

**STATE OF UTAH**  
**BEFORE THE PUBLIC SERVICE COMMISSION**

**In the Matter of the Application of        )**  
**Rocky Mountain Power for Authority    )**  
**To Increase Its Retail Electric Service   )**  
**Rates In Utah and for Approval of Its   )**  
**Proposed Electric Service Schedules and)**  
**Electric Service Regulations            )**

**Docket No. 09-035-23**

**DIRECT TESTIMONY OF**  
**PAUL CHERNICK**  
**ON BEHALF OF**  
**THE UTAH OFFICE OF CONSUMER SERVICES**

Resource Insight, Inc.

**OCTOBER 8, 2009**

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OCS Exhibit 6.1                      *Professional Qualifications of Paul Chernick*

1 **I. Identification and Qualifications**

2 **Q: Mr. Chernick, please state your name, occupation and business address.**

3 A: I am Paul L. Chernick. I am the president of Resource Insight, Inc., 5 Water  
4 Street, Arlington, Massachusetts.

5 **Q: Summarize your professional education and experience.**

6 A: I received an SB degree from the Massachusetts Institute of Technology in June  
7 1974 from the Civil Engineering Department, and an SM degree from the  
8 Massachusetts Institute of Technology in February 1978 in technology and  
9 policy. I have been elected to membership in the civil engineering honorary  
10 society Chi Epsilon, and the engineering honor society Tau Beta Pi, and to  
11 associate membership in the research honorary society Sigma Xi.

12 I was a utility analyst for the Massachusetts Attorney General for more  
13 than three years, and was involved in numerous aspects of utility rate design,  
14 costing, load forecasting, and the evaluation of power supply options. Since  
15 1981, I have been a consultant in utility regulation and planning, first as a  
16 research associate at Analysis and Inference, after 1986 as president of PLC,  
17 Inc., and in my current position at Resource Insight. In these capacities, I have  
18 advised a variety of clients on utility matters.

19 My work has considered, among other things, the cost-effectiveness of  
20 prospective new generation plants and transmission lines, retrospective review  
21 of generation-planning decisions, ratemaking for plant under construction,  
22 ratemaking for excess and/or uneconomical plant entering service, conservation  
23 program design, cost recovery for utility efficiency programs, the valuation of  
24 environmental externalities from energy production and use, allocation of costs  
25 of service between rate classes and jurisdictions, design of retail and wholesale

26 rates, and performance-based ratemaking and cost recovery in restructured gas  
27 and electric industries. My professional qualifications are further described in  
28 OCS Exhibit.

29 **Q: Have you testified previously in utility proceedings?**

30 A: Yes. I have testified approximately one hundred and ninety times on utility  
31 issues before various regulatory, legislative, and judicial bodies, including the  
32 Arizona Commerce Commission, Connecticut Department of Public Utility  
33 Control, District of Columbia Public Service Commission, Florida Public  
34 Service Commission, Maryland Public Service Commission, Massachusetts  
35 Department of Public Utilities, Massachusetts Energy Facilities Siting Council,  
36 Michigan Public Service Commission, Minnesota Public Utilities Commission,  
37 Mississippi Public Service Commission, New Mexico Public Service  
38 Commission, New Orleans City Council, New York Public Service  
39 Commission, North Carolina Utilities Commission, Public Utilities Commission  
40 of Ohio, Pennsylvania Public Utilities Commission, Rhode Island Public  
41 Utilities Commission, South Carolina Public Service Commission, Texas Public  
42 Utilities Commission, Utah Public Service Commission, Vermont Public Service  
43 Board, Washington Utilities and Transportation Commission, West Virginia  
44 Public Service Commission, Federal Energy Regulatory Commission, and the  
45 Atomic Safety and Licensing Board of the U.S. Nuclear Regulatory  
46 Commission.

47 **Q: Have you testified previously before the Commission?**

48 A: Yes. I testified on behalf of the Utah Office of Consumer Services<sup>1</sup> (“the  
49 Office”) in the following dockets:

50 • Docket No. 98-2035-04, on the proposed acquisition of PacifiCorp by  
51 Scottish Power. My testimony addressed proposed performance standards  
52 and valuation of performance.

53 • Docket No. 99-2035-03, on the sale of the Centralia coal plant. My  
54 testimony addressed the costs of replacement power, the allocation of plant  
55 sale proceeds, and the potential rate impacts on Utah customers of  
56 PacifiCorp’s decision to sell the plant. I testified that the sale of Centralia  
57 was not in the interest of ratepayers and that if the Commission approved  
58 the sale it should allocate more of the sale proceeds to Utah to mitigate  
59 potentially high replacement power costs. The Commission adopted this  
60 latter recommendation as part of approving the sale.

61 • Docket 07-035-93, on the reasonableness of RMP’s Cost-of-Service study,  
62 rate spread and residential rate design proposals.

63 I also assisted the Office in analyzing various issues in the multi-state  
64 process. These issues included resource planning, cost allocation of generation-  
65 and-transmission plant, regulatory policy and risk analysis.

## 66 **II. Introduction**

67 **Q: On whose behalf are you testifying in this rate case proceeding?**

68 A: My testimony is sponsored by the Office of Consumer Services.

69 **Q: What issues does your testimony address?**

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<sup>1</sup> Formerly the Utah Committee of Consumer Services.

70 A: I evaluate the Cost-of-Service Study (“COS Study”) filed by Rocky Mountain  
71 Power (“RMP” or “the Company”) and recommend certain improvements be  
72 made to the Company’s COS Study in the next rate case filing. I also specifically  
73 address the reliability of RMP’s load data for the irrigation class and the  
74 allocation of residential service lines (i.e., shared services).

### 75 **III. Evaluation of RMP’s Cost-of-Service Study**

76 **Q: What is the purpose of the cost-allocation process?**

77 A: The purpose of the cost-allocation process is the fair assignment of the total  
78 Utah jurisdictional revenue requirement to the various tariffed rate classes.<sup>2</sup> A  
79 fundamental principle of the process is that allocation based on cost causation  
80 results in an equitable sharing of embedded costs.

81 **Q: What role should the embedded COS Study play in revenue allocation?**

82 A: Any embedded-cost-based COS Study is approximate and based on judgment.  
83 Therefore, it should serve only as a guide to class rate spread.

