

Rocky Mountain Power
Docket No. 10-035-124
Witness: Gregory N. Duvall

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Direct Testimony of Gregory N. Duvall

Net Power Costs

January 2011

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

3 A. My name is Gregory N. Duvall. My business address is 825 NE Multnomah, Suite
4 600, Portland, Oregon, 97232. My present position is Director, Long Range
5 Planning and Net Power Costs.

6 **Qualifications**

7 **Q. Briefly describe your education and business experience.**

8 A. I received a degree in Mathematics from University of Washington in 1976 and a
9 Masters of Business Administration from University of Portland in 1979. I was
10 first employed by PacifiCorp in 1976 and have held various positions in resource
11 and transmission planning, regulation, resource acquisitions and trading. From
12 1997 through 2000 I lived in Australia where I managed the Energy Trading
13 Department for Powercor, a PacifiCorp subsidiary at that time. After returning to
14 Portland, I was involved in direct access issues in Oregon and was responsible for
15 directing the analytical effort for the Multi-State Process (“MSP”). Currently, I
16 direct the work of the integrated resource planning group, the load forecasting
17 group, the net power cost group, and the renewable compliance area.

18 **Summary of Testimony**

19 **Q. Will you please summarize your testimony?**

20 A. I present the Company’s proposed net power costs (“NPC”) for the test period of
21 12-months ending June 2012. The first section of my testimony explains the test
22 period NPC increase and describes the major cost drivers underlying the increase.
23 I also review how the Company has modeled NPC in this case.

24 Additionally, in the last case in which NPC was fully litigated, the
25 Company's 2009 general rate case, Docket No. 09-035-23 ("2009 GRC"), the
26 Commission's order ("2009 Rate Case Order") directed the Company to provide
27 additional information and analysis on certain issues. The second section of my
28 testimony addresses these issues. On several major issues, including market caps
29 and wind integration, I explain how the Company has refined and developed its
30 modeling approaches since the 2009 GRC.

31 **Summary of Net Power Costs in the Current Filing**

32 **Q. What are the forecasted normalized system-wide NPC for the 12-month**
33 **period ending June 2012?**

34 A. The Company's total forecasted normalized system-wide NPC for the test period
35 of 12-months ending June 30, 2012, are approximately \$1.521 billion on a total
36 Company basis, and \$649.1 million on Utah allocated basis.

37 **Q. Please compare NPC forecasted in this case to NPC now in rates.**

38 A. NPC on a total Company basis as authorized by the Commission in the
39 Company's 2010 second major plant addition case ("MPA 2 Case"), Docket No.
40 10-035-89, are approximately \$994.2 million. The Company's forecast net power
41 costs in this case are higher by approximately \$527.1 million on a total Company
42 basis.

43 **Q. How does the test period NPC in the current case compare with the actual**
44 **NPC?**

45 A. For the 12-month period ended June 30, 2010, which is the test period in the MPA
46 2 Case, the Company's actual NPC are approximately \$1,064.2 million, or \$70.0

47 million higher than normalized NPC from that case. The most recent 12-month
48 actual NPC through November 2010 are \$1,172.3 million or \$178.1 million
49 higher than normalized NPC from the MPA 2 Case. Actual NPC illustrates the
50 escalation of NPC since the MPA 2 Case, which reflected one of the lowest NPC
51 levels of the last several years.

52 **Q. Please generally describe the drivers of the increased NPC reflected in this**
53 **filing.**

54 A. The increase in NPC is driven by three main factors: load growth, increases in
55 coal costs, and the reduction in wholesale sales revenue for the test period. NPC
56 in this case also reflects many changes in the Company's portfolio of resources.
57 Each of these factors is described below.

58 **Major Cost Drivers in the Forecast Test Period NPC**

59 **Q. How does the retail load forecast impact the Company's NPC?**

60 A. This filing reflects an increase of approximately 3.4 million megawatt-hours, or
61 5.9 percent, in the total Company load forecast compared to loads in the 2009
62 GRC (which were also the basis of NPC in the MPA 2 Case). All else held
63 constant, increased load increases NPC. In this case, load growth increased NPC
64 by approximately \$109 million. For further details on the load forecast, please
65 refer to the testimony of Company witness Dr. Peter C. Eelkema.

66 **Q. Have the Company's coal costs impacted the NPC in the current proceeding?**

67 A. Yes. NPC are higher due to increases in the costs of third-party coal supply and
68 transportation agreements, and cost increases at the Company's captive mines.
69 Approximately one-third of the NPC increase in this case is attributable to coal

70 costs. This issue is addressed in detail in the direct testimony of Company witness
71 Ms. Cindy A. Crane.

72 **Q. How does the reduction in wholesale sales revenue impact the NPC in the**
73 **current filing? Please explain.**

74 A. The wholesale sales revenues in the current filing are lower than what are in the
75 MPA 2 case, which increases NPC in the current filing. The drop in wholesale
76 sales revenues is mainly caused by the changes in the Company's load and
77 resource balances. As stated above, the Company's system load is approximately
78 3.4 million megawatt-hours higher. In addition, due to expiration of long term
79 contracts, the Company's purchased power under the long term contracts is
80 approximately 1.6 million megawatt-hours lower. That is, the Company has lost
81 approximately 5.0 million megawatt-hours of resources that could be sold to the
82 wholesale market because of just these two changes. The 91 percent drop from
83 over 5 million megawatt-hours to less than 0.5 million megawatt-hours in the
84 short term firm sales is reflective of such an impact.

