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A DIVISION OF PACIFICORP

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RE: UT Docket No. 16-035-15
DPU 4th Set Data Request (1-6)

Please find enclosed Rocky Mountain Power's Responses to DPU 4th Set Data Requests 4.1-4.6. Also provided are Attachments DPU 4.1, and 4.5 –(1-3).

If you have any questions, please call Tarie Hansen at (801) 220-2053.

Sincerely,

Bob Lively / lsw

Bob Lively
Manager, Regulation

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DPU Data Request 4.1

Revenue adjustments:

(a) Why is the temperature normalization adjustment for 2015 10,251,052 lower than 2015 (From a 10,556,970 for 2014 to a positive 305,888 2014)? (Page 3.1).

(b) Why are the biggest differences in Residential and Commercial? (Page 3.1).

(c) Why is revenue normalization for 2015, 16,945,316 higher than 2014? This adjustment has gone up significantly the last three years. Why? (Page 3.2).

(d) The description of the adjustments for 3.2 states that the general business revenue for 2015 and 2014 needed to be adjusted for reporting and ratemaking regulatory results. The adjusting items included removal of Revenue Accounting Adjustments, Deferred Net Power Costs, Demand-side Management Revenue, Buy-through and Normalization of Special Contract Revenue and Out-of-period Revenue. Please break out the totals for 2015 (118,405,447) and 2014 (104,460,131) into the above categories, compare the amounts in the categories and then please explain material differences (10% increase or greater).

(e) What is the main reason why REC revenue in 2015 is basically comparable to 2014? (Page 3.4.1).

(f) What was the main driver for the increase in 2015 wheeling revenue (2015-92,780,346 / 2014-86,909,187)? (Page 3.5).

(g) Why is the 2015 98 REC revenue adjustment 4,718,520 less than the 2014 adjustment (353,338 / 5,071,858)? Why the significant decrease in the Net Power Cost Accrual from 2014 to 2015? (Page 3.6).

Response to DPU Data Request 4.1

(a) The temperature normalization adjustment for 2015 (page 3.1) is different than 2014 due to differences in temperature in 2015 versus 2014 as compared to normal temperatures.

(b) The kilowatt-hour (kWh) usage of the residential and commercial class is more temperature sensitive than the kWh usage of the industrial class. Therefore, when temperatures are below or above normal, the temperature normalizing adjustment will be larger for the residential and commercial class than for the industrial class.

(c) Please refer to Attachment DPU 4.1.

(d) Please refer to Attachment DPU 4.1, which provides the category detail of the differences between calendar years 2013, 2014, and 2015.

(e) There has been no change to the California compliance market in regards to the product definitions adopted by the State of California under SB2 (1X) and under California Public Utilities Commission (CPUC) Renewable Portfolio Standards (RPS) Product Content decision. These continue to limit the Company's ability to sell renewable energy credits (REC) into the California market. Therefore, REC revenues remain comparable between 2014 and 2015.

(f) The drivers to the increase in wheeling revenues from $86.9 million to $92.8 million is driven by the following:

- Transmission rate effective for 2014 was $25.52 per kilowatt per year ($/kw per year) whereas in 2015 the effective rates for the year were roughly $2 and $3 higher than the 2014 true-up rate.

- Peak transmission volumes for legacy agreements were approximately 2,000 megawatts (MW) higher in 2015 compared with 2014 while network and long-term point-to-point (PTP) volumes were roughly equal.

- Non-firm (NF) volumes are significantly lower in 2015 compared with 2014, which result in a drop in revenues of approximately $2 million.

- Ancillary services are higher for Schedule 1, Schedule 2, and Schedule 3, but lower for Schedule 3a, Schedule 5, and Schedule 6 by a net decrease of approximately $150,000.

