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Division of Public Utilities

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MEMORANDUM

DIVISION INITIAL EBA COMMENTS AND RECOMMENDATIONS

To: Public Service Commission

From: Division of Public Utilities
Chris Parker, Director
Energy Section
Matt Croft, Utility Analyst
Claire Oman, Utility Technical Consultant
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Date: April 27, 2012

Subject: Docket No. 12-035-67, EBA Amortization, Review Report— The Division's Initial Comments on Rocky Mountain Power's request to increase rates through the Energy Balancing Account

RECOMMENDATION (INTERIM APPROVAL):

Rocky Mountain Power's ("Company") application requests the recovery of Energy Balancing Account ("EBA") costs consisting of (1) $9.3 million (including interest) representing the difference between actual Energy Balancing Account Costs[1] ("EBAC") and base EBAC for the period October 1, 2011 through December 31, 2011; and (2) $20 million of deferred net power costs approved by the Utah Public Service Commission (Commission) in Docket No. 10-035-124.

[1] See definition of EBAC on page 4.

After a preliminary review of the application, the Division of Public Utilities ("Division") recommends the Commission approve a requested rate change of $9,028,831 associated with EBA costs, on an interim basis, effective June 1, 2012. This rate change, which represents the difference between actual EBAC and base EBAC is $257,175 less than the Company's requested increase. These new rates will remain on an interim basis until the Division finishes its audit at which time the Division will file a final report with the Commission.

The Division recommends that the Commission approve, on an interim basis, the Company's request to increase rates to recover the $20 million in deferred NPC previously approved by the Commission. The Division recommends an "interim" rate approval from the perspective that a final true-up of deferred NPC may be necessary at the end of the three year amortization period as ordered by the Commission in Docket No. 10-035-124.

The Division recommends that the Commission approve the Company's requested rate spread for the $9.0 million EBA deferral balance. The Company's chosen rate spread is a close representation of the general revenue requirement spread approved by the Commission in Docket No. 10-035-124. Certain limitations prevented the exact rate spread percentages from Docket No. 10-035-124 from being incorporated in the Company's EBA filing. These limitations are discussed later.

Finally, the Division recommends that the Commission approve the Company's requested rate spread of the $20 million NPC deferral amortization. The Company's chosen rate spread is a close representation of the general revenue requirement spread approved by the Commission in Docket No. 10-035-124. Certain limitations prevented the exact rate spread percentages from Docket No. 10-035-124 being incorporated in the Company's EBA filing. These limitations are discussed later.

In Docket No. 11-035-T10, Division witness Mr. Matthew Croft outlined several items the Division would consider in its 45 day review of the Company's annual March 15th filing. These items include the following:

1. Conformity of the Company's filing to expectations set forth in the Division's Draft EBA Pilot Program Evaluation Plan.

2. Correct implementation of the EBA formula.

3. Whether the correct FERC accounts, sub accounts and sub-sub accounts were used in the EBA deferral calculations.

4. Overall mathematical accuracy

5. General Review of Company explanations for deviations between actual and base EBA costs.

6. Proper Implementation of the Commission approved rate spread.

This memorandum addresses the issues outline above as well as other issues. To the extent that the Commission's findings and order changes the Company's proposed tariff in the EBA tariff docket, Docket No. 11-035-T10, the Division notes that the Company commits to incorporating those changes prior to June 1, 2012. Similarly, the Division's recommendations may be subject to change depending on the Commission's order in Docket No. 11-035-T10.

ISSUE:

On March 15, 2012 Rocky Mountain Power ("Company") filed an application (Docket No. 12-035-67) to increase rates through the Energy Balancing Account ("EBA"). On March 19, 2012, the Commission issued to the Division of Public Utilities an Action Request in this matter. The Commission subsequently closed the Action Request and established a scheduling order that instructed the Division to file initial comments on the Company's application. These are the Division's initial comments on the Company's application.

The Company's application requests an increase of rates through Schedule 94 of $29.3 million, or 1.7 percent. The $29.3 million consists of two principal components. $9.3 million of the requested increase is related to the difference between actual and base EBA costs ("EBAC") plus accrued interest. The remaining $20.0 million of the requested increase represents the first installment of the $60.0 million deferred net power cost amortization that was established in the Settlement Agreement ("Stipulation") between the Company and eight other parties in Docket No. 10-035-124. Consistent with the Commission's order, the Company requests that these rates become effective June 1, 2012.