85 **Q. What are the major changes to the long term firm power contracts in the test**
86 **period of 12-months ending June 2012?**

87 A. The contracts with changes in the test period include:

- 88 • On October 1, 2010, the purchase contract between the Company and the Top
89 of the World Wind Energy, LLC went in effect. This contract and the
90 procurement process are described in the direct testimony of Company
91 witness Mr. Stefan A. Bird.
- 92 • On January 1, 2011, the amount of sales to the Public Service Company of

93 Colorado (“PSCol”) reduced per the contract terms, and then expires on
94 December 31, 2011. The contract is a legacy sales contract at relatively high
95 contract prices.

- 96 • On June 30, 2011, the exchange contract between the Company and the Alcoa
97 Power Generating Inc. (“APGI”) for approximately 100 megawatts of
98 capacity from the Rocky Reach project expires. Under this contract, the
99 Company receives capacity during peak periods and returns energy during off-
100 peak periods.
- 101 • On August 31, 2011, the contract between the Company and the Bonneville
102 Power Administration (“BPA”) for 575 megawatts of capacity expires. Under
103 this contract, the Company receives energy during peak periods and returns
104 energy during off-peak periods. In addition, power received under this
105 contract is delivered directly to a variety of the Company’s load pockets in the
106 western area at the Company’s discretion.
- 107 • On September 30, 2011, the contract between the Company and the Grant
108 Public Utility District (“Grant PUD”) for displacement generation expires,
109 which is priced at BPA’s Priority Firm Power (“PF”) rate.
- 110 • On October 31, 2011, the contract between the Company and the Chelan
111 Public Utility District (“Chelan PUD”) for generation from the Rocky Reach
112 project expires. Power purchased by the Company under this contract is priced
113 at the embedded cost of the project.
- 114 • On December 31, 2011, the contract between the Company and the Biomass
115 One qualifying facility expires, which was in effect since 1987 and at then

116 relatively high prices for purchases from qualifying facilities.

117 **Q. Has the Company made assumptions about the power rates and transmission**
118 **rates proposed in the current rate cases of BPA?**

119 A. Yes. The BPA rate cases are to determine the new rates for the fiscal period
120 beginning in October 2011. Given the current proposals made by BPA, the
121 Company assumes that the wheeling expenses of the transmission contracts that
122 the Company has with BPA would not change in the new rate effective period
123 beginning in October 2011. In the current filing, the Company has incorporated
124 the proposed wind integration charge at \$1.32/kW-month beginning in October
125 2011, which is a change from the current \$1.29/kW-month. The Company has
126 also incorporated the impact of BPA's proposal in charges for reserves and
127 power.

128 **Q. Does the Company expect to update the expenses related to all contracts with**
129 **BPA?**

130 A. Yes. The Company will update its NPC on rebuttal with the final decision of the
131 BPA rate cases, or when better information becomes available.

132 **Q. Has the Company included in the current filing a retail interruptible**
133 **contract that expires prior to the test period?**

134 A. Yes. The current contract between the Company and Monsanto for operating
135 reserve purchases expired at the end of 2010. The price of this contract is
136 currently under review by the Idaho Public Utilities Commission in the Company
137 general rate case. In this filing, the terms of the existing contract are assumed to
138 continue. The Company will update to the terms of the new contract when

139 available. The Company expects the Idaho Public Utilities Commission to rule on
140 this issue in February 2011.

141 **Q. Does the Company model the impact of capital additions from the**
142 **Company's two major plant addition cases in 2010, Docket Nos. 10-035-13**
143 **and 10-035-89?**

144 A. Yes. In this filing, the Company has incorporated the impact of Dave Johnston
145 unit 3 scrubber, the Populus to Terminal transmission line, and the Dunlap wind
146 facility.

147 **Modeling of NPC and Model Inputs and Outputs**

148 **Q. Please explain NPC.**

149 A. NPC are defined as the sum of fuel expenses, wholesale purchase power expenses
150 and wheeling expenses, less wholesale sales revenue.

151 **Q. Please explain how the Company calculates NPC.**

152 A. NPC are calculated for a future test period based on projected data using the
153 Generation and Regulation Initiative Decision ("GRID") model. GRID is a
154 production cost model that simulates the operation of the Company's power
155 system on an hourly basis.

156 **Q. Is the Company's general approach to the calculation of NPC using the**
157 **GRID model the same in this case as in previous cases?**

158 A. Yes. The Company has used the GRID model to determine NPC in its filings for
159 several years.

160 **Q. Is the Company using the same version of the GRID model as used in its 2009**
161 **GRC and MPA 2 Case?**

162 A. Yes, except a new release of the same version providing additional reports to
163 address the thermal generating unit commitment logic issue.

164 **Q. What inputs were updated for this filing?**

165 A. All input data have been updated since the 2009 GRC and MPA 2 Case, which
166 include system load, wholesale sales and purchase contracts for electricity, natural
167 gas and wheeling, market prices for electricity and natural gas, fuel expenses,
168 characteristics and availability of the Company's generation facilities.

169 **Q. Has the Company changed its topology modeled in GRID?**

170 A. Yes. To assure the reliability of the transmission network in the area governed by
171 the Western Electricity Coordinating Council ("WECC"), the constraint in the cut
172 plane named Tot 4A in Wyoming has been redefined by PacifiCorp Transmission
173 and approved by WECC. As a result, the previously modeled transmission areas
174 of "Wyoming NE" and "Wyoming SW" in GRID have been redefined. In
175 addition, because of constraints that are present in the previous "Wyoming SW"
176 transmission area, a "Trona" transmission area has been added to the topology to
177 reflect such constraints.

178 In addition, the Company proposed a different modeling of non-firm
179 transmission, which I will address later in my testimony.

