDougal Rebuttal/11, l. 221-22, l. 246.
[104] Exhibit RMP SRM-1R-RR at 4.10.2; 4.10.15.
[105] *Id.*; Wilson Rebuttal/24-25, ll. 535-549.
[106] Exhibit RMP SRM-1R-RR at 4.10.2; 4.10.15; Wilson Rebuttal/24, ll. 513-514.
[107] Exhibit RMP SRM-1R-RR at 11.7; McDougal Rebuttal/11, l. 220-12, l. 246.

Company calculates CWC through a lead-lag study. A lag, which creates a need for working capital, results from the fact that cash payments are generally received from customers after service has been provided. A lead, which is the source of working capital, results when there is a delay between the recording of an expense and the actual cash payment of the expense. The difference between the lead and the lag can be either positive or negative, and is expressed in days; that number of days is then multiplied by the average daily operating which quantifies the working capital required for, or available from, the utility operations.[108] The Company's lead-lag study shows a CWC requirement for the Utah jurisdiction of $31.6 million. DPU and CCS have each raised different objections to the Company's lead-lag study—neither of which is valid.

DPU Adjustment: Mr. Garrett argues that the Company's lead-lag study is unreliable, and that therefore the Company's CWC requirement should be set at zero. Specifically, DPU argues that certain factors such as Company processes and procedures may have changed since the lead-lag study was first conducted in 2003, which changes may have affected the outcome of the study. Mr. Garrett also expresses concern that because the Company provided only a summary of its study in this case, and because the Company no longer retains the source documents (such as cancelled checks and payment vouchers), the study cannot be validated. Finally, Mr. Garrett claims that the lead-lag study has never been vetted or validated by any regulatory body,[109] and in fact was rejected by the only Commission that ever considered the study.[110] Mr. Garrett is wrong on the facts and the law.

First, Mr. Garrett's claim that the lead-lag study has never been vetted is untrue. The 2003 lead-lag study has been filed with the Commission since 2004 and was relied upon by the Company in its 2004 and 2006 rate cases. In the 2004 rate case, DPU Bruce Moio filed testimony on the Company's CWC request, but voiced no criticism of the lead-lag study.[111] These facts are completely inconsistent with Mr. Garrett's speculation that no one from DPU

[108] McDougal Rebuttal/42, ll. 917-930.
[109] DPU Exhibit 5.0SR, Garrett Surrebuttal/4, ll. 47-51.
[110] DPU Exhibit 5.0, Garrett Direct/5, ll. 82-88.
[111] RMP requests that the Commission take administrative notice of the DPU testimony filed in Docket No. 04-035-42.

reviewed the lead-lag study.

Second, there is no change in circumstances that renders the 2003 study obsolete. The Company has typically prepared a lead-lag study every five years, and the current study is no exception. However, as explained by Mr. McDougal, the Company updates its lead-lag studies whenever there is a material change in circumstances affecting the lead-lag calculation, such as changes in billings, collections, or accounts payables. Accordingly, the Company revised the 2003 study to reflect changes in the timing of its tax payments. That said, the Company is not aware of any other changes in circumstances that would require additional adjustments.[112]

Moreover, this Commission has never indicated that it would reject a five-year-old lead-lag study because of its age. On the contrary, the Company filed its general rate case in Docket 99-035 based on 1998 test year data using the Company's December 1991 lead-lag study. That seven-year-old study was accepted by the Commission in determining the appropriate level of CWC to include as a rate base component.[113]

Finally, Mr. Garrett's suggestion that the Washington Utilities and Transportation Commission ("WUTC") rejected the 2003 lead-lag study because of its age is incorrect. In fact, in the case cited by Mr. Garrett the Commission rejected both WUTC Staff and Company CWC calculations for reasons entirely unrelated to the age of the studies.[114]

[112] McDougal Rebuttal/48, ll. 1042-1052.

[113] *Id.* ll. 1055-1059.

