

Rocky Mountain Power
Docket No. 10-035-124
Witness: Steven R. McDougal

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Direct Testimony of Steven R. McDougal

Revenue Requirement & Test Period

January 2011

1 **Q. Please state your name, business address and present position with**
2 **PacifiCorp, dba Rocky Mountain Power (“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 educational 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 Utah Public Service Commission, the
26 Washington Utilities and Transportation Commission, the California Public
27 Utilities Commission, the Idaho Public Utilities Commission, the Oregon Public
28 Utility Commission, the Wyoming Public Service Commission, and the Utah
29 State Tax Commission.

30 **Purpose of Testimony**

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

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

- 35 • Calculation of the \$232.4 million requested rate increase.
- 36 • The test period utilized in this case, the 12 months ending June 30, 2012
37 ("Test Period").
- 38 • The inter-jurisdictional allocation methodology utilized to compute the
39 requested price increase and the procedure that is currently ongoing before
40 the Utah Public Service Commission ("the Commission") addressing
41 inter-jurisdictional allocations.
- 42 • Support for the ongoing accounting for property and liability insurance
43 expense and charges from MidAmerican Energy Holdings Company
44 ("MEHC") for administrative services, two items addressed in MEHC
45 merger commitments that are set to expire prior to the end of the Test
46 Period.

47 • The Company’s process for compiling the Test Period revenue
48 requirement and a detailed explanation of the normalizing adjustments
49 included in the case.

50 **Revenue Requirement Summary**

51 **Q. What price increase is required to achieve the requested Return on Equity**
52 **(“ROE”) in this case?**

53 A. Exhibit RMP____(SRM-1) provides a summary of the Company’s Utah-allocated
54 results of operations for the Test Period, the 12 months ending June 30, 2012. At
55 current rate levels Rocky Mountain Power will earn an overall ROE in Utah of
56 5.5 percent during the Test Period. This return is less than the 10.5 percent return
57 recommended by Dr. Samuel C. Hadaway in this case. An overall price increase
58 of \$228.8 million would be required to produce the 10.5 percent ROE under the
59 Revised Protocol allocation method. However, according to the stipulation
60 approved by the Commission in Docket No. 02-035-04, a Rate Mitigation
61 Premium applies in this case adding \$3.6 million to the price change, for a total
62 requested increase of \$232.4 million.

63 **Q. Please explain the Rate Mitigation Premium.**

64 A. The Company’s calculation of its Utah results of operations for the Test Period is
65 based on the Revised Protocol allocation method as approved by the Commission
66 in Docket No. 02-035-04. The stipulation approved by the Commission in that
67 docket prescribes the method of calculating revenue requirement for setting rates
68 along with certain rate mitigation measures. The stipulation states:

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3. Rate Mitigation Premium

Subject to the conditions of Paragraph 4b, below, for the period from April 1, 2009 to March 31, 2012, the Company may collect a Rate Mitigation Premium as follows: the Company's Utah revenue requirement as calculated pursuant to the Revised Protocol multiplied by 100.25 percent.¹

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4b. Unless and until any amendments to the Revised Protocol are ratified by the PSCU, for the Company's fiscal years beginning April 1, 2009 through March 31, 2014, for all general rate proceedings, the Company's Utah revenue requirement to be used for purposes of setting rates for Utah customers will be the lesser of: (i) the Company's Utah revenue requirement calculated under the Rolled-In Allocation Method multiplied by 101.00 percent; or (ii) the Company's Utah revenue requirement resulting from the Revised Protocol, plus the Rate Mitigation Premium referenced in Paragraph 3, if applicable.²

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In this case the Rate Mitigation Premium applies. As shown on page 1 of my Exhibit RMP___(SRM-1), Revised Protocol plus the Rate Mitigation Premium is the lesser of (i) and (ii) above. For purposes of this case the Company prorated the Rate Mitigation Premium of 100.25 percent to apply to nine months of the Test Period which ends June 30, 2012.

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Test Period and Revenue Requirement Preparation

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

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A. The Company projected results of operations for the period of time beginning July 1, 2011, and ending June 30, 2012. The Test Period utilizes an average (13 month) rate base with a historical base period of the year ended June 30, 2010.

¹ Stipulation in Docket No. 02-035-04, page 3.

² Stipulation in Docket No. 02-035-04, page 4.

96 **Q. Why did the Company use the year ending June 30, 2012, as the Test Period?**

97 A. The Company's primary objective in determining a test period is to develop
98 normalized results of operations based on a period of time that will best reflect the
99 conditions during which the new rates will be in effect. Beyond satisfying this
100 fundamental ratemaking principle, the Company also considered the Utah
101 statutory constraints, issues addressed in previous regulatory proceedings, the
102 current regulatory environment, and the need for transparency with customers and
103 regulators. The Company's proposed test period in this case balances the need for
104 adequate recovery of prudent costs with these other considerations.

105 **Q. What business factors influenced the Company's choice of test period in this**
106 **case?**

107 A. Two main drivers are causing the need for a revenue increase in this case: net
108 power costs and capital investment. As a regulated utility we must continue to
109 incur these increased costs to meet our customers' growing demand for electricity
110 and to improve service reliability.

111 Rocky Mountain Power is building new generation facilities, improving
112 the efficiency and reducing the environmental footprint of existing generating
113 plants, increasing the capacity of its transmission system, and building new
114 distribution lines and substations. New facilities are significantly more expensive
115 than similar facilities currently included in rates. The test period includes \$2.2
116 billion more electric plant in service on a total Company basis and \$1.2 billion
117 more on a Utah-allocated basis than the previous case, adjusted for the major
118 plant addition cases completed during 2010. On a Utah-allocated basis, total rate

119 base in this case is over \$340 million higher. Company witnesses Mr. Darrell T.
120 Gerrard, Mr. Douglas N. Bennion, and Mr. Chad A. Teply provide support for
121 investments in new facilities required to serve customers. As explained by
122 Company witness Mr. Gregory N. Duvall, total Company net power costs are
123 expected to rise from the \$994.2 million set in the Docket No. 10-035-89
124 settlement to \$1.521 billion in the Test Period.

125 **Q. Has the Company been able to manage other costs of doing business that are**
126 **within its control?**

127 A. Yes. It is important to note that, on a per-unit basis, Utah-allocated non-net power
128 cost operations, maintenance, administrative and general costs are lower than
129 included in the 2009 general rate case.

130 **Q. Why is the Company's Test Period necessary to represent the conditions**
131 **when new rates from this case are in effect?**

132 A. As described above, the Company is in an environment of rapidly increasing costs
133 related to capital investment and changes in net power costs which emphasizes the
134 need for rates to be set based on a test period that is closely synchronized with the
135 rate effective period to adequately reflect conditions expected during the time
136 rates will be in effect. Only a test period strongly aligned with the rate effective
137 period can sufficiently capture the rate-making impacts of growing customer load,
138 the capital investment required to serve it, and the operation and maintenance
139 ("O&M") costs required to maintain system safety and reliability. If the rates in
140 this case were set based upon outdated historical investment levels and costs, the
141 Company would have no chance of being compensated properly for the service

142 provided to customers and would not have a reasonable opportunity to earn the
143 return authorized by the Commission.

144 Prices paid by consumers should be set at a level that matches
145 contemporaneously the cost to provide service. A rate base, rate of return
146 regulated utility like Rocky Mountain Power must be given a reasonable
147 opportunity to recover its cost of service, and I believe that the Company's current
148 circumstances are a perfect example of the need for the Test Period in this case.

149 **Q. Why is a forward-looking test period necessary?**

150 A. Robert Hahne, in his book *Accounting for Public Utilities*, states that “[T]he test
151 period, by nature and by design, is a surrogate for conditions of the period of rate
152 use and, to repeat, is presumed to be representative of future conditions.” (7-11,
153 Section 7.06.) This objective is captured in Section 54-4-4(3)(a) of the Utah Code
154 which states:

155 If in the commission's determination of just and reasonable rates
156 the commission uses a test period, the commission shall select a
157 test period that, on the basis of evidence, best reflects the
158 conditions that a public utility will encounter during the period
159 when the rates determined by the commission will be in effect.

160 Ordered rate changes in general rate cases become effective at the end of the
161 statutory 240-day period provided under section 54-7-12(3) of the Utah Code.
162 Based on the anticipated filing date of the full revenue requirement in this case,
163 January 24, 2011, new rates will become effective on or before September 21,
164 2011. A forecast test period allows for better matching of costs with revenues
165 during the rate-effective period. In order for rates to be based on costs to support
166 the financial integrity of the Company, it is essential to have rates set on costs that

167 reflect the time period that the rates will be in effect.

168 A forecast test period is fundamental during a period of major construction
169 and/or rising expenses. In the current environment, a future test period best
170 reflects the costs the Company will necessarily incur in the rate-effective period to
171 provide the level of service required by its customers. The Company expects load
172 growth to continue to be an issue in the Utah service territory over the long term.
173 Planning to serve growing load requires the Company to acquire new generating
174 resources. Significant new investments in transmission and distribution systems
175 are required to integrate these new resources, connect new customers and ensure
176 continued reliability. During this period of increased capital investment and rate
177 base growth, a historical or near term forecast test period cannot adequately
178 capture the conditions that the Company will experience during the rate-effective
179 period; rather, use of a historical test period or a near term forecast test period
180 would understate the true cost of service.

181 **Q. What is the impact of “regulatory lag” on the Company?**

182 A. “Regulatory lag” refers to the time difference between when costs are incurred
183 and when they are included in rates. More than anything else, regulatory lag can
184 be the result of the rate-making process, including test period selection. If new
185 rates do not reflect the costs being incurred at the time the rates are in effect,
186 regulatory lag is created.

187 Regulatory lag is a serious problem for the Company when rates are based
188 on a time period other than the anticipated rate-effective period, especially when
189 the Company is experiencing a steady upward trend in investments. Basing rates

190 on a test period that doesn't reflect the true costs to serve customers during the
191 rate-effective period gives poor price signals to customers while also effectively
192 denying the Company a reasonable opportunity to recover the costs of providing
193 service, including the opportunity to earn the return on investment authorized by
194 the Commission.

195 **Q. Why did the Company choose the year ending June 30, 2012, as the Test**
196 **Period?**

197 A. As previously discussed and as allowed by statute, the primary objective of
198 determining a test period is to develop normalized results of operations based on a
199 period of time that will best reflect the conditions during which time the new rates
200 will be in effect. Many factors must be considered to determine which test period
201 best reflects those expected conditions. This Commission previously identified
202 eight such factors,³ including:

- 203 (1) the general level of inflation;
- 204 (2) changes in the utility's investment, revenues, or expenses;
- 205 (3) changes in utility services;
- 206 (4) availability and accuracy of data to the parties;
- 207 (5) ability to synchronize the utility's investment, revenues, and expenses;
- 208 (6) whether the utility is in a cost increasing or cost declining status;
- 209 (7) incentives to efficient management and operation; and
- 210 (8) the length of time the new rates are expected to be in effect.

