

Rocky Mountain Power  
Docket No. 13-035-184  
Witness: Steven R. McDougal

BEFORE THE PUBLIC SERVICE COMMISSION  
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

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Direct Testimony of Steven R. McDougal

Revenue Requirement & Test Period

January 2014

1 **Q. Please state your name and business address with PacifiCorp dba Rocky**  
2 **Mountain Power (“the Company”).**

3 A. My name is Steven R. McDougal, and my business address is 201 South Main,  
4 Suite 2300, Salt Lake City, Utah 84111.

5 **Qualifications**

6 **Q. What is your current position at the Company, and what is your employment**  
7 **history?**

8 A. I am currently employed as the director of revenue requirements for the  
9 Company. I have been employed by Rocky Mountain Power or its predecessor  
10 companies since 1983. My experience at Rocky Mountain Power includes various  
11 positions within regulation, finance, resource planning, and internal audit.

12 **Q. What are your responsibilities as director of revenue requirements?**

13 A. My primary responsibilities include overseeing the calculation and reporting of  
14 the Company’s regulated earnings or revenue requirement, assuring that the inter-  
15 jurisdictional cost allocation methodology is correctly applied, and explaining  
16 those calculations to regulators in the jurisdictions in which the Company  
17 operates.

18 **Q. What is your education background?**

19 A. I received a Master of Accountancy from Brigham Young University with an  
20 emphasis in Management Advisory Services in 1983 and a Bachelor of Science  
21 degree in Accounting from Brigham Young University in 1982. In addition to my  
22 formal education, I have also attended various educational, professional, and  
23 electric industry-related seminars.

24 **Q. Have you testified in previous proceedings?**

25 A. Yes. I have provided testimony before the Public Service Commission of Utah  
26 (“Commission”), the Washington Utilities and Transportation Commission, the  
27 California Public Utilities Commission, the Idaho Public Utilities Commission,  
28 the Oregon Public Utility Commission, the Wyoming Public Service  
29 Commission, and the Utah State Tax Commission.

30 **Purpose of Testimony**

31 **Q. What is the purpose of your direct testimony?**

32 A. My direct testimony addresses the revenue increase requested in the Company’s  
33 application and the calculation of the Company’s Utah-allocated revenue  
34 requirement. In support of this calculation, I provide testimony on the following:

35 Calculation of the \$76.3 million requested rate increase.

- 36 • The test period utilized in this case, 12 months ending June 30, 2015 (“Test  
37 Period”).
- 38 • The Company’s process for compiling the Test Period revenue requirement  
39 and a detailed explanation of the normalizing adjustments made to the  
40 unadjusted base period data to arrive at the Test Period.
- 41 • The treatment of various items from the stipulation in the Company’s last  
42 general rate case (“2012 GRC Stipulation”) Docket No. 11-035-200 as  
43 approved by the Commission (“2012 GRC”).
- 44 • The impact of the depreciation rates approved effective January 1, 2014, in the  
45 Company’s recent depreciation study, Docket No. 13-035-02 (“2013  
46 Depreciation Study”), on the depreciation expense reflected in the Test Period.

- 47           • The 2010 Protocol and Rolled-In inter-jurisdictional allocation methodologies  
48           as approved by the Commission.
- 49           • My testimony addresses the Company’s proposal to revise Test Period results  
50           in the event the Environmental Protection Agency (“EPA”) allows extension  
51           of Naughton Unit 3 as a coal-fired facility; the case is currently prepared  
52           under the assumption the unit will cease operations as a coal-fired facility in  
53           December 2014. A decision on this matter is expected from the EPA January  
54           10, 2014.

55   **Revenue Requirement Summary**

56   **Q.    What price increase is required to achieve the requested return on equity**  
57           **(“ROE”) in this case?**

58    A.    At the current authorized rates, Rocky Mountain Power will earn an overall ROE  
59           in Utah of 8.5 percent during the Test Period. This is less than the 10.0 percent  
60           return recommended by Dr. Samuel C. Hadaway in this case and is less than the  
61           9.8 percent return authorized by the Commission in the 2012 GRC. An overall  
62           price increase of \$76.3 million is required to produce a 10.0 percent ROE under  
63           the 2010 Protocol allocation methodology. As I will explain later in my  
64           testimony, the same price increase is required when Utah revenue requirement is  
65           determined using the Rolled-In allocation methodology. Exhibit RMP\_\_(SRM-  
66           1) provides a summary of the Company’s Utah-allocated results of operations for  
67           the Test Period. Exhibit RMP\_\_(SRM-2) provides a summary index identifying  
68           each normalizing adjustment and where each adjustment is addressed in the

69 Company's filing.<sup>1</sup> Details supporting the revenue requirement by FERC account  
70 and the allocation of the various revenue requirement components to Utah are  
71 provided in Exhibit RMP\_\_\_\_(SRM-3).

72 **Test Period and Revenue Requirement Preparation**

73 **Q. What test period did the Company use to determine revenue requirement in**  
74 **this case?**

75 A. The Test Period utilized by the Company to calculate results of operations is  
76 based on the 12 month historical period ended June 30, 2013, ("Base Period")  
77 forecasted to the 12 month period beginning July 1, 2014, and ending June 30,  
78 2015. Rate base is reflected on a 13-month average basis in the Test Period.

79 **Q. Why did the Company use the 12 months ending June 30, 2015, as the Test**  
80 **Period?**

81 A. Paragraph 41 of the 2012 GRC Stipulation states:

82 The Parties agree that in the Company's 2014 GRC application,  
83 the Company will use, and the Parties will not oppose, use of a  
84 forecast test period of July 1, 2014 through June 30, 2015, with a  
85 13-month average rate base, if the Company files its application  
86 prior to March 1, 2014.

87 On November 5, 2013, the Company filed with the Commission a notice of intent  
88 to file a general rate case and proposed a test period ending June 30, 2015,  
89 consistent with the 2012 GRC Stipulation. On December 10, 2013, the  
90 Commission issued an order approving the Company's test period. The order  
91 states:

92 In light of the test year stipulation quoted above and the absence of  
93 opposition to the Company's proposed test year, we find the  
94 proposed test year meets the statutory requirements. See Utah

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<sup>1</sup>In conformance with filing requirement R746-700-10.A.1.c.

95 Code Ann. § 54-4-4(3). It is approved. Accordingly, consistent  
96 with Utah Administrative Code R746-700-10(B), the Company  
97 need not provide the alternative test period demonstration required  
98 by Subsection (A)(2) of that rule.

99 My testimony and exhibits provide a detailed explanation of all adjustments that  
100 were made to the Base Period data to accurately reflect the normal operating  
101 conditions the Company expects to occur during the Test Period.

102 **Q. Does the Base Period match the unadjusted results of operations previously**  
103 **filed with the Commission?**

104 A. Yes. The accounting data relied on for the Base Period in this case is the same  
105 data used for the unadjusted results of operations for the 12 months ended June  
106 30, 2013, filed with the Commission in October 2013. However, the jurisdictional  
107 allocation model (“JAM”) used for the rate case synchronizes interest and cash  
108 working capital for the unadjusted inputs while the JAM used for the results of  
109 operations does not. This synchronization of the unadjusted data produces an  
110 apparent difference between the two models for interest expense, current income  
111 taxes, and the cash working capital allowance.

112 **Q. When will a rate change become effective in this proceeding?**

113 A. The Company is requesting that new rates become effective September 1, 2014,  
114 which is 241 days after the submission date of this filing.

115 **Q. What are the primary drivers of this case?**

116 A. The primary drivers of the revenue increase requested in this case are the  
117 significant levels of capital investment the Company is making on behalf of  
118 customers, increases in depreciation expense reflecting new depreciation rates  
119 from the 2013 Depreciation Study and decreases in retail revenues and renewable

120 energy credit (“REC”) revenues. These are partially offset by higher wheeling  
121 revenues, reductions to operations, maintenance and administrative and general  
122 expense (“OMAG”) and reduced Utah allocation factors resulting from the load  
123 forecast utilized in this case. Company witnesses Mr. Douglas N. Bennion, Mr.  
124 Chad A. Teply, Mr. Mark R. Tallman and Ms. Natalie L. Hocken provide  
125 testimony in support of the capital investments reflected in the Test Period  
126 required to serve customers. Ms. Kelcey A. Brown provides testimony on the load  
127 and retail sales forecast, Ms. Stacey J. Kusters’ testimony supports the level of  
128 REC revenues included in the Test Period and my testimony summarizes the Test  
129 Period impact of applying the new depreciation rates.

130 **Q. Please explain how the Company developed the revenue requirement for the**  
131 **Test Period.**

132 A. Preparation of the revenue requirement began with historical accounting  
133 information; in this case, the Company used the 12 months ended June 30, 2013,  
134 as the Base Period for developing the revenue requirement in this case. Each of  
135 the revenue requirement components in the Base Period was analyzed to  
136 determine if an adjustment would be warranted to reflect normal operating  
137 conditions expected to occur during the Test Period. The Base Period data was  
138 adjusted to reflect known, measurable, and anticipated events and to include  
139 previously ordered Commission adjustments.

140 **Q. Is the development of the Test Period in this case consistent with that of the**  
141 **Company’s previous general rate cases in Utah?**

142 A. Yes.

143 **Q. What is the significance of Rocky Mountain Power’s method of beginning**  
144 **with historical information to develop Test Period results?**

145 A. The Company utilizes historical accounting information as the base and makes  
146 discrete adjustments to arrive at the Test Period revenue requirement. Beginning  
147 with historical accounting data provides known operation and investment  
148 information that is readily available for audit by all participants involved in the  
149 case. Individual adjustments made to the historical accounting data in order to  
150 develop Test Period results are also available for review.

151 **Q. Please summarize the process used to adjust the historical accounting**  
152 **information to reflect Test Period results of operations.**

153 A. Historical retail revenue is adjusted to reflect normal weather conditions and  
154 remove items that should not be included in the revenue requirement calculation.  
155 Revenue is also adjusted for the effect of applying the rates from the current  
156 Commission approved tariffs to the Test Period load projection. The testimony of  
157 Company witness Ms. Brown describes the comprehensive approach used to  
158 project Test Period loads for this case. Net power costs (“NPC”) were developed  
159 using the Generation & Regulation Initiative Decision (“GRID”) model, which  
160 has been used extensively in prior general rate cases and other regulatory  
161 proceedings in Utah. The calculation of Test Period NPC is described in the  
162 testimony of Company witness Mr. Gregory N. Duvall. Historical operations and  
163 maintenance (“O&M”) expenses, excluding NPC, were split into labor and non-  
164 labor components. Non-labor costs were adjusted for projected price changes  
165 using nationally recognized inflation indices provided by IHS (formerly IHS



166 Global Insight) and for other discrete changes required to reflect conditions  
167 expected during the Test Period. Historical labor costs were also adjusted for  
168 expected wage and benefit changes through the end of the Test Period. Rate base  
169 was adjusted to capture planned additions to electric plant in service and known  
170 changes to other rate base items. In addition, asset retirements, removal costs, and  
171 accumulated depreciation balances were walked forward through the end of the  
172 Test Period by plant function. I explain the development of the Utah Test Period  
173 results of operations and specific adjustments in greater detail later in my  
174 testimony and exhibits.

175 **Q. How has the Company addressed areas where the expected change in OMAG**  
176 **is different than the price changes projected by IHS?**

177 A. The Company has identified costs that are projected to change in the future due to  
178 causes other than inflation. Specific adjustments for these items are included in  
179 the Test Period revenue requirement calculation. Testimony supporting these cost  
180 changes is provided as part of the Company's filing. An example of this type of  
181 adjustment is the Incremental O&M Adjustment, No. 4.9, which includes the cost  
182 of operating and maintaining the Company's generating plants.

### 183 **Inter-Jurisdictional Allocations**

184 **Q. What allocation methodology did the Company use to calculate the Utah**  
185 **revenue requirement in this case?**

186 A. The Company's requested price increase is based on the 2010 Protocol allocation  
187 methodology as described in the Agreement Pertaining to PacifiCorp's September  
188 15, 2010, Application for Approval of Amendments to Revised Protocol

189 Allocation Methodology (“2010 Protocol Agreement”) filed with the Commission  
190 on June 27, 2011, in Docket No. 02-035-04, and approved November 8, 2011.  
191 Consistent with the 2010 Protocol Agreement, allocation of results are based on  
192 the Rolled-In allocation methodology with the Hydro Endowment and Klamath  
193 adjustments, which are included in the 2010 Protocol, zeroed out. Consequently,  
194 Utah-allocated results of operation are identical under either the 2010 Protocol or  
195 the Rolled-In allocation methods. For comparison purposes, the Test Period  
196 results for this case in Exhibit RMP\_\_\_\_(SRM-3) are provided using both the 2010  
197 Protocol (Tab 2) and Rolled-In (Tab 9) methods. In addition, I have provided a  
198 calculation of the 2010 Protocol results including the Hydro Endowment and  
199 Klamath adjustments using Test Period information in (Tab 10) as required by the  
200 2010 Protocol Agreement.

201 **Docket No. 11-035-200 Stipulation**

202 **Q. Please describe how various items from the 2012 GRC Stipulation are**  
203 **included in this case.**

204 A. The stipulation reached by parties in the 2012 GRC addressed several items that  
205 impact the development of the Test Period results and revenue requirement in this  
206 case. Below I address how certain of these items were reflected in the  
207 development of the Test Period results or where further information on treatment  
208 of these items in the case can be found.

