

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power for Alternative Cost Recovery for Major Plant Additions of the Ben Lomond to Terminal Transmission Line and the Dave Johnston Generation Unit 3 Emissions Control Measure)	Docket No. 10-035-13
)	Direct Testimony of Donna Ramas
)	For the Office of Consumer Services

REDACTED

REDACTED INFORMATION HIGHLIGHTED IN GRAY

April 26, 2010

Revised April 28, 2010

Table of Contents

	Page
INTRODUCTION	1
SO2 EMISSION ALLOWANCES	6
DAVE JOHNSTON UNIT 3 POLLUTION CONTROL EQUIPMENT –	
JOINT/Common COSTS	15
BEN LOMOND TO TERMINAL TRANSMISSION LINE.....	21

1 **INTRODUCTION**

2 **Q. WHAT IS YOUR NAME, OCCUPATION AND BUSINESS ADDRESS?**

3 A. My name is Donna Ramas. I am a Certified Public Accountant licensed in
4 the State of Michigan and a senior regulatory analyst at Larkin &
5 Associates, PLLC, Certified Public Accountants, with offices at 15728
6 Farmington Road, Livonia, Michigan 48154.

7

8 **Q. PLEASE DESCRIBE THE FIRM LARKIN & ASSOCIATES, PLLC.**

9 A. Larkin & Associates, PLLC, is a Certified Public Accounting Firm. The firm
10 performs independent regulatory consulting primarily for public
11 service/utility commission staffs and consumer interest groups (public
12 counsels, public advocates, consumer counsels, attorneys general, etc.).
13 Larkin & Associates, PLLC has extensive experience in the utility
14 regulatory field as expert witnesses in over 600 regulatory proceedings,
15 including numerous electric, water and wastewater, gas and telephone
16 utility cases.

17

18 **Q. HAVE YOU PREPARED AN EXHIBIT SUMMARIZING YOUR**
19 **QUALIFICATIONS AND EXPERIENCE?**

20 A. Yes. I have attached Appendix I, which is a summary of my regulatory
21 experience and qualifications.

22

23 **Q. ON WHOSE BEHALF ARE YOU APPEARING?**

24 A. Larkin & Associates, PLLC, was retained by the Utah Office of Consumer
25 Services (OCS) to review Rocky Mountain Power's (the Company or
26 RMP) application for alternative cost recovery for major plant additions
27 associated with the Ben Lomond to Terminal transmission line and the
28 Dave Johnston Unit 3 pollution control related plant additions.
29 Accordingly, I am appearing on behalf of the OCS.

30

31 **Q. HAVE YOU PREPARED ANY EXHIBITS IN SUPPORT OF YOUR**
32 **TESTIMONY?**

33 A. Yes. I have prepared Exhibits OCS 2.1 through 2.4, which are attached to
34 this testimony.

35

36 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

37 A. I recommend three separate modifications to the revenue requirement
38 calculations presented by RMP in its case, two of which pertain to the
39 Dave Johnston Unit 3 pollution control investment and one for the Ben
40 Lomond to Terminal transmission line. Specifically, I recommend that:

41 (1) The full annual level of projected revenues associated with the sale
42 of incremental SO₂ emissions allowances resulting from the
43 pollution control investment at Dave Johnston Unit 3 be reflected to
44 offset the increase in costs caused by the project;

45 (2) 50% of the costs that are common to both Dave Johnston Unit 3
46 and Dave Johnston Unit 4 pollution control equipment not be

47 depreciated for ratemaking purposes until such time as the Dave
48 Johnston Unit 4 pollution control equipment is placed into service;
49 and
50 (3) The projected plant in service for the Ben Lomond to Terminal
51 transmission line be reduced by \$8.5 million to remove the costs
52 identified as “forecast risk.”
53

54 **Q. IS THE OCS RECOMMENDING ANY ADDITIONAL ADJUSTMENTS?**

55 A. Yes. OCS witness Randall Falkenberg is recommending several
56 modifications to RMP’s calculation of the net power cost impact of the
57 projects at issue in this case. Cheryl Murray will provide a policy
58 recommendation that impacts the OCS’ revenue requirement
59 recommendation.
60