211 In its Order on Test Period issued February 14, 2008 in Docket No. 07-
212 035-93, the Commission also expressed its desire to balance Company and
213 ratepayer interests. The Company is proposing the Test Period in this case after
214 consideration of the current regulatory environment, Utah statutes governing test
215 period development, and the factors identified above by the Commission.

³ Order Approving Test Period Stipulation, Docket No. 04-035-42 (October 20, 2004); Order on Test Period, Docket No. 07-035-93 (February 14, 2008).

216 **Q. Please describe how the Company considered the factors identified above in**
217 **choosing the Test Period in this rate case.**

218 A. Below is a brief discussion of the factors identified by the Commission and an
219 explanation of how the Company evaluated its proposed Test Period based on
220 these factors.

221 • **Level of Inflation** – While inflation is not one of the major drivers of this rate
222 case, inflationary pressures still remain and must be reflected in test period
223 cost projections. The Company is striving to absorb cost increases as much as
224 possible, and has managed to keep non-NPC O&M expenses flat compared to
225 the last Utah general rate case on a \$/MWh basis. However, the Company will
226 still experience inflationary cost increases along with other increases such as
227 labor costs due to negotiated increases in many of its union labor contracts.

228 • **Changes in Utility Investment, Revenues, and Expenses** – The Utah service
229 territory continues to grow and long term load growth is expected to continue.
230 Because of past, current, and future load growth, the Company will have to
231 acquire new resources, impacting not only the level of investment needed to
232 be included in rate base, but also retail revenues, net power costs and
233 operation and maintenance costs. The impact of the Company's capital
234 expenditure program will continue to put pressure on the Company's earnings
235 even with the use of forecasted test periods.

236 This case includes Utah's portion of approximately three billion
237 dollars in new plant investments the Company has made or will make between
238 the July 1, 2010 and June 30, 2012, the end of the Test Year. In addition,

239 because of the use of June 30, 2010 average rate base in the last general rate
240 case, the Company has not included all of the capital investments from July 1,
241 2009 through June 30, 2010 in Utah rates. In addition, although the Company
242 was allowed to add the Dave Johnston Unit 3 Scrubber, Dunlap I wind plant
243 and the Populus to Terminal transmission line in rates as major plant
244 additions, the Company has made a significant amount of smaller capital
245 additions since July 1, 2010 that are not included in customer rates. The
246 failure to include these investments in rates understates the cost of serving
247 customers and puts significant financial pressure on Rocky Mountain Power. I
248 will provide a more detailed description of the current and projected major
249 capital projects later in my testimony.

250 • **Changes in Utility Services** – No change in service levels is anticipated,
251 however the Company continues to fund maintenance to allow for the
252 provision of safe and reliable electric service and meet our merger
253 commitments.

254 • **Availability and Accuracy of Data to Parties** – The Company remains open
255 and willing to share information with the parties involved in the case. The
256 Company has provided a significant amount of information along with this
257 filing as part of the Commission’s filing rules. During this general rate case
258 the Company is committed to responding to additional data requests from the
259 parties in a timely manner.

260 Other parties have suggested in prior cases that the most important
261 criteria for test period selection is the accuracy of the data or forecasts during

262 the test period. If this suggestion is taken to its logical extreme, it would
263 always require the use of a historic test period because data from a historic test
264 period is always going to be more accurate than data from a forecast test
265 period. However, such a conclusion misses the point. As Dr. Alfred Kahn
266 noted years ago,

267 The fact is ... regulatory commissions have always been in the business of
268 projecting, whether they knew it or not. When they used historic test year
269 statistics, fully verifiable and verified, graven in stone, as the basis of
270 future rates, they were in fact projecting. They were assuming that the
271 future would be similar to the past. It is no more speculative, then, to make
272 the best possible estimate of future costs when setting future rates; and
273 honesty compels it.⁴

274 The issue is not that data for a historic test period may be audited or
275 may be certain. The issue is whether the data for the historic test period is a
276 better predictor of the rate-effective period than a forecast for that period.

277 • **Ability to Synchronize the Utility's Investment, Revenues, and Expenses**

278 The synchronization or "matching" of a utility's revenues, expenses and
279 investments in setting rates is a traditional rate making concept; however, it is
280 one that cannot be viewed in isolation without taking into consideration the
281 rate-effective period. The goal in setting rates should be to set rates that
282 properly reflect the costs that will be incurred by a utility during the period
283 that the rates will be in effect. If the rate-effective period is not considered,
284 then the process of matching revenues, expense and investments may capture
285 interdependent impacts, but the result may not reflect the costs to be incurred
286 during the rate-effective period. For example, a test period based on purely

⁴ A. Kahn, "Between Theory and Practice: Reflections of a Neophyte Public Utility Regulator," *Public Utilities Fortnightly* 29 (Jan. 2, 1975).

287 historical information may be properly synchronized between the revenues,
288 expenses and investments included in the test period, but may have very little
289 to do with the costs that will be incurred when new rates go into effect. When
290 the test period does not properly match the rate-effective period, other
291 regulatory tools have been used to adjust the test period to reflect the proper
292 level of costs to be considered in new rates, including, year-end rate base,
293 known and measurable adjustments (often one-sided, non-matching
294 adjustments), and budget levels.

295 The Company is using a 13 month average rate base for the test period.
296 The Company believes this is appropriate in this case because the test period
297 corresponds quite closely with the first year of the rate-effective period. The
298 rate-effective period is likely to start about 80 days after the start of the test
299 period.

300 The important synchronization under the statute is synchronization
301 between the revenue requirement determined for the test period and the costs
302 that will be incurred during the rate-effective period. Notably, section 54-4-
303 4(3)(a) requires the Commission to select a test period that best reflects the
304 conditions that a utility will encounter during the rate-effective period. The
305 purpose of using a test period is simply to attempt to predict the costs that the
306 utility will incur during the rate-effective period. Synchronization of revenues,
307 expense and rate base is only helpful if it achieves that end.

308 As previously mentioned, the most important element of matching is
309 that the test period should reflect the costs that the Company expects to incur

310 during the rate-effective period. As stated in *Accounting for Public Utilities* by
311 Robert L. Hahne “If the period forecasted coincides with the period in which
312 the new rates will be in effect, the matching of investment levels to operating
313 results should produce the earnings levels authorized”. (Hahne 7-5, Section
314 7.04).

315 • **Whether the Utility is in a Cost Increasing or Cost Declining Status** – As
316 discussed above, while there is minimal pressure associated with increasing
317 O&M costs, as a result of its capital investment program and changes in net
318 power costs the Company is in a rising cost environment. This is discussed in
319 greater detail later in my testimony and in the testimony of Mr. Duvall.

320 • **Incentives to Efficient Management and Operation** – The Company
321 management is continually looking for ways to increase the efficiency of the
322 Company. The Company is adding investment to serve load growth and
323 improve reliability and needs the level of investment included in the proposed
324 Test Period. To not allow the proposed Test Period would be a disincentive to
325 the Company in these efforts.

326 Some parties have argued that regulatory lag provides an incentive for
327 management efficiency because it forces management to cut costs in order to
328 have the opportunity of recovering the Company’s true costs of providing
329 service to customers when rates are based on a period prior to the rate-
330 effective period. The circular logic of this argument is dubious in any
331 circumstances, but is particularly dubious in the context of a case in which the
332 rate increase is sought to recover the costs of new investments which are

333 necessary to provide reliable service to customers. The incurrence of prudent
334 costs of major capital resources cannot be reduced by management efficiency.

335 • **Length of Time New Rates Are Expected To Be in Effect** – The Company
336 has not made any decision on the length of time the new rates are expected to
337 be in effect. Future rate cases will be filed based on Utah jurisdictional
338 earnings and the Company’s ability to get timely recovery of its costs. This
339 factor is best satisfied by setting rates that are expected to recover the true
340 costs of providing service during the first full year that new rates are in effect.

341 **Q. Should each of these factors be given equal weight by the Commission?**

342 A. No. Certain factors will be more important at a given point in time than other
343 factors. In this case, changes in utility investments should be given predominant
344 weight

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

346 A. The main drivers for this general rate case are the significant level of capital
347 investment the Company is making on behalf of our customers and increases in
348 the Company’s net power costs. As mentioned earlier in my testimony, Company
349 witnesses Mr. Gerrard, Mr. Bennion, and Mr. Teply provide support for
350 investments in new facilities required to serve customers, and Mr. Duvall
351 provides testimony on net power costs

352 **Q. Given the level of capital investments, what would be the impact of choosing
353 a test period that ends earlier than the Test Period proposed by the Company
354 in this case?**

355 A. Using a test period that ends earlier than June 2012 would assure that customers

356 will not pay and that the Company will not recover its actual costs of providing
357 service during the rate-effective period. As I have previously testified, one of the
358 drivers for this rate case is the capital investments the Company has made and
359 will be making through June 30, 2012.

360 **Q. What is the most appropriate test period to use in this case?**

361 A. The Company's proposed 12 months ending June 30, 2012 test period is the Test
362 Period that is most likely to represent conditions during the period the rates set in
363 this case will be in effect. The major driver of the Company's need for a rate
364 increase is the capital investments the Company has made and will make through
365 June 2012 and changes in net power costs required to serve our customers. These
366 increases must be included in rates if the Company is to have a reasonable
367 opportunity to recover its costs of providing service to customers including a
368 reasonable return on its investments.

369 **Q. Did the Company prepare the Alternative Period as required in Utah Rule**
370 **R746-700-10.A.2?**

371 A. Yes. In compliance with that rule, the Company has provided normalized results
372 of operations for the 12 months ending June 30, 2011 ("Alternative Period"),
373 which is the closest of June or December following the filing date of this
374 application.

375 **Q. Should the Alternative Period be relied on to set rates in this case?**

376 A. No. The alternative period will be concluded over two months prior to the
377 implementation of any rate changes related to this case. Therefore, the use of the
378 alternative period would result in the use of historical information at the time rates

379 are updated, and would reflect a step backwards in setting Utah rates.

380 On January 1, 2011 rates were changed in Utah in Docket No. 10-035-89
381 for the major plant additions made by the Company for the Populus to Ben
382 Lomond Transmission Line and the Dunlap I Wind Project. However, in the July
383 1, 2010 to June 30, 2011 Alternative Period neither of these investments is
384 completely included due to the use of average rate base. These two major plant
385 additions are in-service, providing benefits to Utah customers, and are already
386 included in Utah rates. It would be illogical and contrary to the intent of the major
387 plant addition statute to use a test period that partially removes from rate base
388 major plant additions that are already in-service and included in rates.