209 REC Revenues

210 Paragraph 39 of the 2012 GRC Stipulation allows the Company to retain 10  
211 percent of REC sales revenue pursuant to terms specified in the stipulation. The

212 Company has not reflected REC revenue retention in the Test Period results, but  
213 rather intends to address this issue in the upcoming REC Balancing Account  
214 (“RBA”) filing in March 2014. The results in this GRC filing reflect REC  
215 revenues at the level expected during the Test Period as supported by the  
216 testimony of Company witness Ms. Kusters. Further detail on this issue may be  
217 found in REC Revenue Adjustment, No. 3.4. of my Exhibit RMP\_\_\_\_(SRM-3).

218 Depreciation Study

219 Depreciation expense levels and accumulated depreciation reserve balances  
220 included in Test Period results reflect the impact of the new depreciation rates  
221 established in the 2013 Depreciation Study, including the excess reserve  
222 givebacks for Steam plant and Utah distribution plant. Paragraph 44 of the 2012  
223 GRC Stipulation addresses the treatment of the net difference in depreciation  
224 expense resulting from the application of new depreciation rates until they are  
225 reflected in base retail rates. The stipulation allows deferral for future recovery of  
226 any aggregate net increase in Utah-allocated depreciation expense in excess of  
227 \$2.0 million annually. The new depreciation rates result in an aggregate net  
228 increase in Utah-allocated depreciation expense. As detailed in Deprecation Study  
229 Adjustment, No. 6.3 of Exhibit RMP\_\_\_\_(SRM-3), the Company has projected the  
230 level of depreciation expense to be deferred from January 1, 2014, through  
231 August 31, 2014, and has reflected in Test Period results amortization of this  
232 deferral beginning September 1, 2014, and continuing through June 30, 2015. My  
233 testimony describes the treatment of these items in the Test Period revenue  
234 requirement as detailed in Tab 6 of Exhibit RMP\_\_\_\_(SRM-3).

235 Paragraph 45 of the 2012 GRC Stipulation specifies the Company will  
236 propose a class cost of service allocation of the deferred depreciation expense to  
237 customers as part of the this rate case. This matter is addressed in the testimony of  
238 Company witness Ms. Joelle R. Steward.

239 Carbon Plant

240 Paragraphs 46 through 50 of the 2012 GRC Stipulation address matters raised in  
241 Docket No. 12-035-79 concerning retirement and decommissioning of the Carbon  
242 plant. Among other items, the 2012 GRC Stipulation specifies: (i) creation of the  
243 Remaining Carbon Balances regulatory asset to be amortized from the date  
244 Carbon plant net balances are transferred to the regulatory asset through calendar  
245 year 2020; (ii) creation of the Carbon Removal Costs regulatory asset to be  
246 recovered from customers from the time the plant is retired (currently projected to  
247 occur in April 2015) through calendar year 2020; (iii) agreement by the parties to  
248 not challenge recovery of the Remaining Carbon Balances regulatory asset on the  
249 grounds of used and useful standards; (iv) the Company is required to propose  
250 updates to the Carbon Removal Costs regulatory asset in each future rate case  
251 filing, based on the best available cost removal projections;. and (v) any changes  
252 to projected Carbon Removal Cost estimates will be identified and explained as  
253 part of each future rate case filing, including this rate case.

254 Later in my testimony, I describe the treatment of the Remaining Carbon  
255 Balances regulatory asset in Test Period results. Further detail on this item may be  
256 found in Carbon Plant Adjustment, No. 8.13 of Exhibit RMP\_\_\_\_(SRM-3).  
257 Concerning the Carbon Removal Costs regulatory asset, the Company is

258 proposing in this case to defer any recovery and amortization of this balance until  
259 the next general rate case filing. Deferral of this matter to the next general rate  
260 case will ensure that amortization of removal costs do not begin until  
261 decommissioning activities have commenced and will also enable the Company to  
262 develop a more current removal cost estimate prior to inclusion in customer rates.  
263 At this time, the Company does not have a more current estimate of Carbon  
264 removal costs than the \$117/kw figure that was utilized in the 2013 Depreciation  
265 Study.

266 Naughton Unit 3 Development Costs

267 Paragraphs 52 and 53 of the 2012 GRC Stipulation specifies treatment of the  
268 Naughton Unit 3 development costs for which the Company requested deferred  
269 accounting treatment in Docket No. 12-035-80. Pursuant to the stipulation, Utah's  
270 allocated share of the Naughton Unit 3 development costs of \$7.9 million would  
271 be deferred and fully amortized by September 1, 2014, providing full recovery  
272 prior to the effective date of this rate case. As addressed later in my testimony,  
273 Naughton Write-off Adjustment, No. 4.10 of Exhibit RMP\_\_\_(SRM-3) removes  
274 amortization of the Naughton Unit 3 development costs from Test Period results  
275 ensuring the amortization is not reflected in the requested revenue requirement.

276 Klamath

277 Paragraphs 58 through 60 of the 2012 GRC Stipulation address the revenue  
278 requirement treatment of various items related to the Company's Klamath  
279 hydroelectric facility. Among other items, the stipulation specifies: (i) the  
280 Company is permitted to fully depreciate the Klamath dam facilities through 2022

281 beginning June 1, 2012; (ii) the Company may recover a return on and return of  
282 the Klamath dam balances by including depreciation expense and net unrecovered  
283 plant rate base in results through calendar year 2022, even if the plant is  
284 decommissioned prior to 2022; (iii) the Klamath related relicensing and process  
285 costs of \$81.8 million are included in Utah rates through amortization of the  
286 balance through 2022, beginning October 12, 2012, with a carrying charge set at  
287 the long term cost of debt. Since a carrying charge is reflected in the amortization  
288 expense, the relicensing and process cost asset is not included in rate base; and  
289 (iv) the Company may not recover from Utah customers dam removal or removal  
290 related costs associated with the Klamath Hydroelectric Settlement Agreement  
291 (“KHSA”). The Test Period treatment of these items is addressed later in my  
292 testimony and in Klamath Hydroelectric Settlement Agreement Adjustment, No.  
293 8.11 found in Exhibit RMP\_\_\_(SRM-3).

294 Utah Solar Program

295 Paragraph 61 of the 2012 GRC Stipulation specified that costs for the Utah Solar  
296 Incentive Program, which was being developed and was not approved by the  
297 Commission at the time the stipulation was written, be added as a surcharge to the  
298 Step 1 rate increase of the 2012 GRC effective October 12, 2012. The program  
299 was subsequently approved in Docket No. 11-035-104. In the order approving the  
300 program, a separate rate schedule (Schedule 195) was developed to recover the  
301 revenue requirement of this program. Schedule 195 charges are added to the  
302 energy charges of each customer’s applicable tariff rate schedule. Accordingly,  
303 costs associated with this program are excluded from the Test Period results.

304 **Utah Results of Operations**

305 **Q. Please describe Exhibit RMP\_\_\_(SRM-3).**

306 A. Exhibit RMP\_\_\_(SRM-3), which was prepared under my direction, is Rocky  
307 Mountain Power's Utah results of operations report ("Report"). The historical  
308 starting point for the Report is the 12 months ended June 30, 2013, which was  
309 normalized and then projected forward to calculate the revenue requirement for  
310 the Test Period, 12 months ending June 30, 2015. The Report provides totals for  
311 revenue, expenses, depreciation, net power costs, taxes, rate base, and loads in the  
312 Test Period. Rate base has been walked forward through the Test Period using a  
313 13-month average methodology. The Report presents operating results for the  
314 period in terms of both return on rate base and ROE.

315 **Q. Please describe how Exhibit RMP\_\_\_(SRM-3) is organized.**

316 A. The Report is organized into sections marked with tabs. Tab 1 Summary contains  
317 the Utah-allocated results according to the 2010 Protocol Agreement. Page 1.0  
318 summarizes the revenue requirement calculation based on the Utah's results of  
319 operations for the Test Period. The Total Adjusted Results column is carried  
320 forward from the results of operations summary, page 2.2, and shows an ROE for  
321 Utah of 8.5 percent. The Price Change (column 2 of Tab 1, page 1.0) shows that  
322 an increase of \$76.3 million in revenue is required to increase the ROE from 8.5  
323 percent to 10.0 percent. Column 3 reflects Utah's adjusted revenue requirement of  
324 \$1.96 billion with the \$76.3 million price increase included. Page 1.1 of Tab 1  
325 supports the calculation of additional revenue related uncollectible expense and  
326 income taxes associated with the price change. Page 1.2 details the calculation of

327 the net operating income percentage. Page 1.3 shows the same details as page 1.0  
328 but under the Rolled-In rather than the 2010 Protocol allocation methodology.  
329 This sheet is provided to show that results are identical under either method,  
330 consistent with the 2010 Protocol Agreement. Pages 1.4 through 1.5 contain a  
331 summary of adjustments made to the actual results to arrive at the normalized  
332 results of operations for the Test Period.

333 Tab 2 details total-Company and Utah-allocated results based on the 2010  
334 Protocol Agreement. Pages 2.3 through 2.39 contain total-Company and Utah-  
335 allocated revenue, expenses and rate base detail by FERC account. Actual results  
336 of operations are supplied side-by-side with the normalized Test Period results, on  
337 both a total-Company and Utah-allocated basis.<sup>2</sup> Supporting documentation for  
338 the data in Tab 2, along with the normalizing adjustments required to reflect on-  
339 going costs of the Company, is provided under Tabs 3 through 8. These  
340 adjustments are described later in my testimony. Tab 9 is Tab 2 restated with the  
341 Utah allocation based on the Rolled-In allocation methodology. Tab 10 is Tab 2  
342 restated with the Utah allocation based on the 2010 Protocol allocation  
343 methodology including a dynamic Embedded Cost Differential adjustment  
344 (“ECD”). Tab 11 contains the calculation of the 2010 Protocol allocation factors  
345 and the Hydro Endowment component of the ECD.

346 At the beginning of each tabbed section, a summary document is provided  
347 which directs the reader to where the underlying electronic workpapers utilized to  
348 develop the content in each section can be located in the Company’s filing.<sup>3</sup>

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<sup>2</sup>In conformance with filing requirement R746-700-22.B.1.

<sup>3</sup>This is provided in compliance with R746-100-3.C.



349 **Tab 3 – Revenue Adjustments**

350 **Q. Please describe the information contained behind Tab 3 Revenue**  
351 **Adjustments.**

352 A. Tab 3 begins with the Revenue Adjustment Index, which is a list of adjustments  
353 used to project retail revenue for the Test Period. The numerical summary (page  
354 3.0.2) identifies each adjustment made to actual revenue and that adjustment's  
355 impact on the case. Each column has a numerical reference to a corresponding  
356 page in Exhibit RMP\_\_\_(SRM-3), which contains a summary showing the  
357 affected FERC account(s), allocation factor, dollar amount and a brief description  
358 of the adjustment.

359 **Q. Please describe the adjustments made to revenue in Tab 3.**

360 A. **Pro Forma Revenue (page 3.1)** – This adjustment begins with June 30, 2013,  
361 general business revenues and adjusts to the pro forma level for the Test Period  
362 based on Commission authorized tariffs applied to forecasted loads. Revenue for  
363 the Company's other jurisdictions during the Test Period is also computed using  
364 current rates in the respective states. Several items are removed from actual  
365 booked revenue that should not be included in Test Period results including  
366 special contract buy-through revenue, deferred net power costs, demand side  
367 management (Schedule 193) revenue, Utah solar program (Schedule 195)  
368 revenue, and out-of-period adjustments to revenue. Test Period revenue reflects  
369 the recent changes to base rates approved in the 2012 GRC, including the Step 1  
370 rate change effective October 12, 2012, the Step 2 rate change effective  
371 September 1, 2013, and special contract changes effective January 1, 2014.

372 **Wheeling Revenue (page 3.2)** – This adjustment reflects the projected level of  
373 wheeling revenue for the Test Period by adjusting the actual Base Period revenue  
374 for normalizing, annualizing, and pro forma changes. On May 23, 2013, a  
375 settlement agreement reached in the Company’s transmission rate case, FERC  
376 Docket No. ER11-3643 (“FERC Rate Case”), was approved by the Federal  
377 Energy Regulatory Commission (“FERC”). This adjustment incorporates into  
378 Test Period results the revenue impact associated with the changes to the Open  
379 Access Transmission Tariff (“OATT”) resulting from the settlement agreement as  
380 approved by FERC. Paragraph 51 of the 2012 GRC Stipulation specifies that  
381 incremental wheeling revenues resulting from the FERC Rate Case will be  
382 deferred from July 1, 2012, through the effective date of this rate case (September  
383 1, 2014) and included as a 100 percent pass-through credit in the Company’s  
384 Energy Balancing Account (“EBA”) application subsequent to FERC’s final order  
385 in the FERC Rate Case. Pursuant to the terms of the 2012 GRC Stipulation, the  
386 Company’s EBA application filed in March 2014 will reflect a credit for deferred  
387 wheeling revenues.

388 **SO<sub>2</sub> Emission Allowances (page 3.3)** – The Environmental Protection Agency  
389 (“EPA”) has established guidelines that govern the volume of sulfur dioxide  
390 (“SO<sub>2</sub>”) that can be emitted from power plants and granted the issuance of SO<sub>2</sub>  
391 emission allowances to cover each ton emitted. Plants that are not in compliance  
392 with EPA guidelines may purchase emission allowances from other companies  
393 that have excess allowances. Consistent with the Commission order in Docket No.  
394 97-035-01, the Company has amortized sales of emission allowances over a four-

395 year period. This adjustment replaces the sales from the historical period with the  
396 appropriate annual amortization, taking into account projected sales through the  
397 Test Period.