84 **Q: Should the Commission expect classification and allocation methods to  
85 change over time?**

86 A: Yes. The COS Study methodology should not be fixed in stone. It should be  
87 updated or revised as needed to address changes in any of the following:

- 88 • the conceptual models of cost causation;  
89 • data availability;  
90 • the environment in which utilities operate, such as the structure of whole-  
91 sale markets and cost patterns;

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<sup>2</sup>There are also cost-allocation implications for certain special contract customers due to escalation clauses in their respective contracts.

92 • energy and regulatory policy.

93 **A. Irrigator Load Data**

94 **Q: Does the irrigation class present special load research challenges?**

95 A: Yes. The irrigation loads are diverse, highly variable from year to year, and hard  
96 to characterize. Recognizing this variability, RMP used an unusually large  
97 sample size.

98 **Q: Does the irrigation customer load data used in the Company's COS Study  
99 in this case provide a valid basis for cost allocation?**

100 A: No. As can be seen from the data provided in Company Witness Scott  
101 Thornton's Exhibit SDT-1, there are sizeable discrepancies between estimated  
102 and actual monthly usage.<sup>3</sup> The overestimates of irrigation class usage in the  
103 summer months (the only months for which RMP uses the irrigation load-  
104 research data) range from 18% in May to 62% in August; see Table 1.

105 **Table 1: Errors in RMP's Irrigation Load Reconstruction**

	<b>Sample MWh</b>	<b>Billing MWh</b>	<b>Adj. Factor</b>	<b>Over- estimate</b>
<i>May</i>	35,079	29,728	0.8475	18.0%
<i>June</i>	48,924	38,702	0.7911	26.4%
<i>July</i>	68,699	44,108	0.6420	55.8%
<i>August</i>	69,803	43,086	0.6173	62.0%
<i>September</i>	44,524	28,760	0.6459	54.8%

106 The load-research data over-predict actual usage of irrigation customers by  
107 45% in the summer months. Even including the winter months, for which RMP  
108 uses billed sales, not the load-research data, RMP's analysis overstates usage by  
109 41%.

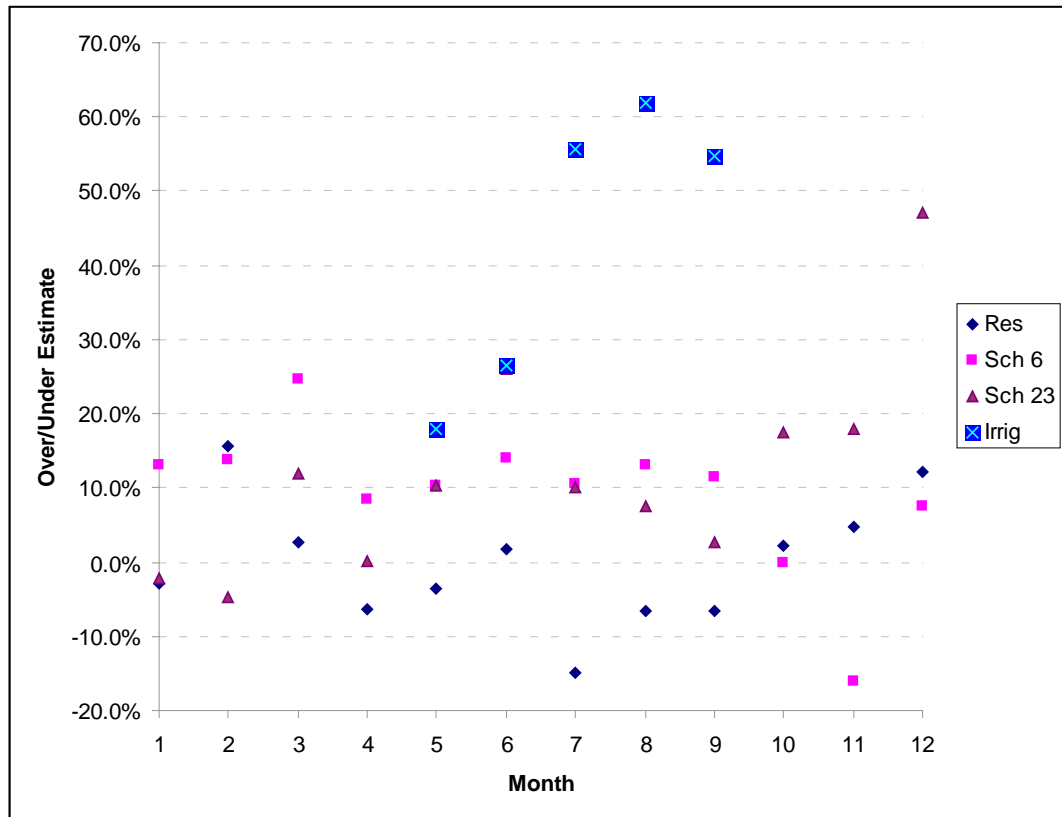
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<sup>3</sup>The values that Exhibit SDT-1 reports as annual totals and averages are actually only for July–December.

110 **Q: Are these estimation errors typical for RMP's load-research efforts?**

111 A: No. As shown in Figure 1, the five months of irrigation load data include the  
112 three largest errors and five of the seven largest errors, out of the 41 monthly  
113 samples in Exhibit SDT-1.

114 **Figure 1: Errors in RMP Load Sampling**



115



116 **Q: Has RMP offered an explanation for the large errors in the irrigation load**  
117 **data?**

118 A: Yes. Mr. Thornton states,

119 sample customers are drawn from a pool of the irrigation customers who  
120 were actively irrigating in the prior two year period. The effect of this  
121 change is that the sample estimates will always be greater than the energy  
122 derived from billing records. This is by design. Our intent is to accurately  
123 construct the load curve of those customers actively irrigating. We avoid  
124 overstating the peak demand of the irrigation class by then adjusting that  
125 load curve down to the level of the billed energy. This explains the large  
126 downward adjustment factor shown for the irrigation class in Exhibit  
127 RMP\_(SDT-1). (Thornton Direct at 9)

128 **Q: Does Mr. Thornton’s explanation resolve your concerns about the irrigation**  
129 **load study?**

130 A: No, for a couple reasons. First, it is not clear why not “actively” irrigating in the  
131 previous two years should exclude a customer from the sample. Considering  
132 crop rotations, a farmer may be more likely to irrigate a parcel of land that has  
133 been fallow for two years than a parcel of land that has been recently irrigated.