389 **Q. Please explain how the Company developed the revenue requirement for the**
390 **Test Period.**

391 A. Revenue requirement preparation began with historical accounting information; in
392 this case the Company used the 12 months ended June 30, 2010. Each of the
393 revenue requirement components in that historical period was analyzed to
394 determine if an adjustment would be warranted to reflect normal operating
395 conditions. The historical information was adjusted to recognize known,
396 measurable, and anticipated events and to include previously ordered Commission
397 adjustments. Exhibit RMP____(SRM-2) provides a summary index identifying
398 each normalizing adjustment and where each adjustment is addressed in the
399 Company's filing.⁵

⁵ In conformance with filing requirement R746-700-10.A.1.c.

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

402 A. Yes.

403 **Q. What is the significance of Rocky Mountain Power’s method of beginning**
404 **with historical information?**

405 A. The Company begins with historical accounting information and makes discrete
406 adjustments to arrive at the Test Period revenue requirement. Beginning with
407 historical information provides a realistic foundation that is readily available for
408 audit by all participants involved in the case. Individual adjustments are also
409 available for review, and regulators and intervenors may determine each
410 adjustment’s relevance and accuracy.

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

413 A. Historical retail revenue is first adjusted to reflect normal weather conditions and
414 remove items that should not be included in regulated results. Revenue is also
415 adjusted for the effect of applying the current Commission-approved tariff rates to
416 the Test Period load projection. The testimony of Dr. Peter C. Eelkema describes
417 the comprehensive approach used to project Test Period loads for this case. Net
418 power costs were developed using the Generation & Regulation Initiative
419 Decision (“GRID”) model, which has been used extensively in prior general rate
420 cases and other regulatory proceedings in Utah. The calculation of Test Period net
421 power costs is described in the testimony of Company witness Mr. Duvall.
422 Historical operations and maintenance (“O&M”) expenses, excluding net power

423 costs, were split into labor and non-labor components. Non-labor costs were
424 adjusted for projected price changes using nationally-recognized inflation indices
425 provided by IHS Global Insight and for other discrete changes required to reflect
426 conditions expected during the Test Period. Historical labor costs were also
427 adjusted for expected increases through the end of the Test Period. Rate base was
428 adjusted to capture planned additions to electric plant in service and known
429 changes to other rate base items. In addition, asset retirements and accumulated
430 depreciation were walked forward through the end of the Test Period based on
431 composite retirement and depreciation rates by plant function. Specific
432 adjustments are described in greater detail later in my testimony and exhibits
433 where I explain the development of the Utah results of operations.

434 **Q. How has the Company addressed areas where the expected change in O&M**
435 **is different than the price changes projected by IHS Global Insight?**

436 A. The Company's business units provided regulation with insight into costs that
437 may be changing in the future due to causes other than inflation and also provided
438 support for specific changes in the number or frequency of activities which would
439 drive changes in costs. Examples of these types of adjustments are the Utah
440 Automated Meter Reading ("AMR") Program adjustment (Adjustment 4.13)
441 which reflects efficiencies from automated meter reading projects, and the
442 Incremental Generation and Transmission O&M adjustment (Adjustment 4.15)
443 which includes the cost of operating and maintaining new plants as well as
444 changes in costs at some existing facilities. These adjustments are necessary
445 because inflation indices are applied to costs for existing units of production

446 which will not capture changes in volume or processes.

447 **Inter-Jurisdictional Allocations**

448 **Q. What methodology did the Company use to calculate the Utah-allocated**
449 **revenue requirement in this case?**

450 A. The Company’s requested price increase is calculated using the Revised Protocol
451 allocation method as approved by the Commission in Docket No. 02-035-04.
452 According to the terms of the stipulation approved previously in that Docket,
453 “PacifiCorp agrees that, until such time as the Revised Protocol is amended in
454 accordance with its terms, all general rate case filings made by it in Utah,
455 subsequent to PSCU ratification of the Revised Protocol, will be based upon the
456 provisions of the Revised Protocol.”⁶ The Company recently proposed
457 modifications to the Revised Protocol in an application filed with the Commission
458 also under Docket No. 02-035-04; the revised methodology is called the ‘2010
459 Protocol.’ The 2010 Protocol contains proposed amendments to the Revised
460 Protocol based on collaboration with multiple stakeholders through the multi-state
461 process (“MSP”) Standing Committee, the group tasked with evaluating the
462 continued use of the Revised Protocol for setting rates. For comparison purposes
463 the Test Period results for this case in Exhibit RMP___(SRM-3) are provided
464 using Revised Protocol, 2010 Protocol, and Rolled-In.

465 **Q. What is the status of the Company’s application in Docket No. 02-035-04?**

466 A. The Company’s application was filed with the Commission on September 15,
467 2010, and is currently pending before the Commission. Interested parties are

⁶ Stipulation in Docket No. 02-035-04, page 2.

468 working toward a possible settlement agreement, and testimony is scheduled to be
469 filed on February 23, 2010, if a settlement is reached.

470 **Q. What are the direct impacts on this case related to the 2010 Protocol?**

471 A. Compared to the Revised Protocol there are three main impacts in this case. First,
472 the scope of the Embedded Cost Differential (“ECD”) is reduced and is now a
473 fixed amount rather than allowed to change with each set of results. Second,
474 seasonal allocation of certain resources is eliminated. Third, state income taxes
475 are calculated for each jurisdiction using the weighted statutory state tax rate
476 rather than allocated using the Income Before Tax (“IBT”) allocation factor.
477 Overall, using the 2010 Protocol reduces Utah-allocated revenue requirement in
478 the Test Period when compared to the Revised Protocol. Tab 10 of Exhibit
479 RMP___(SRM-3) provides the test period results using the 2010 Protocol
480 allocation methodology for comparison purposes.

481 **Q. Does the Company intend to reflect the outcome of its application in Docket
482 No. 02-035-04 in this case?**

483 A. Yes. The Company intends to include in this case any Test Period impacts related
484 to any Commission-approved outcome in that Docket.

485 **Q. Are there any other allocation related issues that have been raised outside of
486 the Company’s 2010 Protocol filing?**

487 A. Yes. The Company also has a general rate case under way in Idaho and is
488 anticipating a final order in February. Parties to that case have raised the issue of
489 system allocating the costs and benefits related to Idaho’s Irrigation Load Control
490 program, currently classified as a class 1 demand-side management (“DSM”)

491 program. The Idaho irrigation program provides the Company with over 200 MW
492 of irrigation load curtailment during June, July, and August. In Utah, the Cool
493 Keeper DSM program provides the Company with approximately 100 MW of air
494 conditioning load curtailment during the summer months. These programs and
495 other smaller programs are currently classified as DSM for allocation purposes,
496 meaning the load reductions are reflected in jurisdictional loads for allocation and
497 the program costs are situs assigned to the individual state. Parties to the Idaho
498 case have recommended that the Idaho Irrigation Load Control Program be
499 system allocated rather than situs assigned. The Company will continue to work
500 with those parties, as well as interested parties in Utah, to ensure resolution of the
501 issue that is acceptable to all states. The Company's filing in this Docket
502 continues to assign these DSM programs on a situs basis, but an adjustment may
503 be required in this case to reflect any accepted changes.

504 **Insurance Expense**

505 **Q. Please explain the Company's proposed treatment of property and liability**
506 **insurance.**

507 A. In this case the Company is proposing to replace its current captive insurance
508 policy with self insurance coverage for third-party liability, transmission and
509 distribution ("T&D") property, and non-T&D property. The Company's proposal
510 eliminates the expense for captive insurance premiums and instead provides an
511 accrual to self-insurance reserves. These self insurance reserves will cover O&M
512 related damages. Capital related damages will be recovered as projects are added
513 to rate base, consistent with other capital investments.

514 **Q. How has insurance coverage for these three categories been provided since**
515 **the acquisition of PacifiCorp by MEHC?**

516 A. Since the MEHC acquisition the Company has utilized a captive insurance
517 company to provide property and liability insurance. Commitments specific to
518 states other than Utah limited premiums paid to the captive insurance company to
519 \$7.4 million annually, on a total Company basis, and the Company has limited the
520 captive insurance premiums in rates at that level. In March 2010 the captive
521 insurance policy was renewed for one additional year, but the commitment to
522 utilize a captive insurance company with limited premiums expired December 31,
523 2010.

524 **Q. What level of coverage was provided by the captive insurance?**

525 A. The coverage under the captive varies by category:

- 526 • Excess liability insurance provides indemnity for amounts the Company is
527 legally obligated to pay for damages due to bodily injury, personal injury
528 or property damage. The captive covers \$750,000 per occurrence, in
529 excess of a \$250,000 deductible. Commercial insurance covers \$175.0
530 million per occurrence after a deductible of \$1 million.
- 531 • T&D property damage insurance covers property damage to overhead
532 transmission and distribution lines related to both O&M and capital
533 events. The first \$25,000 damages per event are defined as a deductible
534 and are allocated to O&M and capital. The captive then covers \$10.0
535 million annually in excess of an annual \$5.0 million aggregate deductible
536 (over and above the \$25,000 per-event deductible). There is no

537 commercial insurance for T&D property damage.

538 • Non-T&D property damage covers all risks of direct physical loss or
539 damage including boiler explosion, machinery and electrical breakdown,
540 flood and earthquake. The captive covers \$6.0 million per occurrence, in
541 excess of a \$1.5 million deductible. Commercial insurance covers \$400
542 million per occurrence after a deductible of \$7.5 million.

543 **Q. When will the policy change from captive insurance coverage to self**
544 **insurance be implemented?**

545 A. The Company's proposed treatment would take effect after the current captive
546 coverage expires on March 21, 2011. Coverage currently provided by commercial
547 carriers will continue, and the related premiums are included in this case at actual
548 levels. The Test Period in this case includes a full year of the new accounting for
549 self insurance accruals.

550 **Q. What will be the new level of coverage?**

551 A. The initial deductible for each storm or casualty O&M event damaging
552 distribution property will be raised from the current level of \$25,000 to \$250,000.
553 The deductible for O&M transmission and non-T&D property damages will be \$1
554 million per event. O&M related damages for all costs up to these deductible limits
555 will be charged to the proper functional O&M FERC account. Amounts
556 exceeding these deductible limits will be charged to the accumulated insurance
557 reserve. There will be no deductible amounts applied to capital projects.

558 **Q. Please describe the Test Period treatment of third-party liability insurance.**

559 A. As shown on page 4.11.2 of Exhibit RMP___(SRM-3), captive insurance

560 premiums and coverage are assumed only through March 21, 2011. For the Test
561 Period self-insurance accruals replace the captive premiums. The level of the self-
562 insurance accrual is a three-year average of liability claim payments by MEHC
563 captive insurance from July 2007 through June 2010. Utah's allocated portion of
564 the test period amount is based on the System Overhead ("SO") factor. The
565 injuries and damages expense the Company incurs in addition to the amount
566 currently covered by the captive are included based on a three-year average of the
567 cash paid net of insurance reimbursements, consistent with the Company's
568 previous general rate cases in Docket Nos. 08-035-38 and 09-035-23.