DISCUSSION:

Definitions and Terminology

Certain terms are used in the Division's comments that may need clarification or explanation. These terms are discussed below.

1. Net Power Cost (NPC): The sum of fuel expenses, wholesale purchase power expenses and wheeling expenses, less wholesale sales revenue.

2. Energy Balancing Account Costs (EBAC): The combination of NPC and wheeling revenue.

3. Actual NPC: The actual total Company unadjusted NPC dollars. These Actual NPC dollars are shown in Mr. Dickman's Workpaper 3.5.

4. Adjusted Actual NPC: These are the Actual NPC dollars adjusted for out-of-period events. Total Company Adjusted Actual NPC dollars flow through the monthly EBA deferral calculations. These Adjusted Actual NPC are shown in Mr. Dickman's Workpaper 3.3.

5. Accounting NPC: These NPC dollars are reported in the Company's SAP system and are different than the Adjusted Actual NPC dollars that flow through the EBA calculations.

6. 2011 GRC Stipulation: Either the revenue requirement or cost-of-service stipulation agreed to by various parties in Docket 10-035-124.

7. Medium Detail: DPU Exhibit 2.6D in Docket 11-035-T10. This exhibit depicts the FERC accounts, FERC sub accounts, and sub-sub accounts (SAP accounts) that are included or

excluded from the EBA. The Medium Detail is essentially the description of the reconciliation between the amounts booked into the Commission approved FERC accounts and the amounts shown in Actual NPC.

8. Deferral Period: October 1, 2011 through December 31, 2011.

RMP REVISIONS TO THE MARCH 15TH 2012 EBA FILING

On April 24th, 2012, the Company notified the Division of corrections that needed to be made to the Short Term Firm Purchases included in the Company's filing. Dollars associated with buy-through curtailments were not properly removed from the Adjusted Actual NPC in the Company's initial filing. Removing these buy-through dollars results in the $257,175 adjustment (includes interest adjustments) referred to in the Division's recommendation. According to the Company, the MWhs associated with Short Term Purchases included in the Company's original filing are correct. Confidential DPU Exhibit 4 (Revised Dickman Workpapers) is the Company's revised version of the workpapers filed with Mr. Dickman's testimony. The Division has also added an additional worksheet (highlighted in red) to the Company's revised workpapers Excel file. The Division finds this correction to be appropriate and therefore recommends the originally filed increase of $29,286,005 be revised to $29,028,831.

COMPONENTS OF THE REVISED REQUESTED INCREASE

As mentioned previously, the Company's requested increase of $29.0 million is attributed to two principal components; the EBA balance of $9.0 million and the deferred NPC amortization of $20 million. The basic summary of how the $29.0 million was calculated is shown herein in Table 1. This same table is shown in the "Summary" tab in DPU Exhibit 4 (Revised Dickman Workpapers)

TABLE 1

Incremental EBA Deferral		
Actual EBA Rate ($/MWh)		23.44
Base EBA Rate ($/MWh)		21.39
$/MWh Differential	$	2.05
Utah Load (MWh)		6,103,728
Total Deferrable	$	12,506,572
EBA Deferral at 70% Sharing	**$**	**8,754,600**
EBA Deferral Account Balance		
Beginning EBA Deferral Balance: Oct 1, 2011		-
Incremental EBA Deferral		8,754,600
Interest		51,856
EBA Revenues		-
Ending EBA Deferral Balance: Dec. 31, 2011	**$**	**8,806,457**
Accrued Interest through June 1, 2012		222,374
Stipulated Deferred Net Power Costs Amortization		20,000,000
Requested EBA Recovery	**$**	**29,028,831**

Actual Utah EBAC for the three month period ending December 31, 2011 totaled $143.1[2] million compared to $135.5 million assumed in base Utah EBAC. This difference accounts for approximately $5.5 million[3] of the $9.0 million EBA balance. Conversely, Utah's actual jurisdictional load for the same period was 228,208 MWhs less than what was included in the base MWhs. This decrease in load can be attributed to $3.5 million of the $9.0 million EBA balance. The remaining $20 million of the $29.0 million increase represents the first year of the stipulated deferred NPC amortization agreed to in Docket No. 10-035-124.