398 **REC Revenue (page 3.4)** – RECs represent the environmental attributes of  
399 electricity produced from renewable energy facilities and can be detached from  
400 the electricity commodity and sold separately. RECs may also be used to meet  
401 renewable portfolio standards (“RPS”) in various states. To comply with current  
402 or future year RPS requirements in California, Oregon, and Washington, the  
403 Company does not sell RECs that are eligible for RPS requirements in those  
404 states. This adjustment ensures Test Period REC revenues are correctly allocated  
405 among the Company’s jurisdictions after considering the banking of eligible  
406 RECs for RPS compliance purposes. Company witness Ms. Kusters’ testimony  
407 supports the development of the total-Company REC revenue forecast for the Test  
408 Period. In addition, this adjustment removes REC deferrals reflected in Base  
409 Period results consistent with the treatment of NPC deferrals in the Net Power  
410 Cost Adjustment, No. 5.1. Differences between REC revenues reflected in rates  
411 and actual REC revenues received are accounted for in the RBA, which the  
412 Company files on an annual basis.

413 **Joint Use Revenue (page 3.5)** – This adjustment reflects a change to Joint Use  
414 Revenue, Schedule 4, resulting from a proposed decrease in the attachment rate  
415 from \$6.33 to \$5.76 per pole. The amount proposed by the Company is calculated  
416 in accordance with Commission Rule R746-345-5. Company witness Mr. Jeffery  
417 M. Kent provides additional supporting detail in his testimony.

418 **Ancillary Revenue (page 3.6)** – This adjusts other electric revenue to account for  
419 ancillary services contracts that will expire before or during the Test Period. The  
420 Foote Creek 2 contract expires before the beginning of the Test Period and the  
421 Foote Creek 3 contract expires effective July 2014. Revenues from these contracts  
422 are removed from Test Period results (other than one month of revenue associated  
423 with the Foote Creek 3 contract) since revenue will not be received during the  
424 Test Period due to expiration of these contracts.

425 **Tab 4 – Operation and Maintenance (O&M) Adjustments**

426 **Q. Please describe the information contained behind Tab 4 O&M Adjustments.**

427 A. Tab 4 includes the Operation and Maintenance Expense Adjustment Index  
428 followed by a numerical summary and the specific adjustments. The numerical  
429 summary (pages 4.0.2 – 4.0.3) identifies each adjustment made to actual expenses  
430 and that adjustment’s impact on the case. Each column has a numerical reference  
431 to a corresponding page in Exhibit RMP\_\_\_\_(SRM-3), which contains a summary  
432 showing the affected FERC account(s), allocation factor, dollar amount, and a  
433 brief description of the adjustment.

434 **Q. Please describe the adjustments made to O&M expense in Tab 4.**

435 A. **Miscellaneous General Expense (page 4.1)** – This adjustment removes certain  
436 miscellaneous expenses from the Base Period results that should have been  
437 charged below-the-line to non-regulated expense. It also reallocates certain gains  
438 and losses on property sales included in Base Period results to reflect the  
439 appropriate allocation.

440 **Wage & Employee Benefits (page 4.2)** – Labor related costs for the Test Period

441 are computed by adjusting salaries, incentives, health benefits, and costs  
442 associated with pension, post-retirement benefits, post-employment benefits and  
443 other benefits for changes expected beyond the actual costs experienced in the  
444 Base Period. Company witness Mr. Erich D. Wilson's testimony provides an  
445 overview of the compensation and benefit plans provided to employees and  
446 supports the costs included in the Test Period.

447 Collective bargaining agreements are used to escalate union wages where  
448 increases are specified, and wage increases for non-union and exempt employees  
449 are based on the Company's targets. Incentive compensation for non-union  
450 employees is included in Test Period results using a three-year historical average,  
451 calculated by multiplying the pro forma wages in this case by the three-year  
452 historical average of the actual payment rate. Pension expense and other employee  
453 benefit costs are adjusted to the planned expense levels for the Test Period, based  
454 on actuarial reports where available or by escalating actual costs. Pension  
455 administrative costs are based on a three year historical average.

456 Page 4.2.1 of Exhibit RMP\_\_\_(SRM-3) provides further description of the  
457 procedure used to compute Test Period labor costs. Page 4.2.2 contains a  
458 numerical summary of actual labor costs in the Base Period and summarizes the  
459 adjustments made to project costs through the Test Period. This summary is  
460 followed by detailed worksheets on pages 4.2.3 through 4.2.11.

461 **Idaho Irrigation Load Control Program (page 4.3)** – Incentive payments made  
462 to Idaho customers participating in the irrigation load control program and a  
463 portion of the program's administrative costs are initially system allocated in

464 unadjusted accounting data. Consistent with the 2010 Protocol, demand-side  
465 management (“DSM”) program costs are situs assigned to the states in which the  
466 costs are incurred to match the benefit of reduced load reflected in the inter-  
467 jurisdictional allocation factors. This adjustment corrects the booked allocation to  
468 assign these costs directly to Idaho.

469 **Remove Non-Recurring Entries (page 4.4)** – A few accounting entries were  
470 made to expense accounts during the Base Period that are non-recurring in nature,  
471 or relate to a prior period. These items, which include an adjustment to remove  
472 the costs related to the Pilot Solar Photovoltaic Incentive Program, which has  
473 been superseded by the Schedule 107 Solar Incentive Program, are removed from  
474 results of operations to normalize Test Period results. Details on the specific items  
475 in the adjustment can be found on page 4.4.1.

476 **Uncollectible Accounts (page 4.5)** – Expense for uncollectible accounts is  
477 adjusted to the Test Period level by applying the historical uncollectible rate to the  
478 normalized general business revenue in the Test Period. The rate is calculated by  
479 dividing the Utah uncollectible accounts expense in FERC account 904 by the  
480 Utah general business revenues. This treatment is the same methodology used in  
481 Dockets No. 10-035-124 and No. 11-035-200 (the Company’s last two general  
482 rate case filings).

483 **DSM Expense (page 4.6)** – This adjustment removes expenses related to DSM  
484 programs in various states because these costs are recovered via separate  
485 surcharges and are not included in base rates. In Utah, these costs are recovered  
486 through the Demand Side Management Cost Adjustment, Schedule 193. The

487 associated DSM revenues are removed in Pro Forma Revenue Adjustment No.  
488 3.1.

489 **Insurance Expense (page 4.7)** – This adjustment normalizes insurance expense  
490 related to third-party liability for injuries and damages as well as damage to  
491 Company property. Injuries and damages expense is set at the three-year historical  
492 average using the cash method, consistent with the Utah Commission ruling in  
493 Docket No. 07-035-93.

494 Insurance expense for damage to Company property is currently accrued  
495 to a reserve account. This treatment for property damage expense was included in  
496 Dockets No. 10-035-124 and No. 11-035-200. The balance of the reserve account  
497 at June 2013 was \$1.6 million. The Company believes this is a reasonable reserve  
498 level, so no adjustment to the property damage accrual is proposed in this case.

499 In addition, this adjustment removes an out-of-period allocation correction  
500 for an injuries and damages accrual and also removes accounting entries booked  
501 in the Base Period related to the California Catastrophic Event Memorandum  
502 Account regulatory asset that should not be reflected in Utah results.

503 **Generation Overhaul Expense (page 4.8)** – This adjustment normalizes  
504 generation overhaul expense using a four-year historical average for the 12 month  
505 periods ending June 2010 through June 2013. For Lake Side 2, scheduled to be  
506 placed in service June 2014, the four-year average is comprised of the overhaul  
507 expense planned for the first four full years the plant is operational. Prior to  
508 averaging, annual expenses are restated to June 2013 dollars to make the dollars  
509 comparable. A four-year average is consistent with the normalized outages

510 assumed in the GRID model to compute Test Period net power costs.

511 Use of a four-year historical average to set overhaul costs in customer  
512 rates was approved by the Commission in Docket No. 07-035-93, as was the use  
513 of a four-year average of projected expenses for the Company's new gas plants.  
514 The use of a four-year average methodology has been utilized in all Company rate  
515 case filings since the 07-035-93 case. However, the Commission rejected the  
516 treatment of restating the annual components of the average to constant dollars  
517 prior averaging in the 07-035-93 and 09-035-23 cases; settlement agreements,  
518 which did not address this matter, were reached in the remaining cases. The  
519 Company continues to believe that the purpose of averaging is to adjust for  
520 uneven costs, and that without the restatement to constant dollars in the average  
521 calculation, overhaul expenses reflected in rates will be systematically  
522 understated.

523 New evidence in support of this position has been presented in the 10-035-  
524 124 and 11-035-200 cases, but was not heard by the Commission as settlement  
525 agreements were reached in those proceedings. In both the 10-035-124 and 11-  
526 035-200 cases, the Division of Public Utilities ("DPU") provided testimony in  
527 support of restating annual expenses to constant dollars prior to averaging.<sup>4</sup> DPU  
528 witness Dr. William Powell correctly pointed out that from an economic  
529 standpoint, averaging dollars from multiple years requires the dollars to be stated  
530 on a consistent basis prior to averaging. On lines 139 – 143 of his direct revenue  
531 requirement testimony in Docket 11-035-200, Dr. Powell states:

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<sup>4</sup>Direct testimony of Dr. William Powell, Docket No. 10-035-124, lines 443 – 560. Direct testimony of Dr. William Powell, Docket No. 11-035-200, lines 94 – 203.



532 First, economic theory suggests that in order to compare two  
 533 values separated by time, the values need to have a common  
 534 monetary base. That is, the values should be expressed in real  
 535 terms, where the effects of inflation are taken into account, as  
 536 opposed to nominal terms. Comparing values expressed in nominal  
 537 terms—ignoring inflation—can lead to erroneous conclusions.

538 The Company agrees with Dr. Powell’s statement in this regard. A simple  
 539 example below shows the impact of averaging, assuming a 2.5 percent inflation  
 540 rate, a \$100 amount in year one, and a four-year average of years one through  
 541 four used to project costs in year five. Using this assumption, Example 1 shows  
 542 the impact without adjusting for inflation and Example 2 shows the impact when  
 543 years one through four are stated in real or constant dollars.

544 As shown in the first example, with no restatement to account for  
 545 inflation, a four-year average of costs is \$103.8, much less than the projected  
 546 costs in year five, resulting in an expense level that is 2.5 years old compared to  
 547 the current expenses. In Example 2, the average is equal to the year five amount  
 548 resulting in an accurate forecast.

Example 1		Example 2			
Year	Amount	Year	Amount	Escalation	Adjusted Amount
1	\$ 100.0	1	\$ 100.0	1.104	\$ 110.4
2	102.5	2	102.5	1.077	\$ 110.4
3	105.1	3	105.1	1.051	\$ 110.4
4	107.7	4	107.7	1.025	\$ 110.4
5	110.4	5	110.4		

Average } \$103.8

Average } \$110.4

549 **Incremental O&M (page 4.9)** – This adjustment accounts for changes in costs at  
 550 the Company’s thermal, hydro, and wind generation plants due to changes in  
 551 operations and regulatory requirements. Support for the thermal generation costs  
 552 reflected in this adjustment is provided in the testimony of Company witness Mr.  
 553 Dana M. Ralston. Consistent with the treatment proposed in my rebuttal

554 testimony in the 2012 GRC, wind plant oil change costs for the Test Period are  
555 reflected on a three-year average basis in the wind generation O&M included in  
556 this adjustment.

557 **Naughton Unit 3 Write-Off Adjustment (page 4.10)** – As stated in the 2012  
558 GRC Stipulation, recovery for Utah's allocated share of the Naughton Unit 3  
559 development costs is to be deferred and fully amortized by September 1, 2014,  
560 prior to the effective date of this general rate case. Therefore, this adjustment  
561 removes the regulatory asset, related amortization, and the write-off expenses  
562 reflected in the Base Period associated with this matter.

563 **O&M Expense Escalation (page 4.11)** – This adjustment increases non-labor  
564 expenses for projected inflation through the Test Period. Projected increases or  
565 decreases in costs are based on IHS indices, which provide a detailed assessment  
566 of the electric market both historically and into the future. The indices used are  
567 based on electric utility costs for materials and services only, which exclude labor  
568 expense, according to the Uniform System of Accounts defined by FERC for  
569 major electric utilities.

570 The IHS indices are prepared at the FERC functional subcategory and are  
571 denoted with their corresponding FERC account number. The individual FERC  
572 account indices are then combined into broader indices representing operation,  
573 maintenance, or total operation and maintenance expenses. The IHS study used to  
574 prepare this filing was the third quarter 2013 forecast, released November 4,  
575 2013. The IHS data is proprietary and subject to copyright protection, therefore  
576 the indices utilized in the Company's case are provided in Confidential Exhibit

577 RMP\_\_\_\_(SRM-4).

578 **Tab 5 – Net Power Cost Adjustments**

579 **Q. Please describe the information contained behind Tab 5 Net Power Cost**  
580 **Adjustments.**

581 A. The Net Power Cost Adjustment Index on page 5.0.1 is a numerical summary of  
582 adjustments made to NPC related items. The numerical summary (page 5.0.2)  
583 identifies each adjustment made to actual expenses and that adjustment’s impact  
584 on overall revenue requirement. Each column has a numerical reference to a  
585 corresponding page in Exhibit RMP\_\_\_\_(SRM-3) which contains a summary  
586 showing the affected FERC account(s), allocation factor, dollar amount and a  
587 brief description of the adjustment.

