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Department of Commerce
Division of Public Utilities

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# ACTION REQUEST RESPONSE

To: Utah Public Service Commission

From: Division of Public Utilities

Chris Parker, Director
Artie Powell, Manager, Energy Section
David Thomson, Technical Consultant
Abdinasir Abdulle, Technical Consultant
Justin Christensen, Utility Analyst

Subject: Docket No. 14-035-36. Action Request from the Commission to review and make recommendations. PacifiCorp's December 2013 Results of Operations. In the Matter of PaciCorp's Financial Reports.

Date: September 30, 2014.

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**RECOMMENDATION (No Action)**

After a review of the above mentioned report, the Division of Public Utilities (''Division") recommends that the Public Service Commission ("Commission") take no action other than directing the Company, for reasons outlined in this report, to not make adjustments in future filings that in total or in part are based on past rate case filings by the Company in Utah that have yet to be accepted by Commission order, stipulated agreement or accepted procedure.

**ISSUE**

On April 30, 2014, Rocky Mountain Power ("Company") filed its December 2013 Results of Operations and a confidential Wind Resources Report for the twelve months ended December 31, 2013 with the Commission. The wind report was provided in compliance with the Commission's final order in Docket No.07-035-93. On May 2, 2014, the Commission issued an Action Request

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to the Division requesting a review of the filing and to make recommendations. The Commission asked the Division to report back by June 2, 2014.

Upon initial review of the filing, the Division determined that the review would require it to (1) submit requests for information to Company and (2) to independently check the Company's spreadsheets used in its filing to obtain regulatory results of operations for 2013. The Company told the Division that its initial request for a reconciliation of the results to its FERC Form 1 and SEC 10K filings for 2013 would take up four to six weeks. Also, the Company's responses to the Division's additional follow-up data requests would require an additional 30 days. Therefore, the Division requested on May 20, 2014, that the Commission extend the due date of the Division's response to the Action Request to September 30, 2014.

On May 28, 2014, the Commission granted the Division's request for an extension of time to September 30, 2014.

**COMMENTS**

In late 2010 and early 2011, the Division, Commission, and at times the Office of Consumer Service, met on an informal basis to discuss the Company's semi-annual reporting. Prior to the informal meetings, the historical unadjusted information provided by the Company in its filings of Semi-Annual Operations was adjusted using three types of adjustments to arrive at normalized results. Those adjustments were Type 1 adjustments – normalization for out of period and unusual items that occurred during the test period; Type 2 adjustments – annualized changes that occurred during the test period; and Type 3 adjustments – known and measurable items that will occur in a future period. As a result of the informal meetings, there was change regarding how the unadjusted information would be adjusted to arrive at normalized results. Now actual results are adjusted to arrive at normalized results using two types of adjustments. They are Type A – reporting and ratemaking adjustments and Type B – normalizing adjustments. Future period adjustments have been discontinued. Except for these adjustment changes, the rest of the filing's basic format and presentation of information remains the same as in previous filings. The first semi-annual filing using the new Type A and Type B adjustment method was the Semi-Annual filing filed for the year ended December 31, 2011.

The Division's review of the Semi-Annual filing under this Action Request was done using three major review procedures. The first major procedure was comparing information given and adjustments made for the year ended December 31, 2012 Semi-Annual filing to the same information given and adjustments made for the December 31, 2013 Semi-Annual filing. The second procedure was to review a reconciliation provided by the Company that reconciled the year ended December 31, 2013 Semi-Annual filing to the Company's FERC Form1 and its SEC 10K filing for the same period. Third, the Division used the IJA model provided by the Commission to check the Company results of operations filings independently. The Division had no informal meetings with Company during its review of the results of operations for 2013.

Net Power costs are a major operating expense of the Company. For the year ending December 31, 2013, these costs were reviewed by the Division pursuant to an order in another docket, and thus Net Power Cost was not reviewed again for this Action Request. The result of the Division's latest audit regarding Net Power Costs can be found in Docket No. 14-035-31. The Division also filed reports on the REC Balancing Account in Docket No. 14-035-30. The Division did do a comparison review of Net Power Cost and REC Balancing account adjustments made to the 2012 and 2013 December 31 filings. The questions it had for these items were covered in the above Dockets and will not be addressed in this report.

