

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain)	Docket N. 07-035-93
Power for Authority to Increase its Retail Electric)	
Utility Service Rates in Utah and Approval of its)	
Proposed Electric Service Regulations, Consisting of)	Division of Public Utilities
a General Rate Increase of Approximately 161.2)	
Million per Year, and for Approval of a New Large)	
Load Surcharge.)	DPU Exhibit No. 9.0R

**Rebuttal Testimony of
Abdinasir M. Abdulle, Ph. D.**

COST OF SERVICE AND RATE DESIGN

**For the Division of Public Utilities
Department of Commerce
State of Utah**

September 3, 2008

1 **Q. Please state your name and business address.**

2 A. My name is Abdinasir M. Abdulle; my business address is Utah Division of
3 Public Utilities, 160 East 300 South, Salt Lake City, Utah.

4 **Q. Are you the same Abdinasir M. Abdulle that submitted Direct Testimony for**
5 **the Division in this Docket (07-035-93)?**

6 A. Yes.

7 **Q. What is the purpose of your testimony?**

8 A. The purpose of my testimony is to revise my direct testimony to make consistent
9 with the Docket No. 07-035-93 Commission Order on revenue requirement and
10 cost of capital and to rebut certain comments in the direct testimonies of the
11 following witnesses:

- 12 1. Paul Chernick – Committee of Consumer Services (CCS)
- 13 2. Dan Gimble - Committee of Consumer Services (CCS)
- 14 3. Kevin Higgins – Utah Association of Energy Users (UAE)
- 15 3. Maurice Brubaker – Utah Industrial Energy Consumers (UIEC)

16

17 **Comments on Mr. Chernick’s Testimony**

18

19 **Q. Are you familiar with any work done earlier to determine what the**
20 **appropriate demand-energy split should be?**

21 A. Yes. In Docket No. 97-035-01, the Division made a qualitative argument in
22 support of its recommendation for the Commission to adopt the 75%-25%

23 demand-energy classification that the Commission has adopted. On page 79 of
24 the Commission Order, Docket No. 97-035-01, the Commission stated:

25 We conclude that the appropriate allocation factor for
26 production and transmission plant costs is composed of
27 twelve coincident peaks, 75 percent demand and 25
28 percent energy.

29

30 Later, the Company performed a stress factor analysis which came to the
31 conclusion that the 75% demand and 25% energy split is most appropriate.

32

33 **Q. Could the appropriate demand-energy split costs of generation plant be**
34 **quantitatively determined?**

35 A. Yes. There are a number of methods used to estimate the energy-related portion
36 of generation plant cost. One of them is the peaker method used by Mr. Chernick.
37 Another one is the stress factor analysis which was used by the Company earlier
38 to prove that the appropriate demand-energy split is 75% demand and 25%
39 energy.

40 **Q. Which of these two methods produce more reliable results?**

41 A. I don't know. Neither the Division nor Mr. Chernick performed a comparison of
42 the two methods. However, the Division believes that the stress factor analysis is
43 more rigorous than the method used by Mr. Chernick. There are a number of
44 relevant factors that are considered in stress factor analysis that Mr. Chernick did
45 not consider in his peaker method. These factors include loss of load probability,

46 monthly reserve margins adjusted for maintenance, monthly reserve margins
47 adjusted for capacity costs, and the probability of contribution to peak. Therefore,
48 the Division believes that Mr. Chernick did not provide enough evidence to
49 support his proposed changes of the demand-energy split.

50 **Q. Could you comment about the impact of changing Rocky Mountain Power's**
51 **Factor 10 (the demand allocated portion of fixed plant cost) from 75% to**
52 **50% on the rate spread?**

53 A. Yes. On Table 1, page 10, of his direct testimony, Mr. Chernick shows that if the
54 demand energy split of the generation plant costs is changed from 75% demand
55 related and 25% energy related, to 50% demand related and 50% energy related,
56 about \$8.5 million will be shifted off of Schedules 1, 6, and 23 and about \$3.8
57 million will be shifted onto Schedules 8 and 9.

58 **Q. How would these numbers change if the COS is updated with the**
59 **Commission Order of Phase I of this case?**

60 A. A shift of \$7,088,395 million dollars from Schedules 1, 6, 23 and 25 will occur
61 and \$3,658,988 will be shifted onto Schedules 8 and 9, 10, and (7, 11, 12, 13).