- The resulting rate change and volume changes results in long-term revenues, short-term firm (STF) revenue, legacy contract revenues, and use of facilities revenue, to be roughly $8 million higher in 2015 compared with 2014. This is offset by a drop in NF revenues of approximately $2 million, and $150,000 for ancillary revenues.

(g) The 2015 98 REC revenue adjustment is less than the 2014 adjustment due to the REC revenues in base rates. The 2014 98 REC revenue adjustment reflected a total of $7.3 million REC revenues in base rates as determined in Step 2 of the stipulation from Docket No. 11-035-200 and Step 1 of the stipulation from Docket No. 13-035-184. The 2015 98 REC revenues in base rates decreased to $2 million as determined in Step 1 of the stipulation from Docket No. 13-035-184. This created a smaller deferral to be collected from customers in 2014 than in 2015. The change in the Net Power Costs (NPC) accrual is due to the decreased amount requested in Docket No. 16-035-01, 2015 energy balancing account (EBA), in comparison to the amount requested in Docket No. 15-035-03, 2014 EBA.

DPU Data Request 4.2

O & M adjustments:

(a) Please explain in detail the Gains and Loss on Property sales shown on Page 4.1. For 2015 there is a Rent from Electric property adjustment. Please explain this adjustment and why it was required?

(b) Why did irrigation load control incentive payments decrease in 2015? (Page 4.2).

(c) Why did Utah DSM expenses increase from 68,050,713 in 2015 from 65,547,937 in 2014? (Page4.4).

(d) Why is there no non-recurring entries adjustment in 2015? (Type A 4.3 2014)

(e) Why is the id the three year average for Insurance expense increase in 2015? (Page4.4.1.)

(f) Why did the 2015.generation overhaul expense decrease so significantly for 2015 as compared to 2014 (684,540 / (2,430,803)? (Page 4.5).

(g) The Company in its computation of generation overhaul expense restates cost to constant dollars. Is this restating of the cost in agreement with a past Commission order?

(h) Why 2015 uncollectible expense increase 20%? ((707,188 – 3,064,795) / 3,064,795)).

Response to DPU Data Request 4.2

(a) When preparing the Results of Operations (ROO), the Company reviews the booked gains and losses on sales to ensure that they are correctly booked to match the allocation factor of the underlying asset that caused the gain or loss. The adjustment to FERC Account 421 reflects any correction necessary as a results of the Company's review. The Company began working with Google Fiber on joint use poles in Salt Lake City, Utah. Some of the project cost reimbursements were inadvertently allocated system instead of situs. This adjustment was necessary to reallocate the reimbursements from a system overhead (SO) allocation factor to a situs UT factor.

(b) In 2015, the average available load in Idaho throughout the program season was approximately 20 percent lower compared to 2014. Changes in available load between 2015 and 2014 are driven by a number of factors, including weather (i.e., temperature and precipitation that drive the need for irrigation) and crop types (i.e., water needs of particular crops). Additionally, in 2015, the average performance factor across all customers in Idaho was 78 percent, versus 82 percent in 2014. Changes in performance factor is a function of several variables including customer program knowledge (i.e., customers' understanding of how load control event participation affects performance factors and associated payments) and event timing (i.e., how the timing of an event impacts a customer's irrigation schedule and the potential risk to their associated crops).

(c) Amortization expense was greater in 2015 because demand-side management (DSM) collections in 2015 were greater than those of the previous year. DSM collections are based on a percentage of revenues recorded. Collections are amortized to expense and are limited to spend recorded to date.

(d) In the December 2015 results, no entries were identified as non-recurring. Therefore, no adjustment was necessary.