134 Second, non-irrigation load on the irrigation meter may be significant.<sup>4</sup>  
135 The Company assumes that usage by irrigation customers in October through  
136 April—which RMP assumes is for non-irrigation purposes—is at a 100% load  
137 shape. Irrigation-class sales in the non-irrigating month of April 2008 were  
138 35%–54% of sales in the irrigation months. If RMP’s sample excludes a large

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<sup>4</sup>If the 45% estimation discrepancy is due entirely to exclusion from the sample of customers that RMP deemed to not be actively irrigating, and that did not actually irrigate in 2008, more than a third of customers would need to be in that category, in addition to the customers who (1) did not irrigate in 2006–2007, but did in 2008, and (2) irrigated in 2006–2007, but did not irrigate in 2008. This would seem to require quite a large percentage of irrigation customers to be non-irrigating in any particular year.

139 amount of high-load factor non-irrigating load, it may be grossly understating  
140 the aggregate irrigation-class load factor.

141 Third, in addition to being large on average, RMP's estimation errors for  
142 the irrigation class show much greater spread than the other three sampled  
143 classes. Table 2 below compares the coefficient of variation (the ratio of standard  
144 deviation to the mean) for the monthly adjustment factors computed by RMP for  
145 each of the four sampled classes. Since the irrigation class was sampled only for  
146 May through September, I performed this computation only for that period. The  
147 variability in the required adjustment factors for the irrigation class is about  
148 twice that of the residential class and Schedule 23, and about ten times the  
149 variation for Schedule 6.

150 **Table 2: Variability in RMP's Adjustment Factors, May–Sept 2008**

	<b>Coefficient of Variation in Adjustment Factor</b>
<i>Residential</i>	0.066
<i>Schedule 6</i>	0.015
<i>Schedule 23</i>	0.074
<i>Irrigation</i>	0.146

151 Finally, even if RMP adjusted its load estimates down by the annual  
152 adjustment factor to force the annual average to match sales, each of the  
153 adjusted monthly estimates would still vary substantially from the actual sales,  
154 ranging from 13% less than actual to 20% more. In three of the five sampled  
155 months, the error exceeds 11%, which seems unlikely to comply with RMP's  
156 target of 90% of estimates being within 10% of actual loads.

157 **Q: Can RMP's pro rata adjustment to load in all hours provide an adequate**  
158 **correction to the estimated irrigation loads?**

159 A: No. In its derivation of the class hourly load estimates from the sample load data  
160 (as explained above), RMP's adjustment holds load shape constant. In other

161 words, RMP assumes that the class demand factors are in constant proportion to  
162 energy use and the load profile is unaffected, no matter what the cause of the  
163 discrepancy. This is an unrealistic assumption, especially in the case of  
164 discrepancies as large as 62%. The factors that significantly alter kWh usage  
165 (such as crop rotations, changes in weather, temperature and rainfall, and  
166 customer diversity) are likely also to affect load shape.

167 **Q: Mr. Thornton observes that RMP “over-samples the irrigation class relative**  
168 **to other classes.” How does RMP’s sampling for the irrigation class**  
169 **compare to that of other classes?**

170 A: Mr. Thornton says,

171 we over-sample the irrigation class relative to other classes. As an example,  
172 the total number of Utah residential class sample customers (170) represent  
173 0.026% of the total residential class. By contrast, the total number of  
174 irrigation sample customers (130) represent 6.1 percent of the total class. In  
175 doing so, we can afford to lose one or more of the sample customers for the  
176 irrigation season without adversely affecting the load estimates. (Thornton  
177 Direct at 9)<sup>5</sup>

178 His characterization of the irrigation class as being “over-sampled” is  
179 somewhat misleading. Despite the great variety within the irrigation class, RMP  
180 actually meters fewer irrigation customers than residential customers. The  
181 number of meters required for the sample depends on the diversity within the  
182 class, not on its size. If we knew that all customers used energy in the same time  
183 pattern, metering a single customer would be adequate. The 2005 irrigation-  
184 sampling study, on which the current cost of service study is still based,

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<sup>5</sup>Mr. Thornton does not explain how he computed that 130 load-research meters are 6.1% of total class, but he seems to have been using the 2,126 customers reported in the 2005 Utah irrigation sampling study (Attachment UEIC 2.1-1). The cost-of-service study reports 2,769 irrigation customers, of which the 130-meter sample would be about 4.7%.

185 recommended a sample of 123 meters, so the 130 meters are essentially what the  
186 sampling study recommended. The 1990 residential sampling study  
187 recommended 169 meters, while the 2008 study recommended only 73 meters;  
188 if anything, the 2008 study indicates that the residential class has been  
189 oversampled.

190 **Q: Does Mr. Thornton argue that his sampled class load data meet the**  
191 **accuracy standards adopted by RMP?**

192 A: He makes that claim for the residential class and Schedule 23:

193 These comparisons indicate that, for the year 2008, the residential class and  
194 Schedule 23 load samples were providing load estimates that fall within the  
195 limits established in the sample design criteria, based on the comparison to  
196 the auxiliary variable kWh.<sup>6</sup> (Thornton Direct at 8)

197 Mr. Thornton implicitly acknowledges that the Schedule 6 data do not meet  
198 the standards: “The Schedule 6 comparison, falls outside these limits” (Thornton  
199 Direct at 8). He also acknowledges that “there is a substantial difference  
200 between the billed and sampled energy for the irrigation class,” but argues that  
201 the estimation error does not indicate a problem, because “The irrigation class  
202 presents a number of challenges from a sampling viewpoint.” (Thornton Direct  
203 at 8–9) The fact that the irrigation class is difficult to sample accurately does not  
204 reduce the accuracy targets.

205 **Q: How far do RMP’s load estimates for the irrigation class vary from “the**  
206 **limits established in the sample design criteria” that Mr. Thornton**  
207 **discusses on page 8 of his testimony?**

208 A: That is difficult to determine, but the variance could be very large. The design  
209 criteria Mr. Thornton presents are (1) the PURPA standard that “An accuracy of

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<sup>6</sup>Mr. Thornton does not define “auxiliary variable kWh,” and it is not clear to what that phrase refers.

210 plus or minus 10 percent at the 90 percent confidence level shall be used as a  
211 target for the measurement of group loads at the time of system and customer  
212 group peaks” and the Load Research Working Group standard that the sample be  
213 “accurate within  $\pm 10$  percent on 90 percent of the observations” (Thornton  
214 Direct at 4).