61 **Q. WHAT IS THE IMPACT ON THE REQUESTED REVENUE**
62 **REQUIREMENT RESULTING FROM THE OCS RECOMMENDED**
63 **ADJUSTMENTS IN THIS CASE?**

64 A. The impact of the recommended adjustments presented in this testimony,
65 combined with the impact of the adjustments recommended by OCS
66 witness Randall Falkenberg, results in a \$1,833,2562,335,734 reduction to
67 RMP’s requested increase under the rolled-in allocation methodology.
68 The reduction to RMP’s requested increase is \$1,902,0882,359,092 when
69 the 1% factor is applied. This percentage adder to the OCS adjustments

70 is necessary to analyze them on an equivalent basis to the Company's
71 request. Exhibit OCS 2.1 presents a summary of each of the OCS
72 recommended adjustments using the rolled-in allocation method along
73 with the revenue requirement impact of each adjustment both with and
74 without the 1% factor applied by RMP.

75

76 In deriving the revenue requirement impact of each adjustment, the
77 Company's jurisdictional allocation model was not used. The impact of
78 each adjustment was calculated on Exhibit OCS 2.1 and uses the
79 Commission authorized rate of return and the tax factors and revenue
80 conversion factors used by the Company. I was unable to tie the model
81 provided by the Company to the revenue requirement amounts¹
82 presented on Exhibit RMP__(SRM-1S) so I opted not to use the model in
83 deriving the impact of each of the adjustments.

84

85 Each of my recommended revisions will be addressed below. OCS
86 witness Randall Falkenberg is also recommending adjustments
87 associated with the impact of the projects on the net power costs incurred
88 by RMP in his direct testimony.

89

¹ The model provided by RMP resulted in the change in revenue requirement caused by the adjustments presented Exhibit RMP__(SRM-1S) being close, but not the same as, the amounts identified in Exhibit RMP__(SRM-1S), page 1.0, when the model is run using the rolled-in allocation methodology. The amounts differ substantially using the revised protocol allocation method in the model, which should not be the case.

90 **Q. HOW IS THE MULTI-STATE ALLOCATION CONSIDERED IN**
91 **DETERMINING THE COMPANY'S REVENUE REQUIREMENT AND**
92 **THE OCS ADJUSTMENTS?**

93 A. The Company's filing, as supplemented in Exhibit RMP__(SRM-1S),
94 requests an incremental increase in revenue requirement of \$33,018,593,
95 consisting of \$17,958,231 associated with the Dave Johnston Unit 3
96 pollution control investment and \$15,060,362 for the Ben Lomond to
97 Terminal transmission line. These amounts are derived using the rolled-in
98 allocation methodology plus 1% which RMP indicates is the revised
99 protocol mitigation cap. The application of the 1% factor increases the
100 Company's request by \$326,917.

101

102 The adjustments made by RMP in its filing are predominately allocated
103 using the System Generation (SG) allocation factor. A few items included
104 in the adjustments, such as the revenues from the sales of SO2 emissions
105 allowances and fuel costs, are allocated via the System Energy (SE)
106 allocation factor. Both the SG and the SE factors remain unchanged
107 under the rolled-in allocation method as compared to the revised protocol
108 allocation method. Thus, there is minimal difference between the revenue
109 requirement resulting from the major plant additions at issue in the case
110 between the rolled-in and the revised protocol allocation methods.

111

112 **SO2 EMISSION ALLOWANCES**

113 **Q. COULD YOU PLEASE PROVIDE A SUMMARIZATION OF THE**
114 **ADJUSTMENTS MADE BY RMP IN ITS FILING ASSOCIATED WITH**
115 **THE DAVE JOHNSTON UNIT 3 POLLUTION CONTROL EQUIPMENT?**

116 A. Yes. The Company's adjustment to include the revenue requirement
117 impact of the Dave Johnston Unit 3 pollution control equipment is
118 presented in Exhibit RMP__(SRM-1S), pages 2.0 and 2.1. The capital
119 expenditures included in the filing for the plant in service additions is
120 \$293.4 million, projected operation and maintenance costs associated with
121 operating the pollution control facilities are \$1.45 million per year and the
122 overall revenue requirement request associated with the project is \$17.96
123 million. In deriving the revenue requirement impact, RMP also reflected
124 \$19.9 million of associated plant retirements and reflected some of the
125 projected revenues from the sales of incremental SO2 emission
126 allowances. The associated impacts of the Company's adjustments on
127 depreciation and taxes were also reflected.