(e) The three-year average for Insurance expense increased in 2015 over 2014 because in the rolling average, 2012 was replaced by 2015. 2015 had a smaller amount of net claims requested, but had no cash received on third party insurance claims:

	2012	2015	Increase
Cash paid on claims	11,419,288	15,520,215	4,100,927
Cash payments not requested	(3,031,650)	(9,948,374)	(6,916,724)
Net claims requested	8,387,638	5,571,841	(2,815,797)
Third-party insurance claim proceeds	(5,125,000)	-	5,125,000
	3,262,638	5,571,841	2,309,203
	Effect on 3-year average		769,734

Three-year average in Results	
2015	3,839,081
2014	3,069,347
	769,734

(f) The purpose of the Generation Overhaul adjustment is to adjust the base period expense to a historical four-year average. The primary driver for the adjustment decrease on page 4.5 is the increase in base year expense from \$36.2 million in 2014 to \$44.1 million in 2015.

Although the size of the generation overhaul expense adjustment decreased from 2014 to 2015, the historical four-year average held fairly constant at \$35.4 million for calendar year 2013 (CY) and \$35.7 million for CY 2015 on a Total Company basis.

(g) The restating to constant dollars in the computation of the generation overhaul expense in the ROO filing is consistent with the last several rate case filings by the Company in Utah.

(h) Bad debt expense is calculated on aging report based on a 13-month rolling average of actual write-off activity. As dollars age through the buckets they become increasingly at risk of a write-off. The Company's calculation applies the risk of write-off to the current month aging to come up with the estimate of the reserve required. The reserve in 2014 was unusually low due to overall receivables being down over $(24) million from 2013 as well as a decrease in the risk factors applied to the aging buckets. CY 2015 saw a rebound in overall receivables of $19 million as well as a slight increase in the risk factors applied to some of the aging buckets which drove the increase in the bad debt expense from 2014 to 2015.

DPU Data Request 4.3

Net power cost adjustments:

(a) Why the large decrease in the Type B NPC normalization adjustment from 2014 (positive 6,346,538) to 2015 (negative 21,351,886)?

(b) Why the large decrease in Type A normalization adjustment from 2014 (negative 27,875,210) to 20154 (negative 50,064,842)? (Page 5.1).

Response to DPU Data Request 4.3

(a) The negative normalization in 2015 is primarily a result of hydro generation that was significantly below normal, partially offset by load normalizing adjustments. The positive adjustment in 2014 was primarily a result of load normalizing adjustments, with a slight offset due to slightly below normal hydro generation.

(b) The change in the Type A adjustment is mainly due to an increase to the net power costs (NPC) deferral and amortization accounts. Many of the NPC deferrals have been amortized over multiple years and each year new NPC deferrals are added to the amortization account. Therefore, the NPC amortization account continues to grow as new NPC deferrals are accumulated before the past NPC deferrals are fully amortized.

DPU Data Request 4.4

Tax adjustments:

(a) Why did the interest true up amount decrease from negative 7,999,258 (2014) to negative 4,415,509 (2015)? (Page 7.1).

(b) What was the driving factor for the increase of the ADIT balances for 2014 as compared to 2013 for accumulated deferred tax; accelerated Amortization of Pollution Control: and ADIT – Utah? (Page 7.2).

(c) Why was the Medicare Deferred Accounting adjustment not required for 2015?

Response to DPU Data Request 4.4

(a) Interest true-up is the difference between normalized interest and unadjusted interest expense. The normalized total rate base for 2015, used for the calculation of normalized interest expense, was larger compared to the 2014 normalized rate base. The rate base increase was mainly due to the rise in gross Plant in Service by $472 million on a Utah allocated basis. This contributed to the 2.8 percent increase to total net rate base driving the need for the interest true up adjustment.

(b) On December 2015, the Protecting Americans from Tax Hikes (PATH) was signed into law, extending 50 percent bonus tax depreciation for qualifying property purchased and placed in-service during 2015 and before January 1, 2018. For 2018 and 2019 the bonus tax depreciation will phase down to 40 and 30 percent, respectively.