180 **Q. What reports does the GRID model produce?**

181 A. The major output from the GRID model is the NPC report. This is attached to my
182 testimony as Exhibit RMP__(GND-1). Additional data with more detailed

183 analyses are also available in hourly, daily, monthly and annual formats by heavy-
184 load hours and light-load hours.

185 **Q. Do you believe that the GRID model appropriately reflects the Company's**
186 **forecasted net power costs over the test period?**

187 A. Yes. The GRID model reasonably simulates the operation of the Company's
188 system load and resource portfolio consistent with the Company's operation of its
189 system including operating constraints and requirements. GRID produces a
190 reasonable forecast based on "static" assumptions that are different from actuals
191 for the same period.

192 **Issues Identified in the 2009 Rate Case Order**

193 **Q. Pursuant to the 2009 Rate Case Order, is the Company providing further**
194 **information and analysis on specific NPC issues?**

195 A. Yes. In the 2009 Rate Case Order, the Commission requested that the Company
196 address certain NPC issues in its next full NPC filing. Pursuant to this directive,
197 my testimony addresses the following issues, which are listed in Paragraph III.B.3
198 of the 2009 Rate Case Order:

- 199 1. GRID Market Capacity Limits
- 200 2. Uneconomic Modeled Operation
- 201 3. Start-up Fuel Energy Value
- 202 4. Chehalis Start-up Costs
- 203 5. Short-Term Firm (STF) Transmission Test Year Synchronization
- 204 6. Transmission Imbalance
- 205 7. Wind Integration Charge

206 8. Stateline and Long Hollow Wind Integration Costs

207 9. Minimum Loading Deration and Heat Rate Modeling

208 **1. GRID Market Capacity Limits**

209 **Q. As a part of approving the Company's market caps in the 2009 GRC, did the**
210 **Commission request updated support for the caps in the future?**

211 A. Yes. At page 27 of the 2009 Rate Case Order, the Commission stated that "(w)e
212 will, in this case, accept the Company's use of the market caps but will require
213 updated support in the future to determine if these caps continue to be relevant
214 and if they are not resulting in unintended and inappropriate consequences with
215 respect to forecasting STF sales in graveyard hours."

216 **Q. How did the Company model the market capacity limits in GRID in the 2009**
217 **GRC and previous cases?**

218 A. The GRID model assumes unlimited market depth for system balancing sales and
219 purchases. To reflect the illiquidity of the four major wholesale sales markets,
220 Mid-Columbia ("Mid C"), California Oregon Border ("COB"), Four Corners, and
221 Palo Verde ("PV") during graveyard hours and in all hours for the illiquid market
222 hub of Mona, the Company modeled caps on market depth. The Commission first
223 recognized the need for market caps in Docket No. 03-035-14, Order (Oct. 31,
224 2005) (approving the Company's use of market caps when calculating avoided
225 costs).

226 **Q. Has the Company refined its modeling of the limits on market depth for the**
227 **wholesale sales markets in GRID in the current filing?**

228 A. Yes. After the 2009 GRC, the Company reviewed its approach to market caps and

229 developed a more accurate and comprehensive approach to modeling market
230 depth. Instead of specifying market depth for graveyard hours only, the Company
231 now proposes to specify market depth during all hours, segregated by heavy-load-
232 hour (“HLH”) and light-load-hour (“LLH”) periods. The Company believes that a
233 market may be liquid, but this liquidity does not translate into unlimited sales at
234 any time of day or night. Due to load requirements and transmission constraints in
235 the region and static assumptions about market prices in GRID, among other
236 things, the Company may not be able to sell all its economic generation to the
237 markets.

238 **Q. How has the Company determined the market depths it uses as an input to**
239 **GRID?**

240 A. The market depths for wholesale sales in GRID are determined based on the
241 historical short term firm transactions during the same 48-month period on which
242 availability of the thermal generation is based. The depths are then reduced by the
243 quantity of short term firm transactions that the Company has included in the
244 normalized NPC study for the test period in all sales markets.

245 **Q. What is the impact of this change in methodology?**

246 A. The new methodology allows GRID to make more sales in the graveyard hours,
247 but limits sales at some other times. A study using data from the 2009 GRC shows
248 that the net impact of the change in modeling methodology is an increase in NPC
249 of less than \$1 million on a total Company basis.

250 **Q. Have you compared the coal generation in GRID using the new market caps**
251 **against the historical coal generation?**

252 A. Yes. In that study using data from the 2009 GRC, the coal generation during the
253 LLH increased by approximately 550,000 megawatt-hours with the new market
254 caps compared with the study using the graveyard-hour caps from the 2009 GRC.
255 The HLH coal generation is 140,000 megawatt-hours lower than what was
256 modeled previously. As compared with the actual coal generation in the historical
257 period used as the basis in the 2009 GRC, the coal generation in that study is
258 higher in both HLH and LLH periods. Thus, based on the data from the 2009
259 GRC, the new caps (1) continued to allow GRID to model more than actual coal
260 generation, proving that they do not unduly constrain the markets; and (2) allowed
261 GRID to reflect more coal generation on a net basis than the old market caps.

262 **2. Uneconomic Modeled Operation**

263 **Q. How did the 2009 Rate Case Order address the commitment logic screens?**

264 A. On pages 29-30 of the 2009 Rate Case Order, the Commission adopted the daily
265 screening method proposed by the Office of Consumer Services (“OCS”) and, in
266 future cases, directed the Company to provide certain information requested by
267 OCS to facilitate modeling of the screens.