[114] In support of his position Mr. Garrett cites an order issued by the WUTC in the Company's consolidated general rate case and hydro deferral docket. Dockets UE-050684 and UE-050412. In those cases the staff of the WUTC ("Washington Staff") argued that the Commission should reject the Company's lead-lag study as a means of determining CWC, and should instead base its findings on the its own Investor-Supplied Working Capital ("ISWC") analysis derived from the Company's balance sheet. *Wash. Util. & Transp. Comm'n v. PacifiCorp dba Pacific Power & Light Co*., Docket No. UE 050684, Order 4 at 64 (Apr. 17, 2006). In support of its proposal, Washington Staff argued that the Commission had always rejected the use of lead-lag studies in favor of ISCW analysis and that the ISCW was the superior method. *Id.* at 65. The Commission rejected the arguments of both Washington Staff and the Company for two reasons: First, the Commission found that the actual amounts of current assets and CWC in dispute were derived by *both* studies based on the Revised Protocol allocation that had been rejected in the same order. *Id.* Second, finding that the "core of the dispute" was "as much about methodology as about numbers", the WUTC concluded that neither party had made a strong enough evidentiary case for its own methodology. *Id.* at 66. However, contrary to Mr. Garrett's claims, the WUTC found no fault at all with the Company's lead-lag study itself, and certainly made no suggestion that the study was too old to be valid. In fact, the WUTC stated that it was puzzled by the parties' arguments about alleged errors in the study given that no party cited to the record for evidence of the study or facts or methods used in the study. *Id.* at 67 n.268.

While Mr. Garrett argues generally that he believes that the Company's lead-lag study is outdated, he can point to no specific update that the Company should have made. Nor can he point to any valid case law to suggest that the study should be disregarded. Therefore, the Commission should reject DPU's adjustment to CWC.

CCS Adjustment: CCS does not ask the Commission to reject the lead-lag study, but instead recommends that the Commission alter the Company's methodology to incorporate the lag associated with payment of long term debt. CCS reasons that because the Company recovers in rates the funds to pay interest on long-term debt, it makes sense to include it in the lead-lag study. *Tr. 574, ll. 6-12.* CCS' position should be rejected for several reasons.

As discussed in Mr. McDougal's testimony, the favored approach to calculating CWC is to consider only those revenues and expenses connected with day-to-day operations. Accordingly, the cash lead associated with the components of operating income—interest on long-term debt, and common and preferred dividends (as well as the non-cash item of depreciation)—are commonly excluded[115] on the theory that these revenues are not related to the provision of source[116] or, similarly, because these are capital expenses.[117] On the other hand, if the lead associated with interest on long-term debt or the payment of common or preferred dividends is to be included in the calculation, then there must be a corresponding adjustment for lag involved in the receipt of operating income.[118] Moreover, the lead associated with payment of interest on long-term debt is also considered in setting the cost of debt incorporated in the Company's allowed return on equity. If the cost of debt is to be altered by including this lead in setting CWC, then the calculated cost of debt would need to be reconsidered as well.

CCS witness Ms. DeRonne's approach fails to consider all of these factors. Ms. DeRonne recommends that the Commission include the lead associated with the payment of

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[115] McDougal Rebuttal/44, ll. 945-959.

[116] *Hawaiian Elec. Co. v. Hawaii Pub. Util. Comm'n*, Order No. 7678 at 69-70 (Sept. 16, 1983).

[117] *Re Public Service Co. of Colorado*, Order No. C84-589 at 21 (May 22, 1984).

[118] McDougal Rebuttal/46, l. 1001-47, l. 1027. *See also*, *Re Application of PacifiCorp for a Retail Electric Utility Rate Increase of $14.8 Million Per Year*, Docket No. 2000-ER-03-198, Order at para. 57a, 57b (Feb. 28, 2004).

interest on long-term debt, while ignoring the lag associated with the receipt of operating income or the effect of its inclusion on the calculation of the Company's ROE. Ms. DeRonne says nothing about why she is recommending the inclusion of the lead associated with one aspect of operating income and not others. Indeed, when asked at hearing whether she had provided a comprehensive analysis of the impact of including the lead associated with the other components of operating income, Ms. DeRonne conceded: "I didn't cite each of these individual factors. I believe they're intuitive in looking at the cash and what the CWC, the purpose of that is." *Tr. 594, ll. 5-9*

This is precisely the approach rejected the Commission rejected when it excluded consideration of depreciation, interest expenses, and common and preferred dividends from CWC calculations, when it stated: "If this method is to be changed, a strong burden of persuasion will first have to be met which must include a comprehensive analysis of all four of [these] above-mentioned items."[119]

b. O&M Escalation

In calculating non-labor O&M expenses, the Company started with Base Period expenses, and then to account for inflation, applied escalation factors published by Global Insights to bring the Base Period costs to the Test Year.[120] The Global Insights factors, which range from 1.3% to 5.7%, are prepared at the FERC functional subcategory level to more accurately capture growth in cost categories that may be higher or lower than indexed inflation.[121]