215 The only information about accuracy that Mr. Thornton provides is the  
216 ratio of annual irrigation billed sales to annual irrigation sales estimated from  
217 the sample data. These ratios do not demonstrate that the irrigation load  
218 estimates met the standards, for the following four reasons:

- 219 • Mr. Thornton reports that actual billed irrigation sales were 15% less than  
220 his estimate of irrigation sales, and suggests that this discrepancy may be  
221 explained by his exclusion of the customers who had not been irrigating in  
222 previous years (Thornton Direct pp. 8–9). But the 15% is the error for  
223 January–June, including four months in which RMP reports actual sales for  
224 both the actual and estimated sales (Exhibit SDT-1).<sup>7</sup> The error is actually  
225 29% of the estimate and over 40% of actual sales.
- 226 • The data compare total energy usage over the year, while the PURPA  
227 standard refers to estimates of monthly coincident and class non-coincident  
228 peak load. The purpose of the load study is to estimate the class monthly  
229 peaks. Therefore, even if Mr. Thornton demonstrated that the irrigation-  
230 load sample produces roughly the billed annual energy, that would not  
231 demonstrate the peak-load estimates are accurate.
- 232 • The standards require a confidence level of 90% that any particular load  
233 estimate is within 10% of the actual load. Yet Mr. Thornton compares the  
234 actual annual sales (the sum of hourly loads) to the sum of the expected

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<sup>7</sup>As I noted above, the totals in Exhibit SDT-1 are totals only for the first half of the year.

235 values from the load-research sample. In effect, he is testing whether the  
236 *average* of his hourly estimates is within 10% of the *average* of the actual  
237 loads. His estimates could pass that test even if there were no hour in  
238 which the estimate was within 10% of actual load.

239 • If Mr. Thornton's test indicates anything about the accuracy of the hourly  
240 estimates for irrigation, it might represent an estimate of the average or  
241 (assuming a symmetrical distribution) perhaps median error. The average  
242 of Mr. Thornton's estimates is 40% greater than the billed sales. But the  
243 high end of the 90% confidence interval (the value exceeded in 5% of the  
244 hours) may well be 60% or 100% more than actual.

245 Hence, it seems highly unlikely that the irrigation load-research data really  
246 meet RMP's accuracy targets.

247 **Q: Can the current irrigation load data be relied on to support a**  
248 **disproportionate increase in irrigation rates?**

249 A: No. Given the very large disparity between estimated and actual usage for the  
250 irrigation class, the load data should not be relied upon to support a major cost  
251 allocation action.

252 **B. Allocation of Service Drops**

253 **Q: How does RMP allocate service lines?**

254 A: They are allocated on weighted customer number, where the weights are  
255 calculated from the cost of a new service by type of customer (Exhibit  
256 RMP\_\_(CCP-3), Tab 1, at 9).

257 **Q: Does the allocator reflect any sharing of services?**

258 A: No. It assumes that each residential customer requires its own service line and  
259 ignores the sharing of services by customers in multi-family buildings (Paice  
260 Direct at 9).

261 **Q: Has the Company acknowledged that its approach overstates the**  
262 **residential's share of service costs?**

263 A: Yes. In Docket No. 07-035-93, RMP Witness Lowell Alt agreed that the services  
264 allocation should be modified to reflect shared services if Utah data is  
265 representative of RMP Utah customers:

266 If the Utah census information [Chernick] presented is representative of the  
267 magnitude of residential shared service drops in the Company's Utah  
268 service area, then a change in the calculation of the service drop allocation  
269 factor would be warranted. (Alt Rebuttal, Docket No. 07-035-93, at 19–20).

270 **Q: Has the Company agreed with that position in this case?**

271 A: Yes.

272 The Company supports Mr. Alt's position regarding services allocation  
273 factor derivation as long as modification is based on reasonable data. The  
274 data [criteria] he identifies...[are] listed below:

- 275 • data reflective of RMP's Utah customer base
- 276 • typical number of customers sharing services
- 277 • size of shared service conductors and related costs (OCS 7.3)

278 **Q: To address the first two criteria listed by RMP, have you revised your**  
279 **analysis to reflect only the census information for the specific counties that**  
280 **RMP serves?**

281 A: Yes. The 2000 Census of Housing indicates that about 29% of housing units in  
282 the Utah counties that RMP serves are in multi-family structures.<sup>8</sup> Of those,

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<sup>8</sup>In calculating the average mix of housing type, I weighted each county's mix by the number of RMP customers in that county (from Attachment OCS 17.5).

283 13% of RMP’s customers live in housing structures with two to nine units, and  
 284 11% live in structures with more than nine units.

285 Depending on the number of units in each category sharing services, the  
 286 total number services to residential customers may be 20% less than RMP  
 287 assumes for allocation purposes (as shown in the Table 3).

288 **Table 3 Estimate of Residential Sharing of Service Drops**

<b>Units in Structure</b>	<b>Number of Units</b>	<b>Customers per Service</b>
<i>1-unit, detached</i>	489,360	1.00
<i>1-unit, attached</i>	35,353	0.75
<i>2 units</i>	28,084	0.50
<i>3 or 4 units</i>	34,781	0.29
<i>5 to 9 units</i>	27,265	0.15
<i>10 to 19 units</i>	29,986	0.07
<i>20 to 49 units</i>	22,957	0.03
<i>50 or more</i>	23,074	0.02
<b>Total RMP housing units</b>	690,859	
<b>Number of residential services</b>		547,456.00
<b>Average number of services per residential customer</b>		0.79

289 **Q: Has the Company conducted a study of the number of shared services, as**  
 290 **recommended by its witness?**

291 A: No. The Company’s efforts consisted of a review of accounting data and  
 292 confirmation from personnel “that Company records do not contain shared  
 293 services data” (OCS 17.8 and 17.9).<sup>9</sup> The Company did not attempt to determine  
 294 the portion of its residential customers that are in multi-family buildings, the  
 295 number of residential service drops installed and in use, or a process for  
 296 identifying shared services (OCS 17.6, 17.7, and 17.11). RMP instead seeks to

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<sup>9</sup>I find it difficult to believe that RMP cannot identify the service drop that serves each meter, or the number of meters at any given location. Perhaps the Company staff did not consider the diagrams of customer connections to be “shared service drop data.”