268 **Q. Has the Company adopted daily screens?**

269 A. Yes. The Company has refined the daily screens ordered in the 2009 GRC, and
270 developed a set of more effective daily screens as inputs to GRID. The Company
271 models all the gas units to run starting at the beginning of the test period, and then
272 uses daily screens to turn them off if they are not economical to run. Once all

273 other inputs have been set, final NPC are determined after a series of GRID runs
274 to screen out the uneconomic commitment of gas-fired plants. The screens are set
275 in a manner that prevents the gas-fired plants from being committed to run if they
276 displace less expensive resources taking into consideration start-up costs and
277 other operational constraints of starting up and shutting down gas units.

278 **Q. Has the Company modified the outputs from GRID to provide more**
279 **information to facilitate such screens?**

280 A. Yes. The Company has implemented a new release of GRID that has a new report
281 consolidating several individual reports necessary for the screening process, as
282 requested by OCS and directed by the Commission.

283 **3. Start-Up Fuel Energy Value**

284 **Q. How did the Commission decide the issue of the value of start-up energy in**
285 **the 2009 Rate Case Order?**

286 A. The Commission stated on page 34 of its 2009 Rate Case Order that “(w)e will
287 accept the Company’s explanation in this case and make no adjustment to value
288 start-up energy. However, in the future the Company must demonstrate
289 quantitatively that the value associated with GRID model simplifications offsets
290 the value of start-up energy.”

291 **Q. Why does the Company believe that it is inappropriate to model the value of**
292 **start-up energy in GRID?**

293 A. Start-up costs are not limited to fuel. In order to accommodate the start-up of a
294 500 to 600-megawatt gas unit, the Company must re-dispatch the system. In doing
295 so, the Company incurs costs beyond what it would have incurred had the start-up

296 not occurred. These costs could result from ramping down the lower-cost hydro
297 and thermal units to lower efficiency levels, and increasing generation from
298 higher-cost units prior to when they are needed. None of these costs are included
299 in GRID. In addition, if start-up energy is to be considered, the multi-hour start-up
300 sequence must also be considered. The end result is that the units would need to
301 stay offline and be unavailable for a longer time in order for the adjustment for
302 start-up energy to be applicable.

303 **Q. Did the Company perform a study to quantify one of the aspects mentioned**
304 **above -- extending minimum down time of the units?**

305 A. Yes. Extending the minimum down time for those gas-fired units in GRID and
306 using the same methodology proposed by the Division of Public Utilities
307 (“DPU”), the system NPC increases by approximately \$0.6 million.

308 **Q. Is the impact of increasing NPC limited to the value stated above?**

309 A. No. As discussed above, extending the minimum down time is only one of the
310 aspects that need to be considered in modeling the start-up energy of the gas-fired
311 units. Incorporating the other aspects in NPC, (e.g., less efficient operation of
312 hydro and thermal units) would increase NPC further.

313 **4. Chehalis Start-up Costs**

314 **Q. How did the Commission rule on the issue of Chehalis start-up costs?**

315 A. The Commission stated on page 39 of its 2009 Rate Case Order that “(a)s the
316 Chehalis plant has limited operational data, we will accept use of the Currant
317 Creek derived data for this case as a reasonable proxy at this time. In the next
318 power cost case, we direct the Company to provide documentation supporting any

319 Chehalis start-up assumptions and to provide a detailed explanation comparing
320 these assumptions to those used in the Chehalis approval proceeding, Docket No.
321 08-035-35.”

322 **Q. Does the Company continue to use the same assumption for the Chehalis**
323 **start-up costs, which is based on data from Currant Creek?**

324 A. Yes.

325 **Q. Please explain.**

326 A. The Currant Creek and Chehalis facilities are both 2x1 configured combined
327 cycle plants which burn natural gas as their fuel. Both plants use two General
328 Electric 7241FA combustion turbine generators and one conventional steam
329 turbine. The gas turbines at both plants are connected to heat recovery steam
330 generators, which take the combustion turbine exhaust gas and use it to convert
331 water into steam as in a conventional boiler. The steam is then passed through
332 conventional steam turbines to generate additional electrical energy. At both
333 plants, the exhaust steam from each of the steam turbines is passed through an air-
334 cooled condenser where it is condensed back to water and reused in the heat
335 recovery steam generator. Total nominal output is approximately 540 megawatts
336 at Currant Creek, which includes 105 megawatts of duct firing capability and 520
337 megawatts at Chehalis.

338 The major factor contributing to the differences in the combined cycle
339 capability is that the Currant Creek plant is sited at 5,051 feet elevation and
340 Chehalis plant is located at 230 feet of elevation. At Chehalis, inlet air cooling is
341 achieved with a spray mist fog cooling system, whereas the Currant Creek facility

342 utilizes evaporative cooling. Other than elevation differences, the only material
343 difference between the plants are that the Currant Creek plant has approximately
344 105 megawatts of duct-firing capability whereas the Chehalis plant has no duct
345 firing capability.

346 Operational similarities exist as well between Currant Creek and Chehalis.
347 The full time staffing at both plants is comparable with 18 full time equivalents at
348 Currant Creek and 19 full-time equivalents at Chehalis. The largest plant
349 operating costs, excluding fuel and labor, at each facility are the costs to maintain
350 the combustion turbines. General Electric provides this service at both facilities
351 under long-term contractual service agreements. The Company renegotiated both
352 long-term contractual service agreements in 2009 to take advantage of having
353 multiple, like-kind combustion turbines. The two facilities now share major
354 combustion turbine parts needed for performing planned combustion turbine
355 overhauls.