CCS recommends that the Company discard the Global Insights indices in favor of an across-the-board escalation factor of 1.25%, resulting in a $5,856,025 reduction in revenue requirement on a Utah basis.[122] As justification for this proposal, Ms. DeRonne states that the Company expects to hold O&M costs in 2008 and 2009 level with those experienced in 2007 by

[119] *Re Mountain Fuel Supply Co*., Docket No. 93-057-01, Order at 52 (Jan. 10, 2004).
[120] McDougal Direct/23, ll. 509-513.
[121] McDougal Direct/24, ll. 523-525; McDougal Direct/25, ll. 546-549.
[122] Exhibit CCS-2D, DeRonne Direct/23, ll. 497-509 and 27, ll. 592-597.

absorbing and offsetting inflationary pressures with labor efficiencies.[123] These documents, however, do not support Ms. DeRonne's adjustment.

O&M costs in the Company's case account for *both* inflation *and* the labor savings. As discussed above, the Company used the most specific and accurate escalation factors available to account for inflation. And as also discussed above, the labor costs in this case include significant efficiencies related to MEHC transition-related labor reductions and AMR savings.[124] When both of these forces are accounted for, it can be seen that overall O&M costs in this case are indeed decreasing.[125]

CCS' adjustment however, would have the Commission include the savings in its filing, but exclude the real inflationary pressures faced by the Company. In so doing, CCS would effectively double count the cost reductions and penalize the Company for taking cost control initiatives. This adjustment should be rejected.

c. Property Taxes

The Company's rate filing reflects a property tax estimate of $79.7 million. *Tr. 161, ll. 13-19.* This estimate, which represents an approximate $10.6 million rise over the Company's actual 2007 property tax expense, is a direct result of the Company's higher level of taxable property. *Tr. 161, ll. 20-24.*

CCS recommends a property tax expense of $70.7 million.[126] Ms. DeRonne calculated this expense by applying the Company's property tax increase from 2006 to 2007—2.36 percent—to the Company's actual 2007 property tax expense.[127] Ms. DeRonne's method is flawed. First, this method bears no relationship to how states actually assess property taxes. *Tr. 162, ll. 16-22.* Property taxes are based on property values as determined using appraisal methodologies. Appraisers simply do not use a percentage change method to value property. *Tr. 162, l. 19-163, l.1.* Second, the method assumes that all of the factors relevant to establishing tax

[123] Exhibit CCS-2D, DeRonne Direct/23, ll. 504-509.
[124] McDougal Rebuttal/36, ll. 782-791.
[125] For a quantitative illustration see, Appendix B.
[126] Exhibit CCS-2SR, DeRonne Surrebuttal/27, ll. 600-602.
[127] Exhibit CCS-2D, DeRonne Direct/34, ll. 750-756.

rates and property assessment in 2007 will affect the Company's tax rates in 2008 in the same way. *Tr. 163, ll. 2-7*. This is an unreasonable assumption, given that recent decreases in property tax rates and recent changes in laws that both depressed tax rates are unlikely to continue. *Tr. 163, ll. 8-21*.

Third, Ms. DeRonne's method fails to consider the substantial rise in property value that is subject to tax in 2007. *Tr. 164, ll. 4-11*. The Company has received 2008 property tax assessments in four of the ten states in which the Company operates that equal a *$901,000,000 increase* in assessed property over the 2007 level. *Tr. 166, l. 21-167, l. 4; Tr. 599, ll. 1-18*. If the Company applies a 1.2% tax rate to that property increase, the increase in property tax will be $10.8 million. *Tr. 167, ll. 1-4*. Given that the increase in assessed property accounts for only four of the Company's ten states where it owns property, the $10.8 million increase is conservative.