297 put the onus on third parties to compile “reasonable” data on RMP’s own  
298 customers and installations and propose a “reasonable” allocator:

299 Company records do not contain data regarding the number of customers  
300 per service drop and unless an alternate allocation method is proposed and  
301 deemed reasonable, the cost of service study will continue to allocate these  
302 costs assuming a single service per average customer. (Paice Direct at 9)

303 and

304 Subsequent to RMP witness Lowell Alt’s rebuttal testimony  
305 recommendation the Company reviewed distribution-related accounting  
306 system data. This review reaffirmed that Company records do not contain  
307 shared service drop data.... (OCS 7.3)

308 **Q: Is your use of census data to derive the number of shared services a**  
309 **“reasonable” basis for a services allocator?**

310 A: Yes. The use of census housing data is clearly an improvement over RMP’s  
311 assumption that every residential customer has its own service drop. However,  
312 the Commission should direct the Company to conduct a study of shared services  
313 to determine the split of service drops by single and multi-family residential  
314 dwellings.

315 **C. Reasonableness of Other Classification and Allocation Factors**

316 **Q: Have you identified areas in which RMP’s COS Study should be improved?**

317 A: Yes. I have identified a number of improvements that should be made to the  
318 Company’s classification and allocation factors to reflect cost causation better.  
319 In particular, future RMP COS Studies should recognize the following realities,  
320 each of which I discuss further below:

- 321 • At least 50% of generation plant, especially coal and wind resources, is  
322 energy-related;
- 323 • More than 50% of firm power purchase costs are energy-related;

- 324       • The duration of high loads, not just a few single hourly peaks, drive  
325       distribution investment; and
- 326       • The potential for overloading on substations and feeders, not a simple  
327       count of substations peaking in the month, determines the effect of each  
328       month's load on distribution costs.
- 329

330    1.    *The Classification of Generation Plant*

331    **Q: How is generation plant classified?**

332    A: The COS Study classifies generation plant as 75% demand-related and 25%  
333       energy-related. RMP's approach recognizes that power-production facilities are  
334       built both to serve demand (i.e., to meet reliability requirements) and to produce  
335       energy economically.

336    **Q: How did PacifiCorp come to use a demand-energy split of 75-25 for  
337       generation?**

338    A: As I understand the history of this classification, the 75-25 split was initially a  
339       compromise between Pacific Power and Light's 50-50 demand-energy  
340       classification and the Utah Power and Light's 100% demand classification, in  
341       place at the time of the PacifiCorp merger. I also understand that PacifiCorp  
342       analyzed the demand-energy classification in the early 1990s, as part of the  
343       work performed within the PacifiCorp Interjurisdictional Task Force on  
344       Allocations process. However, the Utah Commission never ruled on the  
345       classification issue until its rate case decision in Docket No. 97-035-01.

346    **Q: What did the Commission decide in that rate case proceeding?**

347 A: Acknowledging that energy needs are a significant driver of generation capital  
348 costs, the Commission adopted the Division's *qualitative* argument in support of  
349 a 75-25 split:

350 Citing both past operating experience and future resource planning, the  
351 Division notes that resources with higher energy availability are chosen  
352 over those with lower energy availability. Since energy plays a role in the  
353 selection of least-cost resources, the Division concludes that some weight  
354 needs to be given to energy in planning for new capacity, and the current  
355 weight of 25 percent is reasonable. We find the *qualitative argument*  
356 offered by the Division to be...convincing. (PSC Order, Docket No. 97-  
357 035-01 at 82, emphasis added)

358 **Q: Did the Commission also find in that case that PacifiCorp's inter-**  
359 **jurisdictional and Utah retail class allocations must always be consistent?**

360 A: No. The Commission recognized that the most appropriate retail class allocator  
361 may differ from the inter-jurisdictional allocator. In its Report and Order  
362 (Docket No. 97-035-01 at 113), the Commission stated,

363 We also want to insure that these fundamental cost-of-service decisions are  
364 applied consistently at interjurisdictional and class levels...*unless good and*  
365 *sufficient cause shows otherwise* [emphasis added].

366 **Q: Should the inter-jurisdictional allocations be the default for Utah retail**  
367 **class allocations?**

368 A: No, for two basic reasons. First, the 75-25 split was and remains an arbitrary  
369 compromise, rather than a result of cost-causality analysis. Second, the 75-25  
370 split understates the portion of generation investment—particularly in coal and  
371 wind plants—that is incurred to meet energy needs, rather than peak load.

372 **Q: From a quantitative standpoint, how can the energy-related portion of**  
373 **generation plant costs be estimated?**

374 A: One approach is the *peaker method*, which considers the demand-related portion  
375 of production plant to be the minimum cost of providing the current system  
376 reliability level, and the remainder to be the energy-related portion.

377 **Q: Has the Company considered the peaker method to be reasonable?**

378 A: Yes. The Company previously endorsed this concept in the 1989 UP&L  
379 Distribution Study at 11:

380 The increased cost of a baseload unit over a peaking plant represents an  
381 investment made to save fuel costs. The additional investment can be  
382 classified as energy related.... The generation plants have two equally  
383 important ratings, energy and demand.

384 **Q: Is the peaker approach consistent with the current electricity markets?**

385 A: Yes. The Independent System Operators (“ISOs”) for restructured markets apply  
386 pricing models similar to the peaker method, but even more weighted to energy.  
387 Essentially, ISOs structure capacity markets to allow generators to recover the  
388 “Cost of New Entry” (CONE), without the withholding of capacity and excess  
389 profits. For example,

- 390 • The New York ISO (“NYISO”) and PJM Interconnection (“PJM”)  
391 determine the price of capacity from a formula that sets the capacity price  
392 near the cost of a peaking unit, net of energy revenues, when installed  
393 capacity is close to the required level.

394 The CONE revenue requirements are based on the total project  
395 capital cost and annual fixed operations and maintenance expenses of  
396 a combustion turbine (“CT”) simple cycle peaker power plant  
397 addition. The plant configuration is the “Reference Resource”  
398 prescribed by the PJM Tariff, i.e., two General Electric Frame 7FA  
399 combustion turbines with selective catalytic reduction technology,  
400 dual fuel capability, inlet air cooling, and a heat rate of 10,500  
401 MMBtu/MWh. (PJM Tariff Amendments submitted to FERC,  
402 12/12/08, at 10)

403 • The New England ISO sets capacity prices through a forward auction. The  
404 initial starting price for the auction, as well as minimum and maximum  
405 prices, is determined by the cost of a new peaker, net of energy revenues.  
406 In addition, the formula for these energy revenues reflects the  
407 characteristics of a combustion turbine. When market energy price is very  
408 high, the capacity price is reduced by the “peak energy rent,” which  
409 assumes a proxy unit operating on ultra-low sulfur No. 2 oil at a heat rate  
410 of 22,000 Btu. This pricing prevents over-collection in the capacity and  
411 energy markets by

412                   Ensuring that the heat rate continues to reflect a level slightly  
413                   higher than the marginal generating unit in the region that would be  
414                   dispatched as the system enters a scarcity condition. (New England  
415                   ISO, Market Rule 1, §III.13.7.2.7.1.1.1(iii))

416 • Other ISOs, including the California ISO, Midwest ISO, and ERCOT, have  
417 no installed-capacity requirements at all, and charge load primarily on  
418 time-of-use energy consumption.