Tab 2 in the Semi-Annual filing is entitled Results of Operations. This section of the filing has a one page summary of actual results for the Total Company and Utah, and normalized results for the Total Company and Utah. The normalized results are obtained by applying the Type A and Type B adjustments. In this Tab the allocation of total cost to Utah is done by using the 2010 MSP Protocol without the ECD (Embedded Cost Differential). The summary also uses a 13-month Average Rate Base. Behind the summary are the detail amounts by FERC account. The detail, also by FERC account, shows the business function of the account and the allocation factor or factors used to allocate total FERC account amounts to Utah. The allocation factors are found in Tab 11 – Reporting and Ratemaking Allocation Factors. Tab 11 has the allocation factors for all Company's jurisdictions and how they were computed. Actual loads were used in determining many of the allocation percentages. For its Utah filing the Company used only the Utah allocation percentages from Tab 11.

Also in Tab 2 is a page that has user specific information, tax information, and capital structure information. The capital structure information is calculated using a five quarter average from December 31, 2012 to December 31, 2013.

Tab 1 of the Semi-Annual filing is called Summary. This tab starts with actual results for Total Company and Utah allocated, then shows the Type A adjustments for Total Company and Utah Allocated to arrive at amounts for Total Company and Utah Allocated after adjustments. These results are shown under a column with a heading of Reporting and Ratemaking Results. These results are then adjusted for Type B adjustments to arrive at normalized results for Total Company and Utah Allocated. The final normalized results in this Tab agree with those in Tab 2. Tab 2 does not show the Type A and Type B adjustments. This section also has an adjustment summary whereby the Utah allocated reconciled actual results of operations, rate base and tax calculations are shown along with all of the adjustment tabs line item totals (combining A and B adjustments) to arrive at the Utah Allocated Normalized Results. The table below provides the following summary information for comparative purposes from the latest filings. All numbers are the Utah Allocated normalized results amounts ($000,000).

| | December 2013 | June 2013 | December 2012 |
|---|---|---|---|
| Total Operating Revenues | $2,108 | $2,061 | $2,037 |
| Total O&M Expenses | $1,224 | $1,199 | $1,202 |
| Depreciation and Amortization | $ 265 | $ 261 | $ 253 |
| Taxes Other Than Income | $ 59 | $ 57 | $ 56 |

| | December 2013 | June 2013 | December 2012 |
|---|---|---|---|
| Income Taxes and Deferrals | $ 135 | $ 128 | $ 122 |
| Operating Revenue for Return | $ 425 | $ 416 | $ 404 |
| Total Electric Plant | $10,793 | $10,506 | $10,309 |
| Total Rate Base Deductions | $ 5,007 | $ 4,804 | $ 4,648 |
| Total Net Rate Base | $ 5,786 | $ 5,702 | $ 5,661 |
| Earned Return on Rate Base | 7.339% | 7.303% | 7.141% |
| Earned Return on Equity | 9.174% | 9.088% | 8.707% |

Through a stipulation approved by the Commission in the Company's last general rate case[1] the Commission authorized an Earned Return on Equity amount of 9.80%. The Division notes that per the last three Semi-Annual filings the Company is earning less than its authorized Return on Equity of 9.80%. Tab 9 of the filing is labeled Rolled-in. The amounts and the results of operation in this Tab are exactly the same as Tab 2. A comparison of the years above indicates a gradual increase in Revenues and O&M expenses. Also, the total net rate base is also increasing along with the earned return on rate base and the earned return on equity.