On the other hand, CCS' proposed property tax expense level of $70.7 million is only $1.6 million more than the Company's 2007 actual property tax expense of $69.1 million. *Tr. 598, ll. 8-24.* Ms. DeRonne states that CCS' proposed $1.6 million increase in property taxes is sufficient to account for the $901,000,000 in assessed property value. *Tr. 599, l. 25-600, l. 6.* The increase in assessed property would need to be taxed at a rate of only .18% for CCS' result to be accurate. This result is patently unreasonable, as even Ms. DeRonne appeared to agree. *Tr. 604, ll. 7-20.* The Commission should therefore reject CCS' adjustment.

d. Generation Overhaul Expense

In its rebuttal testimony, the Company agreed to revise its calculation of generation overhaul expense to a four-year historical average, as recommended by CCS, rather than an escalation of Base Year costs. As explained by Mr. McDougal at hearing, this approach makes sense for two reasons. First, overhaul costs have historically varied from year to year, and employing an average serves as a smoothing—or normalizing—mechanism to produce a reasonable annual number. Second, the Company's GRID model schedules planned outages at a four-year average rate to determine net power costs. *Tr. 53, ll. 15-23.*

However, as further explained by Mr. McDougal, if a four-year average is to be used to calculate overhaul costs, the method must be employed correctly. First, the costs incurred in each of the four previous years must be escalated to account for inflation.[128] Failing to account for inflation understates the amount of overhaul expenses the Company can expect to incur in the future.[129] Second, the historic overhaul expenses must be adjusted to include new Lake Side and Currant Creek facilities. Excluding overhaul for new generation would unacceptably ignore the real need to maintain these facilities and jeopardize the safety and reliability of the Company's generation resources. For these reasons, the Company's rebuttal adjustment includes inflation factors for the four historic years and a four-year average of Currant Creek overhaul costs. The Company included the projected four-year average Lake Side overhaul costs in the incremental generation O&M adjustment.[130]

Ms. DeRonne argues that the historical costs should not be escalated to the 2008 level because the costs fluctuate over time, both upward and downward.[131] Ms. DeRonne appears to be confusing the purpose of normalizing—to "smooth out" fluctuations in cost—and the purpose of escalating—to account for inflation. There is no question that generation expenses the Company incurred in 2004 would cost the Company more in 2008 and in future years. Consequently, there is no reasonable basis for excluding inflation from the calculation.

At hearing, Ms. DeRonne stated that the Company used escalation factors as high as 15% to escalate the historical costs to 2008, apparently in an attempt to imply that the Company's escalation factors are unreasonable. *Tr. 577, ll. 4-8.* Ms. DeRonne clarified, however, that the 15% she cited was the total escalation factor used to bring the 2004 numbers to 2008, not an annual escalation factor. *Tr. 597, l. 17-598, l. 4.* There is no valid evidence that the escalation factors used by the Company were inappropriate.

Ms. DeRonne also argues that the Company's overhaul expense should not be adjusted

[128] McDougal Rebuttal/6, ll. 100-109, 117-119.
[129] McDougal Rebuttal/6, l. 120-7, l. 122.
[130] McDougal Rebuttal/7, ll. 123-133.
[131] Exhibit CCS-2SR, DeRonne Surrebuttal/13, ll. 279-286.

for inflation or to include new generation because, even without those adjustments, CCS' proposed overhaul expense level is higher than the Company's budgeted amount for the Test Year.[132] This argument is based on the fact that the Company has stated its intention to file another general rate case in June of 2008, so rates will likely not be in effect for multiple years.[133] It would be unreasonable, however, for the Commission to attempt to predict how long rates will be in effect in this or other rate cases. The Company has not yet filed a new rate case, and even when it does, that case may be delayed or settled without Commission decision. The Company is entitled therefore to a reasonable determination of prudent overhaul costs. Moreover, as pointed out at hearing, while the Company's proposed overhaul costs exceed the amount budgeted for overhaul in 2008, the same costs are significantly below the overhaul costs budgeted for 2009—a year in which the rates adopted in this case will certainly be in effect.

e. Renewable Energy Adjustments

No party has raised a direct challenge to the prudence of the renewable projects included in this case. *Tr. 100, ll. 3-8.* Instead, UIEC has proposed to reduce recovery for these and future projects by imputing various credits—for REC values, capacity factors if lower than projected, and the production tax credit if the credit expires before completion of a project. The latter two adjustments are proposed on a policy basis only, without a specific revenue requirement impact in this case. *Tr. 144, ll. 2-4.* These proposals either change the Commission's prudence standard or are unnecessary because of this standard, warranting their rejection in either case.[134] In addition, adoption of these proposals could deter renewable resource acquisition by creating regulatory uncertainty for resources or transactions without a guaranteed outcome. *Tr. 144, l. 5-145, l. 13.*

UIEC proposes to increase the Goodnoe Hills' REC value from $3.50 MWh to $6.05/MWh, reducing Utah revenue requirement by $290,000.[135] The Company applied the

[132] Exhibit CCS-2SR, DeRonne Surrebuttal/13, l. 288-14, ll. 297.
[133] Exhibit CCS-2SR, DeRonne Surrebuttal/14, ll. 309-314.
[134] Tallman Rebuttal/9, l. 186-10, l. 226; 13, l. 285-14, l. 293.
[135] *Id.* at 16, ll. 336-340.