419 **Q: For the ISOs that include capacity markets, how have the market capacity**  
420 **prices compared to the cost of new peakers?**

421 A: Most of the capacity auctions have resulted in capacity prices significantly  
422 below the cost of a new peaker. Table 4 shows the estimated cost of new  
423 peaking capacity and the market price response for the most recent annual  
424 auctions for various PJM zones, the NYISO upstate zone, and ISO-NE.<sup>10</sup>

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<sup>10</sup>The PJM and ISO-NE auctions are for forward markets, while the NYISO auctions are for one to six months ahead. Since NYISO has not completed the final auction for summer 2009 (which includes October). I use the summer 2008 and winter 2008/2009 results. I do not include the NYISO prices for New York City (which have been regulated) or Long Island (where there is essentially only a single buyer).

**Table 4: Recent Capacity Market Prices**

ISO	Zone	Year Starting	Dollars per kW-yr		Price: Peaker Ratio
			Cost of New Peakers (Estimated)	Market Capacity Price	
PJM	RTO	Jun-12	\$115	\$6	5%
	MAAC	Jun-12	\$113	\$49	43%
	EMAAC	Jun-12	\$122	\$51	42%
	PSEG-North	Jun-12	\$122	\$68	55%
	DPL-South	Jun-12	\$122	\$81	66%
NYISO	ROS	May-08	\$105	\$25	23%
ISO-NE	All	Jun-11	\$90	\$37	42%

426           The ISO-NE price for the year starting June 2011 was set by the price floor  
427           for the auction; the same was true for the previous year. The price floor will be  
428           lower for the year starting June 2010, and the price is expected to fall further.

429   **Q: Please explain how the peaker method would be used to classify generation**  
430   **plant in a COS Study.**

431   A: For each generation unit, a good initial estimate of the demand- or reliability-  
432   related portion of its cost is the cost per kW of a peaker (generally a simple-  
433   cycle combustion turbine) installed in the same period times the rated capacity  
434   of the unit. The cost of the unit in excess of the equivalent gas turbine capacity  
435   is energy-related.<sup>11</sup>

436   **Q: Have you applied the peaker method to PacifiCorp's existing coal plants?**

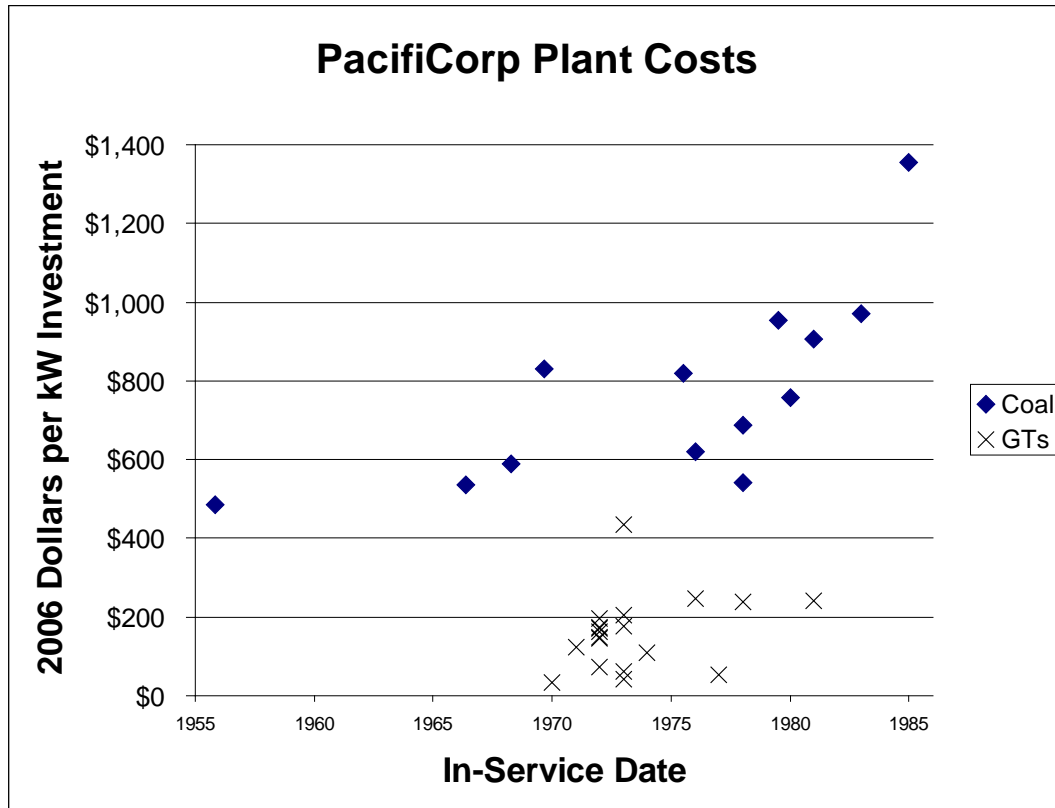
437   A: Yes. I compared the gross capital cost per kilowatt, in year-end 2006 dollars, for  
438   each existing PacifiCorp coal plant and for contemporaneous combustion-

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<sup>11</sup>This calculation overstates the reliability-related portion of plant cost: it assumes steam plant supports as much firm demand as would be supported by the same capacity of combustion turbines. Higher forced outage rates, large maintenance requirements, and the size of large units all tend to reduce the contribution of large units to system reliability.

439 turbine plants, sorted by in-service date.<sup>12</sup> The peakers averaged under  
 440 \$200/kW, compared to \$500–\$1,000/kW for PacifiCorp’s coal plants, suggesting  
 441 that 60% to 80% of the coal plant capital costs are energy-related. See Figure 2  
 442 below.

443 **Figure 2: PacifiCorp Coal Plant Costs versus GT Plant Costs**



444

445 **Q: Do PacifiCorp’s projections of new generation plant costs support your**  
 446 **findings from existing plant data?**

447 **A:** Yes. According to the 2008 Integrated Resource Plan, the lowest-cost new coal  
 448 plant would be a Utah pulverized coal plant, at fixed costs of \$291/kW-yr.