For the last General Rate Case the Overall Capital Structure and Cost of Capital was stipulated as follows:

| Component | Percent of Total | Cost | Weighted Average |
|---|---|---|---|
| Long-term Debt | 48.55% | 5.20% | 2.53% |
| Preferred Stock | 0.02% | 6.75% | 0.00% |
| Common Stock Equity | 51.43% | 9.80% | 5.04% |
| TOTAL | 100.00% | | 7.57% |

[1] Docket No. 13-035-184

In this Semi-Annual the calculated five quarter average Overall Capital Structure and Cost of Capital is:

| Component | Percent of Total | Cost | Weighted Average |
|---|---|---|---|
| Long-term Debt | 47.35% | 5.31% | 2.516% |
| Preferred Stock | 0.22% | 5.47% | 0.012% |
| Common Stock Equity | 52.44% | 9.80% | 5.139% |
| TOTAL | 100.00% | | 7.667% |

The filing has a Tab 10 that is labeled 2010 Protocol With ECD. This Tab uses normalized allocation factors from Tab 12 to allocate Total Company normalized results to Utah. Tab 12 uses temperature normalized loads to derive its allocation factors. Overall, this method causes fewer costs to be allocated to Utah. The Earned Returns on Equity for Tab 10 for December 2013, June 2013 and December 2012 are 9.011%, 8.678%, and 8.019%, respectively.

Per the last general rate case, the stipulated Utah base Net Power Costs were $630.0 million on an annual basis. For the December 2013, June 2013, and December 2012 Semi-Annual filings the Utah Net Power Cost were computed to be $659.6, $639.8, and $640.2 million, respectively.

On Page 1.2 of Tab 1 – Summary – for the June 2013 and December 2012 results of operations, there is a note just below line 65 that states the following: “Results do not reflect prepaid and other postretirement welfare plan balances which will be included in the next general rate case filing”. This statement is also applicable to past Semi-Annual filings not just these two previous filings. As per the above statement, these balances were included in the last general rate case filing Docket No. 13-035-184 and the December 2013 results of operations. The rate case testimony explained why these balances were included in the rate case. Whether or not the Commission will accept these balances in rate base was not determined by the settlement in the last rate case.

The Company has chosen to include these balances in its December 2013 results of operations without Commission order or approval for inclusion. This inclusion in the filing was done in tab 8

– Rate Base Adjustment. The adjustment is 8.11 Type A. Based on this adjustment's inclusion in this filing, the Division anticipates the Company will include this adjustment in future results of operation filings unless the Commission directs it not to do so. Again as stated above, there is no Commission order supporting the use of this adjustment to obtain Utah normalized results of operations for the semi-annual filing. The Division asked in a data request to the Company to determine what would be the impact on the December 2013 filing if adjustment 8.11 was eliminated. The Company provided only the total company effect on Rate Base of excluding Adjustment 8.11 and that would be to reduce Rate Base by $150,416,699.

The Division was hoping for a greater detail and thus has prepared its own analysis. This analysis was to run the company's JAM model without adjustment 8.11 and then generate a new results of operations summary. We then compared the new results of operations summary we produced to the Company's original results of operations summary with the adjustment 8.11 in it as filed with the Commission. Exhibit A has the results of the comparison. The pertinent results for not including adjustment 8.11 is as follows: not including adjustment 8.11 decreased operating taxes by $615,194; decreased rate base by $116,295,924; decreased rate base deductions by $51,574,417; increased return on rate base from 7.339% to 7.411% (plus 0.072) an increase of .98%; and increased return on equity from 9.174% to 9.311% (plus 0.137) an increase of 1.49%. See exhibit A for details.

The Division believes that only Commission long accepted regulatory and normalizing adjustment practices or adjustments required by Commission order or stipulated agreement should be in the results of operations filings and until such time as the Commission addresses the prepaid pension cost matter we recommend that this adjustment should not be made to future results of operation filings.

For the reasons, as stated above we recommend that the Company in future filings not restate generation overhaul expenses to constant dollars when it does its normalizing adjustment for generation overhaul expenses (see adjustment page 4.6.1 in the filing). Similarly, past rate case positions to normalize wind turbine oil change costs using a three year average should not be used until accepted by the Commission (see adjustment page 4.9 in the filing).