62 **Q. What is the Division's recommendation regarding Factor 10?**

63 A. Based on Mr. Chernick's analysis in his direct testimony, which was later verified
64 by the Division, it is apparent that any change in the demand allocated portion of
65 fixed plant cost (F10), will result in significant shifts of the fixed plant costs
66 between the different service classes. Most of these costs will be shifted onto
67 Schedules 8 and 9 and away from Schedules 1, 6, and 23. Since this analysis was
68 based on the peaker method and it has a substantial adverse impact on some of the

69 Schedules, the Division recommends that the Commission order the Company to
70 convene a study group to address what the appropriate demand allocation portion
71 of the fixed plant cost should be. This working group should compare the
72 different methods of estimating the energy-related portion of generation plant
73 cost, including the peaker method and the stress factor analysis. This group could
74 also examine several of the issues that I will identify below as needing further
75 study.

76 **Q. In his direct testimony Mr. Chernick also proposes to change the demand**
77 **allocated portion of firm non-seasonal purchases (F87) from 75% to 25%.**
78 **Do you agree with this proposal?**

79 A. No. As is indicated in Mr. Chernick's direct testimony (page12, lines 247 and
80 248) and as was later verified by the Division, Changing F87 from 75% to 25%
81 will shift approximately \$13 million off of Schedules 1, 6, and 23, and
82 approximately \$5.5 million onto Schedules 8 and 9. Using the COS model
83 updated with the Commission Order of phase I of this case, approximately
84 \$2,229,074 will be shifted from Schedules 1, 10, and 23 and \$1,489,330 onto
85 Schedules 8 and 9.

86 Given the relatively small rate increase ordered by the Commission in Phase I of
87 this case (about \$36 million), the cost shifts proposed by Mr. Chernick are
88 significant. These cost shifts between the classes of service are generally in favor
89 of Schedules 1, 6, and 23 and against Schedules 8 and 9. These impacts are
90 exacerbated by Mr. Chernick's proposed changes in the allocation of firm sales
91 revenue, classification of the transmission plant and the classification and

92 allocation of distribution costs. The Division believes that changes in the
93 classification and allocation methods that have this level of impact should be
94 carefully looked into and discussed by the interested parties in this case.
95 Particularly, when the changes in the classification and allocation factors are not
96 consistent with the way it is done at the inter-jurisdictional level. Therefore, the
97 Division recommends the Commission direct the Company to include these issues
98 in the work of the group described above.

99 **Q. Did the Commission express preference as whether or not cost of service**
100 **decisions be applied consistently at the jurisdictional and class levels?**

101 A. Yes. In its Report and Order (Docket No. 97-035-01, p.113), the Commission
102 stated

103 We also want to insure that these fundamental cost-of-service
104 decisions are applied consistently at interjurisdictional and class
105 levels.

106 In that same page of the Commission Order, the Commission also
107 states that “In our view, these presumptions must hold unless good and
108 sufficient cause shows otherwise.”

109 This demonstrates the Commission’s desire to see the cost of service
110 decision applied consistently at the inter-jurisdictional and class levels
111 unless there is a strong evidence to do otherwise. As I indicated
112 earlier, in the Division’s opinion, Mr. Chernick did not provide enough

113 evidence to warrant applying different demand-energy split at the
114 inter-jurisdictional and class levels.

115 **Q. What demand-energy split of the generation plant cost is applied**
116 **at the Inter-jurisdictional level?**

117 A. It is 75% demand and 25% energy.

118 **Q. On Page 28, Line 573, Mr. Chernick, indicated that since the irrigation load**
119 **research resulted in a large discrepancy between the sample and actual**
120 **usage, the data should not be relied upon to support a major cost allocation**
121 **action. Do you agree with this assessment and conclusion?**

122 A. Though the Division did not perform an in depth analysis of the irrigation load
123 research data, the Division looked into the analysis that Mr. Chernick performed
124 on these data. The results of his analysis indicate that there is a large discrepancy
125 between the sample and actual usage. If he is correct, there may be a legitimate
126 concern of relying on the irrigation load data to increase rates for the irrigation
127 class relative to the jurisdictional average. Therefore, without taking a position on
128 the quality of the irrigation load research or data, the Division is proposing an
129 alternative rate spread and rate design for the irrigation class than that presented
130 in direct testimony. Details of this alternative proposal are described below.

131 **Q. On Page 34, lines 722 to 725, of his direct testimony, Mr. Chernick indicated**
132 **that by removing the costs of service drops from the calculation of the**
133 **residential customer charge, the customer charge will become \$2.40 per**
134 **month. Do you agree with this?**

135 A. No. Mr. Chernick argued that, in the case of multi-family housing, each customer
136 will share a service drop with other customers. According to Mr. Chernick, the
137 cost of the service drop varies with the load of the building and not the number of
138 customers, and therefore does not belong in the customer charge. He then went
139 ahead and calculated the customer charge without service drop costs and found it
140 to be \$2.40 per month.