PATH was the primary driving factor for the year-over-year increase in the Accumulated Deferred Income Taxes (ADIT) balances, including ADIT-Utah. Specifically for accelerated Amortization of Pollution Control, Jim Bridger Unit 3 clean air scrubber, Hayden Unit 1 clean air scrubber, Jim Bridger Units 1 through 4 mercury control devices, and Dave Johnson Units 1 through 4 mercury control devices were placed into service in 2015 with bonus tax depreciation taken into account.

(c) The Medicare Tax regulatory asset was fully amortized in 2014 and therefore this adjustment was no longer necessary after December 31, 2014.

DPU Data Request 4.5

Rate base adjustments:

(a) Why Miscellaneous asset sales and removals adjustment 2015? (Page 8.10) Additionally, please provided supporting documentation for amounts in the adjustments. Was Olmstead sold? If so please explain the sale. Why the Olmstead O&M adjustment?

(b) Please provide the Pension and postretirement welfare plan net prepaid balance adjustment amount for 2014 in rate base.

(c) Why did the Cash Working Capital adjustment in 2015 decrease by more than double as compared to 2014 (Page 8.1)?

(d) Why did the Other Tangible Property amount decrease in 2015 as compared to 2014 for Trapper Mine Rate Base and increase for Bridger Mine Rate Base? (Page 8.2 / 8.3).

(e) What caused the decrease in Utah customer advances from (3,937,400) in 2014 to (3,432,699) in 2015? (Page 8.4).

(f) (i) Please update the Division on what is happening currently and into the future with the Klamath-related relicensing and process costs and the settlement agreement, and (ii) how adjustment 8.7 (2015) relates to that activity?

(g) Please provide a more expanded explanation of adjustment 8.8. Why has the Utah allocated amount for 2015 decreased so significantly as compared to 2014? (Page 8.8).

(h) Please explain why this Deer Cree mine closure adjustment is required. (Page 8.9).

Response to DPU Data Request 4.5

(a) The purpose for the Miscellaneous Asset Sales and Removals adjustment is to remove any residual balances in unadjusted results for assets that have either been sold, retired, abandoned or otherwise discontinued for various reasons. Please refer to Attachment DPU 4.5 -1 for the requested supporting documentation.

The Olmsted plant was owned and operated by the Company until about 1987 when the United States (U.S.) Bureau of Reclamation filed a Declaration of Taking and condemned portions of the property. In subsequent filings the Bureau of Reclamation amended their filings and to take control of the

Olmsted plant in connection with the development of water supplies for the Central Utah Project. A legal settlement on the condemnation was reached between the U.S. and Rocky Mountain Power's (RMP) predecessor, Utah Power and Light Co. (UP&L), which provided that the Company could continue to operate and take the energy from the plant under the contract as water was available, for a period of 25 years (through 2015). The plant was retired in 1990 on settlement of the condemnation suit, which transferred ownership to the Federal government. Under the terms of the settlement, the Company continued to operate the plant and held and maintained assets relating to the training facilities and other general plant on the site until final shutdown in September 2015. This adjustment removes those remaining rate base items and operating costs to reflect that the plant is now closed and is no longer used and useful.

(b) Please refer to Attachment DPU 4.5 -2.

(c) This adjusts the cash working capital (CWC) balance from unadjusted levels as calculated in the normalized results of operations (ROO) report. CWC is calculated by taking total operation and maintenance (O&M) expense allocated to the jurisdiction and adding its share of allocated taxes, including state and federal income taxes and taxes other than income. This total is divided by the number of days in the year to determine the Company's average daily cost of service. The daily cost of service is multiplied by net lag days to produce the adjusted cash working capital balance. CWC components are calculated for each adjustment individually within the Jurisdictional Allocation Model (JAM). The CWC Adjustment in 2015 is roughly twice the corresponding adjustment in 2014 because the aggregate impact of normalizing adjustments on total O&M and allocated taxes is larger in 2015 than 2014. In other words, 2015's CWC balance on an unadjusted basis is less closely aligned with 2015's normalized CWC balance than the corresponding balances in 2014.