569 **Q. Please describe the treatment of property insurance in the Test Period.**

570 A. As shown on page 4.11.3 of Exhibit RMP____(SRM-3), captive insurance
571 premiums and coverage for T&D and non-T&D property are assumed to be in
572 place only through March 21, 2011. For the Test Period, self insurance accruals
573 are included using a three-year average of actual damages from April 2007
574 through March 2010. Damages are included only to the extent they exceed the
575 revised deductibles by category. The allocation of accruals and actual storm or
576 casualty costs will be consistent with the allocation of similar types of electric
577 plant in service (i.e. distribution is situs assigned and transmission and non-T&D
578 are allocated on the SG factor).

579 Due to the increase in deductible limits, expenses for property damages
580 that are currently classified as insurance expense are effectively being transferred
581 to O&M. Page 4.11.4 shows that the increase in deductible limits reduces the
582 amount of storm or casualty events that would be covered by the insurance

583 reserve. Costs not covered by the insurance reserve would need to be covered by
584 the Company's ongoing O&M. The Company has included the effect of this
585 transfer as an O&M expense of \$4.5 million in the Test Period in order to set rates
586 at a level that will adequately cover expected storm and casualty damage.

587 **Q. Please describe the accounting entries that will be booked once self insurance**
588 **coverage begins.**

589 A. Page 4.11.5 of Exhibit RMP___(SRM-3) shows an example of the accounting
590 entries to be made in the future based on the Company's proposal in this filing.
591 Each month, debits will be made to FERC accounts 924 – Property Insurance and
592 925 – Liability Insurance, with the corresponding credits booked to insurance
593 reserves in FERC account 228. Separate internal accounting orders will be used
594 for the reserve balances to track the state-specific amounts associated with the
595 liability and property balances. When the Company experiences an insurance
596 event, the reserve balance will be debited and cash or accounts payable will be
597 credited to pay for the damages incurred allocated to Utah using then-current
598 allocation factors. If the Company experiences events in excess of the
599 accumulated reserve balance, or anticipated reserve balance through the
600 remaining portion of each calendar year, the Company will accumulate these
601 amounts as a regulatory asset until such time as the allowed annual accrual
602 amount covers such losses or specific recovery for an event is requested and
603 approved.

604 **Q. What is the impact of the Company's proposal on Utah customers in this**
605 **case?**

606 A. Overall the Company's proposal results in an increase in costs allocated to Utah
607 compared to the actual costs in the year ended June 2010. Page 4.11 of Exhibit
608 RMP___(SRM-3) shows the Utah-allocated impact of the adjustments for both
609 liability and property insurance. The net expense for Utah-allocated liability
610 insurance increases approximately \$290,535. Utah-allocated property insurance
611 expense is reduced by over \$3.5 million, but is offset by O&M expense of
612 approximately \$4.5 million.

613 **MEHC Administrative Services**

614 **Q. Please explain the Company's proposed treatment of charges for MEHC**
615 **administrative services.**

616 A. Since the MEHC acquisition, the corporate management fee billed to PacifiCorp
617 has been capped in accordance with commitment 38, which states:

618 MEHC commits that the corporate charges to PacifiCorp from
619 MEHC and MEC will not exceed \$9 million annually for a period
620 of five years after the closing on the proposed transaction.

621 This commitment expires March 21, 2011, prior to the Test Period in this case.
622 Charges for the Test Period are based on the actual amount booked in the year
623 ended June 30, 2010, after adjusting for amounts that should have been booked
624 below the line.

625 **Q. What is the result of the Company's proposed treatment?**

626 A. The net impact of the Company's adjustment is to reduce the expense for MEHC
627 administrative services in this case to approximately \$7.0 million, or about

628 \$500,000 less than the amount included in regulated expenses in the year ended
629 June 30, 2010. Page 4.4.1 of Exhibit RMP___(SRM-3) provides additional details
630 regarding the charges included in results.

631 **Q. Is there an agreement filed with the Commission that governs the terms and**
632 **conditions for MEHC administrative services to PacifiCorp?**

633 A. Yes. The MEHC inter-company affiliated services agreement (“IASA”) governs
634 these services. In merger commitment 13 the Company agreed to file the IASA
635 with the Commission. The Company made this filing on March 31, 2006, and it
636 was approved by the Commission in October, 2006.

637 **Q. Please describe the types of charges for MEHC administrative services**
638 **governed by the IASA.**

639 A. There are two kinds of charges assigned for MEHC administrative services, direct
640 charges and allocated costs.

641 Direct charges are those costs where the employee performing the service
642 is working directly for or on behalf of the Company. Examples of these types of
643 charges would include, among other things, participation in Company specific
644 meetings, negotiations on behalf of the Company or performing individual tasks
645 related solely to the Company. The party receiving the benefit of the services
646 provided is charged for the operating costs incurred by the party providing the
647 service.

648 Allocated charges are for costs incurred for the general benefit of the
649 entire corporate group or multiple segments including the Company for which
650 direct charging is not practical. These include costs where the Company is

651 receiving benefits through joint participation in the larger group. Examples
652 include, among other things, senior management oversight of common functions
653 such as human resources, environmental, information technology and finance. An
654 allocation methodology is established to assign these charges fairly and is used
655 consistently from year to year.

656 **Q. Does MEHC charge out all of its costs?**

657 A. No. For example, in the year ended June 30, 2010 MEHC charged out only 46
658 percent of its labor costs. Of this amount, the Company received 35 percent. In
659 other words, the Company only received approximately 16 percent of the total
660 labor charges at MEHC.

661 **Q. Have the services provided to the Company under the IASA permitted the
662 Company to substantially reduce its administrative and general costs?**

663 A. Yes. Prior to the IASA, for the 12 months ended March 31, 2006, administrative
664 and general costs totaled \$248 million on a total company basis. For the Test
665 Period in this case administrative and general costs total \$161 million including
666 the IASA charges.

667 **Q. Please describe how the Company uses its participation in the IASA to the
668 benefit of its customers.**

669 A. The IASA provides the Company with a range of services, including executive
670 leadership, strategic management and planning, financial planning and analysis,
671 insurance, environmental compliance, financial reporting, human resources, legal,
672 accounting and other administrative services, at a fraction of the cost it would
673 otherwise incur for such services. Because of the IASA, there are several major

674 PacifiCorp business departments where the highest ranking employee is at the
675 director level, including information technology, human resources, and
676 environmental services. These directors report to MEHC management and, in
677 turn, PacifiCorp is charged only a fraction of the total costs for these senior
678 MEHC management positions. The Company believes that this is an efficient and
679 effective way to manage the business and help control costs.

680 **Q. How does the Company benefit from using other MEHC subsidiary**
681 **employees to provide some services to the Company versus using outside**
682 **contractors?**

683 A. MEHC and its subsidiaries' staff are very experienced in dealing with the
684 Company's business needs given their extensive background in working with U.S.
685 regulated businesses. For example, MEHC corporate staff is well versed in
686 dealing with Federal Energy Regulatory Commission, North American Electric
687 Reliability Corporation, and U.S. Securities and Exchange Commission matters.
688 In addition, MEHC has a consistent program of establishing salaries for
689 employees across all of its platforms and a consistent overarching employee
690 business expense policy. This consistency provides assurance that when
691 employees from other platforms provide services under the IASA, the Company is
692 obtaining the same benefit as if the work was performed by one of its employees.
693 This allows PacifiCorp to have access to a broader population of expertise when
694 dealing with specific issues on a direct cost basis.

695 **Q. Please provide examples of where the Company has received benefits from**
696 **belonging to the larger MEHC organization.**

697 A. The MEHC corporate management style emphasizes prudent cost management.
698 This has resulted in direct savings to the Company's customers both through
699 lower costs and higher benefits. For example, the Company's audit fees are lower
700 since the MEHC transaction. The current hourly rate is \$162 per hour, as
701 compared to a rate of over \$216 per hour prior to the transaction.

702 **Settlement Fees**

703 **Q. Please describe your Exhibit RMP___(SRM-6).**

704 A. In the revenue requirement Order in Docket No. 09-035-23, page 87, the
705 Commission directed the Company to provide a summary exhibit detailing actual
706 settlement fees for the past five years and proposed test year settlement fees. In
707 compliance with that order, Exhibit RMP___(SRM-6) contains a five-year history
708 of settlement fees, by FERC account and allocation factor, for the 12 months
709 ended June 30, 2006 through June 30, 2010. This exhibit also includes details of
710 the settlement fees included in the June 2012 test year, which are the June 30,
711 2010 settlement fees escalated for inflation through June 30, 2012, resulting in
712 \$129,144 on a total Company basis in the Test Period.

713 **Q. Please describe the process by which this exhibit was prepared**

714 A. Exhibit RMP___(SRM-6) was prepared by summarizing on a mid-year basis all
715 transactions posted to the Company's settlement fees accounts 545500 and
716 545501 over a period of five years, from July 1, 2005 to June 30, 2010. The
717 related FERC account assignments are derived by the location and cost center

718 charging the cost. Figures for all mid-years are reflected at an unadjusted Total
719 Company level. Test Year June 2012 results are also reflected on a total company
720 level including escalation. This exhibit excludes settlement fees that have been
721 charged to accounts below the line that are not included in this filing, as well as
722 those charged to capital. Additionally, it omits any Injuries and Damages
723 settlements, as these are normalized to a three year average in Adjustment 4.11 –
724 Insurance Expense in Exhibit RMP___(SRM-3).

725 **Q. Were there adjustments made to the unadjusted data summarized in Exhibit**
726 **RMP___(SRM-6)?**

727 A. Yes, the ‘Adjustments’ section within RMP Exhibit___(SRM-6) is broken up into
728 two sections. Section I outlines adjustments made to the base year in Adjustment
729 4.3 of Exhibit RMP___(SRM-3). Net of adjustments and including escalation, the
730 total settlement fee balance for test year ending June 2012 is \$129,114. Section II
731 provides a summary of prior year adjustments made in prior Utah filings
732 including general rate cases or Semi-Annual Results of Operations reports. These
733 adjustments are shown as a measure of providing a more leveled depiction of
734 settlement fees.

735 **Uncollectible Expense**

736 **Q. Please explain how the Company calculated the amount of uncollectible**
737 **expense included in this request.**

738 A. As shown in my Exhibit RMP___(SRM-3) in Adjustment 4.17, the Company first
739 calculated the test period uncollectible rate of 0.315% by dividing Utah’s June
740 2010 unadjusted uncollectible expense (FERC 904) by Utah’s June 2010

741 unadjusted general business revenues. This unadjusted uncollectible rate was then
742 applied to the June 2012 normalized general business revenues, resulting in a total
743 uncollectible expense for the 12 months ending June 30, 2012 of approximately
744 \$5.4 million. The Company's request includes an increase in uncollectible
745 expense of approximately \$646k to account for the incremental uncollectible
746 expense the Company anticipates during the test period as a result of the
747 additional revenue requested in this docket.