141 The problem with this is that, even if you agree that the service drop cost for
142 multifamily dwellings is a function of the load of the building and does not belong
143 to the customer charge calculation, the service drop for family houses is still a
144 function of the number of customers and should be included in the calculation of
145 the customer charge. In other words, even if you except Mr. Chernick's argument
146 with regards to multi-family dwellings, there is no rational reason to remove all
147 costs associated with services drops from the calculation of the customer charge.

148 **Q. Do you agree with Mr. Chernick's argument that the service drop for multi-**
149 **family dwellings is a function of the load and not the number of customers?**

150 A. No. Even if you agree that the service drops for multi-family housing depends on
151 the building, one has to recognize that the load of the building is at least partially
152 a function of the number of customers who are expected to live in the apartment
153 complex. In other words, the load is a function of the potential number of
154 residents in the building. To apply Mr. Chernick's logic to the problem, one
155 needs to estimate what portion of the cost of the service drop in the multi-family
156 houses is attributable to the number of customers and use this in the calculation of

157 the customer charge, which Mr. Chernick did not attempt to do. Dropping the
158 whole cost of the service drop from the calculation is not the correct thing to do.

159 **Q. Can you summarize how Mr. Chernick proposes to establish residential**
160 **summer tail block rates?**

161 A. Yes. Mr. Chernick's proposal pegs rates for peak summer use with given 3rd
162 quarter market prices at the Palo Verde and Mid-C hubs. Mr. Chernick states that
163 these peak use rates reflect total generation costs that range between \$0.11 and
164 \$0.12/kWh. His proposal also claims that "marginal" load-related (T&D) would
165 add another couple of cents per kWh.

166 The problem with this is that it is not clear what is included in the Palo Verde and
167 Mid-C prices and Mr. Chernick made no attempt to at a clarification. Mr.
168 Chernick simply took the weighted average of the on-peak and off-peak prices
169 and added capacity cost and used this number to approximate marginal cost. The
170 inference from this approach is that the index prices do not include any capacity
171 related costs. This is exactly one of the disputes that have risen in the past with
172 pricing qualifying facilities: some parties argue that the index prices include
173 capacity components other parties claim that the index prices do not include any
174 capacity components.¹

175 In the market place a firm has to cover its fixed costs in the long run if it is to stay
176 in business. Hence, in the Division's opinion, the Palo Verde and Mid-C prices

¹ In the context of QF pricing, some have argued that the difference between off-peak and on-peak prices is indicative of the value of capacity. If one agrees with this argument, then Mr. Chernick's weighted average of the two contains at least some coverage for capacity if not complete coverage.

177 must (at least for some of the time) already contain both energy and capacity
178 components. In other words, over the long-run, the index prices must cover, on
179 average, the seller's variable and fixed costs. Mr. Chernick is assuming that these
180 prices reflect only energy costs. If this assumption is true, then Palo Verde and
181 Mid-C prices would not allow sellers of power from these hubs to cover their
182 fixed costs in the long run resulting in losses that would eventually force them out
183 of the market. By adding a separate capacity amount to the weighted average,
184 Mr. Chernick is potentially double counting the value of capacity in his
185 recommendation.

186 If we agree that these market prices can be used as a proxy for marginal cost, then
187 the marginal cost would be equal to Mr. Chernick's weighted average \$0.9/kWh.

188 **Q. Does the Division oppose marginal cost pricing strategies?**

189 A. In general, no. The Division does not oppose the principle of using marginal costs
190 as a guide to proper ratemaking. However, the Division has expressed its
191 concerns about the complexity and pitfalls of attempting to approximate true
192 marginal cost pricing. Such strategies are very difficult to implement effectively
193 when the necessary information cannot be obtained or is difficult to obtain and
194 when the required conditions for marginal cost pricing are not met.

195 **Q. What are some of the problems with this approach?**

196 A. One of the key requirements of marginal cost pricing is to determine exactly how
197 costs change with each corresponding unit change in output. However, the proxy
198 prices used in Mr. Chernick's approach do not necessarily represent resultant

199 incremental changes in the Company's cost structure from a related unit change of
200 Company output. In other words, the proposal does not sufficiently demonstrate
201 the degree to which Palo Verde or Mid-C market energy prices are actually
202 related to the Company's additional costs that all purchasers impose on the system
203 by the production of one additional unit of electrical output.²

204 **Q. Why are conditions such as this critical?**

205 A. Failure to meet necessary marginal cost pricing conditions can result in negative
206 impacts upon customers. In my discussions on the problem of second best in my
207 direct testimony, I explained how efforts to approximate marginal cost pricing for
208 the residential tail block will potentially lead to undesirable outcomes. In
209 addition, marginal cost pricing not accompanied by optimal production levels
210 based on the same marginal cost principles may not result in an efficient outcome.