128

129 **Q. HAS THE COMPANY PROJECTED THAT THE INSTALLATION OF THE**
130 **DAVE JOHNSTON UNIT 3 POLLUTION CONTROL EQUIPMENT WILL**
131 **RESULT IN INCREASES IN THE SALES OF SO2 EMISSIONS**
132 **ALLOWANCES?**

133 A. Yes. According to the direct testimony of RMP witness Chad Teply, the
134 Dave Johnston Unit 3 dry flue gas desulphurization system and baghouse

135 will reduce SO2 emissions from the plant by approximately 6,600 tons per
136 year. As a result, the Company has estimated that it will sell the resulting
137 additional 6,600 tons of SO2 emissions allowances on an annual basis. In
138 response to OCS Data Request 4.15, the Company has confirmed that at
139 least for the next five years, 2010 through 2015, it estimates that it will sell
140 these 6,600 tons of SO2 emissions allowances on an annual basis.

141

142 **Q. HAS THE COMPANY INCLUDED THE RESULTING REVENUE FROM**
143 **THE SALE OF THE SO2 EMISSION ALLOWANCES AS AN OFFSET**
144 **TO THE DAVE JOHNSTON UNIT 3 COSTS INCLUDED IN ITS FILING?**

145 A. The Company's filing includes a small portion of the projected total annual
146 sales of the incremental tons of SO2 emission allowances that result from
147 implementation of the Dave Johnston Unit 3 pollution control equipment.
148 RMP projects annual revenues from the sales of the 6,600 tons of SO2
149 emission allowances of \$1,036,200. This is based on the 6,600 additional
150 tons of SO2 emission allowances and a projected price of \$157 per ton
151 sold. According to the response to OCS Data Request 4.11, the price of
152 \$157 per ton for 2010 SO2 emission allowances is based on the Clean Air
153 Interstate Rule spot price that was published by Evolution Markets and is
154 consistent with the price per ton that was incorporated in the test year in
155 the Company's most recent rate case, Docket No. 09-035-23, for the
156 months of January through June 2010.

157

158 While the Company is projecting annual sales of the incremental SO2
159 emission allowances of \$1,036,200 per year, the Company's filing only
160 reflects \$161,910 of revenues on a total Company basis. The amount
161 included by the Company as an offset to the costs is only 15.6% of the
162 projected annual level of incremental sales ($\$161,910 / \$1,036,200 =$
163 15.6%).
164

165 **Q. GIVEN THAT THE COMPANY HAS PROJECTED OVER \$1 MILLION**
166 **OF REVENUES FROM THE SALES OF THE INCREMENTAL SO2**
167 **EMISSION ALLOWANCES, WHY IS IT ONLY REFLECTING A**
168 **PORTION OF THOSE REVENUES AS AN OFFSET TO THE**
169 **INVESTMENT COST IN ITS FILING?**

170 A. This is due to the methodology used by the Company in reflecting the
171 revenues from the sales of the SO2 emission allowances. According to
172 the response to OCS Data Request No. 4.14, RMP has included the
173 proceeds from the projected sales of the incremental SO2 emission
174 allowances in accordance with the Commission's Order in Docket No. 97-
175 035-01. The Order in Docket No. 97-035-01 approved a four-year
176 amortization of SO2 sales revenues.