As can be seen in Table 1, the Company included accrued interest through June 1, 2012 on the December 31, 2011 EBA balance. The interest was calculated as follows:

[EBA Balance of \$8,806,457 x $(1.005)^5$] - \$8,806,457 = \$222,374

[2] Before the 70% sharing.
[3] See DPU Exhibit 1

This interest calculation was not specifically ordered by the Commission but it does seem reasonable to include since five months will have passed between the ending EBA balance date of December 31, 2011 and June 1, 2012 when rates become effective. The 6% annual rate (.5% monthly rate) used by the Company is consistent with the 6% used in the monthly interest calculations.

The testimony of Mr. Dickman presents the underlying causes for the increase in NPC during the three month period. It should be noted that the Company's explanation for the underlying causes is based on a comparison of the Company's rebuttal NPC position in Docket 10-035-124 to Actual NPC. This comparison is necessary since the nature of the settled adjustments to NPC in that docket were not specifically called out. The principal cause of the increase in NPC during the deferral period was a result of the decrease in natural gas and wholesale electricity prices. Because of these price decreases, the Company could not economically run its coal and natural gas plants at previously anticipated volumes. These volumes were therefore reduced and the Company's wholesale sales declined while purchased power increased. There was also a second factor that caused actual coal generation volumes to be less than what was assumed in Base NPC. The second factor is the difference between normalized and actual planned outages. Base NPC includes a four-year average outage rate for normalization purposes. This normalization will not match actual outages, especially when considering the shortened Deferral Period. According to the Company, because of this normalization process, actual outages exceeded the outages in the base NPC and therefore coal generation volumes were lower.

DIVISION REVIEW:

<u>FILING EXPECTATIONS</u>

The Division staff has reviewed the information filed with the Company's application and finds that information to generally conform to the expectations set by the Division in its Draft EBA Pilot Program Evaluation Plan. While reconciling the Accounting NPC to the Adjusted Actual NPC, it was discovered that additional accounting detail from January 2012 was needed in order to conduct a complete review. This January 2012 accounting data is needed in order to arrive at the December 2011 Adjusted Actual NPC. This accounting detail was requested and provided by the Company. This additional data is included in DPU Exhibit 2.0-2.2. It will also be necessary for future EBA filings to include this January (first month following the deferral period) accounting data. The Division has requested that the Company provide this data in future filings.

The Commission has requested[4] that the Company file an alternative method for calculating the EBA deferral balance. The Company did file the alternative method and it is included with Mr. Dickman's testimony. Starting on line 82 of his direct testimony in this docket, Mr. McDougal states:

> The allocation factors were calculated using actual 2011 energy and coincident peak information, consistent with the Commissions January 20, 2012 prehearing order in Docket No. 11-035-T10 on page 4 where it states:
>
> > "That is, the approved allocation factors and their *general rate case values* will be used to determine Utah's share of the *base* power-related expenses and revenues approved for balancing account treatment, and the approved allocation factors calculated using *actual company load conditions* during the period of balancing account accrual will be used to determine Utah's share of the Company's *actual* power-related expenses and revenues eligible for the EBA."

The Division has not reviewed the alternative method at this time but it will be reviewed as part of the Division's Evaluation Report.

<u>IMPLEMENTATION OF EBA FORMULA</u>

Pages 75 and 76 of the Commission's March 3, 2011 Corrected Order in Docket No. 09-035-15 provide two formulas to be used in the EBA deferral calculations. The first formula is shown below and relates to calculating the monthly deferral.

$$Deferral_{Utah,month} = 0.70 \times \left(\frac{NPC^{actual}_{Utah,month}}{MWh^{actual}_{Utah,month}} - \frac{NPC^{base}_{Utah,month}}{MWh^{base}_{Utah,month}} \right) \times MWh^{actual}_{Utah,month}$$

[4] See page 3 of the Commission's Prehearing Order in Docket 11-035-T10.

The second formula is shown below and relates to the monthly deferral balance calculation which includes interest calculations.

$$Balance_{current\_month} = \left[Ending\_Balance_{previous\_month} + Deferral_{current\_month}\right] + \left[\left(Ending\_Balance_{previous\_month} + \left(Deferral_{current\_month} \times 0.5\right)\right) \times 0.005\right]$$

The Company utilized these formulas and made one extra addition to the second formula. To the second formula above, the Company added EBA Revenues. EBA revenues represent the sur-charge or sur-credit paid by or collected from customers during a particular month. The Division believes this addition to be necessary in order to maintain the correct monthly EBA balance. Since this is the Company's first EBA filing, no sur-charge or sur-credit existed during the Deferral Period and therefore the EBA Revenues included in the Company's monthly EBA calculations is zero.