In a data request, the Division asked if the restating of overhaul costs to constant dollars was in agreement with a past Commission Order. The Company's response to that questions was as follows, "The restating to constant dollars in the computation of the generation overhaul expense in the results of operations filing is consistent with the last several rate case filings by the Company in Utah."

In its August 11, 2008 Order issued in Docket No. 07-035-93 and in its February 18, 2010 Order issued in Docket No. 09-035-23 the Commission directed that historic costs should not be inflated prior to determining the normalized four-year average expense level. As stated above by the Company, in its rate case filings subsequent to the above orders it has restated overhaul expense amounts in constant dollars. In past rate cases the Company has written testimony to support it doing so. The Division in recent rate case testimony has also provided reasons and analysis why historical costs should be adjusted to constant dollars. However, all of the rate cases subsequent to the above Orders on this matter have been settled with this restating to constant dollars not addressed in the stipulated settlements.

In its December 2012 results of operations filing, the Company also did an overhaul adjustment restating overhaul expense to constant dollars in that filing. As a matter of curiosity, the Division wanted to see the impact of adjustment 4.6 to results of operations using historical dollars instead of constant dollars as filed by the Company in the 2013 filing. Using the same method and analysis as that used for prepaid pension costs above, the results were as follows: not including constant dollars decreased O&M expense $576,114; increased taxes ay $218,697; decreased rate base working capital $5,861; increased return on rate base from 7.339 to 7.349 (plus 0.006) an increase of .08%; and increased return on equity from 9.174 to 9.186 (plus 0.012) an increase of .13%. See exhibit A for details. The differences appear to be immaterial for this year and would most likely be immaterial for 2012.

If the Company had not done a three year average of costs in its normalizing adjustment for wind turbine oil changes, the Utah dollar impact and rates of return impacts would be in total nearly unchanged. The dollar difference would have been a $387,145 decrease, on a Utah-allocated basis, from what was filed. Because of the lack of impact comparison results are not provided.

Also in Exhibit A, the Division has included a comparison of the original results of operations summary with one prepared by the Division without prepaid pension costs and the constant dollar adjustment to generation overhaul expenses. The results are as follows: using the Divisions two adjustment positions decreases O&M expenses $576,112; increases taxes $833,891; decreases rate base $116,306,012; increase working capital by $4,227; decreases rate base deductions $51,874,417; increases return on rate base from 7.339% to 7.417% (plus 0.078) an increase of 1.06%; and increases return on equity from 9.174 to 9.323 (plus 0.149) an increase of 1.62%. See exhibit A for details.

The Division received a response to a data request asking the Company if any of its Type A or Type B adjustments (in full or in part as in the generation overhaul adjustment) to the Results of Operations were done for the same reason as it provided and as is quoted above: to reflect the way the Company has filed previous cases. The Company's response to that question was that, "All adjustments in the Results of Operations are consistent with the Company's last GRC filing, unless specific adjustments were called out in the settlement stipulation or Commission Order."

Even though the Company may believe that adjustments, as filed in its past general rate case or cases, have merit and should be part of the Results of Operations filed with the Commission, it is the Division's opinion that results of operation adjustments in the Company's semi-annual filings with the Commission should be included in the filing only if they were approved in an order, stipulation agreement or have been long accepted by the commission in past filings. The Division believes that it would be a poor precedent to start allowing rate case adjustments that have yet to be accepted or are contrary to Commission order or were contested by parties prior to settlement without resolution or agreement into semi-annual results of operation filings even if such adjustments were immaterial. The Company cannot win by inertia what it has not yet won by order or adjustment.