356 Based on the similarities in configuration, operation and maintenance
357 described above, the Company believes it is appropriate to assume that both
358 plants will have the same start-up cost.

359 **Q. Is this start-up cost different from what the Company assumed in Docket No.**
360 **08-035-35? Please explain.**

361 A. Yes. The Chehalis start-up costs assumed in Docket No. 08-035-35 were based on
362 the tolling agreement for operating the Chehalis plant with Suez energy
363 Marketing NA, Inc., which was the best information available to the Company at
364 the time and appropriate for the purposes of evaluating the initial plant

365 acquisition. However, the start-up costs as specified in the tolling agreement were
366 not comparable to the start-up costs used in GRID for determining whether to
367 commit the plant to run. For the purposes in Docket No. 08-035-35, there were
368 other fixed and variable O&M costs applied in the studies, which included the
369 impact of the starting up the plant. For purposes of modeling the Chehalis plant in
370 GRID, proxy data based on Currant Creek's start-up costs is more accurate than
371 the information from the tolling agreement.

372 **5. STF Transmission Test Year Synchronization**

373 **Q. What did the Commission request the Company to provide in its 2009 Rate**
374 **Case Order?**

375 A. On page 42 of its order, the Commission accepted the Company's modeling of
376 STF transmission, but directed the Company to explain several issues related to
377 modeling of STF and non-firm ("NF") transmission in GRID, including the
378 reason why the wheeling expenses are not modeled the same as wheeling
379 revenues and outside the model and what the distinctions are between the two
380 types of transmission.

381 **Q. How did the Company model STF and NF transmission in the Company's**
382 **2009 GRC?**

383 A. The availability of STF transmission was modeled based on the historical four-
384 year averages, and the expenses of the STF transmission was based on the most
385 recent actual STF wheeling expenses. The availability and variable expenses of
386 the NF transmission were both based on the historical four-year averages.

387 **Q. Has the Company made any changes to its modeling of NF transmission in**
388 **the current filing and why?**

389 A. Yes. The Company has included the NF transmission in the current filing in the
390 same manner as STF transmission, both the capability and expenses.

391 **Q. Please explain why the Company now treats the NF transmission the same as**
392 **the STF transmission.**

393 A. In the process of reviewing how the Company has utilized NF transmission, it is
394 clear that the Company purchases and uses STF and NF transmission in the same
395 way. The transmission providers offer certain amounts of transmission capacity as
396 firm products, and the rest as non-firm. The only difference between the two
397 products is that NF transmission will be cut for reliability purposes first. The
398 Company purchases NF transmission in the same way as the STF transmission, so
399 the expenses are incurred whether the amount of transmission capacity purchased
400 is fully utilized each hour or not. As a result, the Company has combined the STF
401 and NF transmission, and modeled all the short term transmission capability based
402 on four-year average of the historical purchases of transmission, and the expenses
403 in the base period of the current filing.

404 **Q. Why does the Company use the four-year average for availability and the**
405 **most recent year of data for costs in modeling short term transmission?**

406 A. The volume of the short term transmission varies from year to year. The Company
407 uses four-year average availability to smooth such variation and to estimate the
408 amount of transmission that would reasonably be available in the test period, and
409 uses the most recent year of expense to capture the most recent costs associated

410 with acquiring transmission services from third-party transmission providers
411 whose tariff rates could update periodically.

412 **Q. Since short term wheeling expenses do not vary with the energy transferred**
413 **through those transmission paths, why doesn't the Company model the**
414 **expenses outside the model?**

415 A. The Company could capture the wheeling expenses outside the GRID model.
416 However, consistent with how the other costs are treated in GRID that do not vary
417 with amount of energy delivered, such as the capacity payments of wholesale
418 power contracts and reservation charges of the pipelines for delivery of natural
419 gas, the Company elected to capture the wheeling expenses in GRID.

420 **Q. Why does the Company treat wheeling expenses differently from wheeling**
421 **revenues?**

422 A. Wheeling expenses and wheeling revenues are caused by different activities.
423 Wheeling expenses are incurred by the Company's merchant function to serve its
424 retail load obligations, and to make off-system wholesale sales, and are paid to
425 third parties for the rights to use their transmission facilities. In contrast, wheeling
426 revenues are received by the Company's transmission function to operate its
427 owned transmission facilities, and are paid by third parties who requested the
428 rights to wheel power on those facilities.

429 **6. Transmission Imbalance**

430 **Q. What did the Commission direct the Company to address related to the**
431 **transmission imbalances?**

432 A. In accepting the Company's modeling of transmission imbalances, on page 44 of

433 the 2009 Rate Case Order, the Commission stated that“(w)e note two factors
434 raised by the Company that will need to be addressed in the next case addressing
435 power costs. The first is the assumption of no intra-hour markets for power. We
436 understand this issue is evolving and direct the Company to explain how the
437 existence of such a market will impact the transmission imbalance issue. Second,
438 we direct the Company to explain and demonstrate that basing the imbalance
439 energy tariff on the market price index is better for retail rate payers than
440 incremental and decremental generation price.”

441 **Q. What is the requirement placed on the Company in providing imbalance**
442 **services as a balancing area authority?**

443 A. Under the Company’s Open Access Transmission Tariff (“OATT”), the Company
444 is obligated by the Federal Energy Regulatory Commission (“FERC”) to provide
445 imbalance service for wholesale transmission customers consistent with
446 Schedules 4 and 9 of the OATT.