<u>EBA ACCOUNTS</u>

Upon initial review it appears the correct FERC accounts, FERC sub accounts and related SAP accounts (sub-sub accounts) were included in the EBA calculations. DPU Exhibit 5 shows the workpapers used by the Division to review the accounts the Company included and excluded from the EBA. The Division used the Medium Detail contained in DPU 2.6D in Docket No. 11-035-T10 to measure whether the correct accounts were used in the EBA calculations. The Division recognizes that the Medium Detail has not, at this time, been ordered by the Commission to be included in the Company's tariff. Regardless of the outcome in Docket No. 11-035-T10, the Division believes the Medium Detail serves as an adequate guideline to measure whether the correct accounts have been included in the EBA. Actual NPC are presented in the same format (by contract and generation plant) as the "GOLD" (GRID) report used in the Company's general rate case filings. This reconciliation serves to show that the types of costs included in the Company's EBA filing are the same as the types of costs used in the NPC included in the Company's general rate case filings. The Division does recognize that upon future examination of specific SAP accounts, there is the possibility that the "type" of cost reflected in a particular SAP account may not match any of the "types" of costs reflected in base NPC established in a general rate case. These more specific SAP account examinations will be part of the Division's audit. In order for the Division to conduct its audit however, there needs to be an adequate guideline for beginning to evaluate whether or not the correct accounts have been included in the EBA calculations. Thus, the Medium Detail was used by the Division in evaluating whether or not the correct accounts were used.

MATHEMATICAL ACCURACY (EBA BALANCE CALCULATION)

The Division has reviewed the Company's calculations and finds the Company's calculations to be correct given the assumptions used by the Company. Since there is a Commission order still pending in Docket No. 11-035-T10, the Company had to make certain assumptions regarding how Utah actual NPC are calculated. The Company utilized the "Stipulated Scalar" methodology to determine Utah actual NPC. Specifically, the Company used the 100.014% scalar value from the Stipulation in Docket No. 10-035-124 to determine Utah actual EBA costs. For allocating total Company Wheeling revenues to Utah, the Company used SG and SE allocation factors that were calculated based on the loads for the 12 months ending December 31, 2011. An example showing how the scalar and allocation factors were used in the Company's EBA calculations is shown in Table 2.

TABLE 2

				Oct-11
1	Actual Adj. NPC (Total Company)		$	108,624,061
2	System Load (Total Company MWh)			4,623,090
3	Actual $/MWH (Total Company)	Line 1 / Line 2	$	23.50
4	Utah Allocation Scalar	Settlement Stipulation		100.014%
5	Utah Actual $/MWh Before Wheeling Revenue	Line 3 * Line 4	$	23.50
6	Utah Jurisdictional Load (MWh)			1,937,228
7	Utah Actual NPC Before Wheeling Revenue	Line 5 * Line 6	$	45,523,454
8	Actual Firm Wheeling Revenues (Total Company)		$	(5,169,348)
9	SG Factor			42.05%
10	Utah Actual Firm Wheeling Revenues	Line 8 * Line 9	$	(2,173,466)
11	Actual Non-Firm Wheeling Revenues (Total Company)		$	(804,118)
12	SE Factor			41.91%
13	Utah Actual Non-Firm Wheeling Revenues	Line 11 * Line 12	$	(337,017)
14	UT Actual EBA Costs	∑ Lines 7,10,13	$	43,012,971
15	Utah Jurisdictional Load (MWh)	Line 6		1,937,228
16	Actual EBA Deferral Rate $/MWh	Line 14 / Line 15	$	22.20

The Division recognizes that the methodologies used in Table 2 above may change depending on the outcome of Docket No. 11-035-T10. Should the Commission order different methodologies, the Division will review any revised calculations made by the Company.

In order to ascertain whether the EBA balance shown in the Company's calculations is correct, the Division recalculated the EBA balance using its own Energy Balancing Account Model (EBAM). The EBAM is an Excel file that uses Company provided accounting transaction values as inputs. In accordance with the Medium Detail mentioned previously, the SAP accounts not included in the EBA are then filtered out of the booked accounting transactions. The accounting transactions that are included in the EBA are then reconciled to the correct EBA month. The calculation of the allocation factors is also reviewed. The EBAM used for this filing is included electronically as DPU Exhibit 3. The Division calculated the same EBA balance as the Company's corrected EBA balance of $9,028,831.