588 **Q. Please describe the adjustments included in Tab 5.**

589 A. **Net Power Cost Study (page 5.1)** – The NPC study presents normalized Test  
590 Period steam and hydro power generation, fuel, purchased power, wheeling  
591 expense and sales for resale based on the Company’s GRID model. It also  
592 normalizes hydro generation, weather conditions and plant availability as  
593 described in the testimony of Company witness Mr. Duvall.

594 **James River Royalty Offset (page 5.2)** – On January 13, 1993, the Company  
595 executed a contract with James River Paper Company (“James River”) with  
596 respect to the Camas mill, later acquired by Georgia Pacific. Under the  
597 agreement, the Company built a steam turbine and is recovering the capital  
598 investment over the twenty-year operational term of the agreement as an offset to  
599 royalties paid to James River. The contract costs of energy for the Camas unit are

600 included in the Company's NPC as purchased power expense, but GRID does not  
601 include an offsetting revenue credit for the capital and maintenance cost recovery.  
602 This adjustment adds the royalty offset to FERC Account 456, Other Electric  
603 Revenue, for the Test Period.

604 **Little Mountain (page 5.3)** – The Little Mountain plant is an electric generation  
605 facility located near Ogden, Utah, which ceased operations on May 31, 2013. This  
606 adjustment removes the steam revenues, depreciation, and O&M expense incurred  
607 in the Base Period, as well as plant and depreciation reserve balances to reflect the  
608 retirement and decommissioning of the Little Mountain plant in Test Period  
609 results.

610 **Tab 6 – Depreciation and Amortization Expense Adjustments**

611 **Q. Please describe the information contained behind Tab 6 Depreciation and**  
612 **Amortization Adjustments.**

613 A. Tab 6 includes the Depreciation and Amortization Adjustment Index followed by  
614 a numerical summary and the specific adjustments. The summary on page 6.0.1 is  
615 an index of adjustments to depreciation and amortization expense and reserve.  
616 The numerical summary (page 6.0.2) identifies each adjustment made to actual  
617 results and that adjustment's impact on the case. Each column has a numerical  
618 reference to a corresponding page in Exhibit RMP\_\_\_\_(SRM-3), which contains a  
619 summary showing the affected FERC account(s), allocation factor, dollar amount  
620 and a brief description of the adjustment.

621 **Q. Please describe the adjustments included in Tab 6.**

622 A. **Depreciation and Amortization Expense (page 6.1)** – The depreciation and

623 amortization expense for the Test Period is calculated by applying functional  
624 composite depreciation and amortization rates to projected plant balances by  
625 month. Depreciation related to pro forma capital additions is computed from the  
626 date the depreciable asset is placed into service. Depreciation rates set in the 2013  
627 Depreciation Study are used to develop Test Period depreciation expense.  
628 Depreciation expense prior to January 1, 2014, which impacts the depreciation  
629 reserve balance developed in this case, is calculated using rates approved in  
630 Docket No. 07-035-13. Depreciation expense also includes the accrual for hydro  
631 decommissioning. Details are provided on pages 6.1.2 through 6.1.17.

632 **Depreciation and Amortization Reserve (page 6.2)** – Accumulated depreciation  
633 and amortization balances for the Test Period are calculated by walking the June  
634 2013 13-month average actual reserve balances forward using the pro forma  
635 depreciation and amortization expense, plant retirements and removal costs as  
636 calculated in the Depreciation and Amortization Expense Adjustment (page 6.1)  
637 and the Pro Forma Plant Additions and Retirements Adjustment (page 8.6).  
638 Accruals and planned spending for hydro decommissioning are also included in  
639 the adjusted depreciation reserve balance. The reserve balances are calculated on  
640 a monthly basis through June 30, 2015, as detailed on pages 6.2.2 to 6.2.11.  
641 Consistent with electric plant-in-service, the accumulated depreciation and  
642 amortization reserve balance included in Test Period rate base is stated on a 13-  
643 month average basis.

644 **Depreciation Study (page 6.3)** – This adjustment incorporates into Test Period  
645 results the impacts of the 2013 Depreciation Study. Pursuant to the Commission’s

646 order in that docket, new depreciation rates and other components of the  
647 depreciation study became effective January 1, 2014. The depreciation and  
648 amortization expense for the Test Period calculated in Adjustment 6.1 reflects the  
649 new depreciation rates and Adjustment 6.2 reflects the accumulated reserve  
650 impact of the new rates beginning January 2014. This adjustment captures other  
651 elements of the depreciation study that are not reflected elsewhere in the  
652 development of Test Period results.

653 The new depreciation rates approved by the Commission result in a net  
654 increase to Utah-allocated depreciation expense. Paragraphs 43 through 45 of the  
655 2012 GRC Stipulation specify the treatment of 2013 Depreciation Study items to  
656 be included in this rate case. As addressed in paragraph 44 of the stipulation, any  
657 aggregate net increase in Utah-allocated depreciation expense in excess of \$2.0  
658 million annually may be deferred for future recovery. The period of deferral  
659 begins when the new depreciation rates became effective (January 1, 2014) until  
660 the new rates are reflected in customer rates. To calculate this deferral for  
661 inclusion in Test Period results, both the depreciation rates in effect prior to  
662 January 2014 and those effective beginning in January 2014 going forward were  
663 applied to projected Electric Plant in Service balances on a monthly basis from  
664 January 2014 through August 2014. The variance between the old and new rates  
665 totaled approximately \$5.0 million from January to August 2014. To this balance,  
666 the \$2.0 million annual deadband was applied at a rate of \$166,667 per month  
667 (\$2.0 million divided by 12-months) to calculate the balance allowed for deferral.  
668 As allowed in paragraph 45 of the 2012 GRC Stipulation, the deferred

669 depreciation expense balance is amortized through June 30, 2031, beginning  
670 September 1, 2014. Amortization of the deferred depreciation expense balance  
671 adds \$178,159 of amortization expense to Utah-allocated Test Period results. No  
672 carrying charge is allowed on the deferred balance, pursuant to paragraph 45 of  
673 the 2012 GRC Stipulation, so a regulatory asset for the deferred balance is not  
674 reflected in the adjustment.

675 The details of this calculation are provided on pages 6.3.2 through 6.3.6 of  
676 Exhibit RMP\_\_\_(SRM-3). This methodology is consistent with Exhibit C to the  
677 2012 GRC Stipulation which was provided in that proceeding to detail the  
678 calculation of the depreciation deferral amortization. Paragraph 45 of the  
679 stipulation also specified that the Company agrees to propose an allocation of any  
680 deferred amount in this rate case. This is addressed in the testimony of Company  
681 witness Ms. Steward.

682 In addition, this adjustment reflects into Test Period results excess reserve  
683 amortizations identified in the 2013 Depreciation Study. Excess reserves were  
684 identified for both steam and distribution plant and are addressed by crediting  
685 depreciation expense with an offsetting debit to the depreciation reserve. Excess  
686 reserves were identified for the Hunter, Gadsby, Colstrip and Blundell steam  
687 plants in addition to Utah distribution plant. In total, the steam plant excess  
688 reserve Test Period amortization is \$11.3 million (total-Company basis) whereas  
689 the Utah distribution plant Test Period amortization is \$23.1 million. The  
690 amortization period for the steam balance varies by plant; the Utah distribution  
691 balance is to be amortized over 6.5 years. Amortization for both the steam and

692 distribution items begins January 1, 2014. Additional detail on these items can be  
693 found in paragraphs 21, 22 and 23 of the 2013 Depreciation Study stipulation.  
694 This adjustment also reflects into Test Period results the change in vehicle  
695 depreciation resulting from rate changes in the 2013 Depreciation Study.

696 **Tab 7 – Tax Adjustments**

697 **Q. Please describe the information contained behind Tab 7 Tax Adjustments.**

698 A. Tab 7 includes the Tax Adjustment Index (page 7.0.1) followed by a numerical  
699 summary and the specific adjustments. The numerical summary (pages 7.0.2 –  
700 7.0.3) identifies each adjustment made to the various tax components and that  
701 adjustment’s impact on the case. Each column has a numerical reference to a  
702 corresponding page in Exhibit RMP\_\_\_(SRM-3), which contains a lead sheet  
703 showing the affected FERC account(s), allocation factor, dollar amount, and a  
704 brief description of the adjustment.

705 **Q. Please describe the adjustments included in Tab 7.**

706 A. **Interest True-Up (page 7.1)** – Details the adjustment to interest expense required  
707 to synchronize the Test Period expense with rate base. This is done by multiplying  
708 normalized net rate base by the Company’s weighted cost of debt in this case.

709 **Property Tax Expense (page 7.2)** – Property tax expense for the Test Period was  
710 computed by adjusting actual property tax expense for known or anticipated  
711 changes in assessment levels through June 30, 2015. The property tax expense in  
712 this case was estimated using methods similar to those employed by the Company  
713 in previous rate cases. These methods give necessary consideration to the effect  
714 that changes in the level of operating property and net operating income may have



715 on state-by-state assessed values. Confidential Exhibit RMP\_\_\_\_(SRM-5) provides  
716 a comprehensive description of the Company’s property tax estimation  
717 procedures along with a detailed calculation of Test Period property taxes.

718 **Renewable Energy Tax Credit (page 7.3)** – The Company is eligible to  
719 recognize certain federal income tax credits as a result of placing qualifying  
720 renewable generation plants into service. The federal tax credit is based on the  
721 kilowatt-hours of generation from those plants, and may be taken for 10 years on  
722 qualifying property. Under the calculation required by Internal Revenue Service  
723 Code Sec. 45(b)(2), the current renewable electricity production credit is 2.3 cents  
724 per kilowatt hour of generation.

725 **Allowance for Funds Used During Construction (“AFUDC”) Equity (page**  
726 **7.4)** – This adjustment aligns the amount of AFUDC equity in regulatory income  
727 with the related tax Schedule M item. Consistent with the stipulation approved by  
728 the Commission in Docket No. 09-035-03, AFUDC equity is treated on a flow  
729 through basis rather than normalized for tax purposes.

730 **Repairs Deduction Deferred Accounting (page 7.5)** – As a result of a  
731 stipulation in Dockets No. 09-035-03 and No. 09-035-23 regarding income tax  
732 treatment, a regulatory liability equal to the revenue requirement impact of the  
733 difference in the deduction for repairs recognized in regulatory results versus  
734 recognized for tax return purposes for calendar years 2009 and 2010 was to be  
735 included in rate base and amortized over a period of not more than five years.  
736 Given the magnitude and direction of this amortization, the Company amortized  
737 this item over one year in the 2012 GRC. This adjustment removes the regulatory

738 liability remaining on the books during the Base Period from Test Period results.

739 **Pro Forma Schedule M's (page 7.6)** – The Base Period Schedule M items were  
740 updated for known and measurable adjustments through the Test Period. Non-  
741 utility items, separate tariff items, and other non-recurring items were removed  
742 from the historical period before updating. The Schedule M items were then used  
743 to develop deferred income tax expenses and balances for the Test Period.

744 **Pro Forma Deferred Tax Expense (page 7.7)** – Non-property related Schedule  
745 M items in the Test Period were used to develop the deferred income tax expense.  
746 Property related deferred income tax expense was generated using the capital  
747 additions and resulting book and tax depreciation. Normalizing adjustments were  
748 added consistent with the Schedule M items.

749 **Pro Forma Deferred Tax Balance (page 7.8)** – The deferred income tax  
750 expense was used to develop the deferred tax balances for the Test Period. This  
751 adjustment normalizes the accumulated deferred income tax balances to the  
752 estimated pro forma 13-month average rate base balance for the Test Period. The  
753 allocation of property related deferred income tax balances are also updated  
754 consistent with the Company's model using the Power Tax fixed asset software  
755 system.

756 Recently, Congress reinstated bonus depreciation for the calendar year  
757 2013. For qualified property placed in service before January 1, 2015, 50 percent  
758 of the tax basis in construction work in progress at December 31, 2013, is  
759 deductible as bonus depreciation. The deferred tax balances reflected in the Test  
760 Period include the tax benefits of the recently reinstated bonus depreciation.

761 **Wyoming Wind Generation Tax (page 7.9)** – The Wyoming wind generation  
762 tax is an excise tax levied upon electricity generated from wind resources in the  
763 state of Wyoming. The tax is on the production of electricity from wind resources  
764 for sale or trade on or after January 1, 2012, and is to be paid by the entity  
765 producing the electricity. The tax is one dollar on each megawatt hour of  
766 electricity produced from wind resources at the point of interconnection with an  
767 electric transmission line. The tax begins three years after the in-service date of  
768 the wind turbine. For the Test Period, all of the production from the Company  
769 owned Wyoming wind turbines qualifies and are therefore subject to this tax. This  
770 adjustment normalizes the Wyoming wind generation tax into the Test Period  
771 results.

772 **Tab 8 – Rate Base Adjustments**

773 **Q. Please describe the information contained behind Tab 8 Rate Base**  
774 **Adjustments.**

775 A. Tab 8 includes the Rate Base Adjustment Index followed by a numerical  
776 summary and the specific adjustments. The summary begins on page 8.0.1 with  
777 an index of adjustments made to electric plant in-service and other rate base  
778 components. The numerical summary (pages 8.0.2 – 8.0.3) identifies each  
779 adjustment made to rate base and that adjustment’s impact on the case. Each  
780 column has a numerical reference to a corresponding page in Exhibit  
781 RMP\_\_\_(SRM-3), which contains a summary showing the affected FERC  
782 account(s), allocation factor, dollar amount and a brief description of the  
783 adjustment.