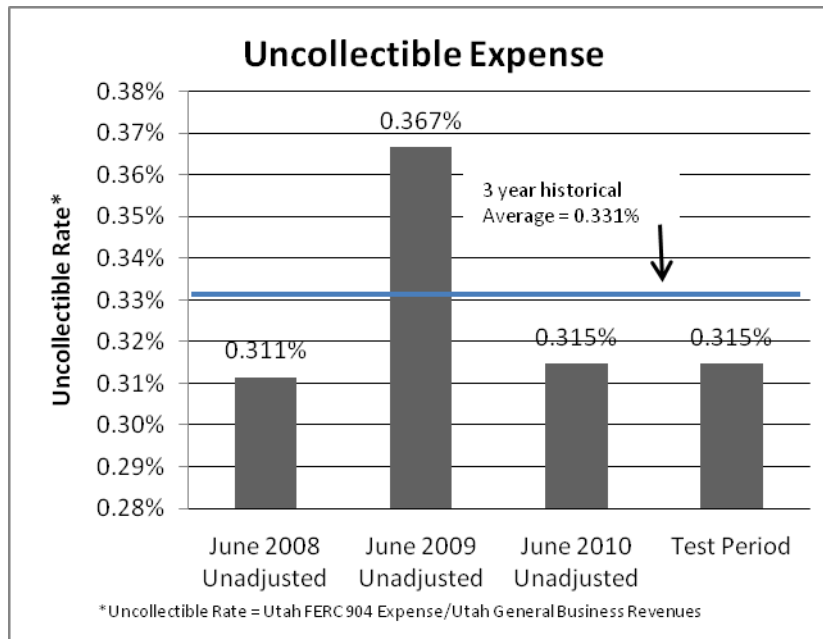
748 **Q. How does this compare to the methodology used by the Commission in its**
749 **order in Docket No. 09-035-23?**

750 A. In the last general rate case Docket No. 09-035-23 the Commission accepted the
751 Division's proposal to apply a 3-year historical average of the uncollectible rate to
752 the test year general business revenues to arrive at the amount of uncollectible
753 expense to be included in rates.

754 **Q. Why does the Company believe that the averaging methodology used in the**
755 **order in Docket No. 09-035-23 is not appropriate for this general rate case?**

756 A. In that docket, the Commission determined that the uncollectible expense in the
757 base period was abnormal and used a 3-year historical average as a "general
758 approach to normalize abnormal amounts."⁷ However, the order explicitly states
759 that they would require additional evidence to establish a consistent policy for
760 calculating test period uncollectible expense. The chart below compares the
761 uncollectible rate in this general rate case to the prior two historical periods and
762 the 3-year average of those periods.

⁷ Docket No. 09-035-23, Commission Order, Page 86.



763 In this case, the base year level of uncollectible expense appears to be well within
 764 normal levels and applying a historical averaging methodology would further
 765 increase the uncollectible expense over the Company's request. The Company
 766 continues to manage its uncollectible expense levels and feels that the unadjusted
 767 uncollectible rate included in its request represents a reasonable and ongoing ratio
 768 of uncollectible expense to general business revenues. Consequently, the
 769 Company requests that the uncollectible expense be increased only to account for
 770 the additional revenue it anticipates in the 12 months ending June 30, 2012.

771 **Pension Administration**

772 **Q. What directives did the order in Docket No. 09-035-23 include regarding**
 773 **pension administration costs?**

774 **A.** In that order the Commission requested that future filings include analysis on
 775 pension administration costs in order to determine if those costs should be
 776 averaged over a period of several years.

777 **Q. In preparation for this general rate case, did the Company examine the base**
778 **period pension administration costs in a historical context?**

779 A. Yes. The pension administration expense was approximately \$310k in the 12
780 months ended June 30, 2010. By comparison, the pension administration expense
781 was \$623k and \$535k in the 12 months ended June 2008 and June 2009,
782 respectively. Applying an average would increase the pension expense by \$178k
783 or 58 percent. Therefore, the Company recommends that the test period level of
784 pension administration expense be held constant at the base period level.

785 **Utah Results of Operations**

786 **Q. Please describe Exhibit RMP___(SRM-3).**

787 A. Exhibit RMP___(SRM-3), which was prepared under my direction, is Rocky
788 Mountain Power's Utah results of operations report (the "Report"). The historical
789 starting point for the Report is the 12 months ended June 30, 2010, which was
790 normalized and used to calculate the revenue requirement for the Test Period, the
791 12 months ending June 30, 2012. The Report provides totals for revenue,
792 expenses, depreciation, net power costs, taxes, rate base, and loads in the Test
793 Period. Electric plant in service, accumulated depreciation, and amortization
794 reserve balances are calculated using a thirteen month average. All other rate base
795 items use a June 2010 historical average starting point and if applicable are
796 forecasted out to a June 2011 and June 2012 average amount. The Report presents
797 operating results for the period in terms of both return on rate base and ROE.

798 **Q. Please describe how Exhibit RMP___(SRM-3) is organized.**

799 A. The Report is organized into sections marked with tabs. Tab 1 Summary contains

800 the Utah-allocated results according to the Revised Protocol allocation
801 methodology. Page 1.0 is the calculation of the Revised Protocol price change
802 (plus the Rate Mitigation Premium) of \$232.4 million. It details the calculation of
803 the Rate Mitigation Premium along with the Rate Mitigation Cap and compares
804 the results to determine the lesser of the two. Page 1.1, starting with the left-hand
805 column 1 labeled Total Adjusted Results, displays the Utah results of operations
806 for the Test Period. The Total Adjusted Results column is carried forward from
807 the results of operations summary, page 2.2, and shows a ROE for Utah of 5.5
808 percent. The Price Change (column 2 of Tab 1, page 1.1) shows that an increase
809 of \$228.8 million in revenue is required to increase the return on equity from 5.5
810 percent to 10.5 percent in Utah. Column 3 reflects the Utah adjusted revenue
811 requirement of \$1.93 billion with the \$228.8 million price increase included. Page
812 1.2 of Tab 1 supports the calculation of additional revenue-related uncollectible
813 expense and franchise taxes associated with the price change requested in column
814 2. Page 1.3 details the calculation of the net operating income percentage. Page
815 1.4 shows the same details as page 1.1 under the Rolled-In rather than the Revised
816 Protocol allocation method. It is used in calculating the Rate Mitigation Cap on
817 page 1.0. Pages 1.5 through 1.6 contain a summary of adjustments made to the
818 actual results to arrive at the Test Period.

819 Tab 2 details Total Company and Utah-allocated results based on the
820 Revised Protocol allocation methodology. Pages 2.3 through 2.39 contain Total
821 Company and Utah-allocated revenue, expenses and rate base detail by FERC
822 account. Unadjusted results of operations are supplied side-by-side with the Test

823 Period results, on both a total Company and Utah-allocated basis.⁸ Supporting
824 documentation for the data in Tab 2, along with the normalizing adjustments
825 required to reflect on-going costs of the Company, is provided under Tabs 3
826 through 8. The calculation of these adjustments is described later in my testimony.
827 Tab 9 is Tab 2 restated with the Utah allocation based on the Rolled-In allocation
828 method and Tab 10 is Tab 2 restated with the Utah allocation based on the
829 Company's proposed 2010 Protocol allocation method. Tab 11 contains the
830 calculation of the Revised Protocol allocation factors.

831 **Tab 3 – Revenue Adjustments**

832 **Q. Please describe the information contained behind Tab 3 Revenue**
833 **Adjustments.**

834 A. Tab 3 begins with the Revenue Adjustment Index (page 3.0.1) followed by a
835 numerical summary and the specific adjustments. The numerical summary (page
836 3.0.2) identifies each adjustment made to actual revenues, and the adjustment's
837 impact on the case. Each column has a numerical reference to a corresponding
838 page in Exhibit RMP___(SRM-3), which contains a lead sheet showing the
839 affected FERC account(s), allocation factor, dollar amount and a brief description
840 of the adjustment.

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

842 A. **Proforma Revenue (page 3.1)** – This adjustment begins with June 2010 general
843 business revenues and adjusts to the pro forma level for the 12 months ending
844 June 2012 based on forecasted loads. Revenue for the Company's other
845 jurisdictions during the Test Period is also computed. Several items are removed

⁸ In conformance with filing requirement R746-700-22.B.1.

846 from actual booked revenue that should not be included in regulatory results,
847 including SMUD regulatory liability amortization and out-of-period revenue. Test
848 Period revenue reflects price changes effective January 1, 2011, from the
849 Company's recent major plant addition filings as approved by the Commission in
850 Docket No. 10-035-89.

851 **Wheeling Revenue (page 3.2)** – This adjustment reflects the level of wheeling
852 revenues the Company expects in the 12 months ending June 30, 2012 by
853 adjusting the actual revenues for normalizing, annualizing, and pro forma
854 changes.

855 **SO₂ Emission Allowances (page 3.3)** – The Environmental Protection Agency
856 (“EPA”) has established guidelines that govern the volume of sulfur dioxide
857 (“SO₂”) that can be emitted from power plants and granted the issuance of SO₂
858 emission allowances to cover each ton emitted. Plants that are not in compliance
859 with EPA guidelines may purchase emission allowances from other companies
860 that have excess allowances. Consistent with the Commission order in Docket No.
861 97-035-01, the Company has amortized sales of emission allowances over a four-
862 year period. This adjustment replaces the sales from the historical period with the
863 appropriate annual amortization, taking into account projected sales through the
864 Test Period.

865 **REC Revenue (page 3.4)** – A market for green tags or Renewable Energy Credits
866 (“REC”) has developed where the green traits of qualifying power production
867 facilities can be sold. These RECs may be used to meet renewable portfolio
868 standards in various states. To comply with current or future year renewable

869 portfolio requirements in California, Oregon, and Washington, during the Test
870 Period the Company will not sell the portion of eligible RECs allocated to those
871 states. This adjustment ensures Test Period REC revenue is correctly allocated
872 among the Company's jurisdictions after considering the banking of eligible
873 RECs. Company witness Mr. Stefan A. Bird supports the development of the total
874 Company REC revenue forecast for the Test Period.

875 **Joint Use Revenue (page 3.5)** – This adjustment reflects the impact of the
876 Company's proposed change to Electric Service Schedule No. 4 – Pole
877 Attachments. The Company's proposal includes an increase in the per-pole
878 attachment rate from \$7.02 to \$8.10. Company witness Mr. Jeffrey M. Kent
879 provides the details of the Company's proposed changes to Schedule No. 4.

880 **Ancillary Revenue (page 3.6)** – An existing ancillary revenue contract will
881 terminate December 31, 2011. This adjustment reduces ancillary revenue booked
882 for this contract as of June 30, 2010 by 50 percent to reflect an expected level
883 through the Test Period.