$3.50/MWh REC value to all renewable projects in the case and there is no basis for applying a different, higher REC value to Goodnoe Hills as a "backdoor" prudence challenge to the project.[136] Additionally, fixing the REC value for Goodnoe Hills at $6.05/MWh in this case could prove detrimental to customers if, as is likely, REC values increase in the future. *Tr. 103, ll. 6-13.*

This case presents another issue related to the Goodnoe Hills RECs. The Energy Trust of Oregon has proposed to fund $4.5 million of the project and assign the RECs associated with this investment to Oregon customers. This case reflects a $358,840 Utah O&M credit associated with the Trust funding applicable during the test period.[137] To the extent that the Utah Commission wishes to displace the Trust funding and receive the allocated share of the RECs that would otherwise be assigned to the Trust, it may do so by reversing the O&M credit in this case and increasing Utah revenue requirement by $358,840.[138] If the Commission decides against displacing the Trust funding, the revenue requirement in this case will not change.

CCS presents another renewable adjustment—whether to include warranty costs of $92,276 on a Utah basis associated with the Leaning Juniper 1 plant for the last quarter of 2008 after the warranty expires.[139] The warranty costs are a reasonable proxy for ongoing equipment repair and replacement expense and should remain in the case.[140]

f. UIEC's Jurisdictional Allocation Adjustment

On the last day of the hearing, in cross examination, UIEC asked Ms. DeRonne a hypothetical question about the impact of the reduction in load on the Company's allocation factors. *Tr. 619, l. 21-621, l. 18.* Apparently based solely on this exchange, *after the hearing*, UIEC for the first time proposed a $22 million adjustment for load forecasts and allocation

[136] *Id.* at 17, l. 368-18, l. 376.

[137] The record from the hearing on this point is confusing because some of the questions and answers wrongly imply that the $358,840 amount associated with the Trust funding was a cost added to revenue requirement, not a credit applied to reduce it. To be clear, a decision to displace the Trust funding would result in removal of the credit, increasing revenue requirement. *Tr. 145, l. 21-146, l. 3.* A decision not to displace the Trust funding would result in no change to revenue requirement because the credit would remain in the case.

[138] Tallman Rebuttal/22, ll. 480-481.

[139] *Id.* at 3, ll. 52-69

[140] *Id.* at 23, ll. 44-49.

factors. UIEC did so by including this adjustment in the joint issue matrix.[141] While UIEC filed testimony raising concerns about load forecasts and allocation factors, it never advocated for an adjustment before or during the hearing. With no notice that UIEC would base a $22 million adjustment on policy-type testimony, the Company waived cross-examination on UIEC's witness.

The Commission's consideration of UIEC's adjustment would violate the Commission's rules and the concept of fundamental fairness upon which the rules are based. In particular, Rule 746-100-10K, states: "The Commission may prohibit parties from making their case through cross examination." Moreover, in its February 13, 2008 ruling, the Commission stated "[w]e continue to expect parties to present their position and evidence in support of their positions through their own witness."[142] The central purpose of these policies is to avoid precisely what has occurred in this case—a party waiting to espouse its position until (or even after) the end of a hearing, allowing the opposing party no opportunity "to be heard and defend."[143] For this reason, the Commission should disregard UIEC's Adjustment.

In addition, UIEC's adjustment lacks evidentiary support.[144] Most fundamentally, there is no testimony proving that the Company has incorrectly forecasted Utah loads in this case. *Tr. 149, l. 18-150, l. 23.* Additionally, not a single witness in the case testified in support of UIEC's adjustment. In fact, Ms. DeRonne's testimony itself undermines UIEC's proposed Adjustment. In response to the question posed by UIEC's counsel regarding the impact that even a 1% change on the SG and SE factors may have on costs allocated to Utah, Ms. DeRonne indicated that she was "not sure" if it was appropriate to change just one factor in isolation, because then "you've

[141] UIEC also included a Transmission Revenue Credit adjustment of $300,000 (Utah) in the joint matrix. The Company assumes that this adjustment was included in error because in UIEC's response to RMP Data Request 2.1, UIEC stated that it was withdrawing this adjustment. RMP relied upon this representation in not addressing the adjustment at hearing. *Tr. 49, ll. 17-24.*

[142] *See Re. Application of Rocky Mountain Power for Authority to Increase Its Retail Util. Serv. Rates in Utah,* Docket No. 07-035-93 Scheduling Order (Dec. 27, 2007).