177

178 **Q. IF THE COMPANY IS REFLECTING A FOUR-YEAR AMORTIZATION**
179 **OF THE SALES, THEN WHY ARE THE REVENUES PROJECTED IN**

180 **THE FILING LESS THAN ONE-FOURTH OR 25% OF THE PROJECTED**
181 **ANNUAL SALES LEVEL?**

182 A. This is because of the methodology employed by the Company in
183 reflecting its adjustment. RMP's filing assumes that the sales will occur
184 evenly throughout the 12-month period and it begins the amortization of
185 each month's projected sales in that month. This results in significantly
186 less than one-fourth of the projected annual level of sales being reflected
187 in the Company's filing.

188

189 **Q. IN YOUR OPINION, IS THE METHODOLOGY USED BY THE**
190 **COMPANY TO REFLECT THE REVENUES RESULTING FROM THE**
191 **INCREMENTAL SO2 EMISSION ALLOWANCE SALES**
192 **APPROPRIATE?**

193 A. No, it is not. The Company's filing includes 100% of the capital cost
194 associated with the Dave Johnston Unit 3 pollution control equipment and
195 100% of the projected incremental operations and maintenance costs,
196 which are \$1.45 million, associated with running that equipment. This
197 includes the full annual cost level associated with removing and disposing
198 of the 6,600 tons of SO₂. The full annual benefit associated with
199 removing the SO₂ and the resulting projected annual revenues resulting
200 from the sales of the incremental SO₂ emission allowances should flow
201 back to customers and not be spread over a four-year period. The
202 Company projects that the sales of the 6,600 tons of SO₂ emission

203 allowances will occur on an annual basis; thus, there is no need to reflect
204 only one-fourth amortization in each year of these incremental sales. It
205 would be unfair to expect ratepayers to pay the full capital and operations
206 and maintenance costs associated with removing the SO2 emissions and
207 not also flow back 100% of the projected revenues resulting from the sales
208 of the incremental SO2 emission allowances.

209

210 **Q. WOULD YOU PLEASE DISCUSS THE COMMISSION'S ORDER IN**
211 **DOCKET NO. 97-035-01, AS IT PERTAINS TO THE SALES OF SO2**
212 **EMISSION ALLOWANCES?**

213 A. The Commission's Order in Docket No. 97-035-01 adopted a stipulation of
214 certain revenue requirement issues in that case. Included in those
215 stipulation issues was an agreement that the SO2 emission allowance
216 sales would be amortized over a period of four-years. Since that time,
217 each year's annual level of revenues was subsequently amortized over a
218 four-year period. The reason this methodology has been used is that the
219 level of SO2 emission allowance sales and revenues vary from year to
220 year. Thus, the amortization of each year's revenues over a four-year
221 period serves to normalize the level of SO2 emission allowance sales and
222 revenues that are incorporated into rates.

223

224 **Q. WHY DO YOU RECOMMEND THAT THE INCREMENTAL SO2**
225 **EMISSION ALLOWANCE SALES THAT WILL RESULT FROM THE**

226 **IMPLEMENTATION OF THE POLLUTION CONTROL EQUIPMENT BE**
227 **REFLECTED AT 100% INSTEAD OF AMORTIZED OVER A FOUR-**
228 **YEAR PERIOD?**

229 A. The installation of this equipment results in the SO₂ emissions coming
230 from Dave Johnston Unit 3 being reduced by 90% each year, which
231 equates to a reduction in the emission of SO₂ of approximately 6,600 tons
232 per year. The Company anticipates that it will have the 6,600 tons of
233 incremental SO₂ emission allowances available for sale each year going
234 forward. This differs from the fluctuations that have occurred historically
235 with the Company's sale of SO₂ emission allowances as the Company
236 projects it will sell these additional 6,600 tons each and every year. As the
237 Company is now allowed special treatment to include the cost associated
238 with the installation and the operation of the pollution control equipment
239 outside of a full general rate case proceeding², the full projected amount of
240 potential offsets to these incremental costs should also be reflected. It is
241 not appropriate to reflect only \$161,910 of SO₂ emission allowance
242 proceeds when the Company projects that it will receive \$1,036,200 each
243 year. As these incremental sales are anticipated to occur on an annual
244 recurring basis going-forward, there is no need to reflect the four-year
245 amortization to normalize these incremental sales. Additionally, as
246 indicated previously, 100% of the costs associated with removing the
247 6,600 tons of SO₂ are reflected in the Company's filing; thus, 100% of the

² Utah Code Section 54-7-13.4 allows for alternative cost recovery for major plant additions meeting certain parameters.