447 **Q. What is the Company’s expectation of how intra-hour markets for power**
448 **would impact the services that it provides for handling transmission**
449 **imbalances as a balancing area authority?**

450 A. The existence of intra-hour markets and intra-hour scheduling is expected to
451 reduce the differences between scheduled and actual generation during the hour.
452 Under current scheduling practices, a customer must schedule generation as final
453 at 20 minutes to the hour and any deviations as a result of actual generation
454 amounts during the subsequent hour create imbalance. A joint initiative group in
455 the western interconnection is working to develop common business practices that

456 will allow schedule adjustments at the half hour. The Company's transmission
457 business practice #48, which is posted on the Company's Open Access Same-
458 Time Information System ("OASIS") website, currently allows limited non-firm
459 intra-hour schedules. Unfortunately, until such time as most balancing authorities
460 in the west provide for similar practices, an intra-hour market will not be
461 available. At the present time, there virtually are no intra-hour markets in the
462 Company's balancing areas. Recently, FERC issued a Notice of Proposed
463 Rulemaking ("NOPR" or the "Proposed Rule") on integration of variable energy
464 resources that I will discuss in more detail below, in which FERC proposes that
465 public utility transmission providers should provide more frequent transmission
466 scheduling intervals, so that transmission customers can adjust their transmission
467 schedules or submit new schedules intra-hour to reflect, in advance of real-time,
468 more accurate generation profiles. Implementation of 15-minute scheduling will
469 provide transmission customers increased opportunities to adjust schedules and
470 better manage imbalances, specifically those caused by variable resources such as
471 wind generation. The Company is actively exploring the proposals in the NOPR
472 and will provide comments to FERC by March 2, 2011.

473 **Q. Would the existence of intra-hour markets change how the Company models**
474 **transmission imbalances in GRID?**

475 A. No. For normalization purposes, the Company assumes transmission schedules
476 and actual transfers will match, meaning it is not necessary to provide imbalance
477 services to transmission customers.

478 **Q. How does the Company charge for imbalance services?**

479 A. The service and associated charges for transmission imbalances are part of the
480 Company's OATT as described in Schedules 4 and 9, which define imbalance
481 charges according to a tiered market price structure. If the Company is making up
482 a customer's energy shortfall, the energy provided to the customer will be at the
483 defined market price as if the Company were to procure the needed energy for
484 that hour from another seller.

485 Conversely, if the Company is paying a customer for any energy surplus, the
486 defined price will be what the Company could sell that surplus into the market.
487 Over time, the imbalance and the associated payments are expected to balance.
488 The tiered approach in Schedules 4 and 9 is established by the FERC as an
489 incentive for transmission customers to properly schedule resources to load and to
490 limit imbalance costs.

491 **Q. Why does the Company use market indexes to price the transmission**
492 **imbalances?**

493 A. The resources that the Company uses to provide imbalance service represent the
494 lost opportunity for the Company to make or avoid market sales or purchases
495 when the service is required by transmission customers. In addition, using market
496 indexes to price the imbalance is a transparent mechanism that the Company can
497 use to recover from or pay to customers using the service. Imbalance charges or
498 payments can create billing disputes with customers if the pricing mechanism
499 isn't clear and transparent or has any hint of subjectivity by the Company. A
500 transparent mechanism eliminates billing disputes and challenges associated with

501 service charges.

502 **Q. Please explain why the Company believes that incremental and decremental**
503 **pricing is not transparent and can lead to disputes.**

504 A. The Company operates its resource portfolio to serve all its obligations, and does
505 not differentiate between resources used for meeting its various load obligations.
506 Furthermore, in order to determine the incremental and decremental generation
507 prices, the Company would need to identify the costs of the resource(s)
508 dispatched for the last incremental obligation, which would require considerations
509 of various factors in the dispatch of the resources, including incremental fuel and
510 O&M of the owned resources, operational requirements of the generating units,
511 contractual requirements of the fuel supply for the units, and dispatchability of
512 contracted resources. As a result, the Company believes that FERC-approved
513 OATT pricing for imbalance service based on market indexes are reasonable.

514 **7. Wind Integration Charge**

515 **Q. How did the Commission decide the issue of wind integration costs in the**
516 **2009 Rate Case Order?**

517 A. On pages 49-50 of the Order, the Commission approved the Company's wind
518 integration charge of \$6.62 per megawatt-hour, but directed the Company "to
519 enhance its wind integration methodology" to address the issues raised by other
520 parties in the 2009 GRC.

521 **Q. Has the Company enhanced its wind integration methodology since its 2009**
522 **GRC?**

523 A. Yes. As part of the 2011 Integrated Resource Plan ("IRP"), the Company

524 performed an extensive study on the impact of integrating wind generation into its
525 resource portfolio (“Wind Study”)¹. The Wind Study was created after reviewing
526 the issues and concerns raised by various parties in Utah and other jurisdictions,
527 such as whether the wind integration costs should be studies independent of load,
528 the amount of additional reserves needed to integrate the wind generation and
529 what resources should be utilized to serve the additional reserve requirements.

530 **Q. Could you briefly describe the Company’s Wind Study?**

531 A. Yes. The purpose of the Wind Study is twofold. First, the Wind Study quantifies
532 how wind generation affects the amount of additional reserves needed to maintain
533 reliability. Second, the Wind Study determines the costs of integrating wind
534 generation by measuring how system costs change with changes in operating
535 reserve demand, and by measuring how system costs are affected by daily system
536 balancing practices.

537 **Q. What are the additional reserve requirements?**

538 A. The Wind Study identified additional reserve requirements in two categories:
539 regulating services that deal with load and wind variability in ten-minute
540 intervals, and load following services that deal with load and wind variability over
541 hourly time intervals. Both services respond to the up and down variations of
542 wind generation. That is, the additional reserve requirements to integrate wind
543 generation into the Company’s resource portfolio consist of regulation up,
544 regulation down, load following up and load following down. The Wind Study

¹ The Wind Study can be found on the Company’s website at http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/Wind_Integration/PacifiCorp_2010WindIntegrationStudy_090110.pdf.