211 **Q. Could you briefly explain what the problem of second best is?**

212 A. I did briefly discuss the problem of second best in my direct testimony. So let me
213 elaborate at some length. The primary focus of the theory of the second best is on
214 what happens when the optimum conditions necessary to achieve the first best
215 solution are not satisfied in an economic model. This could happen whenever
216 there are market distortions in the system. This could be, for example, the case of
217 a regulated monopoly. In this case would it be appropriate for the firm to set
218 price equal to marginal cost?

² The concept of what constitutes "one additional unit" of electrical output is itself a topic of debate. This issue is discussed at length in my direct testimony.

219 Generally, when one optimal condition is not satisfied, for whatever reason, all of
220 the other equilibrium conditions will change. Any policy implemented to correct
221 this market distortion will potentially lead to a different equilibrium level that
222 corresponds to a lower level of social welfare. The best outcome could be
223 achieved if all market imperfections are addressed simultaneously.

224 In this proceeding, the case at hand is trying to increase the residential tail block
225 price to the marginal cost in the long run. If marginal pricing occurs only in the
226 tail block and not in any of the other blocks or Schedules (given that all other
227 residential blocks and the rates of all other Schedules are not priced at the
228 marginal cost), the outcome will likely not be optimal and may actually make
229 some of those affected by this strategy worse off. CCS did not demonstrate how
230 the proposal avoids such outcomes. Neither does CCS show how the proposal will
231 result in a more optimal result.

232 In summary, the problem with the second best is that policies that are appropriate
233 for first best systems (systems that have no imperfections) do not necessarily
234 work in the second best world. In general, if all rates and Schedules are not
235 priced the same way, implementing marginal cost pricing for one class only will
236 create distortions that lead to a second best scenario where the system could be
237 made worse off. In other words, in a second best world, moving less than all the
238 distortions simultaneously may indeed make the system worse off.

239 **Q. Would you comment on the relationship between marginal cost pricing and**
240 **optimal output level?**

241 A. Yes. According to economic theory firms base their production level and price on
242 the marginal cost. The firm attempts to determine the output level that maximizes
243 its profit and charges the price that corresponds to that output level. The output
244 that maximizes the firm's profit is the one that corresponds to where the marginal
245 cost equals price. An output level that corresponds to a point where the marginal
246 cost is larger or smaller than the price will result in the firm making below or
247 above normal profit. Normal profit in this case is zero. This implies that the firm
248 must determine the optimal output level and price simultaneously.

249 In this case, Mr. Chernick is proposing that residential rates need to be based on
250 marginal cost. The problem here is that the determination of the output level in
251 this case was not based on the marginal cost principle and there is no way one
252 could determine whether or not this output level is the optimal output. Hence, the
253 marginal cost that corresponds to this output level may not be the optimal level.
254 This goes back to the problem of the second best that I discussed earlier.

255 **Q. What is the Division's position on Mr. Chernick's proposed "marginal" T &**
256 **D charge?**

257 A. The Division has similar concerns about the T & D charge. As with the proxy
258 market price approach, this charge does not appear to represent a true marginal
259 cost strategy. The proposal contains no information to show how the change in
260 system-wide T & D costs per each unit of output would be determined or
261 accounted for. Again, without complete information on the nature of how all

262 relevant system costs³ change with an additional unit of output and then showing
263 how these costs are imposed upon all system users, there is no guarantee that such
264 a price will result in a more efficient allocation of electrical service.

265 **Q. Can you describe some specific problems that may occur with this proposal?**

266 A. Yes. The proposed high tail block rate may have a stifling effect on high use
267 customers who are already making efforts to reduce peak load. Customers
268 participating in the “Cool Keeper” load control program, for example, would be
269 punished if they fall into the tail block. In addition, there are questions about the
270 relevance of such a pricing scheme in periods such as weekends or holidays
271 where residential demand is high, but system demand is low. During these
272 periods, residential customers in the tail block could bear the burden of an on-
273 peak price, assuming that such a price is fixed. In essence, these users could be
274 paying a price significantly higher than marginal cost during off-peak periods.