248 projected proceeds from the sales of the resulting incremental allowances
249 should also be reflected.

250

251 **Q. WHAT IMPACT DOES THE REFLECTION OF 100% OF THESE**
252 **REVENUES FROM THE PROCEEDS OF THE SALES OF THE**
253 **INCREMENTAL SO2 EMISSION ALLOWANCES HAVE ON THE**
254 **REVENUE REQUIREMENT PRESENTED BY RMP IN ITS**
255 **SUPPLEMENTAL FILING?**

256 A. As shown on Exhibit OCS 2.1, line 52, the impact would be a reduction to
257 revenue requirement of \$345,167 on a Utah jurisdictional basis. Exhibit
258 OCS 2.2 presents the adjustments that need to be made to reflect my
259 recommendation.

260

261 **Q. DO YOU FORESEE ANY EVENTS IN THE FUTURE THAT MAY**
262 **RESULT IN A DIFFERENT TREATMENT OF THE SO2 EMISSION**
263 **ALLOWANCE SALES?**

264 A. Yes, potentially. It is my understanding that there is a docket open before
265 the Commission in which the various parties are addressing whether or
266 not an ECAM should be implemented for Rocky Mountain Power in Utah.
267 In the event that an ECAM is put into place in a future period in the Utah
268 jurisdiction, the revenues associated with the sale of SO2 emission
269 allowances could potentially flow through such an ECAM mechanism.
270 However, since it is unknown at this time if or when an ECAM will be

271 implemented, I recommend that all of the projected incremental annual
272 revenues associated with the SO2 emission allowance sales resulting
273 from the implementation of the pollution control equipment be reflected as
274 an offset to the incremental revenue requirement caused by the
275 implementation of the pollution control equipment as part of this docket.
276 The OCS will address the treatment of SO2 emission allowance sales as it
277 pertains to a potential ECAM in the appropriate docket at the appropriate
278 time.

279

280 **Q. SINCE THE ANNUAL REVENUES ASSOCIATED WITH THE SALES OF**
281 **SO2 EMISSIONS ALLOWANCES ARE CURRENTLY BEING**
282 **AMORTIZED OVER A FOUR-YEAR PERIOD FOR UTAH RATEMAKING**
283 **PURPOSES, HOW COULD THE INCLUSION OF 100% OF THE**
284 **PROJECTED INCREMENTAL SALES ASSOCIATED WITH THE**
285 **IMPLEMENTATION OF THE POLLUTION CONTROL EQUIPMENT BE**
286 **TREATED FOR PURPOSES OF A FUTURE RATE CASE**
287 **PROCEEDING TO ENSURE THE INCREMENTAL REVENUE IS NOT**
288 **POTENTIALLY COUNTED TWICE IN DETERMINING RATES?**

289 A. In this case, I am recommending that \$1,036,200 of projected annual
290 revenues from the sale of the incremental SO2 emissions allowances be
291 included in deriving the revenue requirement associated with the Dave
292 Johnston Unit 3 pollution control equipment. Absent this methodology, it
293 would be at least four years before a full annual level of the incremental

294 sales are reflected in rates. Beginning July 1, 2010, the Company should
295 be permitted to exclude the first \$1,036,200 of annual sales from the
296 deferral and amortization. In other words, the first \$1,036,200 of revenues
297 associated with the sales of SO₂ emissions allowances would not be
298 deferred and amortized. Amounts of revenues from the sale of SO₂
299 emissions allowances in each annual period exceeding the \$1,036,200
300 would continue under the current methodology for ratemaking purposes.