884 **Tab 4 – O&M Adjustments**

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

886 A. Tab 4 includes the O&M Index (page 4.0.1) followed by a numerical summary
887 and the specific adjustments. The numerical summary (pages 4.0.2 – 4.0.4)
888 identifies each adjustment made to actual operations, maintenance, administrative,
889 and general expenses and that adjustment's impact on the case. Each column has a
890 numerical reference to a corresponding page in Exhibit RMP____(SRM-3), which
891 contains a lead sheet showing the affected FERC account(s), allocation factor,

892 dollar amount, and a brief description of the adjustment.

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

894 **A. Miscellaneous General Expense (page 4.1)** – This adjustment removes certain
895 miscellaneous expenses that should have been charged below-the-line to non-
896 regulated expenses.

897 As part of this adjustment the Company is including in results the cost of
898 subsidized sub-leases provided by the Company to the Economic Development
899 Corporation of Utah (“EDCU”) and Utah Sports Authority for office space in the
900 One Utah Center. The Company sub-lets the office space for \$1 per month rent
901 plus operating expenses. These leases are provided by the Company as challenge
902 grants, and the expense is situs assigned to Utah in FERC account 930. The
903 Commission did not allow recovery of these costs in the Company’s 09-035-23
904 general rate case due in part because the Company agreed to adjustments for
905 vacant office space in prior cases which also removed these costs. The Company
906 does not believe these costs should be removed because these costs are prudent
907 and in the customers best interest and are costs that benefit our Utah customers
908 and the state as a whole. The Company has worked with economic development
909 organizations throughout the service territory in an effort to: 1) provide accurate
910 and timely information to companies considering expansion or relocation to the
911 Company’s service territory; 2) help direct companies to locations where
912 sufficient capacity exists to meet their needs at an acceptable cost; and 3)
913 influence economic development policies that impact the overall cost of energy to
914 existing electric customers. Making contributions to EDCU and other entities by

915 absorbing these lease expenses is a key element to partnering with economic
916 development organizations that, in effect, become an industrial customers first
917 point of contact in the state. If these expenses are not allowed to be recovered in
918 rates the Company may be forced to cancel or renegotiate these contracts.

919 **Irrigation Load Control Program (page 4.2)** – Incentive payments made to
920 Idaho customers participating in the irrigation load control program are initially
921 system allocated in unadjusted data. This adjustment assigns these costs directly
922 to Idaho consistent with other demand side management programs. As discussed
923 earlier, some Idaho parties filed testimony in the current Idaho general rate case
924 requesting that the Idaho Irrigation Load Program be treated as a system cost, and
925 discussions are ongoing at the MSP standing committee on this issue.

926 **Non-Recurring Entries (page 4.3)** – A few accounting entries were made to
927 expense accounts during the 12 months ended June 2010 that are non-recurring in
928 nature or relate to a prior period. These transactions are removed from results of
929 operations to normalize the Test Period results. Details on the specific items in the
930 adjustment can be found on page 4.3.1 of Exhibit RMP___(SRM-3).

931 **MEHC Cross Charge (page 4.4)** – As explained earlier in my testimony the
932 commitment limiting the amount of charges to PacifiCorp from MEHC expires
933 March 21, 2011. In this case the Company is including amounts actually booked
934 in the year ended June 30, 2010, after removing an amount that should have been
935 booked below the line.

936 **DSM Expense and Revenue Removal (page 4.5)** – This adjustment removes
937 from regulated results revenues and expenses related to demand-side management

938 (“DSM”) programs in various states because the costs are recovered via separate
939 surcharges and are not included in base rates. As ordered in Decision No. 09-038-
940 T08, a \$10.85 million write-off related to the SMUD liability was made through
941 the Utah DSM account in February 2010. An offsetting amount was booked to
942 retail revenue and is removed in Adjustment 3.1.

943 **Generation Overhaul Expense (page 4.6)** – This adjustment normalizes
944 generation overhaul expenses using a four year average methodology. Overhaul
945 expenses from the years ended June 2007 through June 2010 are averaged. For
946 new generating units (Currant Creek, Lake Side, and Chehalis) where a four year
947 history is not available, the four year average is comprised of the overhaul
948 expense planned for the first four full years these plants are operational. The
949 actual overhaul costs for the year ended June 2010 are subtracted from the four
950 year average to arrive at this adjustment.

951 The Company’s use of a four-year historical average was approved by the
952 Commission in Docket No. 07-035-93, as was the use of a four-year average of
953 planned expenses for the Company’s new gas plants. This treatment, including
954 escalation of the historical components of the average, was utilized in the
955 Company’s filings in Docket Nos. 08-035-38 and 09-035-23, but the Commission
956 did not allow escalation to be applied in its final order in Docket No. 09-035-23.
957 The Company continues to believe that the purpose of averaging is to adjust for
958 uneven costs, not to adjust for inflation and that without escalation overhaul
959 expenses will be systematically understated. However, consistent with the

960 Commission order, the Company has not applied escalation prior to averaging in
961 this case.

962 **MEHC Transition Savings (page 4.7)** – This adjustment removes from the
963 historical results an entry crediting expense to establish an Oregon MEHC
964 change-in-control severance regulatory asset.

965 **Cool Keeper Call Center Labor (page 4.8)** – Starting in January 2010, contact
966 center labor costs associated with maintaining participant agreements, removals,
967 customer data reconciliation, and various other administrative tasks for the Cool
968 Keeper air conditioning load control program in Utah are charged directly to the
969 program and recovered through Utah's system benefit charge. This adjustment
970 removes Cool Keeper related call center labor expenses incurred prior to the
971 accounting change.

972 **Solar Photovoltaic Program (page 4.9)** – This adjustment reflects the contracted
973 annual program costs associated with the pilot Solar Photovoltaic Utility Buy-
974 down Program which is co-sponsored by Utah Clean Energy and Rocky Mountain
975 Power. This pilot solar photovoltaic project was implemented in September 2007
976 and is projected to operate at similar funding levels through 2011. The project
977 gathered important information on the viability of a solar program funded by
978 participating customers, tax incentives and a utility contribution. The project also
979 provided technical information on the integration of distributed solar resources
980 into the Rocky Mountain Power system. This adjustment removes the O&M
981 expenses incurred in the year ended June 2010 and includes \$73,635 to reflect the
982 balance of the program uncollected costs to be recovered after new rates become

983 effective in 2011. A pro rata share of the annual \$20,000 internal administrative
984 expenses allowed are also assigned to this project and situs assigned to Utah.

985 **Advertising Expense (page 4.10)** – This adjustment removes general rate case
986 advertising that was system allocated and assigns the costs directly to the
987 jurisdiction the advertising was for. The Company agreed to this adjustment as
988 part of the settlement reached in Docket No. 08-035-38. As of January 1, 2010,
989 these costs are situs assigned in unadjusted results. The adjustment also removes
990 promotional and institutional advertising costs deemed non-recoverable per Utah
991 Rule R746-406 as well as costs for advertising ordered by the Wyoming Public
992 Service Commission that should not be allocated to Utah.

993 **Insurance Expense (page 4.11)** – This adjustment normalizes injury and damage
994 expenses to reflect a three year average using the cash method, consistent with the
995 Utah Commission ruling in Docket No. 07-035-93. This adjustment also
996 normalizes property and liability insurance expenses to reflect the elimination of
997 the current captive insurance company replaced with self-insurance accruals as
998 described earlier in my testimony.

999 **O&M Expense Escalation (page 4.12)** – This adjustment revises non-labor
1000 expenses for projected price changes through the Test Period. Changes are based
1001 on indices produced by IHS Global Insight, which provides a detailed assessment
1002 of the electric market both historically and into the future. The Company applies
1003 the IHS Global Insight indices to costs for materials and services only. Labor-
1004 related expenses are segregated from non-labor-related expenses and are escalated
1005 separately as described earlier in my testimony.

1006 IHS Global Insight's indices are prepared at the FERC functional
1007 subcategory level and are denoted with their corresponding FERC account
1008 number. The individual FERC account level indices are then combined into
1009 broader indices representing operation, maintenance, or total operation and
1010 maintenance expenses. The IHS Global Insight data is proprietary and subject to
1011 copyright protection. The indices utilized in the Company's filing are provided in
1012 Confidential Exhibit RMP____(SRM-4).

1013 **Utah Automated Meter Reading ("AMR") Program (page 4.13)** – Two new
1014 automated meter reader programs were launched in Utah between July 2009 and
1015 June 2010 for the Tremonton, Laketown, Cedar City and Smithfield areas. The
1016 meters enable the Company to remotely obtain energy usage information and
1017 allow the Company to take advantage of a proven technology to increase
1018 effectiveness and efficiency, improve customer satisfaction and reduce safety
1019 exposures for employees. Starting in November 2009, the Company completed
1020 approximately 9,452 new meter installations in the Tremonton and Laketown
1021 districts. In addition, the Company reduced its workforce by two meter readers.
1022 Starting in March 2010, the Company began the installation of approximately
1023 29,327 automated readers in the Cedar City and Smithfield districts. As a result, it
1024 reduced its workforce by six meter readers. This adjustment reflects the reduction
1025 in meter reading expense the Company anticipates as a result of the program
1026 through June 2012. The associated meter additions and retirements are reflected in
1027 Adjustment 8.8.

1028 **Pension Curtailment and Date Change (page 4.14)** – The Commission's order

1029 in Docket No. 08-035-93 approved a stipulation permitting deferral and
1030 amortization of the pension curtailment gain resulting from employee
1031 participation in the 401(k) retirement plan option and for deferral and
1032 amortization of the increase in the pension and other postretirement welfare
1033 expense caused by the change in the annual measurement date mandated by FAS
1034 158. Amortization of the measurement date change began on the books effective
1035 January 1, 2008. Amortization of the curtailment began on the books effective
1036 January 1, 2009. This adjustment removes the base period amortization and
1037 replaces it with the Test Period amortization.

1038 **Incremental Generation and Transmission O&M (page 4.15)** – This
1039 adjustment annualizes incremental O&M from new plant in service,
1040 improvements to plants, and transmission projects that were placed into service
1041 during the 12 months ended June 2010. It also includes projected O&M for
1042 projects placed into service prior to the end of the Test Period. The adjustment
1043 also captures changes in costs at three existing facilities: first, in the second half
1044 of 2010 the cost of chemicals used at the Cholla IV scrubber will increase due to a
1045 change in the fuel source that will require increased pollution control; second,
1046 expenses are reduced because the Company plans to retire the Little Mountain
1047 plant in March 2012 after the current steam sale contract expires; and third, the
1048 Company recently amended the Lake Side plant's managed long term gas turbine
1049 parts and service contract with Siemens which will cause an increase in O&M
1050 during the Test Period.