DEVIATIONS BETWEEN ACTUAL AND BASE NPC

In the "Components of the Revised Requested Increase" section shown above, the Division reiterated the underlying causes of the differences between base and actual NPC. At this time the Division has not evaluated whether backing off its coal and natural gas units while increasing purchased power was a prudent course of action during the deferral period. The Division will examine this course of action in more detail as part of its audit.

IMPLEMENTATION OF COMMISSION APPROVED RATE SPREAD

Similar to the Company calculations performed to calculate the EBA Deferral Balance, the Company's implementation of rate spread was based on certain assumptions that have not at this time been ordered by the Commission. Therefore, until an order is issued in Docket No. 12-035-T10, the Division has evaluated the Company's rate spread with the assumption that its chosen methodology is what will be approved. Should the Commission order different methodologies, the Division will review any revised calculations made by the Company. The Company spread the $20 million associated with the deferred NPC and the $9.0 million associated with the EBA balance to the customer classes in the same manner. In his direct testimony, starting on line 32, Mr. Griffith states:

> **Q. How does the Company propose to allocate the EBA revenue across customer classes?**
>
> A. The Company proposes to spread the EBA revenue across customer classes consistent with the approved spread of the base EBA costs to rate schedules in the Company's last general rate case, Docket No. 10-035-124 ("2011 GRC").
>
> **Q. How were base EBA costs spread to rate schedules in the 2011 GRC?**
>
> A. Base EBA costs were spread to rate schedules in the 2011 GRC in the same way that all other costs were spread to rate schedules according to the stipulation approved by the Commission in that docket on Cost of Service, Rate Spread, and Rate Design ("Stipulation").
>
> **Q. Please explain.**

A. The parties to the Stipulation agreed that any rate change should be spread according to the percentages of the revenue requirement increase reflected in the column labeled "Stipulated Percentage of Revenue Requirement Increase" of Exhibit A to the Stipulation (Paragraph 5). The parties further agreed to withdraw and not contest any cost of service issues in the case (Paragraph 6), and that the cost of service/rate design issues were suspended (Paragraph 11).

Q. Did the revenue requirement stipulation in the 2011 GRC ("Revenue Requirement Stipulation") provide any further guidance concerning the spread of the EBA in this case?

A. Yes. Paragraph 59 of the Revenue Requirement Stipulation indicated that:

> …The Parties agree that this $60.0 million ("EBA") amount should be recovered through an annual $20.0 million surcharge over three years without a carrying charge applied as a line item in the EBA surcharge commencing June 1, 2012. <u>The surcharge shall be allocated to rate schedules relying on the Cost of Service Stipulation consistent with the EBA Order.</u> (emphasis added)

Q. Please describe Exhibit RMP___(WRG-1).

A. Exhibit RMP___(WRG-1) contains the Company's proposed rate spread which follows the rate spread from the 2011 GRC as discussed above.

Based on the Division's review, Mr. Griffith's written testimony may leave a false impression of what the Company actually did in its filed rate spread workpapers. Rather than following the rate spread from the 2011 general rate case, Mr. Griffith's workpapers show that the Company used an "Adjusted GRC Spread." Table 3 below shows the "Stipulation" Excel worksheet included in Mr. Griffith's filed workpapers, adjusted for the Company's April 24th corrections to the requested rate increase.