As stated above, the Division has compared adjustments from year to year, and at this time the Division is not aware of any other adjustments, other than the three discussed above, that meet its criteria for non-inclusion in future results of operation filings with the Commission

As noted above, one of our major review procedures was to have the Company provide a reconciliation of the Semi-Annual results to the Company's FERC Form 1 and SEC Form 10K. The Company's Semi-Annul filing to the Commission is based on FERC accounting and FERC accounts. The first reason for this reconciliation is to make sure that the unadjusted historical information in the Semi-Annual filing results of operations provided by the Company is reconcilable to the FERC Form 1 data. Through the reconciliation of the Semi-Annual filing, the Division can get assurance that the form and the accounting for the Semi-Annual filing are the same as that provided to another outside regulator, in this case the FERC.

The second reason for the requested reconciliation is that if the 10-K results can be reconciled to the Semi-Annual filing, then the Division can take into account the external auditor's 10K audit opinion on the results shown in the Company's year-end filing of its Semi-Annual. The Division can look to this audit to obtain assurance as to accounting correctness and accuracy for Semi-Annual base unadjusted historical information under this review.

The Company's filing of its 10-K with the Securities and Exchange would be based on historical information from the Company's books and records. The 10-K filing is based on GAAP accounting (General Accepted Accounting Procedures) but the information for that accounting also is the same base information that is used in the FERC Form 1 and the Semi-Annual filing. The SEC filing's historical information is audited by independent external auditors of the Company. The external auditors have expressed a positive opinion on the fairness of the Company's representations on its financial statements according to GAAP for the same period as the Semi-Annual report the Division is reviewing in this memorandum; the opinion issued by the external auditor was what is sometimes termed a “clean” opinion. The Company’s books and records providing the account amounts for the financial statements and for the FERC Form 1 and the Semi-Annual were audited by the External Auditor using Generally Accepted Auditing Procedures as part of its procedures to arrive at its issued opinion.

Third, once the reconciliation is provided, the Division can review the reconciled items to see if they make sense and are proper additions or eliminations to arrive at a proper base or proper starting point for unadjusted historical results of operations in the Semi-Annual filing. This proper base is then adjusted to arrive at Utah normalized results of operations for regulation purposes.

The Division did receive the above requested and explained reconciliation. Specifically, the Company prepared the following reconciliations:

1. Income Statement: 10-K to FERC Form 1.
2. Income Statement: FERC Form 1 to Results of Operations (unadjusted).
3. Balance Sheet: 10-K to FERC Form 1.
4. Balance Sheet: FERC Form 1 to Results of Operations (unadjusted, yearend basis).

These reconciliations are provided with this report as DPU Exhibit B. As part of its review procedures, the DPU compared the reconciliations provided by the Company for its December 2013 review with the reconciliations provided by the Company for its December 2012 review.

The reconciliation format was identical from this year to last year with the vast majority of the reconciliation items from year to year being the same. This was expected since the base accounting and the chart of accounts from year to year follows GAAP and FERC rules and regulations that are highly consistent, with little if any changes from year to year. This consistency provides comparisons that quickly point out differences from year to year in format and reconciling items. During its review of the December 2012 results of operations, the Division requested additional explanation during its review of that year's reconciliations. Those additional explanations were requested in DPU data requests 1.1 to 1.4 and 3.1 to 3.3. That information was read again prior to the review of this year's reconciliations for applicability to the current year. It was useful to the current reconciliation review. This additional information was provided as DPU Exhibits B through L in the December 2012 review and can be found there for reference purposes (Docket 13-035-72). Due to the consistency of the reconciling material from this year to the last, no data requests having to do with the reconciliations for December 2013 were required.

The information provided by the Company in its reconciliations has enabled the Division to better understand why particular financial items are different between the three types of reports (Form 10K, FERC Form 1 and Utah Results of Operations). Due to the large number of differences between the reports and the detail involved, this report will not attempt to explain all of the differences. The explanations for the differences are, however, shown in DPU Exhibit B. The Division has reviewed the Company's explanations for the differences and at this time the Division does not have any reconciliation concerns. However, the Division reserves the right to challenge certain reconciliation treatments or methodologies that may get carried over to future Results of Operation reports if it appears that such a challenge is necessary. For example, the Division may at a future date determine that an item that is currently considered "regulatory" should in fact be "non-regulatory" and should not be included in the Results of Operations.