[143] *See R. W. Jones Trucking, Inc. v. Pub. Serv. Comm'n of Utah*, 649 P.2d 628, 629 (Utah 1982) (citing *Fuller-Toponce Truck Co. v. Pub. Serv. Comm'n*, 96 P.2d 722 (Utah 1939)).

[144] Any finding by the Commission requires substantial evidentiary support. The Utah Supreme Court defines substantial evidence as "that quantum and quality of relevant evidence that is adequate to convince a reasonable mind to support a conclusion." *Bradley v. Payson City Corp.*, 70 P.3d 47 (Utah 2003).

got to change the inputs that affect that factor." *Tr. 620, ll. 13-15 and 19-25.*

Likewise, Mr. McDougal, explained that such a change cannot be viewed in isolation and that inputs affecting a 1% change in the SE and SG factors will necessarily also affect revenues and net power costs. *Tr. 92, ll. 4-11*. For example, assuming a change in the underlying load assumptions causes a percentage change in SG and SE allocation factors, the same load assumptions are used in calculating the situs retail revenues and net power costs in the case. Thus, to the extent the Company uses a lower Utah load in the model, a percentage change in the SG and SE allocation factors will occur, causing not only Utah's allocated costs to decrease, but because the same load assumption is then multiplied by Utah's current rates to calculate Utah revenues, also causing Utah's revenues to decrease. They do not remain the same, as UIEC would have the Commission believe. UIEC's proposed adjustment is without merit and evidentiary support and should be rejected.

g. Powerdale Decommissioning

Prior to the hearing in this case, the Commission issued an order approving deferred accounting treatment for costs related to the decommissioning of the Powerdale hydroelectric facility. That order did not resolve specific issues affecting the revenue requirement in the order.[145] The Company proposes amortizing the Powerdale decommissioning costs over three-years, beginning on January 1, 2008. *Tr. 60, ll. 4-10.*

CCS argues that the Company should defer amortization of Powerdale decommissioning costs until decommissioning actually occurs.[146] Ms. DeRonne argues that the Company may not incur decommissioning costs for Powerdale until April 2010 and that deferring recovery would allow more certainty of actual costs and potential offsets to decommissioning costs, such as insurance proceeds and salvage value.[147]

The Commission should reject CCS' recommended adjustment and allow amortization of

[145] McDougal Rebuttal/8, ll. 152-154 and 158-162; Docket No. 07-035-14.

[146] Exhibit CCS-2SR, DeRonne Surrebuttal/18, ll. 385-392. The Company removed rate base associated with the Powerdale decommissioning from rate base. McDougal Rebuttal/8, l. 163-9, l. 173.

[147] Exhibit CCS-2D, DeRonne Direct at 7, ll. 148-8, l. 172.

Powerdale decommissioning costs as recommended by the Company. This treatment accords with normal ratemaking policy that customers who benefit from a resource should bear the burdens as well.[148] It also is consistent with Commission precedent. The Commission previously allowed the Company to begin recovery of decommissioning costs related to the Glenrock Mine and the Condit Dam prior to the Company incurring such costs. *Tr. 96 ll. 10-20.* CCS' recommendation creates a mismatch between the benefits and the costs of resources and should be rejected.

h. SO2 Allowance Amortization

UAE proposes to reduce the amortization period for SO2 allowance sales occurring after January 1, 2008, from four to three years.[149] The only justification for this change is that it would allow customers to receive the benefit over a shorter period of time.[150] The four-year amortization period in Utah is already the shortest used by the Company.[151] UAE has presented no persuasive reason why the Commission should change course and order a shorter amortization period in this case.

i. Office Reconfiguration Expense

The Company has proposed a three-year amortization of the $324,596 in office reconfiguration expenses (Utah) for which DPU proposed disallowance. *Tr. 62, l. 19-63 l. 1.* The reconfiguration resulted in lease expense savings that benefit customers.[152] The Company expects to incur office configuration expenses each year and should therefore be allowed to recover these expenses, especially given the Company's proposal to amortize them over three years. *Tr. 64, ll. 13-23.*