<u>TABLE 3</u>

	2011 GRC Settlement Exhibit A							
	Forecast Present Rev	GRC Change		Forecast Present Rev	Adjusted GRC Spread		Proposed EBA	
Customer Class	($000)	($000)	%	($000)	($000)	%	($000)	%
Residential (Schs. 1, 2, 3)	$623,014	$45,785	7.3%	$649,981	$47,767	7.3%	$11,332	1.7%
General Service (Schs. 6, 6A, 6B)	$460,779	$29,081	6.3%	$475,083	$29,984	6.3%	$7,113	1.5%
General Service > 1 MW (Sch. 8)	$138,877	$10,140	7.3%	$141,559	$10,336	7.3%	$2,452	1.7%
Lighting (Schs. 7,11,12)	$13,802	$0	0.0%	$12,113	$0	0.0%	$0	0.0%
General Service - High Voltage (Schs. 9, 9A)	$215,590	$18,287	8.5%	$229,321	$19,451	8.5%	$4,615	2.0%
Irrigation (Schs. 10, 10 TOD)	$12,158	$866	7.1%	$13,175	$938	7.1%	$223	1.7%
Metered Outdoor Lighting (Sch. 15)	$1,218	$0	0.0%	$1,145	$0	0.0%	$0	0.0%
Traffic Signals (Sch. 15)	$521	$38	7.3%	$585	$43	7.3%	$10	1.7%
Electric Furnace (Sch. 21)	$281	$24	8.5%	$343	$29	8.5%	$7	2.0%
General Service - Small (Sch. 23)	$121,797	$7,687	6.3%	$129,898	$8,198	6.3%	$1,945	1.5%
Back-Up, Maint., & Suppl. Service (Sch. 31)	$793	$58	7.3%	$4,870	$356	7.3%	$84	1.7%
Security Area Lighting Contracts (PTL)	$1	$0	0.0%	$1	$0	0.0%	$0	0.0%
Street Lighting Contracts (77)	$17	$0	0.0%	$17	$0	0.0%	$0	0.0%
Contract Customer 1	$22,943	$0	0.0%	$24,225	$0	0.0%	$0	0.0%
Contract Customer 2	$30,307	$0	0.0%	$26,946	$0	0.0%	$0	0.0%
Contract Customer 3**	$46,005	$4,267	9.3%	$59,056	$5,257	8.9%	$1,247	2.1%
Contract Customer 4**	$10,558	$768	7.3%					
AGA/Revenue Credit	$3,578	$0	0.0%	$4,532				
Total Utah	$1,702,238	$117,000	6.9%	$1,772,847	$122,358	6.9%	$29,029	1.6%
Total Utah (excl. Customer 1, 2, & AGA)	$1,645,410	$117,000	7.1%	$1,717,145	$122,358	7.1%	$29,029	1.7%

** The actual change will be based on the terms of the contract.

It is true that the dollars shown in the "GRC Change" column above do tie to the dollars shown in Exhibit A of the revenue requirement settlement stipulation in Docket 10-035-124. These dollar amounts also correspond to the rate spread percentages shown in Exhibit A of the cost of service stipulation in Docket 10-035-124. However, as can be seen in Table 3, the Company used an "Adjusted GRC Spread," rather than what was actually shown in Exhibit A of the cost of service settlement stipulation. A comparison of the "adjusted" rate spread to the stipulated rate spread and the associated dollar impact on each class is shown in Table 4.

TABLE 4

Customer Class	Stipulated Spread	RMP Adjusted GRC Spread	Stipulated Spread ($000)	RMP Adjusted GRC Spread ($000)	Difference ($000)
Residential (Schs. 1, 2, 3)	39.1328%	39.0388%	11,360	11,332	27.29
General Service (Schs. 6, 6A, 6B)	24.8554%	24.5048%	7,215	7,113	101.79
General Service > 1 MW (Sch. 8)	8.6664%	8.4469%	2,516	2,452	63.71
Lighting (Schs. 7,11,12)	0.0000%	0.0000%	-	-	-
General Service - High Voltage (Schs. 9, 9A)	15.6296%	15.8970%	4,537	4,615	(77.64)
Irrigation (Schs. 10, 10 TOD)	0.7400%	0.7668%	215	223	(7.77)
Metered Outdoor Lighting (Sch. 15)	0.0000%	0.0000%	-	-	-
Traffic Signals (Sch. 15)	0.0325%	0.0349%	9	10	(0.69)
Electric Furnace (Sch. 21)	0.0204%	0.0237%	6	7	(0.98)
General Service - Small (Sch. 23)	6.5700%	6.7001%	1,907	1,945	(37.78)
Back-Up, Maint., & Suppl. Service (Sch. 31)	0.0495%	0.2906%	14	84	(69.99)
Security Area Lighting Contracts (PTL)	0.0000%	0.0000%	-	-	-
Street Lighting Contracts (77)	0.0000%	0.0000%	-	-	-
Contract Customer 1	0.0000%	0.0000%	-	-	-
Contract Customer 2	0.0000%	0.0000%	-	-	-
Contract Customer 3*	3.6471%	4.2963%	1,059	1,247	(188.47)
Contract Customer 4*	0.6563%	0.0000%	191	-	190.52
AGA/Revenue Credit	0.0000%	0.0000%	-	-	-
Total Utah (excl. Customer 1, 2, & AGA)	100.0000%	100.0000%	29,029	29,029	(0.00)

** The actual change will be based on the terms of the contract.

Although Mr. Griffith's written testimony does appear to give a false impression, the Division considers the Company's actual treatment of rate spread in Mr. Griffith's workpapers to be reasonable. In this particular case, there are two specific reasons why attempting to apply the exact rate spread percentages determined in the 2011 GRC Stipulation is problematic.