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<sup>12</sup>Since PacifiCorp does not own any peakers built in the same period as its coal plants, I used as proxies, peakers built in the relevant period in areas contiguous to PacifiCorp’s service territories. The peakers are those owned by investor-owned utilities in Arizona, Colorado, Montana, New Mexico, Nevada, Oregon, and Washington, and were all built during the period 1970–1981.

449 Netting out the fixed costs of a frame simple-cycle combustion turbine, at  
450 \$69/kW-year, the energy-related fixed cost of the new coal plant would be  
451 \$222/kW-year, or 76% of the total fixed cost.

452 2. *Allocation of Firm Non-Seasonal Purchases*

453 **Q: How does RMP allocate firm non-seasonal purchases?**

454 A: The Company classifies firm non-seasonal purchases as 75% demand-related  
455 and 25% energy-related and allocates each month's cost separately based on  
456 class coincident peak and kWh usage in that month.

457 **Q: What costs does RMP's COS Study include in the category of "firm non-  
458 seasonal purchases?"**

459 A: As shown in the COS Study Model sheet labeled "NPC," the category comprises  
460 all purchases except non-firm and seasonal. It comprises the following  
461 transactions:

- 462 • Long-term firm purchases,
- 463 • Short-term firm purchases,
- 464 • Storage & Exchange,
- 465 • System Balancing Purchases.

466 The last two transaction categories are clearly 100% energy-related.

467 **Q: Does RMP's COS Study understate the energy-related portion of long term  
468 firm purchase costs?**

469 A: Yes, in two important ways. First, the non-seasonal purchases are likely to  
470 reflect RMP's mix of non-seasonal generation plant, which are more energy-  
471 related than the COS Study assumes, as discussed above in Section III.C.1.



472           Second, RMP allocates purchases and generation inconsistently. In the case  
 473 of its own generation plant, RMP treats fuel costs and plant costs separately, and  
 474 classifies fuel as 100% energy-related, and plant as 75% demand–25% energy-  
 475 related. But in the case of firm non-seasonal purchases, RMP does not attempt to  
 476 separate the variable and fixed components and instead treats all purchase costs  
 477 as fixed plant costs. As a result, RMP allocates only 25% of all purchase costs,  
 478 including fuel costs, on energy. This difference is illustrated in Table 5.

479 **Table 5: Share of Cost allocated on Energy**

	<b>Fixed Costs</b>	<b>Fuel and Variable Costs</b>	<b>Total if Half of Cost Is Fuel</b>
<i>Plant</i>	25%	100%	62.5%
<i>Non-Seasonal Purchases</i>	25%	25%	25.0%

480 **Q: Have you estimated the percentage of firm purchase costs that are variable**  
 481 **charges or otherwise energy-related?**

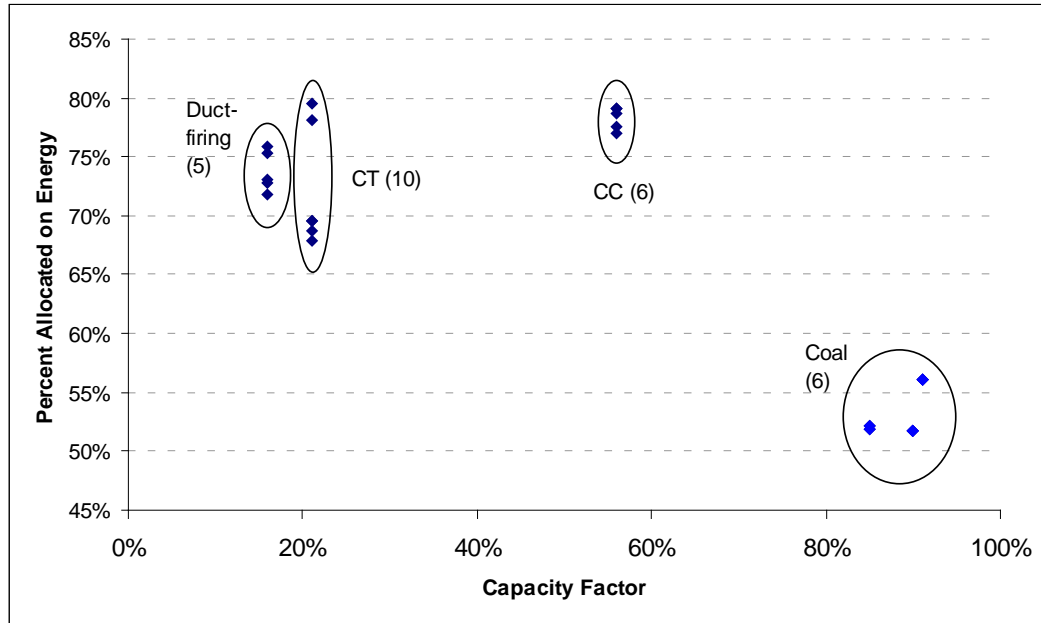
482 A: Yes. Energy charges are about \$431 million—or about 83%—of the \$522  
 483 million of short-term firm and long-term contract costs projected in RMP’s  
 484 GRID run for this proceeding.

485 **Q: How significant is the disparity between RMP’s classification of purchases**  
 486 **and generation?**

487 A: The disparity is large. From PacifiCorp’s’ 2008 Integrated Resource Plan, I  
 488 computed the portion of total costs that RMP would allocate on energy for each  
 489 potential new resource. The energy-related portion of the costs is the sum of  
 490 variable costs plus 25% of fixed costs. The portion of generator costs allocated  
 491 on energy under RMP’s current classification and allocation method ranges from  
 492 52% for pulverized coal with carbon capture and sequestration to 56% for coal  
 493 without carbon capture, 66% to 81% for various types of combustion turbines,  
 494 and 77%–83% for various combined-cycle configurations.

495  
496

**Figure 3: Energy-Related Share of New Resource Costs under RMP's COS Study Approach**



497 3. *Distribution Classification and Allocation Factors*

498 **Q: How does RMP's COS Study classify distribution?**

499 A: The Company classifies substations, primary lines, line transformers, and  
500 secondary lines as demand-related. The remaining distribution plant, services  
501 and meters, are classified as customer-related.