1051 **Wage & Employee Benefits (page 4.16)** – Labor-related costs for the Test

1052 Period are computed by adjusting salaries, incentives, benefits, and costs
1053 associated with FAS 87 (pension), FAS 106 (post retirement benefits) and FAS
1054 112 (post employment benefits) for changes expected beyond the actual costs
1055 experienced in the year ended June 2010. Union contract agreements and planned
1056 rates are used to escalate union labor group wages, while increases for non-union
1057 and exempt employees were based on planned increases. Incentive compensation,
1058 used by the Company to deliver market competitive pay structured in a manner
1059 that benefits customers with safe, adequate, and reliable electric service at a
1060 reasonable cost, is included at the target level for the Test Period. Pension
1061 expense and other employee benefit costs were also itemized starting with the
1062 year ended June 2010 and adjusted to the planned expense for the Test Period.
1063 This adjustment is further supported by the testimony of Company witness Mr.
1064 Erich Wilson.

1065 Page 4.16.1 provides further description of the procedure used to compute
1066 Test Period labor costs. Page 4.16.2 of Exhibit RMP___(SRM-3) starts with a
1067 numerical summary of actual labor costs and summarizes the adjustments made to
1068 project costs to reflect the Test Period expense. This summary is followed by the
1069 detailed worksheets on pages 4.16.3 through 4.16.12 used to adjust the labor costs
1070 forward to the Test Period.

1071 **Tab 5 – Net Power Cost Adjustments**

1072 **Q. Please describe the information contained behind Tab 5 Net Power Cost**
1073 **Adjustments.**

1074 **A.** Tab 5 includes the Net Power Cost Index (page 5.0.1) followed by a numerical

1075 summary and the specific adjustments. The numerical summary (page 5.0.2)
1076 identifies each adjustment made to actual expenses and that adjustment's impact
1077 on the case. Each column has a numerical reference to a corresponding page in
1078 Exhibit RMP____(SRM-3), which contains a lead sheet showing the affected
1079 FERC account(s), allocation factor, dollar amount, and a brief description of the
1080 adjustment.

1081 **Q. Please describe the adjustments included in Tab 5.**

1082 A. **Net Power Cost Study (page 5.1)** – The net power cost adjustment normalizes
1083 steam and hydro power generation, fuel, purchased power, wheeling expense, and
1084 sales for resale in a manner consistent with the contractual terms of the
1085 Company's sales and purchase agreements. It also normalizes hydro, weather
1086 conditions, and plant availability as described in Mr. Duvall's testimony.

1087 **James River Royalty Offset & Little Mountain (page 5.2)** – On January 13,
1088 1993, the Company executed a contract with James River Paper Company with
1089 respect to the Camas mill, later acquired by Georgia Pacific. Under the
1090 agreement, the Company built a steam turbine and is recovering the capital
1091 investment over the 20-year operational term of the agreement as an offset to
1092 royalties paid to James River based on contract provisions. The contract costs of
1093 energy for the Camas unit are included in the Company's net power costs as
1094 purchased power expense, but GRID does not include an offsetting revenue credit
1095 for the capital and maintenance cost recovery. This adjustment adds the royalty
1096 offset to FERC Account 456, other electric revenue, for the Test Period.

1097 This adjustment also normalizes the level of steam revenue related to the

1098 Little Mountain plant. Contractually, steam revenue from Little Mountain is tied
1099 to natural gas prices. The Company's net power cost study includes the cost of
1100 running the Little Mountain plant but does not include the offsetting steam
1101 revenue. This adjustment aligns the steam revenue to the gas prices modeled in
1102 GRID and reflects the termination of the sales agreement effective February 2012.
1103 **Electric Lake Settlement (page 5.3)** – Canyon Fuel Company (“CFC”) owns the
1104 Skyline mine located near Electric Lake, a reservoir owned by the Company
1105 which provides water storage for the Huntington generating plant. The two
1106 companies disputed the claim made by PacifiCorp that CFC's mining operations
1107 caused the lake to leak water into the Skyline mine, thus making it unavailable for
1108 use by the Huntington generating plant. The Company incurred capital costs and
1109 O&M costs to pump water from the breach back into Electric Lake. The two
1110 companies negotiated a settlement of the claims which included reimbursement to
1111 the Company for O&M and capital costs associated with the pumping. The three
1112 year amortization of this settlement ended in December 2010. Therefore, this
1113 adjustment removes amounts included in historical results in order to properly
1114 reflect the Test Period in this case.

1115 **Tab 6 – Depreciation and Amortization Expense Adjustments**

1116 **Q. Please describe the information contained behind Tab 6 Depreciation and**
1117 **Amortization Adjustments.**

1118 A. Tab 6 includes the Depreciation and Amortization Index (page 6.0.1) followed by
1119 a numerical summary and the specific adjustments. The numerical summary (page
1120 6.0.2) identifies each adjustment made to actual results and that adjustment's

1121 impact on the case. Each column has a numerical reference to a corresponding
1122 page in Exhibit RMP____(SRM-3), which contains a lead sheet showing the
1123 affected FERC account(s), allocation factor, dollar amount, and a brief description
1124 of the adjustment.

1125 **Q. How are the Company's pro forma depreciation and amortization expense**
1126 **for the Test Period developed in the Report?**

1127 A. The depreciation and amortization expense for the Test Period is calculated by
1128 applying functional composite depreciation and amortization rates to projected
1129 plant balances. Rates used are those approved by the Commission in Docket No.
1130 07-035-13, effective January 1, 2008. Depreciation expense also includes the
1131 accrual for hydro decommissioning as approved in Docket No. 07-035-13. Details
1132 are provided on pages 6.1.2 through 6.1.17.

1133 **Q. How are the accumulated depreciation and amortization balances included**
1134 **in the filing calculated?**

1135 A. Accumulated depreciation and amortization balances for the Test Period are
1136 calculated by applying pro forma depreciation and amortization expense and plant
1137 retirements to the actual June 2010 balances. Accruals and planned spending for
1138 hydro decommissioning are also included in the adjusted depreciation reserve
1139 balance. The reserve balances are calculated on a monthly basis to walk the
1140 balances forward from June 30, 2010, through June 30, 2012. The 13-month
1141 average reserve balance is included in rate base. Calculations are detailed on
1142 pages 6.2.2 to 6.2.13.

1143 **Tab 7 – Tax Adjustments**

1144 **Q. Please describe the information contained behind Tab 7 Tax Adjustments.**

1145 A. Tab 7 includes the Tax Adjustment Index (page 7.0.1) followed by a numerical
1146 summary and the specific adjustments. The numerical summary (pages 7.0.2 –
1147 7.0.3) identifies each adjustment made to the various tax components and that
1148 adjustment’s impact on the case. Each column has a numerical reference to a
1149 corresponding page in Exhibit RMP____(SRM-3), which contains a lead sheet
1150 showing the affected FERC account(s), allocation factor, dollar amount, and a
1151 brief description of the adjustment.

1152 **Q. Please describe the adjustments included in Tab 7.**

1153 A. **Interest True-Up (page 7.1)** – This adjustment details the adjustment to interest
1154 expense required to synchronize the Test Period expense with rate base. This is
1155 done by multiplying normalized net rate base by the Company’s weighted cost of
1156 debt in this case.

1157 **Renewable Energy Tax Credit (page 7.2)** – The Company is entitled to
1158 recognize certain tax credits as a result of placing qualifying renewable generating
1159 plants into service. The federal tax credit is based on the generation of the plant,
1160 and the credit can be taken for ten years on qualifying property. Under the
1161 calculation required by Internal Revenue Service Code Sec. 45(b)(2), the current
1162 renewable electricity production credit is 2.2 cents per kilowatt hour. The Utah
1163 state tax credit is based on the generation of the Blundell bottoming cycle, and the
1164 credit can be taken for four years. In addition to the Utah tax credit, the Company
1165 is able to recognize the Oregon Business Energy Tax Credit which is based on

1166 investment in specific plants and is taken over a five year period on qualifying
1167 property.

1168 **Allowance for Funds Used During Construction (“AFUDC”) Equity (page**
1169 **7.3)** – This adjustment aligns the amount of AFUDC equity in regulatory income
1170 with the related tax Schedule M item. Consistent with the stipulation approved by
1171 the Commission in Docket No. 09-035-03, AFUDC equity is treated on a flow
1172 through basis rather than normalized for tax purposes.

1173 **Accumulated Deferred Income Tax (“ADIT”) Corrections (page 7.4)** – This
1174 adjustment corrects allocation factors assigned to certain accumulated deferred
1175 income tax balances.

1176 **Property Tax Expense (page 7.5)** – Property tax expense for the Test Period was
1177 computed by adjusting actual property tax expense for known or anticipated
1178 changes in assessment levels through June 30, 2012. The property tax costs in this
1179 case were estimated using methods similar to those employed by the Company
1180 when estimating property tax costs in Docket Nos. 07-035-93, 08-035-38, and 09-
1181 035-23. These methods give necessary consideration to the effect that changes in
1182 the level of operating property and net operating income may have on state-by-
1183 state assessed values. Confidential Exhibit RMP__(SRM-5) provides a
1184 comprehensive description of the Company’s property tax estimation procedures
1185 along with a detailed calculation of Test Period property taxes.

1186 **Non-Deductible Post-Retirement Benefits (page 7.6)** – As established in
1187 Docket No. 10-035-38, this adjustment recognizes the amortization of the
1188 regulatory asset related to the Medicare tax deferral for the 12-months ending

1189 June 2012.
1190 **Pro Forma Deferred Tax Expense (page 7.7)** – Non-property-related Schedule
1191 M items in the Test Period were used to develop the deferred income tax expense.
1192 Property-related deferred income tax expense was generated using the capital
1193 additions and resulting book and tax depreciation. Normalizing adjustments were
1194 added consistent with the Schedule M items.

1195 **Pro Forma Deferred Tax Balance (page 7.8)** – The deferred income tax
1196 expense was used to develop the deferred tax balance for the Test Period. This
1197 adjustment normalizes the accumulated deferred income tax balances to the
1198 estimated proforma level of beginning/ending average rate base balance for the
1199 Test Period. The allocation of property-related deferred income tax balances is
1200 also updated consistent with the Company’s Power Tax model.

1201 Recently, Congress has reinstated bonus depreciation for the calendar
1202 years 2010, 2011, and 2012. For qualified property placed in service on or after
1203 September 9, 2010, through December 31, 2011, 100 percent of the tax basis is
1204 deductible as bonus depreciation. For qualified property placed in 2010 through
1205 2012, but before or after this period, 50 percent of the tax basis is deductible as
1206 bonus depreciation. The deferred tax balances in this general rate case include the
1207 tax benefits of the recently reinstated bonus depreciation.

1208 **Pro Forma Schedule M’s (page 7.9)** – The Schedule M items at June 31, 2010
1209 were updated for known and measurable adjustments through June 30, 2012.
1210 Non-utility items, separate tariff items and other non-recurring items were
1211 removed from the June 30, 2010, historical period before updating. The Schedule

1212 M items were then used to develop deferred income tax expenses and balances for
1213 June 30, 2012.

1214 **Q. How have current state and federal income tax expenses been calculated?**

1215 A. Current state and federal income tax expenses were calculated by applying the
1216 applicable tax rates to the taxable income calculated in the Report. Federal
1217 income tax expense is calculated using the same methodology that the Company
1218 uses in preparing its filed income tax returns. Under the Revised Protocol state
1219 income tax expense is calculated using the state statutory rates applied to the
1220 jurisdictional pre-tax income. The result of accumulating those state tax expense
1221 calculations is allocated among the jurisdictions using the Income Before Tax
1222 (“IBT”) factor. The detail supporting these calculations is contained on pages 2.18
1223 through 2.20.