275 Another problem with the proposal is that it shifts the risk of rate recovery on to
276 the Company. Usage during the summer months is (in part) driven by the weather
277 conditions. If the temperature, during the summer months of a given year, is
278 mild, then the Company may not be able to collect its allowed revenues. Of
279 course, if the weather is hotter than normal, the Company may over collect its
280 revenues. In other words, attempting to push the tail block rates to an extreme
281 could create unacceptable volatility in the Company’s revenues. What is needed

³ Marginal cost analysis also requires a determination of the relevant marginal costs imposed upon society. These are costs imposed upon society, but not explicitly included in the price of the good produced. The classic example is the “external” cost of pollution.

282 here is to set the tail block rate in such a way that energy conservation could be
283 achieved while at the same time not pushing all of the rate recovery risk onto the
284 Company.

285 **Comments on Gimble's Direct Testimony**

286

287 **Q. On page 27, lines 786 to 789, Mr. Gimble stated that the tail block rate he**
288 **proposed (11.806) is the lower end of the marginal generation cost range**
289 **estimated by Mr. Chernick. Can you comment on the appropriateness of this**
290 **tail block rate?**

291 A. Yes. As I discussed earlier in my rebuttal testimony, the marginal cost analysis
292 performed by Mr. Chernick is not correct and could not be relied upon. However,
293 the Division concurs with the Committee that properly developed marginal cost
294 information could be used to guide the rate design. Therefore, the Division
295 supports the Committee's recommendation that the Company be required to
296 undertake a marginal cost study to help guide future rate designs.

297 **Q. On Page 26, lines 742 to 743, Mr. Gimble proposed to leave the residential**
298 **customer charge at \$2.00/month and increase the minimum bill to \$4.00.**
299 **Can you comment on this?**

300 A. Yes. The Division believes that there is no cost basis for the Committee's
301 proposed customer charge. Mr. Gimble justifies his proposal on the basis of
302 gradualism and an analysis performed by Mr. Chernick. The Division argues that,
303 in the rate case under Docket No. 06-035-21, the Commission considered striking
304 a balance between the principles of gradualism and cost causation and moved the
305 customer charge from \$0.98 to \$2.00 per month instead of the recommended

306 \$3.67 per month. This represented a \$1.02 (approximately 38% of the gap
307 between \$0.98 and \$3.67) increase. The Division believes that this was a gradual
308 move of the customer charge and needs to be continued. Leaving the customer
309 charge at \$2.00 is contrary to the principle of gradualism. Rather it is stagnation.

310 Regarding Mr. Chernick's customer charge analysis, it seems that Mr. Gimble is
311 arguing that the \$2.40 per month customer charge is the maximum amount it
312 should be. The Division argues that Mr. Chernick's proposal actually represents a
313 minimum customer charge. Therefore, the \$2.00 per month customer charge
314 proposed by Mr. Gimble does not even represent the minimum suggested by the
315 Committee's consultant, Mr. Chernick.

316
317 **Q. Can you elaborate on why you think that Mr. Chernick's customer charge**
318 **analysis indicates that the residential customer charges should be at least**
319 **\$2.40.**

320 A. Yes. Mr. Chernick estimated that a customer charge of \$2.40 per month
321 accurately reflects the costs of minimum-size residential customers in multi-
322 family housing *without the cost of service drops or any adjustment to estimated*
323 *meter reading costs* (Chernick, Direct Testimony, lines 722 – 725). Mr. Chernick
324 testifies that services for this type of multi-family housing are overpriced, and
325 argues that such residents are subsidizing all other residential customers. It
326 follows, therefore, that the customer costs for residents other than those
327 minimum-size residential customers in multi-family housing should be higher
328 than \$2.40. If Mr. Chernick's \$2.40 figure represents the minimal customer cost
329 for any residential customer, then the current \$2.00 customer charge is too low.

330 **Q. How does Utah’s current \$2 customer charge compare with similar charges**
331 **in other states within the Company’s service area?**

332 A. The Company’s current Utah customer charge is significantly lower than what it
333 charges in other states within its service territory. For example, the current
334 Wyoming residential customer charge is \$10.18. The Company proposes to
335 increase this charge to \$20 in its current Wyoming rate case.⁴ The Company plans
336 to increase this rate to \$26 in its next Wyoming rate case filing. A Company
337 survey of eighteen Wyoming utilities indicates that average residential customer
338 charges are about \$15 month.⁵ Minimum charges for residential services in other
339 states within the Company’s service territory are as follows: Oregon has a basic
340 distribution charge of \$7.50/month; Washington has a basic charge of
341 \$5.25/month; Idaho has a minimum charge of \$10.27/month; California has a
342 basic charge of \$5.49/month.