(d) Trapper Mine rate base declined due to leased asset amortizations, retirements of equipment and facilities, and depreciation expense credits, which in total, exceeded capital project additions for the period.

Bridger Coal Company (BCC) rate base increased due to capital project additions, additional mine development costs, and slightly higher materials and supplies inventories; mostly offset by depreciation expense credits, lower coal pit inventories, and amortization of deferred longwall costs.

(e) Customer advances for construction are deferred credit accounts representing cash advances paid to the utility by customers requiring construction of facilities on their behalf. Customer advances for construction balances fluctuates each year due to the size and complexity of each job, when it started, and how many jobs are in progress for each state.

(f) Please refer below to the Company's response to subpart (i) and (ii):

(i) Klamath-related relicensing and process costs are currently being amortized through December 31, 2022, consistent with the approved depreciation schedule for the Klamath assets. Regarding the Klamath Hydroelectric Settlement Agreement (KHSA), PacifiCorp, the states of California and Oregon, and the U.S. Departments of the Interior and Commerce, and other signatories to the settlement executed an amendment to the KHSA on April 6, 2016. Under the amended KHSA, PacifiCorp will file an application with the Federal Energy Regulatory Commission (FERC) to transfer the license for the four mainstream Klamath River hydroelectric generating facilities to a newly formed private entity, the Klamath River Renewal Corporation (KRRC). The KRRC will file an application to surrender the license and decommission the facilities with the FERC, and will provide PacifiCorp and its customers with liability protection related to potential impacts associated with dam removal. The amended KHSA provides PacifiCorp with liability protections comparable to the KHSA. The amended KHSA also retains PacifiCorp's contribution limit to facilities removal costs to no more than $200 million, of which up to $184 million would be collected from PacifiCorp's Oregon customers with the remainder to be collected from PacifiCorp's California customers. California voters approved a water bond measure in November 2014 from which the state of California's contribution toward facilities removal costs will be drawn, and this contribution is now reflected in the recently approved California state budget.

(ii) Adjustment 8.7 - KHSA, consistent with the stipulation in Docket No. 11-035-200, includes amortization expense of the recovery of relicensing and process costs with a carrying charge at the authorized long-term cost of debt. Since carrying charges will continue to be accrued, the net unrecovered relicensing and process costs are removed from rate base in this adjustment.

(g) On January 1, 2014 new depreciation rates for the Carbon Plant became effective in Utah. The difference in the depreciation in these rates due to the retirement of the Carbon Plant was deferred to be amortized to expense after the plant was retired. This deferral of depreciation expense was booked on a system factor, but needed to be allocated situs to Utah. In 2014, Adjustment 8.8 corrected the allocation of the deferral for all 12 months of the year. In 2015, Adjustment 8.8 corrected the allocation of the deferral for January – April, when the plant was closed. From May to December, it corrected the allocation of the amortization of the unrecovered plant portion of the depreciation deferral. Please refer to Attachment 4.5 -3.

(h) This adjustment is required to re-classify charges to the correct account:

(i) Amortization of the Deer Creek mine unrecovered plant regulatory assets needs to be charged to FERC Account 501, non-power cost related fuel expense. In unadjusted results, this was charged to FERC Account 501NPC, which is part of net power costs (NPC). The Deer Creek adjustment includes this correction.

(ii) Joint owner portion of the Deer Creek Mine regulatory assets needs to be charged to FERC Account 506, instead of FERC Account 501NPC, which is part of NPC. The Deer Creek adjustment includes this correction.

DPU Data Request 4.6

Reporting and Ratemaking Allocation Factors:

(a) What are the major factors that impacted the Utah allocation factors for 2015?

Response to DPU Data Request 4.6

(a) Allocation factors are mainly driven by loads, so the main factors that would have impacted the Utah allocation factors for calendar year (CY) 2015 would be energy usage and Utah's timing and contribution to the system coincidental peak (CP).