First, it is the Division's understanding that Contract Customer 4 is not eligible for an EBA surcharge or sur-credit. In the 2011 GRC Stipulation and for purposes of general rate spread determination for all the classes, .6563% was applied as the rate spread percentage for Contract Customer 4. The actual rates charged to Contract Customer 4 are governed by the terms and conditions of its specific contract. For EBA purposes, the actual terms of the contract do not allow the Company to collect or refund an EBA balance from Contract Customer 4. If, therefore, an EBA rate spread percentage was assumed for Contract Customer 4, the Company would not be able to recover a portion of the $29.0 million.

Second, the University of Utah has changed from Schedule 9 to Schedule 31. As a result, it would seem reasonable that Schedule 31 would be responsible for a greater share of the $29.0 million than what would have otherwise been assumed from the 2011 GRC Stipulation.

The Division is not aware of any parties raising either of these two issues in Docket No. 11-035-T10. Therefore, even if the Commission orders that the rate spread for the EBA should be based upon the overall revenue requirement spread from the 2011 GRC Stipulation, there may not be specific guidance as to how to apply those specific rate spread percentages given the two limitations discussed above. In general, as can be seen in Table 4, it appears the Company has made a good faith effort to devise a rate spread that follows the revenue requirement spread in the 2011 GRC Stipulation given the inherent limitations described previously. The Division reiterates however, that using the overall revenue requirement spread from the 2011 GRC Stipulation may not be the methodology ordered by the Commission in Docket No. 11-035-T10.

In addition to a review of the rate spread used by the Company, the Division also reviewed how the percentage change in rates was calculated by the Company. The percentage changes were calculated by dividing the proposed EBA spread (in dollars for each class) by the forecasted revenues (in dollars for each class) for the 12 months ended May 2013 (EBA rate effective period) at the present price. Since the EBA rate effective period matches the test year in Docket No. 11-035-200, the Company elected to use the same billing determinants for the EBA filing as those that were used in Docket No. 11-035-200. The Division found the billing determinants used in the EBA rate calculations to be the same as those used in Docket No. 11-035-200. The

Division has not at this time completed an in depth analysis as to the appropriateness of the forecasted units used by the Company to arrive at the forecasted revenue dollars. The forecasted units will be an issue in the current rate case and findings or changes affecting those determinants may affect final rates when the Division completes its audit.

OTHER ISSUES

During its initial review, the Division identified other issues that require comment or that will need further investigation during the Division's audit. These issues are discussed below and are in addition to the prudence review the Division will be undertaking during its audit.

Use of Accounting Estimates in the EBA

Based on technical conferences held with other parties and the Company, it was the Division'sunderstanding that accounting estimates would be removed from the EBA calculations. The Company's EBA filing does remove most, but not all accounting estimates from FERC accounts 447, 555, and 565 as outlined in its proposed tariff. The Company's filing does not appear to exclude accounting estimates from the other EBA FERC accounts. The Company responded to a data request concerning this issue, but it is still not clear to the Division what the base conceptual differences are between the estimates included by the Company and those excluded by the Company. It should be noted that the estimates identified in the Division's Medium Detail as being excluded from the EBA, are not affected by this issue. It appears that all the estimates identified in the Division's Medium Level as being excluded, were in fact excluded in the Company's filing. The Division will continue to investigate this issue as part of its audit. Specifically the Division will evaluate whether these accounting estimates ought to be included in the EBA calculations.

Load Differences

During the Division's review, the Division became aware of load differences within the Company's filing. The MWhs directly associated with the total Company Adjusted Actual NPC dollars on line 1 of Mr. Dickman's Exhibit 1 are different than the MWhs shown on line 2 of Mr.

Dickman's Exhibit 1. Table 5 below represents the Division's understanding as to the differences between the two load figures.