545 performed analyses of additional reserve requirements for load only (excluding
546 wind generation) and for wind net of load (including wind generation), based on
547 historical 10-minute data for the Company's system.

548 **Q. Besides providing regulating services and load following services, what other**
549 **costs are incurred to integrate the wind generation?**

550 A. Given the size of the wind portfolio, and the possibility of rapid variations in wind
551 generation from the forecast displayed in the historical actual operation, the
552 Company expects that it will need to continue committing its gas units to be able
553 to quickly respond to the magnitude of changes. At times, this "must-run"
554 operation would require gas units to run when it would otherwise be uneconomic
555 to do so, therefore adding to the wind integration costs.

556 **Q. What are the costs identified by the Wind Study?**

557 A. The Wind Study shows that the costs of integrating wind generation into the
558 Company's resource portfolio (regulation and load following services, system
559 balancing and the requirement of must-run) for the three-year period from 2011 to
560 2013 are \$9.70 per megawatt-hour at the wind generation penetration level of
561 1,833 megawatt, which is the level of wind currently in the Company's balancing
562 areas.

563 **Q. How did the Company apply the results from the Wind Study?**

564 A. Instead of applying the dollar per megawatt-hour charge to the wind generation,
565 the Company updated the amount of load following requirement as modeled by
566 GRID to capture the impact of regulation up and load following up, both of which
567 are identified in the Wind Study. The assumption is that if the resources are

568 sufficient to serve the regulation up and load following up, they may be sufficient
569 to serve the regulation down and load following down. The amount of the total
570 load following requirements is based on the wind penetration level at 1,833
571 megawatts, which are 337 average megawatts and 196 average megawatts for the
572 east and west sides of the Company's system, respectively. In addition, as
573 identified in the Wind Study, the Company also modeled the Currant Creek unit,
574 and Gadsby units 4, 5 and 6 as must-run units that are not subject to the logic of
575 being committed to run only when economic. The result of this approach is an
576 analytically enhanced wind integration charge that is, as reflected in GRID for the
577 current filing, approximately equal to the charge previously approved by the
578 Commission.

579 **Q. How much is included in NPC for system balancing costs which are incurred**
580 **as a result of day-ahead forecast errors for wind and load?**

581 A. The Company modeled \$0.71 per megawatt-hour for system balancing costs,
582 which is the 2011-2012 average of system balancing costs as indentified in the
583 Wind Study.

584 **Q. Do you believe that the Company reasonably modeled the Wind Study**
585 **results in GRID for the current filing?**

586 A. Yes. Given the complexity of the subject, I believe that the result from GRID has
587 reasonably reflected the impact of integrating wind generation into the
588 Company's portfolio. In addition, the Wind Study has addressed all the issues
589 raised by DPU, Utah Association of Energy Users ("UAE") and OCS in the
590 Company's 2009 GRC, such as reserve requirements being modeled within

591 GRID, the requirements for wind generation being considered net of load, and the
592 quality of data used to prepare the study. However, given the limitation of data
593 inputs to the normalized studies, I believe that the GRID modeled impact of
594 integrating wind resources may understate the real costs. For example, the GRID
595 model uses expected wind profiles of the wind projects which lack the variability
596 reflected in the actual operations of the wind projects.

597 **Q. What does the Company include as the system balancing costs for the non-**
598 **owned wind projects, and the overall wind integration costs for projects**
599 **located in the BPA's balancing area?**

600 A. The forecast NPC in the current filing do not include system balancing costs for
601 the wind projects located in the Company's balancing areas that the Company
602 neither owns nor purchases the output based on the assumption that the entities
603 that own and/or operate those wind projects will balance their own system prior to
604 handing over their generation schedule to the Company that balances the
605 variations within the hour as the balancing area authority. Following the same
606 logic, the forecast NPC includes system balancing costs for projects located in
607 BPA's balancing area: Leaning Juniper and Goodnoe Hills.

608 **8. Stateline and Long Hollow Wind Integration Costs**

609 **Q. How did the Commission address the issue related to third party wind**
610 **projects?**

611 A. Stateline and Long Hollow are two wind projects located in the Company's
612 balancing authority areas, but the Company does not receive their output. They
613 require transmission and ancillary services provided under the Company's OATT.

614 The OATT does not contain an explicit charge for integrating wind resources, so
615 the Company cannot charge these costs directly to third party projects. On page
616 51 of its order, the Commission allowed third party wind integration charges but
617 directed “the Company to address this issue prior to its next rate request to avoid
618 the risk of a cost disallowance.”

619 **Q. Does the Company plan to raise this issue in its next FERC rate case?**

620 A. Yes. The Company plans to file a rate case with FERC no later than June 1, 2011,
621 in which the Company will include updated charges for ancillary services needed
622 to integrate wind, pending any FERC guidance on the issue.

623 **Q. Has there been any guidance from FERC in this matter since the Company**
624 **made the plan? If so, please describe.**

625 A. Yes, on November 18, 2010, the FERC issued a Notice of Proposed Rulemaking
626 (“NOPR” or the “Proposed Rule”) on integration of variable energy resources,
627 such as wind. In general, the NOPR proposes that public utility transmission
628 providers implement operational and scheduling changes to help integrate wind,
629 including 15-minute intra-hourly transmission scheduling and power production
630 forecasting using meteorological and operational data. FERC also proposes to add
631 an ancillary service rate schedule through which public utility transmission
632 providers will offer regulation service to transmission customers delivering
633 energy from a generator located within the transmission provider’s balancing
634 authority area.