343

344 **Q. Do you have a recommendation about what a reasonable rate of increase for**
345 **the customer charge should be?**

346 A. Yes. In the previous case, the Company claimed that a customer charge of \$3.67
347 was needed to cover its customer costs. This represented a proposed \$2.69
348 increase from the \$0.98 customer charge that was in effect at that time. In the end,
349 the Commission ordered that the customer charge be increased from \$0.98 to
350 \$2.00. This represented a \$1.02 increase. This was approximately 38 percent

⁴ See William R. Griffith’s Direct testimony, Wyoming PSC, Docket No. 20000-333-ER-8, p. 10.

⁵ Id., p. 11.

351 (\$1.02/\$2.67) of what the Company originally requested. The Division argues that
352 this rate of increase (38 percent) was accepted as reasonable and therefore could
353 be applied as a rate by which the current charge could be increased.

354 **Q. Does this mean that you are no longer testifying in favor of increasing the**
355 **customer charge to \$4.00 as the Company has proposed?**

356 A. That is correct.

357 **Q. Why have you changed this position?**

358 A. We have altered this position largely because of the Commission's revenue
359 requirement order. With an ordered rate increase of \$36 million, the residential
360 class' portion of that increase is actually less than the amount that would be
361 collected by increasing the customer charge to \$4.00. Even if the customer
362 charge were reduced by enough to equal the class' share of the rate increase, we
363 do not believe that it would be a good policy choice to place all of the residential
364 rate increase onto the fixed charge. A major portion of the increase should be
365 placed on volumetric rates in order to improve conservation and efficiency price
366 signals, as I discussed in my direct testimony.

367 **Q. What would the Division's proposed increase to the Residential customer**
368 **charge be if you indexed the current charge the 38% customer charge**
369 **increase from the last rate case?**

370

371 A. The customer charge would be increased from \$2.00 to \$2.76. However, for
372 simplicity, the Division recommends the customer charge to be \$2.75.

373 **Q. Can you show how you arrived at the proposed \$2.76 charge?**

374 A. Yes. In this filing, the Company is proposing a \$4.00 customer charge to cover
375 the Company's customer costs. This represents a \$2.00 increase from the current
376 \$2.00 customer charge. The current charge would be increased by \$0.76,
377 assuming that the Company should again receive 38 percent of the proposed hike
378 ($0.38 \times \$2.00 = \0.76). Adding the \$0.76 increase to the current \$2.00 charge
379 results in a residential customer charge of \$2.76.

380 **Comments on Mr. Higgins' Brubaker's Direct Testimonies**

381

382 **Q. What are your concerns regarding Mr. Higgins and Mr. Brubaker's direct**
383 **testimonies?**

384 A. Mr. Higgins raised a concern regarding how the Company interprets the effect of
385 the Revised Protocol cap on Utah class cost of service. His findings indicate that
386 because of the Company's misinterpretation of the impact of the Revised Protocol
387 cap, the class cost of service model moves approximately \$13 million from Utah
388 distribution and transmission systems to the Utah generation system. This
389 resulted in the cost responsibility of Schedule 9 being overstated.

390 Mr. Brubaker, indicated that the load research samples used by RMP in this
391 proceedings are too old and therefore can not be accepted as representative of
392 RMP's current Utah customers. Mr. Brubaker also indicated that there is a
393 mismatch between the loads used in RMP's class cost of service study and the
394 loads used in the jurisdictional study. Based on these two problems, Mr.

395 Brubaker concludes that the class cost of service is not reliable and should be used
396 as the basis for rate spread.

397 The Division agrees that the problem raised by Mr. Higgins along with the
398 problems raised by Mr. Chernick do have a substantial impact on rate spread
399 between the classes of service. For example, if Mr. Chernick's proposed changes
400 to the cost of service model are correct, more costs will be shifted onto Schedule 9
401 and away from Schedule 1. However, if Mr. Higgins' proposed changes to the
402 cost of service model are accepted, more costs will be shifted from Schedule 9 to
403 Schedule 1. There are many allocation factors in the class cost of service model.
404 Changes to any of these other allocation factors will also have rate spread
405 implications. Therefore, the Division believes that the problems indicated by Mr.
406 Higgins and Mr. Chernick indicate the need for comprehensive study of the class
407 cost of service model. Changing just a few aspects of the model, may result in
408 unfair cost shifting between the classes. Therefore, the Division recommends that
409 the Commission order the Company to comprehensively study the model as part
410 of the broader cost of service study group recommended above.