301

302 This would ensure that ratepayers begin to receive the full benefit of the
303 projected annual sales of incremental SO₂ emissions allowances resulting
304 from the implementation of the pollution control equipment at the time the
305 Company would effectively begin to recover the pollution control
306 equipment capital and operating costs. By setting a dollar amount that is
307 included in rates, or \$1,036,200, it would also protect both the Company
308 and ratepayers in the event the sales prices of SO₂ allowances differ from
309 the projected amount included in this case. The Company's filing
310 assumes a price per ton of \$157; however, the actual price per ton
311 fluctuates. By setting a dollar amount that is included in rates and
312 continuing the current deferral and amortization methodology for SO₂
313 emissions allowance revenues in excess of the \$1,036,200, both RMP
314 and customers will be held harmless should the future sales price differ
315 from the \$157/ton assumed by RMP in its filing.

316

317 **DAVE JOHNSTON UNIT 3 POLLUTION CONTROL EQUIPMENT –**
318 **JOINT/COMMON COSTS**

319 **Q. THE COMPANY'S FILING REFLECTS AN ADDITION TO STEAM**
320 **PLANT IN SERVICE, FERC ACCOUNT 312, OF \$293,401,588 FOR THE**
321 **DAVE JOHNSTON UNIT 3 POLLUTION CONTROL EQUIPMENT. ARE**
322 **ALL OF THE COSTS INCLUDED IN THE \$293.4 MILLION SPECIFIC TO**
323 **THE DAVE JOHNSTON UNIT 3 PROJECTED INVESTMENT?**

324 **A.** No. As part of the project, the Company is also constructing pollution
325 control equipment on Dave Johnston Unit 4. The construction of each of
326 these projects is being done simultaneously as part of the same overall
327 project. The Company currently anticipates that the Dave Johnston Unit 4
328 pollution control equipment will be placed into service during the next
329 scheduled overhaul for that unit in 2012. There are certain joint assets
330 and joint costs being incurred that will be used for both Dave Johnston
331 Unit 3 and Dave Johnston Unit 4 pollution control. The costs included in
332 the Company's case consists of the investments specific to the Unit 3
333 pollution control equipment and all of the joint and common costs that will
334 be used by and benefit both Units 3 and 4.

335

336 **Q. WHAT TYPES OF JOINT COSTS THAT WILL BE USED FOR BOTH**
337 **DAVE JOHNSTON UNIT 3 AND UNIT 4 POLLUTION CONTROL**
338 **INVESTMENT PROJECTS ARE INCLUDED IN THE CAPITAL**
339 **EXPENDITURES REQUESTED FOR RECOVERY IN THIS CASE?**

340 A. OCS Data Request 4.22 (a) asks the Company to identify the costs that
341 are "shared capital" costs for both the Unit 3 and Unit 4 pollution control
342 project. In response the Company stated as follows:






343
344
345
346
347
348
349
350
351
352
353
354
355
356
357
358
359
360
361
362
363
364

Begin Confidential

End Confidential

365 As can be seen from the above quote, there are numerous components of
366 the project that are joint in nature and will be used to serve both the Dave
367 Johnston Unit 3 and Dave Johnston Unit 4 pollution control projects.

368 Again, these projects are being done simultaneously. **Begin**

369 **Confidential**

370 
371 
372 
373 

374 [Redacted]

375 [Redacted]

376 End Confidential

377

378 **Q. HOW WILL THE COMPANY ACCOUNT FOR THE JOINT COSTS**
379 **WHEN BOTH PROJECTS ARE COMPLETE?**

380 A. According to the confidential response to OCS Data Request 4.22 (a),

381 Begin Confidential [Redacted]

382 [Redacted]

383 [Redacted]

384 [Redacted]

385 [Redacted]

386 [Redacted]

387 [Redacted]

388 [Redacted]

389 [Redacted]

390 [Redacted]

391 [Redacted]

392 [Redacted]

393 [Redacted] End Confidential the Company has requested

394 inclusion of \$293.4 million in plant in service in this case associated with

395 the project.