784 **Q. Please describe each of the adjustments to the Base Period rate base**  
785 **balances.**

786 **A. Cash Working Capital (page 8.1)** – This adjustment supports the calculation of  
787 cash working capital included in results based on the normalized results of  
788 operations for the Test Period. Cash working capital is calculated by multiplying  
789 jurisdictional net lag days by the average daily cost of service. Net lag days in this  
790 case are based on the lead lag study prepared by the Company using calendar year  
791 2012 information. A complete copy of the 2012 study is provided as part of the  
792 Company’s response to filing requirement R746-700-22.D.43. Based on the  
793 results of the lead lag study the Company experiences 5.99 net lag days in Utah  
794 and requires a cash working capital balance of \$22.0 million in rate base.

795 **Trapper Mine Rate Base (page 8.2)** – The Company owns a 21.4 percent share  
796 of the Trapper Mine, which provides coal to the Craig generating plant. This  
797 investment is accounted for on the Company's books in account 123.1, investment  
798 in subsidiary company, which is not included as a rate base account. The  
799 normalized coal cost from Trapper Mine in net power costs includes operation  
800 and maintenance costs, but does not include a return on investment. This  
801 adjustment adds the Company’s portion of the Trapper Mine net plant investment  
802 to rate base in order for the Company to earn a return on its investment.

803 **Jim Bridger Mine Rate Base (page 8.3)** – The Company owns a two-thirds  
804 interest in the Bridger Coal Company which supplies coal to the Jim Bridger  
805 generating plant. Due to the ownership arrangement, the mine investment is not  
806 included in the Company’s unadjusted results of operations, and the normalized

807 coal costs for Bridger include all operating and maintenance costs but do not  
808 include a return on investment. This adjustment adds the Company's portion of  
809 the Bridger Mine net plant investment to rate base in order for the Company to  
810 earn a return on its investment.

811 **Plant Held for Future Use (page 8.4)** – This adjustment removes certain Plant  
812 Held for Future Use (“PHFU”) assets from FERC account 105. In my rebuttal  
813 testimony in the 2012 GRC, the Company agreed to remove the Twelve Mile,  
814 Wild Horse, Aeolus, Anticline, and Populus properties from PHFU. The  
815 Company continues to believe it is appropriate to exclude these items from rate  
816 base. However, the Company continues to assess these properties for appropriate  
817 inclusion in rate base and will propose rate base treatment for these items once it  
818 is determined that they are appropriately includable in rate base.

819 **Customer Advances for Construction (page 8.5)** – Refundable customer  
820 advances for construction are booked to FERC account 252. The Base Period  
821 balances do not reflect the proper allocation because amounts were recorded to a  
822 corporate cost center location rather than state specific locations in the  
823 Company’s accounting system. This adjustment corrects the allocation of  
824 customer advances.

825 **Pro Forma Plant Additions and Retirements (page 8.6)** – To reasonably  
826 represent the cost of system infrastructure required to serve our customers, the  
827 Company has identified capital projects that will be placed in-service by the end  
828 of the Test Period. Company business units identified capital expenditures that  
829 will be placed into service prior to the end of the Test Period. Additions by

830 functional category are summarized on separate sheets, indicating the in-service  
831 date and amount by project. Plant additions are included on a 13-month average  
832 basis in the Test Period. Descriptions of large individual projects are included on  
833 pages 8.6.31 through 8.6.39.

834 Plant retirements were applied to pro forma plant balances to reflect  
835 ongoing asset retirements through the Test Period. Retirement levels were  
836 calculated using a normalized five-year average methodology. This adjustment  
837 incorporates these retirements into Test Period electric plant in-service balances.  
838 A corresponding entry to accumulated depreciation and amortization is included  
839 in the calculation of Test Period reserve balances in the Depreciation and  
840 Amortization Reserve Adjustment (page 6.2). In addition, plant removal costs are  
841 reflected into Test Period results through this adjustment. The Company used a  
842 five-year average to project removal costs in the Test Period incurred in capital  
843 projects where existing infrastructure must be removed prior to construction of  
844 the new asset. Removal costs are booked as a reduction or (credit) to electric plant  
845 in service and a reduction (or debit) to accumulated depreciation reserve when  
846 incurred. The impact of removal costs is reflected in the Depreciation and  
847 Amortization Reserve Adjustment (page 6.2).

848 **Miscellaneous Rate Base (page 8.7)** – This adjustment reflects the Test Period  
849 level of fuel stock balance in results based on projected inventory by plant, along  
850 with offsetting working capital deposits. In addition, prepaid overhaul balances in  
851 FERC Account 186 for Lake Side Units 1 and 2, Chehalis, and Currant Creek gas  
852 plants are walked forward to reflect the continued payments and the transfer of

853 these costs into plant in-service through the end of the Test Period. Also, the  
854 balance in FERC Account 105, Plant Held for Future Use, related to the  
855 acquisition of the Cottonwood coal lease is walked forward to reflect  
856 approximately \$6.0 million for additional development costs during the Test  
857 Period. The Cottonwood coal lease was included as part of Plant Held for Future  
858 Use in the 2012 GRC.

859 **Powerdale Hydro Removal (page 8.8)** – Powerdale was decommissioned after it  
860 was damaged by a flood in November 2006. Deferred accounting for the  
861 unrecovered plant balance and decommissioning costs was authorized by the  
862 Commission in Dockets No. 07-035-14 and No. 07-035-93. The regulatory assets  
863 for unrecovered plant and decommissioning costs were fully amortized by  
864 December 2010. This adjustment removes residual items related to the Powerdale  
865 hydroelectric plant from results.

866 **Regulatory Asset Amortization (page 8.9)** – This adjustment incorporates  
867 known and measurable changes to regulatory assets not addressed elsewhere in  
868 results. Amortization expense is reflected at the level expected in the Test Period  
869 and assets are walked forward to Test Period levels on a 13-month average basis.  
870 Assets impacted include: Electric Plant Acquisition Adjustment, Cholla  
871 Transaction Costs, Pension Measurement Date Change, and Weatherization  
872 Assets. The Utah Independent Evaluator costs turned into a balance owing to  
873 customers during the Base Period. This adjustment returns the balance to  
874 customers through the Test Period.

875 **Customer Service Deposits (page 8.10)** – This adjustment includes customer

876 service deposits in results as a rate base deduction and also includes the interest  
877 paid on the customer service deposits in expense. This treatment was stipulated in  
878 Docket No. 97-035-01 and has been upheld in subsequent dockets.

879 **Klamath Hydroelectric Settlement Agreement (page 8.11)** – This adjustment  
880 reflects the appropriate treatment of Klamath related items in the Test Period.  
881 Paragraphs 58 through 60 of the 2012 GRC Stipulation address the revenue  
882 requirement treatment of various items related to this facility. The stipulation  
883 specifies that the Company is permitted to fully depreciate the Klamath dam  
884 facilities through 2022 beginning June 1, 2012. This adjustment removes  
885 depreciation reserve balances from Test Period results that relate to accelerated  
886 Klamath plant depreciation schedules approved by other PacifiCorp state  
887 jurisdictions. Adjustment 6.1 includes depreciation expense for Klamath in the  
888 Test Period at rates which reflect the 2022 schedule approved in Utah.  
889 Adjustment 6.2 reflects the appropriate level of depreciation reserve in the Test  
890 Period for Klamath plant.

891 The 2012 GRC Stipulation also specified that the Klamath-related  
892 relicensing and process costs of \$81.8 million are included in Utah rates through  
893 amortization of the balance through 2022, beginning October 12, 2012, with a  
894 carrying charge at the long term cost of debt. Since a carrying charge is reflected  
895 in the amortization expense, the relicensing and process cost asset is removed  
896 from rate base in this adjustment. This adjustment removes Base Period  
897 amortization expense and accumulated reserve associated with the relicensing and  
898 process cost asset and includes in Test Period results amortization expense



899 calculated using the methodology prescribed in the 2012 GRC Stipulation. This  
900 adjustment also restates Base Period O&M expense for the Klamath facility to  
901 levels expected to occur during the Test Period.

902 **Miscellaneous Asset Sales and Removals (page 8.12)** – This adjusts the  
903 Company’s filing for sales or removal of various assets, including the removal of  
904 Deseret Power's portion of the Hunter Unit 2 scrubber and turbine upgrade, the  
905 decommissioning of the Condit hydroelectric plant, the sale of Snake Creek  
906 hydroelectric plant to Heber Light & Power Company, and the sale of St.  
907 Anthony hydroelectric plant to St. Anthony Hydro, LLC. A brief description of  
908 each item is provided below:

909 Deseret Power’s Portion of Hunter Assets Removal – Removes the  
910 capitalized costs pertaining to Deseret Power’s ownership share of the Hunter  
911 Unit 2 scrubber and turbine upgrade from the Company’s filing. The depreciation  
912 expense is also removed. A similar adjustment was included in the Company’s  
913 2012 GRC filing.

914 Condit Hydroelectric Asset Decommissioning – Removes electric plant in  
915 service, depreciation reserve, depreciation expense, and O&M expense related to  
916 the Condit hydroelectric plant from results. A similar adjustment to remove the  
917 Condit plant from results was included in the Company’s 2012 GRC filing.

918 Snake Creek Hydroelectric Asset Sale – On September 26, 2011, the  
919 Company sold an undivided ownership interest in the Snake Creek hydroelectric  
920 generation plant located in Wasatch County, Utah, to Heber Light & Power  
921 Company. This adjustment removes residual O&M expense from the Base Period.

922 There are no corresponding adjustments on electric plant in service, depreciation  
923 reserve and depreciation expense as these impacts were recorded outside of the  
924 Base Period of this filing. The impacts of this sale were reflected in the  
925 Company's filing in the 2012 GRC.

926 St. Anthony Hydroelectric Generation Plant – On September 30, 2013, the  
927 Company sold its St. Anthony facility, a one-unit powerhouse located within the  
928 city limits of St. Anthony, Idaho, to St. Anthony Hydro, LLC. This adjustment  
929 removes from results the balance in electric plant in-service, depreciation reserve,  
930 depreciation expense, and O&M expense related to St. Anthony.

931 **Carbon Plant (page 8.13)** – As described in the Company's application in Docket  
932 No. 12-035-79, the Carbon plant (a coal-fired generation facility located in  
933 Carbon County, Utah) is scheduled to be retired in early 2015 to comply with  
934 environmental and air quality regulations. In Docket No. 12-035-79, the Company  
935 requested approval to transfer the net book value of the Carbon plant to a  
936 regulatory asset once the facility is retired and to amortize the regulatory asset  
937 through 2020, the remaining depreciable life of the facility. This matter was  
938 addressed in the Company's 2012 general rate case. In that proceeding, stipulating  
939 parties agreed to the Company's proposal in Docket No. 12-035-79 to transfer the  
940 remaining plant balance at the time of retirement to a regulatory asset and  
941 amortization of the balance through 2022. In Docket No. 13-035-02, depreciation  
942 rates for Carbon were established effective January 1, 2014, to fully depreciate  
943 plant by April 2015.

944 This adjustment: 1) removes from results the accelerated depreciation

945 expense for the Carbon plant reflected in Adjustment 6.1; 2) adds back to rate  
946 base incremental depreciation reserve associated with the Carbon plant  
947 accelerated depreciation expense reflected in Adjustment 6.2; 3) includes in rate  
948 base the unrecovered plant regulatory asset for Carbon as of April 2015; and 4)  
949 adds to the Test Period amortization expense for the unrecovered plant regulatory  
950 asset. As addressed earlier in my testimony, the Company is proposing in this  
951 case to defer any recovery and amortization of the Carbon removal costs until the  
952 next general rate case filing.

953 **Pension and Post Retirement Welfare Plan (page 8.14)** – This adjustment adds  
954 into rate base the Company’s prepaid pension and other post-retirement welfare  
955 balance, net of the accumulated deferred income tax liability. This adjustment is  
956 supported in the direct testimony of Company witness Mr. Douglas K. Stuver.

957 **Bridger and Naughton Liquidated Damages (page 8.15)** – In the 2012 Utah  
958 EBA (Docket No. 13-035-32), parties reached a settlement agreement, as  
959 approved by the Commission, which credited customers with the benefit of  
960 liquidated damages payments received by the Company for outages at Bridger  
961 Unit 4 and Naughton Units 1 and 2 through the EBA rather than as a credit to  
962 electric plant in service; the liquidated damages payments amount to  
963 approximately \$1.6 million on a total-Company basis. Parties also agreed that  
964 Utah’s portion of the liquidated damages payments (set at \$700,000 in Docket No.  
965 13-035-32) will be set up as a regulatory asset includable in rate base and  
966 amortized over a 20 year period beginning January 1, 2014, to ensure that Utah  
967 customers do not receive a double count of the liquidated damages benefit as a

968 credit through the EBA and as a credit to rate base. This adjustment reflects in  
969 results the regulatory asset and amortization expense in Test Period results as  
970 agreed to in Docket No. 13-035-32.

971 **Q. Are there any other matters that need to be addressed in your direct**  
972 **testimony?**

973 A. Yes, the revenue requirement for this case has been prepared under the  
974 assumption that Naughton Unit 3 will cease operations as a base load coal-fired  
975 generating unit in December 2014 and be converted to a gas-fired peaking unit by  
976 May 2015. As addressed in the testimony of Company witness Mr. Teply, the  
977 EPA has a deadline of January 10, 2014, to take final action on the Wyoming  
978 Regional Haze State Implementation Plan (“SIP”). The Company has requested  
979 that as part of their review of the SIP, the EPA consider extending the operation  
980 timeframe of the unit as a coal-fired resource from December 31, 2014 to  
981 December 31, 2017.