E. Policy Issues

DPU and CCS have proposed several policy recommendations for future rate filings. Because rate case filing requirements are set forth in the Commission's rules, these issues should

[148] McDougal Rebuttal/9, ll. 178-182.
[149] UAE Exhibit RR 1/3, ll. 17-21.
[150] UAE Exhibit 1.0SR-RR/8, ll. 17-21.
[151] McDougal Rebuttal/29, ll. 635-636.
[152] *Id.* at 38, ll. 829-831.

be addressed in a rulemaking, not in this rate case. DPU appears to acknowledge this in its alternative recommendation that the Commission initiate a rulemaking for filing requirements.[153]

Substantively, both the DPU and CCS recommendations improperly impact the operation of the 240-day statutory timeline. DPU proposes stopping the clock if the Commission selects a test period other than the test period used by the Company in its original application.[154] CCS recommends that the 240-day statutory clock begin only after parties receive supporting documentation, such as that contained in the Master Data Requests.[155]

As DPU acknowledges, proposals that interfere with the operation of the 240-day statutory period raise serious legal issues.[156] Stopping and starting a statutory timeline in effect extends the timeline—a legal decision beyond the Commission's authority. Additionally, these proposals present poor regulatory policy by delaying cost recovery, reducing the Company's ability to achieve its authorized rate of return, and providing customers with poor price signals.[157]

III. CONCLUSION

For the reasons described above, Rocky Mountain Power respectfully requests that the Commission approve its full request for a revenue requirement increase of $74.5 million.

RESPECTFULLY SUBMITTED: June 19, 2008.

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

[153] DPU Exhibit 3.0, Brill Direct/15, l. 305-306.
[154] DPU Exhibit 3.0, Brill Direct/17, l. 356-361.
[155] CCS-1D RR, Murray Direct/6, l. 121-141.
[156] *Id.* at 18, l. 375-376.
[157] Walje Rebuttal/8, l. 182-9, l. 190.

Appendix A

CAPITALIZATION PERCENTAGE IMPACT

LABOR INCLUDED IN RATE CASE

	Forecast December 2008	MEHC Transition Adjustment	MEHC Transition Savings	Total
Utility Labor	542,206,774	(28,449,226)	(12,222,490)	**501,535,058**
Capital/Non-Utility	196,666,438			196,666,438
Total	738,873,213	(28,449,226)	(12,222,490)	698,201,497
Capitalization Percent	26.617%			28.168%

All numbers, other than percents, are per the DPU in data request 49.1. This was included in the revenue requirement proceeding as RMP cross exhibit

Appendix B

			Non-NPC O&M	
	Reference		June 2007 Actual	Dec. 2008 UT Rate Case
Unadjusted	(1)	4.0.4 & 4.0.11	2,631,906,377	3,426,514,714
Remove NPC	(1)	5.1.2	(1,662,276,736)	(2,444,760,953)
Remove BPA	(1)	5.1.2	74,724,465	
Remove DSM	(1)	4.6	(31,936,536)	
MEHC CIC Accrual	(1)	4.11	(28,449,226)	
Non-NPC O&M			983,968,344	981,753,761
Rebuttal Updates				
Wind O&M	(2)	11.2		(1,268,008)
Generation Overhaul	(2)	11.3		(6,521,799)
Labor Merit Increase	(2)	11.5		(446,194)
AMR Reductions	(2)	11.6		(514,061)
Injuries and Damages	(2)	11.7		(3,866,270)
Lease Expense	(2)	11.9		(895,140)
Outside Services	(2)	11.10		(927,637)
Company Plane	(2)	11.11		(111,942)
Advertising Expense	(2)	11.12		(420,016)
Customer Accounting	(2)	11.13		(109,729)
Sierra Club Settlement Fees	(2)	11.14		(524,061)
Dues and Membership Fees	(2)	11.14		(101,203)
			983,968,344	966,047,701
Live Surrebuttal				
Office Consolidation	(3)	12.1		(569,922)
Outside Services	(3)	12.2		(222,037)
Advertising Expense	(3)	12.3		(75,676)
			983,968,344	965,180,066

NOTES:

(1) Per Exhibit RMP___(SRM-1S)
(2) Per Exhibit RMP___(SRM-1R-RR)
(3) Live Surrebuttal