502 **Q: How does RMP's COS Study allocate demand-related distribution plant?**

503 A: The COS Study treats distribution costs as follows:

- 504 • Substations and primary lines are allocated based on weighted monthly  
505 coincident distribution peaks:

506 The coincident distribution peak is the simultaneous combined demand of  
507 all distribution voltage customers at the hour of the distribution system  
508 peak. These monthly values are weighted by the percent of substations that  
509 achieve their annual peak in each month of the year. (Exh. RMP (CCP-35),  
510 Tab 1, at 9)

- 511           • Line transformers and secondary lines are allocated based on weighted  
512           non-coincident peaks, where the “weighting” adjusts for the diversity of  
513           load on shared distribution equipment.

514   **Q: Does RMP’s allocation of distribution costs reasonably reflect cost**  
515   **causation?**

516   A: No. The Company’s approach has the following problems:

- 517           • It overlooks many of the ways that periods of high energy use drive  
518           distribution investment.  
519           • The monthly weighting factors used in deriving the allocator for sub-  
520           stations and primary feeders are not cost-based.

521   a) *Effect of Energy and Duration of Peak on Distribution Costs*

522   **Q: Does RMP acknowledge that energy (that is, duration of peak) affects**  
523   **distribution costs?**

524   A: Yes. In his Rebuttal Testimony in Docket No. 07-035-93, Company Witness  
525   Lowell Alt acknowledged that duration of peak, load cycle, and on-peak energy  
526   are all cost-causal factors. For example, regarding substation sizing, he stated  
527   “The key data are the peak load and *its duration* (at 11, emphasis added).” In the  
528   same Rebuttal Testimony, however, Mr. Alt endorsed RMP’s allocation  
529   assumption that peak demand alone drives distribution costs.

530   **Q: In what ways do periods of high energy use affect distribution costs?**

531   A: Duration of high load affects distribution investment and outage costs in the  
532   following ways:

- 533           • The number of high-load hours determines risk of load loss following  
534           equipment failure, and hence drives investment in redundant equipment to  
535           improve distribution system reliability.

- 536           •     The number and extent of overloads determines the life of the insulation on  
537                     lines and in transformers (both in substations and in line transformers), and  
538                     hence the life of the equipment. A transformer that is very heavily loaded  
539                     for a couple of hours a year, and lightly loaded in other hours, may well  
540                     last 40 years or more, until the enclosure rusts away. A similar transformer  
541                     subjected to the same annual peaks, but to many smaller overloads in each  
542                     year, may burn out in 20 years.
- 543           •     All energy in high-load hours, and even all hours on high-load days, adds  
544                     to heat buildup and results in (1) sagging of overhead lines, which often  
545                     defines the thermal limit on lines; (2) aging of insulation in underground  
546                     lines and transformers; and (3) a reduction the ability of lines and  
547                     transformers to survive brief load spikes on the same day.
- 548           •     Line losses depend on load in every hour (as marginal line losses due to  
549                     another kWh of load generally exceed the average loss percentage in that  
550                     hour). UP&L’s October 1989 Distribution Cost Allocation Study  
551                     recognizes that “energy-related” distribution investments are made to  
552                     reduce energy load losses, namely, certain increases in the sizing of  
553                     conductors and transformers.<sup>13</sup>

554     **Q: Do the Company’s distribution design guidelines indicate that periods of**  
555     **high energy use and duration of peak load are driving factors in**  
556     **distribution costs?**

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<sup>13</sup>In the case of conductors, the UP&L study (at 14) specifies that Company selects the conductor size at the point at which

the incremental savings in capitalized energy losses from switching to the next larger conductor are equal to the incremental cost of installing the larger conductor. Thus the conductor selected is the most economical one to use for the initial loading of the circuit.

557 A: Yes. The Distribution Guidelines identify a number of ways in which expected  
558 energy use, especially in hours close to peak in load or time, affects both the  
559 design standards and investment. For example, the sizing of new conductors and  
560 transformers is determined by the expected hours of high use as well as by the  
561 single peak. Figure 4 of the Guidelines sets out the maximum design loading  
562 without damage assuming four hours of usage and maximum emergency usage  
563 limited to 8 hours with some risk of equipment damage. So the greater the  
564 number of hours of maximum loading, the larger the conductor installed.  
565 Similarly, the Study (at 12) recognizes that heat buildup may limit the capacity  
566 of a substation transformer.

567 b) *Distribution Monthly Peak Weighting Factors*

568 **Q: Why are the distribution weighting factors invalid?**

569 A: Weighting each month by the number of substations that peak in that month  
570 does not reflect cost causality. Under this weighting scheme, for example,

- 571 • The month with the most large substations seriously overloaded could be  
572 the highest-cost month, yet not receive the highest weight.
- 573 • A month would receive a weight of 100% whether each substation's  
574 maximum load were (1) only 1 kVA more than its maximum in every other  
575 month, or (2) four times its maximum in every other month. High loads in  
576 other months that are near the substations' annual peaks can cause  
577 excessive wear and tear. For example, August receives twice the weight  
578 that July does, even though both months experience high loads.
- 579 • A small substation has as much effect on a month's weighting factor as a  
580 large substation does.
- 581 • RMP's approach can produce illogical results. For example, in Docket No.  
582 07-035-93, the only two months with weights greater than 10% were July

583 (41%) and June (18.4%). The Utah distribution peak actually occurred in  
584 August, but received a weight of only 8.5% (Excel file COS UT Dec 2008  
585 (MSP).xls, Tab “Dist. Factors”).

586 Monthly weighting factors should recognize the size of individual sub-  
587 stations and the effect of multiple peaks and the duration of peaks on substation  
588 sizing.

#### 589 **IV. Recommendations**

590 **Q: Please summarize your recommendations.**

591 A: I recommend that the Commission give no weight to the COS Study results for  
592 the irrigation class in this proceeding, due to the large errors in the irrigation  
593 class load estimates. I also recommend the Commission direct the Company to  
594 conduct a study of shared services to determine the split of service drops by  
595 single and multi-family residential dwellings. Lastly, I recommend that the  
596 Commission order the Company to implement improvements in its next COS  
597 Study to meet the following goals:

- 598 • recognize the sharing of service drops by residential customers in multi-  
599 family dwellings;
- 600 • classify a greater percentage of generation plant as energy-related;
- 601 • classify a greater percentage of non-seasonal purchases as energy-related;
- 602 • allocate demand-related distribution costs based on class contribution to  
603 loads in the many high-load hours that determine the duration of peak  
604 loads;
- 605 • revise the monthly weights for the primary distribution allocator to more  
606 reasonably reflect monthly distribution demand.

607

608 **Q: Does this conclude your testimony?**

609 A: Yes.