396

397 **Q. ARE THERE ANY BENEFITS TO PLACING THE PROJECTED**
398 **COMMON COSTS THAT WILL BE COMPLETE AS OF JUNE 30, 2010**
399 **INTO PLANT IN SERVICE AS PART OF THIS CASE?**

400 A. As indicated by the Company, the common facilities that will be shared by
401 Dave Johnston Units 3 and 4 need to be operational and in service prior to
402 the Dave Johnston Unit 3 pollution control equipment being put into place
403 and operational. While the common facilities will not yet be used to their
404 full capacity until such time as Dave Johnston Unit 4 pollution control
405 equipment comes into service, those common facilities will be used to
406 serve customers at the time that the Dave Johnston Unit 3 equipment is
407 placed into service. By placing the common plant costs into service, the
408 result is that the accumulation of allowance for funds used during
409 construction (AFUDC) on the common facilities will cease as of the time
410 the facilities are placed into service. Thus, the total cost associated with
411 the common facilities should not increase in the future as a result of
412 accumulating additional AFUDC on the project costs.

413

414 **Q. ARE YOU RECOMMENDING ANY ADJUSTMENTS ASSOCIATED**
415 **WITH THE COMPANY'S INCLUSION OF 100% OF THE COMMON**
416 **COSTS ASSOCIATED WITH THE DAVE JOHNSTON UNIT 3 AND**
417 **DAVE JOHNSTON UNIT 4 POLLUTION CONTROL INVESTMENT**
418 **PROJECTS IN THIS CASE?**

- 419 A. I am not recommending any reductions to the amount the Company has
420 proposed to include in plant in service as part of this case at this time.
421 However, I am recommending a reduction to depreciation expense
422 associated with the common facilities that will be used as part of both the
423 Dave Johnston Unit 3 and Dave Johnston Unit 4 pollution control projects.
424 I recommend that the portion of the common costs that will ultimately be
425 assigned to the Dave Johnston Unit 4 pollution control equipment, or 50%
426 of those costs, not receive depreciation recovery as part of this case. As
427 part of this recommendation, the Company would begin to receive a return
428 on its common joint facility investment, but not a return of the portion that
429 is associated with the Dave Johnston Unit 4 pollution control investment.
430
431 I recommend that the portion of the common costs associated with Dave
432 Johnston Unit 4, or 50% of the common costs, not begin to be depreciated
433 by RMP for ratemaking purposes until the Dave Johnston Unit 4 pollution
434 control project is placed into service by the Company. The portion of the
435 common costs that will benefit Dave Johnston Unit 4 should be spread
436 over the life of that unit and depreciated with the Dave Johnston Unit 4
437 pollution control project costs that are specific to that unit.
438
- 439 **Q. WHAT AMOUNT IS INCLUDED IN THE \$293.4 MILLION BEING ADDED**
440 **TO PLANT IN SERVICE THAT IS ASSOCIATED WITH THE JOINT OR**
441 **COMMON COSTS THAT BENEFIT BOTH OF THE UNITS?**

442 A. According to the Company's response to DPU Data Request 6.6,
443 confidential attachment DPU 6.6(b), of the total \$293,401,586 being added
444 to plant in service by the Company in this case, Confidential
445 that cost is associated with common facilities.

446

447 **Q. WHAT ADJUSTMENT IS NEEDED TO REFLECT YOUR**
448 **RECOMMENDATION THAT ONLY 50% OF THE COMMON FACILITY**
449 **COSTS BE DEPRECIATED AT THIS TIME?**

450 A. The result is a recommended reduction to depreciation expense included
451 in the filing of Confidential. As shown on Exhibit OCS 2.3 (Confidential),
452 this amount is derived by Begin Confidential

453

454

455 End Confidential This recommendation
456 would also impact the amount of accumulated depreciation and
457 accumulated deferred income taxes incorporated in the Company's filing.

458

459 **Q. WHAT IS THE OVERALL IMPACT ON REVENUE REQUIREMENT AS A**
460 **RESULT OF YOUR RECOMMENDATION REGARDING**
461 **DEPRECIATION EXPENSE?**

462 A. My recommendation that only 50% of the common plant cost be
463 depreciated as part of this case results in a reduction in revenue
464 requirement of ~~\$330,933~~787,936 on a Utah jurisdictional basis.