982 If the EPA grants the Company’s request to extend the operation  
983 timeframe of Naughton Unit 3, the Test Period results will be materially  
984 impacted. In the event the EPA extends the operation timeframe beyond June 30,  
985 2015, the Company will need to restate the Test Period results to reflect the  
986 continuation of the unit as a coal-fired base load generation facility through the  
987 Test Period. This includes revisions to net power costs, electric plant in service  
988 and accumulated depreciation balances, fuel stock balances, generation O&M  
989 expense and related tax impacts. The Company estimates that continuation of  
990 Naughton Unit 3 through the Test Period as a coal-fired facility will reduce the

991 Utah revenue requirement requested in this case by \$5.2 million. If the EPA  
992 allows continuation of the unit as a coal-fired facility beyond the Test Period, the  
993 Company will update the revenue requirement request in this case as part of its  
994 rebuttal filing.

995 **Q. Do you have any final comments regarding the revenue requirement**  
996 **requested by the Company in this proceeding?**

997 A. Yes, in my opinion, the revenue requirement requested in this proceeding is fair,  
998 reasonable and in the public interest. The Test Period results developed as  
999 described previously in my testimony are a reasonable projection of costs the  
1000 Company expects to occur during this period in order to provide electric service  
1001 to customers in the state of Utah.

1002 **Q. Does this conclude your direct testimony?**

1003 A. Yes.

Rocky Mountain Power  
Exhibit RMP\_\_(SRM-1)  
Docket No. 13-035-184  
Witness: Steven R. McDougal

BEFORE THE PUBLIC SERVICE COMMISSION  
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

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Exhibit Accompanying Direct Testimony of Steven R. McDougal

Revenue Requirement Summary

January 2014

**Rocky Mountain Power**  
**UTAH**  
**Normalized Results of Operations - 2010 PROTOCOL**  
**Twelve Months Ending June 2015**

	(1) Total Adjusted Results	(2) Price Change	(3) Results with Price Change
1 Operating Revenues:			
2 General Business Revenues	1,884,107,463	76,252,101	1,960,359,564
3 Interdepartmental	-		
4 Special Sales	149,230,392		
5 Other Operating Revenues	70,387,117		
6 Total Operating Revenues	<u>2,103,724,971</u>		
7			
8 Operating Expenses:			
9 Steam Production	497,679,321		
10 Nuclear Production	-		
11 Hydro Production	17,563,929		
12 Other Power Supply	428,060,883		
13 Transmission	90,397,853		
14 Distribution	84,434,717		
15 Customer Accounting	34,650,973	148,303	34,799,276
16 Customer Service & Info	4,770,211		
17 Sales	-		
18 Administrative & General	60,710,458		
19			
20 Total O&M Expenses	1,218,268,346		
21			
22 Depreciation	262,390,668		
23 Amortization	22,885,961		
24 Taxes Other Than Income	63,068,116	-	63,068,116
25 Income Taxes - Federal	48,273,748	25,427,040	73,700,788
26 Income Taxes - State	10,751,193	3,455,112	14,206,306
27 Income Taxes - Def Net	63,481,630		
28 Investment Tax Credit Adj.	(4,098,178)		
29 Misc Revenue & Expense	682,017		
30			
31 Total Operating Expenses:	1,685,703,501	29,030,456	1,714,733,957
32			
33 Operating Rev For Return:	<u>418,021,470</u>	<u>47,221,645</u>	<u>465,243,115</u>
34			
35 Rate Base:			
36 Electric Plant In Service	10,912,081,614		
37 Plant Held for Future Use	18,651,670		
38 Misc Deferred Debits	170,287,197		
39 Elec Plant Acq Adj	15,449,004		
40 Nuclear Fuel	-		
41 Prepayments	13,702,489		
42 Fuel Stock	97,675,186		
43 Material & Supplies	86,820,549		
44 Working Capital	26,232,065		
45 Weatherization Loans	4,637,895		
46 Misc Rate Base	-		
47			
48 Total Electric Plant:	11,345,537,670	-	11,345,537,670
49			
50 Rate Base Deductions:			
51 Accum Prov For Deprec	(3,234,910,020)		
52 Accum Prov For Amort	(221,249,967)		
53 Accum Def Income Tax	(1,804,104,719)		
54 Unamortized ITC	(80,741)		
55 Customer Adv For Const	(9,924,958)		
56 Customer Service Deposits	(15,625,768)		
57 Misc Rate Base Deductions	(30,313,047)		
58			
59 Total Rate Base Deductions	(5,316,209,220)	-	(5,316,209,220)
60			
61 Total Rate Base:	<u>6,029,328,450</u>	<u>-</u>	<u>6,029,328,450</u>
62			
63 Return on Rate Base	6.933%		7.716%
64			
65 Return on Equity	8.482%		10.000%
66			
67 TAX CALCULATION:			
68 Operating Revenue	536,429,863	76,103,798	612,533,661
69 Other Deductions			
70 Interest (AFUDC)	(22,174,382)	-	(22,174,382)
71 Interest	154,052,563	-	154,052,563
72 Schedule "M" Additions	350,771,023	-	350,771,023
73 Schedule "M" Deductions	518,512,283	-	518,512,283
74 Income Before Tax	236,810,422	76,103,798	312,914,220
75			
76 State Income Taxes	10,751,193	3,455,112	14,206,306
77 Taxable Income	<u>226,059,229</u>	<u>72,648,685</u>	<u>298,707,914</u>
78			
79 Federal Income Taxes + Other	<u>48,273,748</u>	<u>25,427,040</u>	<u>73,700,788</u>

**Rocky Mountain Power**  
**UTAH**  
**Normalized Results of Operations - ROLLED-IN**  
**Twelve Months Ending June 2015**

	(1) Total Adjusted Results	(2) Price Change	(3) Results with Price Change
1 Operating Revenues:			
2 General Business Revenues	1,884,107,463	76,252,101	1,960,359,564
3 Interdepartmental	-		
4 Special Sales	149,230,392		
5 Other Operating Revenues	70,387,117		
6 Total Operating Revenues	<u>2,103,724,971</u>		
7			
8 Operating Expenses:			
9 Steam Production	497,679,321		
10 Nuclear Production	-		
11 Hydro Production	17,563,929		
12 Other Power Supply	428,060,883		
13 Transmission	90,397,853		
14 Distribution	84,434,717		
15 Customer Accounting	34,650,973	148,303	34,799,276
16 Customer Service & Info	4,770,211		
17 Sales	-		
18 Administrative & General	60,710,458		
19			
20 Total O&M Expenses	1,218,268,346		
21			
22 Depreciation	262,390,668		
23 Amortization	22,885,961		
24 Taxes Other Than Income	63,068,116	-	63,068,116
25 Income Taxes - Federal	48,273,748	25,427,040	73,700,788
26 Income Taxes - State	10,751,193	3,455,112	14,206,306
27 Income Taxes - Def Net	63,481,630		
28 Investment Tax Credit Adj.	(4,098,178)		
29 Misc Revenue & Expense	682,017		
30			
31 Total Operating Expenses:	1,685,703,501	29,030,456	1,714,733,957
32			
33 Operating Rev For Return:	<u>418,021,470</u>	<u>47,221,645</u>	<u>465,243,115</u>
34			
35 Rate Base:			
36 Electric Plant In Service	10,912,081,614		
37 Plant Held for Future Use	18,651,670		
38 Misc Deferred Debits	170,287,197		
39 Elec Plant Acq Adj	15,449,004		
40 Nuclear Fuel	-		
41 Prepayments	13,702,489		
42 Fuel Stock	97,675,186		
43 Material & Supplies	86,820,549		
44 Working Capital	26,232,065		
45 Weatherization Loans	4,637,895		
46 Misc Rate Base	-		
47			
48 Total Electric Plant:	11,345,537,670	-	11,345,537,670
49			
50 Rate Base Deductions:			
51 Accum Prov For Deprec	(3,234,910,020)		
52 Accum Prov For Amort	(221,249,967)		
53 Accum Def Income Tax	(1,804,104,719)		
54 Unamortized ITC	(80,741)		
55 Customer Adv For Const	(9,924,958)		
56 Customer Service Deposits	(15,625,768)		
57 Misc Rate Base Deductions	(30,313,047)		
58			
59 Total Rate Base Deductions	(5,316,209,220)	-	(5,316,209,220)
60			
61 Total Rate Base:	<u>6,029,328,450</u>	<u>-</u>	<u>6,029,328,450</u>
62			
63 Return on Rate Base	6.933%		7.716%
64			
65 Return on Equity	8.482%		10.000%
66			
67 TAX CALCULATION:			
68 Operating Revenue	536,429,863	76,103,798	612,533,661
69 Other Deductions			
70 Interest (AFUDC)	(22,174,382)	-	(22,174,382)
71 Interest	154,052,563	-	154,052,563
72 Schedule "M" Additions	350,771,023	-	350,771,023
73 Schedule "M" Deductions	518,512,283	-	518,512,283
74 Income Before Tax	236,810,422	76,103,798	312,914,220
75			
76 State Income Taxes	10,751,193	3,455,112	14,206,306
77 Taxable Income	<u>226,059,229</u>	<u>72,648,685</u>	<u>298,707,914</u>
78			
79 Federal Income Taxes + Other	<u>48,273,748</u>	<u>25,427,040</u>	<u>73,700,788</u>



**Rocky Mountain Power**  
**Normalized Results of Operations**  
**Adjustment Summary**  
**Twelve Months Ending June 2015**

	Exhibit RMP____(SRM-3)		Exhibit RMP____(SRM-3)		
	Tab 2	Tab 2	Tab 3	Tab 4	Tab 5
	Total Company Actual Results June 2013	Utah Allocated Actual Results June 2013	Revenue Adjustments	O&M Adjustments	Net Power Cost Adjustments
1 Operating Revenues:					
2 General Business Revenues	4,440,553,238	1,939,614,638	(55,507,175)	-	-
3 Interdepartmental	-	-	-	-	-
4 Special Sales	328,817,227	135,326,219	-	-	13,904,173
5 Other Operating Revenues	204,043,999	81,139,726	(11,655,644)	-	903,035
6 Total Operating Revenues	4,973,414,464	2,156,080,583	(67,162,819)	-	14,807,208
7					
8 Operating Expenses:					
9 Steam Production	1,088,441,448	458,734,056	-	13,648,689	25,630,640
10 Nuclear Production	-	-	-	-	-
11 Hydro Production	38,234,151	16,298,575	-	967,240	-
12 Other Power Supply	1,045,573,188	450,257,528	-	(1,104,463)	(20,823,201)
13 Transmission	201,709,294	85,930,306	(439,827)	249,064	4,687,199
14 Distribution	204,447,520	83,148,950	-	1,418,190	-
15 Customer Accounting	87,552,407	34,191,361	-	521,449	-
16 Customer Service & Info	109,336,777	50,948,786	-	(46,157,504)	-
17 Sales	-	-	-	-	-
18 Administrative & General	193,795,857	80,957,095	-	(20,094,658)	-
19					
20 Total O&M Expenses	2,969,090,641	1,260,466,657	(439,827)	(50,551,993)	9,494,637
21					
22 Depreciation	572,553,051	237,353,568	-	-	(73,090)
23 Amortization	53,648,631	22,373,319	-	(1,306,020)	-
24 Taxes Other Than Income	163,744,910	56,381,205	-	-	-
25 Income Taxes - Federal	12,635,438	21,573,999	(22,297,301)	19,424,419	1,796,514
26 Income Taxes - State	10,954,096	6,869,149	(3,029,833)	2,639,456	244,116
27 Income Taxes - Def Net	257,849,217	112,745,649	8,977	(2,394,665)	-
28 Investment Tax Credit Adj.	(1,831,667)	(1,502,644)	-	-	-
29 Misc Revenue & Expense	(435,263)	(266,711)	934	16,546	-
30					
31 Total Operating Expenses:	4,038,209,054	1,715,994,191	(25,757,050)	(32,172,258)	11,462,178
32					
33 Operating Rev For Return:	935,205,410	440,086,392	(41,405,770)	32,172,258	3,345,030
34					
35 Rate Base:					
36 Electric Plant In Service	23,605,170,060	10,033,832,359	-	-	(675,776)
37 Plant Held for Future Use	49,098,056	20,907,184	-	-	-
38 Misc Deferred Debits	311,085,926	39,292,022	-	(1,877,667)	-
39 Elec Plant Acq Adj	46,282,303	19,729,367	-	-	-
40 Nuclear Fuel	-	-	-	-	-
41 Prepayments	32,526,049	13,702,489	-	-	-
42 Fuel Stock	264,624,815	111,067,593	-	-	-
43 Material & Supplies	204,876,482	86,820,549	-	-	-
44 Working Capital	59,104,798	26,494,229	(422,534)	(467,156)	189,159
45 Weatherization Loans	(6,814,340)	4,640,730	-	-	-
46 Misc Rate Base	-	-	-	-	-
47					
48 Total Electric Plant:	24,565,954,148	10,356,486,522	(422,534)	(2,344,823)	(486,618)
49					
50 Rate Base Deductions:					
51 Accum Prov For Deprec	(7,379,345,761)	(2,947,460,107)	-	-	825,058
52 Accum Prov For Amort	(502,655,381)	(212,964,427)	-	-	-
53 Accum Def Income Tax	(3,634,945,474)	(1,553,478,568)	9,058	2,875,518	-
54 Unamortized ITC	(2,606,988)	(108,793)	-	-	-
55 Customer Adv For Const	(20,902,843)	(8,237,438)	-	-	-
56 Customer Service Deposits	-	-	-	-	-
57 Misc Rate Base Deductions	(105,083,207)	(30,517,434)	(23,868)	-	-
58					
59 Total Rate Base Deductions	(11,645,539,654)	(4,752,766,766)	(14,810)	2,875,518	825,058
60					
61 Total Rate Base:	12,920,414,494	5,603,719,756	(437,344)	530,694	338,441
62					
63 Return on Rate Base	7.238%	7.853%	-0.738%	0.573%	0.059%
64					
65 Return on Equity	9.073%	10.266%	-1.431%	1.111%	0.115%
66					
67 TAX CALCULATION:					
68 Operating Revenue		579,772,545	(66,723,926)	51,841,468	5,385,660
69 Other Deductions					
70 Interest (AFUDC)		(25,234,835)	-	-	-
71 Interest		143,178,033	(11,174)	13,560	8,647
72 Schedule "M" Additions		343,149,373	-	(145,597)	-
73 Schedule "M" Deductions		653,675,878	23,655	(6,455,483)	-
74 Income Before Tax		151,302,842	(66,736,407)	58,137,794	5,377,013
75					
76 State Income Taxes		6,869,149	(3,029,833)	2,639,456	244,116
77 Taxable Income		144,433,693	(63,706,574)	55,498,339	5,132,897
78					
79 Federal Income Taxes + Other		21,573,999	(22,297,301)	19,424,419	1,796,514
APPROXIMATE REVISED PROTOCOL PRICE CHANGE		(12,408,967)	66,809,428	(51,887,799)	(5,359,285)