It appears to the DPU, after review of the reconciliations, that the December 2013 results of operations on a total Company and unadjusted basis is derived from the same base numbers as those found in the Company's 10K filing to the Securities and Exchange Commission and to the FERC Form 1 filing with the Federal Energy Regulatory Commission.

Another review procedure was to compare the adjustments made to the Utah Results of Operations for the year ended December 31, 2013 to the adjustments to the Utah Results of Operations for the year ended December 31, 2012. In the past ten years, the majority of the rate cases in Utah have been settled. Thus, during this period the adjustments to arrive at Utah regulated results of operations have been consistent with very little change. Generally, the Commission's orders and regulatory precedents used to arrive at Utah regulatory results of operations have been generated many years before and so the regulatory adjustments from one semi-annual results of operation filings to another are basically the same. However, as noted above in the December 2011 results of operations future period adjustments (Called Type 3) were discontinued.

Both Type A and Type B adjustments were compared. In the 2013 and 2012 filings, the adjustments are summarized and explained in detail by various categories which are broken out by Tab Sections in the filing. The adjustment Tabs in the filing are numbered and are as follows: Tab 3 - Revenue Adjustments; Tab 4 - O&M Adjustments; Tab 5 - Net Power Cost Adjustments; Tab 6 - Depreciation and Amortization Adjustments; Tab 7 - Tax Adjustments; and Tab 8 - Rate Base Adjustments.

One purpose of the comparison was to note material differences between the years and to determine if the differences were proper. Accordingly the Division submitted comparison questions through data requests to the Company. Another purpose was to have the Division look at the 2013 adjustments to determine if the presentation, explanations, and balances were consistent and accurate and that the assumptions and the computation of the adjustments seemed to be proper and accurate. The Division noted that the adjustments in the adjustment tabs were consistent with adjustments that the Company makes to results of operations in its General Rate Case filings. As noted above some of those adjustments do not follow commission orders or were contested by parties during the rate case prior to settlement without resolution or agreement.

Based on the Division's comparison analysis and its review of the adjustments, it notes the following.

- In the filing, the reason the temperature normalization adjustments for Residential and Commercial are greater than Industrial is the kilowatt-hour (kWh) usage of the residential and commercial class are more temperature sensitive than industrial class usage.

Therefore, when temperatures are below or above normal the temperature normalizing adjustment will be larger for the residential and commercial class than the industrial class.

- The main diver for the revenue normalization adjustment being $33,365,931 was the DSM adjustment. Other comparable increase of over 20% are detailed and explained in Exhibit C – Company attachment for DPU Data Request 1.4.
- The main driver for the increase in 2013 wheeling revenue as compared to 2012 is explained in Exhibit D – Company response to DPU Data Request 1.6.
- The significant increase in wheeling revenue normalizing adjustments in 2013 as compared to 2012 was due to the fact that the adjustments were based on actuals and did not include any forecasted contract changes. As a result, the adjustment did not include any offsetting revenue for projections of additional volumes. The Division believes these offsets were probably done last year causing the difference but did not check due to immateriality and time constraints. However, no other explanation for the difference was apparent and the Division's interpretation of the Company's data request seems to point to this conclusion.
- The Division reviewed the detail of the reallocation of gains and losses as outlined in the explanation to the O&M adjustment on page 4.1 of the filing with no exceptions noted.
- The Division noted the increase in demand side management costs for 2013 as compared to 2012. This increase and the detail of 2013 demand side management costs is explained in the Company's July 21, 2014 filing of its demand side management report in Docket 09-035-T08.
- There is a significant increase in 2013 generation overhaul expenses as compared to 2012. The purpose of the generation overhaul adjustment is to adjust base period expense to a historical four year average. The primary driver for the adjustment increase is largely due to the decrease in base year expense from $38.9 million in 2012 to $28.4 million in 2013. Although the size of the generation overhaul expense adjustment increased from 2012 to 2013, the historical four-year average decreased from $39.0 million in 2012 to $37.3 million in 2013.
- There is no Utah solar incentive adjustment in the 2013 filing. The Utah solar incentive program was originally scheduled to end December 2011. However, the program was

extended an additional year through December 2012. Following the termination of the program, there were some small additional entries in the early months of 2013. These amounts were included as part of the 4.3 non-recurring entries adjustment.