1224 Under the Rolled In methodology state income tax expense is calculated
1225 the same way described above for Revised Protocol. However, under the
1226 Company’s proposed 2010 Protocol allocation methodology, state income tax
1227 expense is calculated using the Company’s weighted statutory state tax rate of
1228 4.54 percent applied to each jurisdiction’s pre-tax income. The Company
1229 proposed this calculation because it is consistent with the way the Company
1230 calculates tax impacts for its accounting books and it avoids swings in the IBT
1231 factor that are caused more by modeling assumptions than actual changes in
1232 underlying jurisdictional income before taxes.

1233 **Q. Docket No. 09-035-03 recently addressed deferred tax normalization as it**
1234 **relates to the Company's Utah results of operations. Does the revenue**
1235 **requirement in this case reflect the outcome of that Docket?**

1236 A. Yes. The settlement agreement reached in Docket No. 09-035-03 was
1237 incorporated into the Company's rebuttal filing in its last general rate case,
1238 Docket No. 09-035-23, and was approved in the Commission's final order. The
1239 Test Period in this case is consistent with that stipulation.

1240 **Tab 8 – Rate Base Adjustments**

1241 **Q. Please describe the information contained behind Tab 8 Rate Base**
1242 **Adjustments.**

1243 A. Tab 8 includes the Rate Base Adjustment Index (page 8.0.1) followed by a
1244 numerical summary and the specific adjustments. The numerical summary (pages
1245 8.0.2 – 8.0.3) identifies each adjustment made to actual rate base and that
1246 adjustment's impact on the case. Each column has a numerical reference to a
1247 corresponding page in Exhibit RMP___(SRM-3), which contains a lead sheet
1248 showing the affected FERC account(s), allocation factor, dollar amount, and a
1249 brief description of the adjustment.

1250 **Q. Please describe each of the adjustments to the historical rate base balances.**

1251 A. **Cash Working Capital (page 8.1)** – This adjustment supports the calculation of
1252 cash working capital included in rate base using the normalized results of
1253 operations for the Test Period. Total cash working capital is calculated by
1254 multiplying jurisdictional net lag days by the average daily cost of service. Net lag
1255 days in this case are based on the lead lag study recently prepared by the

1256 Company using calendar year 2007 information. Based on the results of the 2007
1257 lead lag study and subsequent revisions proposed by the DPU in Docket No. 08-
1258 035-38 the Company experiences 5.6 net lag days in Utah requiring a cash
1259 working capital balance of \$19.2 million to be included in rate base.

1260 **Trapper Mine Rate Base (page 8.2)** – The Company owns a 21.4 percent share
1261 of the Trapper Mine, which provides coal to the Craig generating plant. This
1262 investment is accounted for on the Company's books in FERC Account 123.1,
1263 investment in subsidiary company, which is not included as a rate base account.
1264 The normalized coal cost from Trapper Mine in net power costs includes O&M
1265 costs but does not include a return on investment. This adjustment adds the
1266 Company's portion of the Trapper Mine net plant investment to rate base in order
1267 for the Company to earn a return on its investment. This treatment is consistent
1268 with Docket No. 99-035-10 and the Company's general rate cases since that time.

1269 **Jim Bridger Mine Rate Base (page 8.3)** – The Company owns a two-thirds
1270 interest in the Bridger Coal Company, which supplies coal to the Jim Bridger
1271 generating plant. The Company's investment in Bridger Coal Company is not
1272 included in electric plant in service. This adjustment is necessary to properly
1273 reflect the Bridger Coal Company investment in rate base in order for the
1274 Company to earn a return on its investment. The normalized coal costs for Bridger
1275 Coal Company in net power costs include the O&M costs of the mine but provide
1276 no return on investment. This treatment is consistent with Docket No. 97-035-01
1277 and the Company's general rate cases since that time.

1278 **Environmental Settlement (PERCO) (page 8.4)** – In 1996, the Company

1279 received an insurance settlement of \$33 million for environmental clean-up
1280 projects. These funds were transferred to a subsidiary called PacifiCorp
1281 Environmental Remediation Company (“PERCO”). This fund balance is
1282 amortized or reduced as PERCO expends dollars on clean-up costs. PERCO
1283 received an additional \$5 million of insurance proceeds plus associated liabilities
1284 from Rocky Mountain Power in 1998. This adjustment includes the unspent
1285 insurance proceeds in results of operations as a reduction to rate base.

1286 **Customer Advances for Construction (page 8.5)** – Customer advances for
1287 construction are booked into FERC Account 252. When they are booked, the
1288 entries do not reflect the proper allocation. This adjustment corrects the allocation
1289 of customer advances for construction in account 252.

1290 **Goose Creek Transmission (page 8.6)** – On April 1, 2008, the Company sold its
1291 undivided interest in 13.85 miles of transmission line, running from the
1292 Company's Goose Creek switching station and extending north to the Decker 230
1293 kV substation near Decker, Montana. The assets sold included structures,
1294 miscellaneous support equipment, easements, and rights-of-way associated with
1295 the transmission line. The sale of the transmission line resulted in the Goose
1296 Creek switching station no longer being needed or useful to the Company. The
1297 Company plans to remove the Goose Creek switching station including all above
1298 ground facilities. This adjustment reduces rate base by the net book value of the
1299 switching station assets. Depreciation expense booked in the 12 months ended
1300 June 30, 2010, is removed in Adjustment 6.1.

1301 **Customer Service Deposits (page 8.7)** – Utah requires the Company to include

1302 customer service deposits as a reduction to rate base. This adjustment reflects the
1303 deposits in results as a rate base deduction and also includes the interest paid on
1304 the customer service deposits in expense. This treatment was stipulated in Utah
1305 Docket No. 97-035-01 and has been upheld in subsequent dockets.

1306 **Pro Forma Plant Additions and Retirements (page 8.8)** – To reasonably
1307 represent the cost of system infrastructure required to serve customers the
1308 Company has identified capital projects that will be completed by the end of the
1309 Test Period. Company business units identified capital expenditures that will be
1310 used and useful prior to the end of the Test Period. Additions by functional
1311 category are summarized on separate sheets, indicating the in-service date and
1312 amount by project. The accumulated depreciation reserve was adjusted forward to
1313 match the depreciation expense and retirements as described earlier in the
1314 depreciation section.

1315 Composite plant retirement rates were applied to pro forma plant balances
1316 included in this filing to reflect ongoing asset retirements through the Test Period.
1317 This adjustment reflects these retirements into results for the gross electric plant
1318 in service. A corresponding entry to accumulated depreciation and amortization is
1319 included in the calculation of Test Period reserve balances in Adjustment 6.2.

1320 **Miscellaneous Rate Base (page 8.9)** – This adjustment walks forward into the
1321 Test Period the balances in fuel stock and prepaid overhauls. The cost of the
1322 Company's coal plant fuel stock is increasing due to increases in the cost of coal.
1323 In order to avoid earning a double return on rate base, balances for prepaid
1324 overhauls at the Lake Side, Chehalis and Currant Creek gas plants are walked

1325 forward to reflect payments and transfers of capital to electric plant in service
1326 during the 12 months ending June 2012.

1327 **Powerdale Hydro Removal (page 8.10)** – Powerdale is a hydroelectric
1328 generating facility located on the Hood River in Oregon. This facility was
1329 scheduled to be decommissioned in 2010; however, in 2006 a flash flood washed
1330 out a major section of the flow line. The Company determined that the cost to
1331 repair this facility was not economical and determined it was in the ratepayers’
1332 best interest to cease operation of the facility.

1333 In Docket No. 07-035-14, the Company requested permission to transfer
1334 the net book value, including an offset for insurance proceeds, of the assets to an
1335 unrecovered plant regulatory asset and asked the Commission to establish an
1336 amortization period for the asset. In that Docket, the Commission approved the
1337 Company’s request regarding the unrecovered plant and also allowed the
1338 Company to defer future decommissioning costs to a regulatory asset. In the order
1339 for Docket No. 07-035-93, the Commission further specified that the regulatory
1340 asset for the decommissioning costs could be amortized over three years
1341 beginning January 1, 2008. This adjustment reflects the plant balances and
1342 amortization expense in the Test Period consistent with the previous Commission
1343 orders.

1344 **Regulatory Assets (page 8.11)** – This adjustment incorporates known and
1345 measurable changes to regulatory assets not addressed elsewhere in results.
1346 Amortization expense is reflected at the level expected in the test period and rate
1347 base is walked forward to its average balance over the test period. Assets

1348 impacted include Trojan unrecovered plant and decommissioning costs, Glenrock
1349 mine closure costs, and Cholla transaction costs. Balances in the electric plant
1350 acquisition adjustment and weatherization related assets are also walked forward
1351 through the Test Period.

1352 **Klamath Hydroelectric Settlement Agreement (page 8.12)** – During FERC
1353 relicensing proceedings, settlement discussions occurred among PacifiCorp and
1354 other stakeholders to remove the Klamath Project. Company witness Mr. Dean S.
1355 Brockbank describes the relicensing and settlement process and the resulting
1356 settlement agreement, the Klamath Hydroelectric Settlement Agreement
1357 (“KHSA”). This adjustment adds the Klamath Project relicensing and settlement
1358 process costs into rate base and ongoing operation and maintenance expense
1359 associated with the Klamath Project is adjusted to the June 2012 level. Also,
1360 consistent with the KHSA, depreciation of all Klamath Project facilities (existing
1361 assets, relicensing and settlement process costs, and future capital additions) is set
1362 at a level that will fully depreciate the assets by December 31, 2019. Depreciation
1363 associated with the existing Klamath Project facilities is accelerated from current
1364 rates starting January 1, 2011. The Company will monitor the depreciation
1365 expense booked in the future to ensure assets reach a zero net book value by
1366 December 31, 2019.

1367 **Q. Please describe the remaining sections of the Report.**

1368 A. Tab 9 Rolled-In recasts Tab 2 based on the Rolled-In allocation methodology.
1369 This information is being provided pursuant to the Commission order from the
1370 application of the Company for an investigation of inter-jurisdictional issues in

1371 Docket No. 02-035-04. Tab 10 2010 Protocol recasts Tab 2 based on the
1372 Company's proposed 2010 Protocol allocation methodology. Tab 11 Allocation
1373 Factors contains the detailed derivation of the jurisdictional allocation factors
1374 applied to Test Period results using the Revised Protocol allocation methodology.

1375 **Q. Does this conclude your direct testimony?**

1376 A. Yes.