TABLE 5

"Scheduled Loads": MWh Associated with Numerator ($) in Total Company $/MWh Calculation
Scheduled Purchased Power MWh (adjusted for out-of-period events and buy-throughs)
+ Generation MWh (at input)
- Scheduled Sales For Resale MWh (adjusted for out-of period events)
MWh Load

"Metered Loads": MWh used in Denominator of Total Company $/MWh Calculation
Metered Loads (at sales, net of line losses) adjusted for buy-throughs of curtailment events

It should be noted that the Metered Loads shown above are the same loads used to develop the Utah jurisdictional loads shown in Mr. Dickman's Exhibit 1. The Metered loads are also the same loads used to develop the SE and the SG allocation factors. The metered loads were higher for each of the months of the deferral period. The exact differences for the months of October 2011 through December 2011 were 909 MWh, 12,180 MWh and 10,699 MWh. Had the Scheduled Loads been used on line 2 of Mr. Dickman's Exhibit 1, the EBA deferral balance would have increased from $9,028,831 to $9,203,316, a difference of $174,486[5]. However, if the Scheduled Loads are used in the denominator of the total Company $/MWh calculation, this would create a mismatch with the Utah jurisdictional loads which are based on the Metered

[5] See the "Load Differences" tab in Confidential DPU Exhibit 4 (Revised Dickman Workpapers). This tab was added by the DPU to the Revised Dickman Workpapers that the Company provided to the Division.

Loads. The Division will continue to seek further understanding with respect to these load differences and which loads are more appropriate to use in the various EBA calculations.

Adjustments to Actual NPC

The NPC dollars that flow through the EBA calculations are the Actual NPC adjusted for out-of-period events. The Division has issued a data request to the Company concerning how these adjustments are derived. The Division will continue to explore this issue during its audit.

In addition to the out-of-period adjustments, it appears the Accounting NPC dollars were adjusted for an item called "GP Camas" in order to arrive at Actual NPC[6]. This adjustment is different in concept than the FERC account transfer adjustments mentioned in the Division's Medium Detail level. It appears this adjustment to Accounting NPC is "imputed and added to 555 per terms of the contract."[7] This adjustment appeared in all three months of the deferral period and totals $2,016,414. The Company's current rate case includes an adjustment[8] to revenues (FERC Account 456) that relates to the GP Camas purchased power expenses. That adjustment states:

> On January 13, 1993, the Company executed a contract with James River Paper Company with respect to the Camas mill, later acquired by Georgia Pacific. Under the agreement, the Company built a steam turbine and is recovering the capital investment over the twenty-year operational term of the agreement as an offset to royalties paid to James River based on contract provisions. The contract costs of energy for the Camas unit are included in the Company's net power costs as purchased power expense, but GRID does not include an offsetting revenue credit for the capital and maintenance cost recovery. This pro forma adjustment adds the royalty offset to FERC account 456, other electric revenue, for the twelve-month period ending May2013, the same period used in determining pro forma net power costs in this filing. (Emphasis added)

It is the Division's understanding that since the expenses and revenues associated with the James River contract are offsetting, there is no accounting effect on the Company's books. Thus, a separate adjustment outside of the Company's accounting system is needed in order to capture

[6] See the row 144 in the "EBA Reconciliation" tab in DPU Exhibit 3.
[7] See column L, row 68 in the "C&T Database Accounts" tab in the Company's filed Excel file called "UT Filing Req 5-1."
[8] See Adjustment 5.2 in Mr. McDougal's SRM-3 Exhibit in Docket 11-035-200.

the James River purchased power expenses as part of FERC 555 in the EBA. The corresponding revenues associated with the James River contract are not included in the EBA as they are part of FERC 456 (Other Electric Revenue) and not FERC 456.1 (Wheeling Revenue). The Commission has specifically included FERC 456.1 in the EBA but has not included any other revenues from FERC 456 in the EBA. The Division reiterates however that the Company does include these revenues in general rate case filings as can be seen in Adjustment 5.2 in the current general rate case.

Deferred NPC True-up

The Division notes that the rates associated with the $20 million deferred NPC will remain in effect from June 1, 2012 to May 31, 2013. New rates associated with the next $20 million installment will be set June 1, 2013. Rates associated with the last $20 million installment will be established June 1, 2014. At the end of the third installment period (May 31, 2015) a possible true-up may be necessary as the actual amounts collected from customers may differ from the $60 million total deferred NPC. The necessary true-up would be done as a one-time adjustment through the EBA account. During the three-year installment period, the Division will monitor the amounts collected from customers.

CONCLUSION:

The Division recommends interim approval of the $9.0 million increase associated with the EBA balance and the $20 million increase related to the first installment of the deferred NPC amortization. The Division also recommends the rate spread proposed by the Company be approved by the Commission. These recommendations are subject to change depending on the Commission's order in Docket 11-035-T10. As discussed above, the Division has identified various issues it will pursue further understanding of during the audit period. The Division will also conduct its prudence review during the audit period.

Cc: Dave Taylor, Rocky Mountain Power

Michele Beck, Office of Consumer Services