411 Regarding, the load research problems for Schedules 1, 6, and 23 indicated by Mr.
412 Brubaker and the load research problems indicated by Mr. Chernick, the Division
413 believes that if their analysis is correct, then there is reason for concern and the
414 class cost of service model should not be used as a guide for spread or design.
415 Therefore, if Mr. Chernick's and Mr. Brubaker's concerns about the load research
416 data are correct, the Division recommends that Schedules receive uniform rate
417 spread and all rate elements for all Schedules increased by an equal percentage.

418

419

UPDATES TO MY DIRECT TESTIMONY

420 **Q. Now that the Commission has issued its decision regarding Phase I of this**
421 **rate case, do you have updates to your direct testimony?**

422 A. Yes. I will update my recommendations regarding the rate spread and rate design.

423 **Q. What rate spread are you recommending?**

424 A. The Division ran the class cost of service model with the modifications ruled by
425 the Commission in Phase I of this rate case. The results of cost of service model
426 run indicate that the ROR index for Schedules 9 and 23 are 0.86 and 0.87,
427 respectively. This shows that both of these schedules are outside of the
428 Commission approved ROR band (0.9 to 1.1) implying that both of these
429 Schedules are earning less than their cost of service and should receive a rate
430 increase more than the jurisdictional average (2.64%). Therefore the Division
431 recommends a 4.14% and 4.46%⁶ increase for Schedules 9 and 23, respectively.
432 The Division arrived at these percent increases by balancing the cost causation
433 and gradualism principles of rate design. It will take the rates of these Schedules
434 to their respective cost based rates within two rate cases.

435 The class cost of service study also suggested a 28.1% rate increase for Schedule
436 10. However, the Division believes that this increase is so large and needs to be
437 applied gradually to promote customer acceptance and rate stability. Therefore,

⁶ COS suggested percent increase for a schedule (5.64% for Schedule 9 and 6.28% for Schedule 23) minus jurisdictional average increase (2.64%) divided by 2 plus the jurisdictional average increase.

438 the Division recommends an increase of 6.72%⁷. This percent increase will bring
439 revenues from Schedule 10 equal to its cost of service within three years. Again
440 this percent increase balances the gradualism and cost causation principles of rate
441 design.

442 The impact of the Division's proposed percent changes for Schedules 9, 23, and
443 10 are that Schedule 9 will pay \$2,384,729 more than the Company proposed and
444 Schedule 23 will pay \$1,904,099 more than proposed by the Company, whereas
445 Schedule 10 \$1,487,393 less than suggested by the COS study. The combined
446 effect is \$2,801,435 more than the COS study suggested for these three
447 Schedules. This money will be distributed among those rate schedules that were
448 either over-earning or where earning revenues that cover their cost of service.
449 These schedules include; Schedules 6, 8, and 25.

450 Further, the COS study indicates that Schedule 6 is over earning (ROR index of
451 1.18) and should receive an increase less the jurisdictional average.

452

453 Based on the above discussion, The Division is proposing the following rate
454 spread for the major classes:

455

456

⁷ COS suggested percent increase (22.81%) minus jurisdictional percent increase divided by three.

Schedule	DPU Proposed Rate Increase
Schedule 1	2.48%
Schedule 6	1.94%
Schedule 8	2.37%
Schedule 9	4.14%
Schedule 10	6.72%
Schedule 23	4.46%
Schedule 25	2.34%

458

459 **Q. What is your updated rate design for Schedule 1?**

460 A. The Division’s proposed residential rate design is summarized in DPU Exhibit
 461 9.4R. The Division proposes that the Commission increase the customer charge
 462 from \$2 per month \$2.75, keep the minimum charge at its current level, eliminate
 463 the CLC, keep the current three-block rate structure and increase the energy block
 464 rates in a manner that customers across the different usage levels receive the
 465 appropriate price signal. The Division proposes to increase the first (\$0.076362)
 466 and second (\$0.0868612) block price differential from approximately 1 cent to
 467 approximately 1.05 cents and to increase the second and third (\$0.102443) block
 468 price differential from approximately 1.5 cents to approximately 1.6 cents. The
 469 Division also proposes the winter energy charge be increased to equal the summer
 470 first block energy charge. These changes will allow recovery of the allowed
 471 residential revenue requirement.

472 **Q. What is the bill impact of your proposed residential rate design?**

473 A. The bill impact of the Division's proposed rate design is reported in DPU Exhibit
474 9.5R. This exhibit shows that the bill impact for the Division's proposed summer
475 and winter remains relatively close to one another for all customers at all
476 consumption levels (mostly between 1% to 1.4% for summer and between 1%
477 and 1.3% for winter) up to 1000 kWh. The percentage impact for the customers
478 in the third block is higher than that reported for the other blocks both during the
479 summer (between 1.4% and 1.6%) and the winter (1.3%). This reflects the
480 Division's policy of sending stringer conservation and efficiency price signal to
481 the customers whose usage level exceeds 1,000 kWh while balancing cost
482 causation and the gradualisms principles of rate design. A customer with an
483 average (summer) usage level (858 kWh/month) will see an increase of \$0.98 per
484 month during the summer and \$0.85 per month during the winter.