- Amortization of Naughton Unit 3 was included in unadjusted results beginning in October 2012. Since unadjusted results in 2013 include the amortization for the full year the adjustment done in 2012 was not required.
- Property, plant and equipment of approximately $984 million were placed in service in 2013. Substantially all of this property was subject to accelerated 50% bonus tax depreciation which leads to large increases in ADIT in the year placed in service. This is the driving factor for the accumulated deferred tax balance and the ADIT – Utah balance. The driving factor for the accelerated amortization of Pollution Control ADIT balance is normal activity where the amortization continues to build the balance until the end of the tax life.
- Exhibit E – Company attachment DPU Data Request 1.17 lists the differences between the 2013 and 2012 cash working capital adjustment (see 2013 filing page 8.1 for the adjustment detail and amounts).
- The primary driver in the decrease of investment in the Trapper Mine and the Bridger Mine is due to the continued depreciation of mine assets.
- The 2013 increase in customer advances of $1.9 million is primarily the result of an increase in the number and balance of distribution construction projects directly assignable to Utah.
- The decommissioning effort for Powerdale Hydro has been completed, however, because accumulated deferred income taxes (ADIT) is calculated using a 13-month average for Utah there will be a tax only adjustment needed in future filings.
- The majority of deposits are charged to customers due to their payment history. In 2013 the Company saw an increase in the amount of reconnects for credit that they processed. The Company reconnected 29% more customers in 2013 than they did in 2012. These customers are assessed a deposit per the Utah Electric Service Regulation number 9.

- The Division asked for an update on what was happening currently and into the future with the Klamath-related relicensing and process costs and the settlement agreement. The Company responded as follows, "Klamath relicensing and settlement process costs are being amortized through the approved recovery period of December 31, 2022. The Klamath Hydroelectric Settlement Agreement (KHSA) remains in effect and the company continues to implement its obligations pursuant to the settlement. Necessary federal legislation, the "Klamath Basin Water Recovery and Economic Restoration Act of 2014" (S.2379), which would fully implement the KHSA, was introduced into the U.S. Senate on May 21,2014, by Senator Wyden of Oregon with Senator Merkley of Oregon and Senators Feinstein and Boxer of California as cosponsors. The legislation was the subject of a June 3, 2014 hearing before the Senate Energy and Natural Resources Committee. Senator Wyden subsequently introduced similar legislation (S. 2727) for referral to the Senate Finance Committee on July 31, 2014. On August 13, 2014, the California legislature approved a bond measure for referral to the California electorate this November that includes funding of the State of California's contribution to dam removal costs, consistent with the KHSA."

The Division used the IJA model provided by Commission staff to model a results of operations for the year ended December 31, 2013. This was then compared to the results of operations provided by the Company for the same period. There were only minor differences in a few areas that were not material. The Division believes these differences were due to the fact that the Division's results did not use iteration and the Company's results did use iteration. This independent check supports the results provided by the Company as being properly computed and presented, with differences being of no consequence.

The Division is still in the process of developing its own Excel revenue requirement/reporting model. The model will be similar in purpose to the JAM (provided by the Company) or IJA models (provided by the Commission).

**CONCLUSION**

After performing the above procedures and after reviewing the results obtained from those procedures, nothing came to the Division's attention during its review that was of material significance suggesting modification of the filing or action to change the Results of Operations as filed.

The Division asks that the Commission direct the Company to not make adjustments in future filings that in total or in part are based on past rate case filings by the Company in Utah that have yet to be accepted by Commission order, stipulated agreement or accepted procedure.

cc: Michele Beck, Office of Consumer Services
Dave Taylor, Rocky Mountain Power