635 **Q. Would the Proposed Rule allow the Company to charge non-owned wind**
636 **generators the cost of integrating their generation into the transmission**
637 **system, and how?**

638 A. Yes. If the proposals in the NOPR remain unchanged and pending any additional
639 guidance from FERC, the Company should be able to propose an ancillary service
640 rate for regulation service to transmission customers delivering energy from a
641 generator located within the Company's balancing authority area, which would
642 include wind. As required by the Federal Power Act, this charge would have to be
643 applied on a non-discriminatory basis. Currently, the OATT does not permit
644 public utility transmission providers to charge generators for regulation service
645 unless the generator is a transmission customer who also serves load in the
646 balancing area.

647 **Q. Does the Company believe that this new wholesale ancillary service charge, if**
648 **approved by FERC, helps recover the costs of integrating wind? Please**
649 **explain.**

650 A. Yes. Regulation service is a type of energy reserve service necessary for
651 integrating resources into the transmission system. Regulating reserves account
652 for the variability of load and generation on the transmission system on a
653 moment-to-moment basis. If the NOPR proposals remain unchanged and are
654 approved as part of a final rule, the new charge would apply to resources when
655 they are exporting to load in other balancing authority areas and would result in
656 additional revenues from non-owned resources that are not delivering power to
657 serve the Company's native load.

658 **Q. Did FERC provide additional guidance in the NOPR on what it proposes to**
659 **require before it will allow public utility transmission providers to impose a**
660 **charge that collects a different volume of regulating reserves from variable**
661 **energy resources? If so, please describe.**

662 A. Yes. In the NOPR, FERC states that to the extent a public utility transmission
663 provider proposes to impose a charge on variable energy resources for a different
664 volume of generator regulation reserves than it proposes to charge transmission
665 customers delivering energy from other generating resources, such differing
666 volumes must be shown to be commensurate with the variability that the
667 resources exhibit on the transmission provider's system and the transmission
668 provider must show that it has implemented the other operational and scheduling
669 reforms proposed in the NOPR. The transmission provider must have
670 implemented the new tools for at least one year prior to filing any such proposal.

671 **Q. Does the Company believe the NOPR proposals support its plans to include a**
672 **proposed charge in its transmission tariff rates as part of its June 2011**
673 **transmission rate case?**

674 A. Yes, the Company believes the FERC NOPR provides important guidance and
675 direction on what the Company must do to address this issue. It is reasonable to
676 assume the NOPR will become a final rule. As such, the Company believes the
677 NOPR lays out the path to follow to begin charging non-owned facilities for the
678 costs incurred to integrate them into the Company's balancing areas. The
679 Company also believes, pending any additional guidance from FERC on this
680 issue, that it can include a proposal for a new regulation service charge as part of

681 the transmission rate case filing and that such a proposal has a higher chance of
682 being accepted because of this recent guidance. If and when approved by FERC,
683 such a charge will increase revenues that can be used to offset costs in the
684 Company's retail revenue requirement calculations.

685 **Q. What are the benefits to the Company's customers of providing such services**
686 **to the non-owned generation?**

687 A. As a balancing area authority, the Company owns and operates an extensive
688 transmission network that it is required to operate safely and reliably for all of its
689 customers, keeping all resources and loads in balance on a moment-to-moment
690 basis. In addition, the Company is mandated to make its transmission network
691 available to all generators in an open access and non discriminatory fashion. By
692 providing wind integration services in addition to other transmission related
693 services as a balancing authority, the Company ensures that its customers are
694 served by a reliable system, with diverse resources. Moreover, any transmission
695 revenues received from non-owned generation, which pays wheeling to the
696 Company, are credited against retail revenue requirement and therefore have the
697 effect of lowering the cost of service for retail customers.

698 **9. Minimum Loading Deration and Heat Rate Modeling**

699 **Q. What did the Commission order regarding whether and how the heat rate**
700 **curves of the thermal units should be adjusted for the impact of derates?**

701 A. The Commission accepted the Company's modeling of this issue, but opined that
702 the issue warranted further investigation. On page 57 of the 2009 Rate Case
703 Order, the Commission stated that“(w)e direct the Company, Division and other

704 interested parties to review alternatives for addressing this issue, review actual
705 operations in comparison to modeling predictions, and to understand the extent of
706 the issue.”

707 **Q. Were there any discussions on the subject since the conclusion of the**
708 **Company’s 2009 GRC?**

709 A. Yes. DPU organized a meeting on September 8, 2010. The Company participated
710 in the discussion at the meeting, along with members of DPU and OCS, and their
711 consultants.

712 **Q. Were the issues resolved at the meeting?**

713 A. No. Both the Company and OCS were requested to provide further analyses
714 related to the impact of heat rate because of deration. Because the Company and
715 OCS’s consultant were litigating this issue in another state, neither the Company
716 nor OCS offered further analyses, and the issues were not resolved.

717 **Q. How does the Company respond to the Commission’s example of**
718 **“proportionally adjusting or compressing the heat rate curves so when a**
719 **plant is running at its full derated capacity it will have a heat rate associated**
720 **with the non-derated full capacity?”**

721 A. The Company does not believe such adjustment is necessary or warranted,
722 because the heat rate at derated capacity is still at a relatively efficient level. In
723 actual operations, a unit can be derated to any level between its minimum and
724 maximum capacities where the units can be significantly less efficient.

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

726 A. Yes.