485 **Q. What rate design would you propose for Schedule 6 customers?**

486 A. The Division's proposal is summarized in DPU Exhibit 9.9R. In short, the
487 Division proposes that the demand charge be increased by 1.04% and 1.29%
488 during the summer and winter months, respectively. The energy charge should be
489 increased by 3.88% during the summer months and 2.23% during the winter
490 months. This will undo the disproportionately high payment by those low load
491 factor customers that was imposed during the 04-035-42 rate case. This proposal
492 also encourages energy conservation throughout the year, particularly during the
493 summer when it is most needed.

494

495 **Q. What is the bill impact of your proposal?**

496 A. DPU Exhibit 9.10R shows that the percent bill increase is higher for those
497 customers with high load factor than those with low load factor. This is achieved
498 while encouraging energy conservation and righting the inequity built into the rate
499 design for the low load factor customers from the 04-035-42 rate case.

500 **Q. What rate design would you propose for Schedules 23 (Distribution Voltage –**
501 **Small Customer) and 10 (Irrigation)?**

502 A. The proposed target revenue for Schedule 10 (Irrigation Service) should receive
503 an increase of 10.16% including its share of the revenue reduction resulting from
504 the increased revenues from Schedules 23 and 9. This in conjunction with the
505 introduction of the new dispatch curtailment option will help the irrigation
506 customers in their bills.

507 DPU Exhibits 9.11R and 9.12R summarize the Division's specific rate designs for
508 Schedules 23 and 10, respectively. To encourage energy conservation, the
509 Division's rate design proposal for Schedule 23 puts most of the additional
510 revenue on the energy and demand charges on an equal percentage basis.

511 Otherwise, the design remains the same except that is rescaled to reflect the
512 Commission's order on Phase I of this rate case.

513 DPU Exhibit 9.13R shows the bill impacts of the Division's proposed rate design
514 for Schedule 23. This Exhibit shows that with any given load size, the bill impact
515 increases with the energy consumption level. It also shows that for the same

516 energy consumption level the bill impact increases with load size.⁸ This indicates
517 that Division's Schedule 23 rate design discourages unnecessary usage of both
518 energy and demand.

519 Exhibit 9.14R shows the bill impacts of the Division's proposals for Schedules
520 10. This Exhibit shows that the Division's proposed rates will have
521 proportionately similar impact on all customers regardless of their consumption
522 level and load size (mostly between 6.5% to 6.9% for all irrigation customers
523 during the irrigation season).

524

525 **Q. What rate design would you propose for Schedule 9 (General Service – High**
526 **Voltage)?**

527 A. DPU Exhibits 9.15R summarizes the Division's specific rate designs for
528 Schedules 9. To encourage energy conservation and efficient use of equipment,
529 the Division's rate design proposal for Schedule 9 puts most of the additional
530 revenue on the energy and demand charges on an equal percentage basis. The rest
531 of the Division's proposal rate design concepts remain the same. The Division's
532 proposal is superior to the Company's in that it encourages energy conservation
533 and will help curb the summer peak.

534 DPU Exhibits 9.16R shows the bill impacts of the Division's proposal for
535 Schedules 9. This Exhibit shows that the bill impacts remains relatively the same

⁸ For example, for energy consumption level of 10,000 kWh the bill impact will be 5% for a load size of 20 kW, 6.3% for a load size of 25 kW and 6.7% for a load size of 30 kW.

536 for all consumption levels and load sizes regardless of what the proportion of the
537 energy consumed during the peak period is.

538 **Q. What rate design would you propose for Schedule 8?**

539 A. The Division's proposal is summarized in Exhibit 9.17R. The Division proposes
540 to collect most of the additional revenue on demand and energy charges on an
541 equal percentage basis. This will encourage energy conservation and efficient use
542 of equipment. The Division also proposes that both the summer and winter
543 differential between the on-peak and off-peak energy rates be slightly increased.
544 Exhibit 9.18R shows the bill impact of the Division's proposed rates for Schedule
545 8. The exhibit shows that this proposal results in an equal percentage change in
546 customer bills for customers at all consumption levels (2.4% for summer and
547 2.3% for winter.)

548 **Q. Does this conclude your testimony?**

549 A. Yes.