**Rocky Mountain Power**  
**Normalized Results of Operations**  
**Adjustment Summary**  
**Twelve Months Ending June 2015**

	Exhibit RMP___(SRM-3)			Exhibit RMP___(SRM-3)
	Tab 6	Tab 7	Tab 8	Tab 2
	Depreciation & Amortization Adjustments	Tax Adjustments	Rate Base Adjustments	Utah Normalized Results June 2015
1 Operating Revenues:				
2 General Business Revenues	-	-	-	1,884,107,463
3 Interdepartmental	-	-	-	-
4 Special Sales	-	-	-	149,230,392
5 Other Operating Revenues	-	-	-	70,387,117
6 Total Operating Revenues	-	-	-	2,103,724,971
7				
8 Operating Expenses:				
9 Steam Production	(334,064)	-	-	497,679,321
10 Nuclear Production	-	-	-	-
11 Hydro Production	(70,332)	-	368,446	17,563,929
12 Other Power Supply	(55,669)	-	(213,312)	428,060,883
13 Transmission	(28,887)	-	-	90,397,853
14 Distribution	(132,422)	-	-	84,434,717
15 Customer Accounting	(61,837)	-	-	34,650,973
16 Customer Service & Info	(10,249)	-	(10,821)	4,770,211
17 Sales	-	-	-	-
18 Administrative & General	(121,683)	-	(30,297)	60,710,458
19				
20 Total O&M Expenses	(815,144)	-	114,016	1,218,268,346
21				
22 Depreciation	37,926,625	-	(12,816,434)	262,390,668
23 Amortization	(735,073)	-	2,553,736	22,885,961
24 Taxes Other Than Income	-	6,686,910	-	63,068,116
25 Income Taxes - Federal	(9,461,231)	45,646,783	(8,409,435)	48,273,748
26 Income Taxes - State	(1,285,624)	6,456,631	(1,142,703)	10,751,193
27 Income Taxes - Def Net	-	(50,844,211)	3,965,879	63,481,630
28 Investment Tax Credit Adj.	-	(2,595,534)	-	(4,098,178)
29 Misc Revenue & Expense	-	-	931,249	682,017
30				
31 Total Operating Expenses:	25,629,552	5,350,580	(14,803,692)	1,685,703,501
32				
33 Operating Rev For Return:	(25,629,552)	(5,350,580)	14,803,692	418,021,470
34				
35 Rate Base:				
36 Electric Plant In Service	-	-	878,925,031	10,912,081,614
37 Plant Held for Future Use	-	-	(2,255,514)	18,651,670
38 Misc Deferred Debits	-	-	132,872,843	170,287,197
39 Elec Plant Acq Adj	-	-	(4,280,363)	15,449,004
40 Nuclear Fuel	-	-	-	-
41 Prepayments	-	-	-	13,702,489
42 Fuel Stock	-	-	(13,392,407)	97,675,186
43 Material & Supplies	-	-	-	86,820,549
44 Working Capital	(189,597)	964,060	(336,096)	26,232,065
45 Weatherization Loans	-	-	(2,835)	4,637,895
46 Misc Rate Base	-	-	-	-
47				
48 Total Electric Plant:	(189,597)	964,060	991,530,659	11,345,537,670
49				
50 Rate Base Deductions:				
51 Accum Prov For Deprec	(302,122,328)	-	13,847,357	(3,234,910,020)
52 Accum Prov For Amort	(13,090,269)	-	4,804,729	(221,249,967)
53 Accum Def Income Tax	-	(197,313,833)	(56,196,894)	(1,804,104,719)
54 Unamortized ITC	-	28,051	-	(80,741)
55 Customer Adv For Const	-	-	(1,687,520)	(9,924,958)
56 Customer Service Deposits	-	-	(15,625,768)	(15,625,768)
57 Misc Rate Base Deductions	-	47,854	180,401	(30,313,047)
58				
59 Total Rate Base Deductions	(315,212,598)	(197,237,928)	(54,677,694)	(5,316,209,220)
60				
61 Total Rate Base:	(315,402,195)	(196,273,868)	936,852,965	6,029,328,450
62				
63 Return on Rate Base	-0.023%	0.193%	-0.985%	6.933%
64				
65 Return on Equity	-0.044%	0.373%	-1.908%	8.482%
66				
67 TAX CALCULATION:				
68 Operating Revenue	(36,376,408)	(6,686,910)	9,217,434	536,429,863
69 Other Deductions	-	-	-	-
70 Interest (AFUDC)	-	3,060,454	-	(22,174,382)
71 Interest	(8,058,695)	(5,014,902)	23,937,094	154,052,563
72 Schedule "M" Additions	-	18,223,651	(10,456,404)	350,771,023
73 Schedule "M" Deductions	-	(128,725,362)	(6,405)	518,512,283
74 Income Before Tax	(28,317,713)	142,216,551	(25,169,659)	236,810,422
75				
76 State Income Taxes	(1,285,624)	6,456,631	(1,142,703)	10,751,193
77 Taxable Income	(27,032,089)	135,759,920	(24,026,957)	226,059,229
78				
79 Federal Income Taxes + Other	(9,461,231)	45,646,783	(8,409,435)	48,273,748
APPROXIMATE REVISED PROTOCOL PRICE CHANGE	2,086,389	(15,815,973)	92,828,307	76,252,101

Rocky Mountain Power  
Exhibit RMP\_\_\_(SRM-2)  
Docket No. 13-035-184  
Witness: Steven R. McDougal

BEFORE THE PUBLIC SERVICE COMMISSION  
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

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Exhibit Accompanying Direct Testimony of Steven R. McDougal

Summary of Adjustments

January 2014

R746-700-10.A.1.c - Summary Index

Adjustment Name	Adj. No.	Application	Direct Testimony	Exhibit
Pro Forma Revenue	3.1	R746-700-22.B.4 - Adjustment Lead Sheet Model R746-700-22.B.4 - Work Papers R746-700-22.B.6 - JAM Model	Steven R. McDougal - Revenue Requirement Calculation and Jurisdictional Allocation	Exhibit RMP__(SRM-3), Tab 3
Wheeling Revenue	3.2	R746-700-22.B.4 - Adjustment Lead Sheet Model R746-700-22.B.4 - Work Papers R746-700-22.B.6 - JAM Model	Steven R. McDougal - Revenue Requirement Calculation and Jurisdictional Allocation	Exhibit RMP__(SRM-3), Tab 3
SO2 Emission Allowances	3.3	R746-700-20.C.5.a - Information R746-700-22.B.4 - Adjustment Lead Sheet Model R746-700-22.B.4 - Work Papers R746-700-22.B.6 - JAM Model	Steven R. McDougal - Revenue Requirement Calculation and Jurisdictional Allocation	Exhibit RMP__(SRM-3), Tab 3
REC Revenue	3.4	R746-700-20.C.5.a - Information R746-700-22.B.4 - Adjustment Lead Sheet Model R746-700-22.B.4 - Work Papers R746-700-22.B.6 - JAM Model	Steven R. McDougal - Revenue Requirement Calculation and Jurisdictional Allocation Stacey J. Kusters - REC Forecast	Exhibit RMP__(SRM-3), Tab 3
Joint Use Revenue	3.5	R746-700-20.C.5.a - Information R746-700-22.B.4 - Adjustment Lead Sheet Model R746-700-22.B.4 - Work Papers R746-700-22.B.6 - JAM Model	Steven R. McDougal - Revenue Requirement Calculation and Jurisdictional Allocation Jeffery M. Kent - Pole Attachment Rate	Exhibit RMP__(SRM-3), Tab 3
Ancillary Revenue	3.6	R746-700-22.B.4 - Adjustment Lead Sheet Model R746-700-22.B.4 - Work Papers R746-700-22.B.6 - JAM Model	Steven R. McDougal - Revenue Requirement Calculation and Jurisdictional Allocation	Exhibit RMP__(SRM-3), Tab 3
Miscellaneous General Expense	4.1	R746-700-22.B.4 - Adjustment Lead Sheet Model R746-700-22.B.4 - Work Papers R746-700-22.B.6 - JAM Model	Steven R. McDougal - Revenue Requirement Calculation and Jurisdictional Allocation	Exhibit RMP__(SRM-3), Tab 4
Wage and Employee Benefits	4.2	R746-700-20.C.3 - Labor Costs R746-700-20.C.7 - Taxes R746-700-22.B.3 - Labor Costs R746-700-22.B.4 - Adjustment Lead Sheet Model R746-700-22.B.4 - Work Papers R746-700-22.B.6 - JAM Model R746-700-22.D.19 - Employee Costs Gross Payroll and Benefits R746-700-22.C.20 - Employee Costs Overtime and Premium Pay R746-700-22.D.24 - Employee Costs Wages and Salaries Levels R746-700-22.D.25 - Employee Costs Incentive Plans	Steven R. McDougal - Revenue Requirement and Jurisdictional Allocation Erich D. Wilson - Compensation and Benefit Plans	Exhibit RMP__(SRM-3), Tab 4
Idaho Irrigation Load Control Program	4.3	R746-700-22.B.4 - Adjustment Lead Sheet Model R746-700-22.B.4 - Work Papers R746-700-22.B.6 - JAM Model	Steven R. McDougal - Revenue Requirement Calculation and Jurisdictional Allocation	Exhibit RMP__(SRM-3), Tab 4
Remove Non-Recurring Entries	4.4	R746-700-20.C.5.a - Information R746-700-22.B.4 - Adjustment Lead Sheet Model R746-700-22.B.4 - Work Papers R746-700-22.B.6 - JAM Model	Steven R. McDougal - Revenue Requirement Calculation and Jurisdictional Allocation	Exhibit RMP__(SRM-3), Tab 4
Uncollectible Accounts	4.5	R746-700-22.B.4 - Adjustment Lead Sheet Model R746-700-22.B.4 - Work Papers R746-700-22.B.6 - JAM Model	Steven R. McDougal - Revenue Requirement Calculation and Jurisdictional Allocation	Exhibit RMP__(SRM-3), Tab 4
DSM Revenue and Expense	4.6	R746-700-20.C.5.a - Information R746-700-22.B.4 - Adjustment Lead Sheet Model R746-700-22.B.4 - Work Papers R746-700-22.B.6 - JAM Model	Steven R. McDougal - Revenue Requirement Calculation and Jurisdictional Allocation	Exhibit RMP__(SRM-3), Tab 4
Insurance Expense	4.7	R746-700-20.C.5.a - Information R746-700-22.B.4 - Adjustment Lead Sheet Model R746-700-22.B.4 - Work Papers R746-700-22.B.6 - JAM Model R746-700-22.D.34 - OMAG Expenses Injuries and Damages R746-700-22.D.35 - OMAG Expenses Insurance Amount R746-700-22.D.36 - OMAG Expenses Insurance - Self Insurance	Steven R. McDougal - Revenue Requirement Calculation and Jurisdictional Allocation	Exhibit RMP__(SRM-3), Tab 4
Generation Overhaul Expense	4.8	R746-700-20.C.5.a - Information R746-700-20.C.5.b - Information R746-700-22.B.4 - Adjustment Lead Sheet Model R746-700-22.B.4 - Work Papers R746-700-22.B.6 - JAM Model	Steven R. McDougal - Revenue Requirement Calculation and Jurisdictional Allocation	Exhibit RMP__(SRM-3), Tab 4