465

466 **Q. DOES THIS RECOMMENDATION RESULT IN THE COMPANY NOT**
467 **BEING ABLE TO RECOVER ALL OF ITS COMMON INVESTMENT**
468 **ASSOCIATED WITH THE INSTALLATION OF THE POLLUTION**
469 **CONTROL EQUIPMENT ON DAVE JOHNSTON UNITS 3 AND 4?**

470 A. No, it does not. Rather, it assigns the depreciation associated with the
471 Dave Johnston Unit 4 pollution control equipment to begin at such time
472 that the unit is actually placed into service and serving customers. In the
473 interim the Company would still earn a return on the common facilities that
474 will serve both units.

475

476 **BEN LOMOND TO TERMINAL TRANSMISSION LINE**

477 **Q. INCLUDED IN THE COMPANY'S FILING IS \$268,202,035 IN**
478 **ESTIMATED CAPITAL COSTS FOR THE BEN LOMOND TO TERMINAL**
479 **TRANSMISSION LINE. ARE YOU RECOMMENDING ANY**
480 **ADJUSTMENTS TO THE COMPANY'S PROPOSED ADDITION TO**
481 **PLANT IN SERVICE ASSOCIATED WITH THIS PROJECT?**

482 A. Yes. Exhibit RMP_(DTG-2), attached to the direct testimony of RMP
483 witness Darrell Gerrard, provides a breakdown of the \$268.2 million of
484 Ben Lomond to Terminal estimated capital cost. This was the Company's
485 estimate of the cost as of December 2009. Included in the breakdown is a
486 component for allowance for funds used during construction and
487 overheads totaling \$29,885,709. This total consists of: (1) AFUDC of

488 \$15,625,709; (2) PacifiCorp overheads of \$5,760,000; and (3) "Forecast
489 Risk" of \$8.5 million. I recommend that the forecast risk item of \$8.5
490 million be removed.

491

492 **Q. WHY DO YOU RECOMMEND THAT THIS COMPONENT BE**
493 **REMOVED?**

494 A. DPU Data Request 8.4 asked the Company to explain what is meant by
495 "forecast risk", inquired if it was considered a contingency item, and asked
496 the Company to describe how the forecast risk was calculated. In
497 addition, the Company was asked to provide all supporting documentation
498 for the \$8.5 million. In response the Company stated as follows:

499 The "forecast risk" line item included in the exhibit of Darrell
500 Gerrard's testimony is not considered a contingency. This
501 amount is an estimate for any changes in AFUDC rates or
502 PacifiCorp overheads until the end of the project. The
503 project will only receive actual AFUDC or overhead charges
504 incurred up through completion of the project.
505

506 The Company has clearly not supported the additional \$8.5 million it
507 included in the \$268.2 million cost estimate. The DPU had specifically
508 asked the Company to describe how the amount was calculated and to
509 provide all supporting documentation for the amount. In response the
510 Company provided no support or data showing how the amount was
511 derived and did not justify inclusion of the \$8.5 million. The Company
512 merely indicated that it is an estimate for changes in AFUDC rates or
513 PacifiCorp overheads until the end of the project. However, the Company

514 has already included \$15.6 million of AFUDC and \$5.76 million of
515 PacifiCorp overheads. At this time RMP has not justified or explained the
516 additional \$8.5 million it has identified as forecast risk; therefore, I
517 recommend that it be removed.

518

519 **Q. WHAT IMPACT ON REVENUE REQUIREMENT DOES THE REMOVAL**
520 **OF THE \$8.5 MILLION FROM THE PROJECT COST HAVE?**

521 A. The removal of \$8.5 million from the additions to plant in service also
522 impacts accumulated depreciation, depreciation expense, and property
523 taxes. The necessary adjustments are reflected on Exhibit OCS 2.4. As
524 shown on OCS Exhibit 2.1, line, 54, the impact on revenue requirement on
525 a Utah jurisdictional basis of removing the \$8.5 million of plant additions
526 as well as the associated impacts is a reduction to revenue requirement of
527 \$561,363. Ms. Murray will provide the OCS' final revenue requirement
528 recommendation.

529

530 **Q. DOES THIS COMPLETE YOUR PREFILED DIRECT TESTIMONY?**

531 A. Yes.