R746-700-10.A.1.c - Summary Index

Adjustment Name	Adj. No.	Application	Direct Testimony	Exhibit
Incremental O&M	4.9	R746-700-22.B.4 - Adjustment Lead Sheet Model R746-700-22.B.4 - Work Papers R746-700-22.B.6 - JAM Model	Steven R. McDougal - Revenue Requirement and Jurisdictional Allocation Dana M. Ralston - Generation O&M	Exhibit RMP__(SRM-3), Tab 4
Naughton Write-off	4.10	R746-700-20.C.5.a - Information R746-700-22.B.4 - Adjustment Lead Sheet Model R746-700-22.B.4 - Work Papers R746-700-22.B.6 - JAM Model	Steven R. McDougal - Revenue Requirement Calculation and Jurisdictional Allocation	Exhibit RMP__(SRM-3), Tab 4
O&M Expense Escalation	4.11	R746-700-20.C.2.b - Escalation Indices R746-700-22.B.4 - Adjustment Lead Sheet Model R746-700-22.B.4 - Work Papers R746-700-22.B.5.b - Escalation Indices R746-700-22.B.6 - JAM Model	Steven R. McDougal - Revenue Requirement Calculation and Jurisdictional Allocation	Exhibit RMP__(SRM-3), Tab 4 Confidential Exhibit RMP__(SRM-4)
Net Power Cost Study	5.1	R746-700-22.B.4 - Adjustment Lead Sheet Model R746-700-22.B.4 - Work Papers R746-700-22.B.6 - JAM Model R746-700-23 - Additional Power Costs Information	Steven R. McDougal - Revenue Requirement and Jurisdictional Allocation Gregory N. Duvall - Net Power Costs Cindy A. Crane - Cost of Coal	Exhibit RMP__(SRM-3), Tab 5
James River Royalty Offset	5.2	R746-700-22.B.4 - Adjustment Lead Sheet Model R746-700-22.B.4 - Work Papers R746-700-22.B.6 - JAM Model	Steven R. McDougal - Revenue Requirement Calculation and Jurisdictional Allocation	Exhibit RMP__(SRM-3), Tab 5
Little Mountain	5.3	R746-700-20.C.3.a - Labor Costs R746-700-22.B.4 - Adjustment Lead Sheet Model R746-700-22.B.4 - Work Papers R746-700-22.B.6 - JAM Model	Steven R. McDougal - Revenue Requirement Calculation and Jurisdictional Allocation	Exhibit RMP__(SRM-3), Tab 5
Depreciation and Amortization Expense	6.1	R746-700-20.C.4.b - Depr and Amort Calculations R746-700-22.B.4 - Adjustment Lead Sheet Model R746-700-22.B.4 - Work Papers R746-700-22.B.4 - Depr / Amort Template R746-700-22.B.6 - JAM Model	Steven R. McDougal - Revenue Requirement Calculation and Jurisdictional Allocation	Exhibit RMP__(SRM-3), Tab 6
Depreciation and Amortization Reserve	6.2	R746-700-22.B.4 - Adjustment Lead Sheet Model R746-700-22.B.4 - Work Papers R746-700-22.B.4 - Depr / Amort Template R746-700-22.B.6 - JAM Model	Steven R. McDougal - Revenue Requirement Calculation and Jurisdictional Allocation	Exhibit RMP__(SRM-3), Tab 6
Depreciation Study	6.3	R746-700-20.C.5.a - Information R746-700-20.C.4.b - Depr and Amort Calculations R746-700-22.B.4 - Adjustment Lead Sheet Model R746-700-22.B.4 - Work Papers R746-700-22.B.4 - Depr / Amort Template R746-700-22.B.6 - JAM Model	Steven R. McDougal - Revenue Requirement Calculation and Jurisdictional Allocation	Exhibit RMP__(SRM-3), Tab 6
Interest True-Up	7.1	R746-700-22.B.4 - Adjustment Lead Sheet Model R746-700-22.B.6 - JAM Model	Steven R. McDougal - Revenue Requirement Calculation and Jurisdictional Allocation Bruce N. Williams - Cost of Debt	Exhibit RMP__(SRM-3), Tab 7
Property Tax Expense	7.2	R746-700-20.C.7 - Taxes R746-700-22.B.4 - Adjustment Lead Sheet Model R746-700-22.B.4 - Work Papers R746-700-22.B.6 - JAM Model	Steven R. McDougal - Revenue Requirement Calculation and Jurisdictional Allocation	Exhibit RMP__(SRM-3), Tab 7 Confidential Exhibit RMP__(SRM-5)
Renewable Energy Tax Credit	7.3	R746-700-20.C.7 - Taxes R746-700-22.B.4 - Adjustment Lead Sheet Model R746-700-22.B.4 - Work Papers R746-700-22.B.6 - JAM Model	Steven R. McDougal - Revenue Requirement Calculation and Jurisdictional Allocation	Exhibit RMP__(SRM-3), Tab 7
AFUDC Equity	7.4	R746-700-20.C.7 - Taxes R746-700-22.B.4 - Adjustment Lead Sheet Model R746-700-22.B.4 - Work Papers 746-700-22.B.6 - JAM Model	Steven R. McDougal - Revenue Requirement Calculation and Jurisdictional Allocation	Exhibit RMP__(SRM-3), Tab 7
Repairs Deduction Deferred Accounting	7.5	R746-700-20.C.5.a - Information R746-700-20.C.7 - Taxes R746-700-22.B.4 - Adjustment Lead Sheet Model R746-700-22.B.4 - Work Papers R746-700-22.B.6 - JAM Model	Steven R. McDougal - Revenue Requirement Calculation and Jurisdictional Allocation	Exhibit RMP__(SRM-3), Tab 7
Pro Forma Schedule M's	7.6	R746-700-20.C.7 - Taxes R746-700-22.B.4 - Adjustment Lead Sheet Model R746-700-22.B.4 - Work Papers R746-700-22.B.6 - JAM Model	Steven R. McDougal - Revenue Requirement Calculation and Jurisdictional Allocation	Exhibit RMP__(SRM-3), Tab 7
Pro Forma Deferred Income Tax Expense	7.7	R746-700-20.C.7 - Taxes R746-700-22.B.4 - Adjustment Lead Sheet Model R746-700-22.B.4 - Work Papers R746-700-22.B.6 - JAM Model	Steven R. McDougal - Revenue Requirement Calculation and Jurisdictional Allocation	Exhibit RMP__(SRM-3), Tab 7

R746-700-10.A.1.c - Summary Index

Adjustment Name	Adj. No.	Application	Direct Testimony	Exhibit
Pro Forma ADIT Balances	7.8	R746-700-20.C.7 - Taxes R746-700-22.B.4 - Adjustment Lead Sheet Model R746-700-22.B.4 - Work Papers R746-700-22.B.6 - JAM Model	Steven R. McDougal - Revenue Requirement Calculation and Jurisdictional Allocation	Exhibit RMP__(SRM-3), Tab 7
Wyoming Wind Generation Tax	7.9	R746-700-20.C.7 - Taxes R746-700-22.B.4 - Adjustment Lead Sheet Model R746-700-22.B.4 - Work Papers R746-700-22.B.6 - JAM Model	Steven R. McDougal - Revenue Requirement Calculation and Jurisdictional Allocation	Exhibit RMP__(SRM-3), Tab 7
Cash Working Capital	8.1	R746-700-22.B.4 - Adjustment Lead Sheet Model R746-700-22.B.6 - JAM Model R746-700-22.D.43 - Lead/Lag Study	Steven R. McDougal - Revenue Requirement Calculation and Jurisdictional Allocation	Exhibit RMP__(SRM-3), Tab 8
Trapper Mine Rate Base	8.2	R746-700-22.B.4 - Adjustment Lead Sheet Model R746-700-22.B.4 - Work Papers R746-700-22.B.6 - JAM Model	Steven R. McDougal - Revenue Requirement Calculation and Jurisdictional Allocation	Exhibit RMP__(SRM-3), Tab 8
Bridger Mine Rate Base	8.3	R746-700-22.B.4 - Adjustment Lead Sheet Model R746-700-22.B.4 - Work Papers R746-700-22.B.6 - JAM Model	Steven R. McDougal - Revenue Requirement Calculation and Jurisdictional Allocation	Exhibit RMP__(SRM-3), Tab 8
Plant Held for Future Use	8.4	R746-700-22.B.4 - Adjustment Lead Sheet Model R746-700-22.B.4 - Work Papers R746-700-22.B.6 - JAM Model	Steven R. McDougal - Revenue Requirement Calculation and Jurisdictional Allocation	Exhibit RMP__(SRM-3), Tab 8
Customer Advances for Construction	8.5	R746-700-22.B.4 - Adjustment Lead Sheet Model R746-700-22.B.4 - Work Papers R746-700-22.B.6 - JAM Model	Steven R. McDougal - Revenue Requirement Calculation and Jurisdictional Allocation	Exhibit RMP__(SRM-3), Tab 8
Pro Forma Plant Additions and Retirements	8.6	R746-700-20.C.4 - Capital Expenditures R746-700-22.B.4 - Adjustment Lead Sheet Model R746-700-22.B.4 - Work Papers R746-700-22.B.4 - Rate Base Template R746-700-22.B.4 - Plant Retirement Template R746-700-22.B.6 - JAM Model	Steven R. McDougal - Revenue Requirement and Jurisdictional Allocation Chad A. Teply - Generation Mark R. Tallman - Hydro Natalie L. Hocken - Transmission Douglas N. Bennion - Local T&D	Exhibit RMP__(SRM-3), Tab 8
Miscellaneous Rate Base	8.7	R746-700-22.B.4 - Adjustment Lead Sheet Model R746-700-22.B.4 - Work Papers R746-700-22.B.6 - Jam Model	Steven R. McDougal - Revenue Requirement Calculation and Jurisdictional Allocation	Exhibit RMP__(SRM-3), Tab 8
Powerdale Hydro Removal	8.8	R746-700-22.C.5.a - Information R746-700-22.B.4 - Adjustment Lead Sheet Model R746-700-22.B.4 - Work Papers R746-700-22.B.6 - JAM Model	Steven R. McDougal - Revenue Requirement Calculation and Jurisdictional Allocation	Exhibit RMP__(SRM-3), Tab 8
Regulatory Asset Amortization	8.9	R746-700-22.C.5.a - Information R746-700-22.B.4 - Adjustment Lead Sheet Model R746-700-22.B.4 - Work Papers R746-700-22.B.6 - JAM Model	Steven R. McDougal - Revenue Requirement Calculation and Jurisdictional Allocation	Exhibit RMP__(SRM-3), Tab 8
Customer Service Deposits	8.10	R746-700-20.C.5.a - Information R746-700-22.B.4 - Adjustment Lead Sheet Model R746-700-22.B.4 - Work Papers R746-700-22.B.6 - JAM Model	Steven R. McDougal - Revenue Requirement Calculation and Jurisdictional Allocation	Exhibit RMP__(SRM-3), Tab 8
Klamath Hydroelectric Settlement Agreement	8.11	R746-700-22.C.5.a - Information R746-700-22.B.4 - Adjustment Lead Sheet Model R746-700-22.B.4 - Work Papers R746-700-22.B.6 - JAM Model	Steven R. McDougal - Revenue Requirement Calculation and Jurisdictional Allocation	Exhibit RMP__(SRM-3), Tab 8
Misc. Asset Sales and Removals	8.12	R746-700-22.B.4 - Adjustment Lead Sheet Model R746-700-22.B.4 - Work Papers R746-700-22.B.6 - JAM Model	Steven R. McDougal - Revenue Requirement Calculation and Jurisdictional Allocation	Exhibit RMP__(SRM-3), Tab 8
Carbon Plant	8.13	R746-700-22.C.5.a - Information R746-700-22.B.4 - Adjustment Lead Sheet Model R746-700-22.B.4 - Work Papers R746-700-22.B.6 - JAM Model	Steven R. McDougal - Revenue Requirement Calculation and Jurisdictional Allocation	Exhibit RMP__(SRM-3), Tab 8
Pension and Post-Retirement Welfare Plan	8.14	R746-700-22.B.4 - Adjustment Lead Sheet Model R746-700-22.B.4 - Work Papers R746-700-22.B.6 - JAM Model	Steven R. McDougal - Revenue Requirement Calculation and Jurisdictional Allocation Douglas K. Stuver - Pension and Post-Retirement Welfare Plan	Exhibit RMP__(SRM-3), Tab 8
Bridger and Naughton Liquidated Damages	8.15	R746-700-22.C.5.a - Information R746-700-22.B.4 - Adjustment Lead Sheet Model R746-700-22.B.4 - Work Papers R746-700-22.B.6 - JAM Model	Steven R. McDougal - Revenue Requirement Calculation and Jurisdictional Allocation	Exhibit RMP__(SRM-3), Tab 8

Rocky Mountain Power  
Exhibit RMP\_\_\_(SRM-3)  
Docket No. 13-035-184  
Witness: Steven R. McDougal

BEFORE THE PUBLIC SERVICE COMMISSION  
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

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Exhibit Accompanying Direct Testimony of Steven R. McDougal

Test Period Results of Operations

January 2014

**THIS EXHIBIT IS VOLUMINOUS  
AND IS PROVIDED UNDER  
SEPARATE COVER**



CONFIDENTIAL  
Rocky Mountain Power  
Exhibit RMP\_\_\_(SRM-4)  
Docket No. 13-035-184  
Witness: Steven R. McDougal

BEFORE THE PUBLIC SERVICE COMMISSION  
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

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Confidential Exhibit Accompanying Direct Testimony of Steven R. McDougal

IHS Factors

January 2014

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CONFIDENTIAL  
Rocky Mountain Power  
Exhibit RMP\_\_\_(SRM-5)  
Docket No. 13-035-184  
Witness: Steven R. McDougal

BEFORE THE PUBLIC SERVICE COMMISSION  
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

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Confidential Exhibit Accompanying Direct Testimony of Steven R. McDougal  
PacifiCorp Property Tax Estimation Procedure and Estimation Worksheet

January 2014

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