

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

3 A. My name is Chad A. Teply. My business address is 1407 West North Temple,
4 Suite 210, Salt Lake City, Utah 84116. My position is vice president of resource
5 development and construction for PacifiCorp Energy. I report to the president of
6 PacifiCorp Energy. Both Rocky Mountain Power and PacifiCorp Energy are
7 divisions of PacifiCorp.

8 **Qualifications**

9 **Q. Please describe your education and business experience.**

10 A. I have a Bachelor of Science Degree in Mechanical Engineering from South
11 Dakota State University. I joined MidAmerican Energy Company in November
12 1999 and have held positions of increasing responsibility within the generation
13 organization, including the role of project manager for the 790-megawatt Walter
14 Scott Energy Center Unit 4 completed in June 2007. In April 2008, I moved to
15 Northern Natural Gas Company as senior director of engineering. In February
16 2009, I joined the PacifiCorp team as vice president of resource development and
17 construction, at PacifiCorp Energy. In my current role, I have responsibility for
18 development and execution of major resource additions and major environmental
19 projects.

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

21 A. The purpose of my testimony is to support the prudence of capital investments in
22 the new Lake Side 2 combined cycle combustion turbine (“CCCT”) natural gas
23 fueled resource, certain pollution control equipment retrofits on existing coal

24 fueled resources, and other significant generation plant projects being placed in
25 service during the test period in this docket, July 1, 2014 through June 30, 2015
26 (“Test Period”).

27 **Background**

28 **Q. Please provide a general description of the Lake Side 2 CCCT project being**
29 **placed in service during the Test Period and the benefits gained from the**
30 **investment.**

31 A. The Lake Side 2 Significant Energy Resource Decision was approved by the
32 Public Service Commission of Utah (“Commission”) in Docket No. 10-035-126
33 on April 20, 2011, following a comprehensive review of the project need and the
34 Company’s 2008 Request for Proposals (“RFP”) by the Commission, the Division
35 of Public Utilities, the Office of Consumer Services and other interested parties.
36 The Lake Side 2 project was determined to be the lowest reasonable cost option to
37 meet additional electricity needs of customers, taking into account costs and risks.
38 The Commission Order in Docket No. 10-035-126 contemplates a June 2014 in-
39 service date at a projected cost of [REDACTED], including transmission, to
40 acquire, construct and integrate the project into PacifiCorp’s system. Rather than
41 repeating what is already on record in Docket No. 10-035-126, I recommend that
42 the Commission take administrative notice of that docket for additional evidence
43 supporting the acquisition of the Lake Side 2 project.

44 The Lake Side 2 project remains on schedule to be placed in service by
45 June 2014 and is currently projected to be completed with a capital cost of
46 approximately [REDACTED], excluding transmission; approximately [REDACTED]

47 when including the Lake Side 2 transmission service project also included in this
48 docket. In each case, the project costs are trending favorably for customers to the
49 Company's previous forecasts and economic assessments originally utilized to
50 support the investment decision.

51 **Q. Please provide a general description of the emissions control equipment**
52 **investments being placed in service during the Test Period and the benefits**
53 **gained from the investments.**

54 A. The emissions control equipment investments included in this case are required to
55 comply with environmental laws, including the Clean Air Act Regional Haze
56 Rules and the Mercury and Air Toxics Standards ("MATS"), being administered
57 by the respective state agencies in which the units reside, as well as the U.S.
58 Environmental Protection Agency ("EPA"). The emissions control investments
59 primarily result in the reduction of nitrogen oxides ("NO_x"), particulate matter
60 ("PM"), sulfur dioxide ("SO₂"), and mercury ("Hg") emissions, depending upon
61 the individual installation at the retrofitted facilities.

62 The investments include a baghouse conversion (approximately [REDACTED]
63 [REDACTED], Company share) and low NO_x burners ("LNB") installation
64 (approximately [REDACTED], Company share) at Hunter Unit 1, and a selective
65 catalytic reduction ("SCR") system installation (approximately [REDACTED],
66 Company share) at Hayden Unit 1. The Hunter Unit 1 projects are required to be
67 installed by spring 2014 by the state of Utah Regional Haze State Implementation
68 Plan ("SIP") and have been determined to be the least cost compliance alternative
69 for the unit when incorporating costs for potential greenhouse gas ("GHG")

70 regulatory outcomes, other emerging environmental regulations, and potential
71 long-term incremental emissions reduction strategies into the economic
72 assessments of the projects.

73 The Hayden Unit 1 SCR is required by the state of Colorado's Regional
74 Haze SIP to be installed by December 31, 2016. The Hayden Unit 1 SCR is also a
75 key component of the NO_x reduction plan required to have been submitted by
76 Public Service Company of Colorado (the operator of Hayden Unit 1) to the
77 Colorado Public Utilities Commission under the Colorado Clean Air Clean Jobs
78 Act. The Colorado Public Utilities Commission ultimately approved Public
79 Service Company of Colorado's NO_x reduction plan, including the Hayden Unit
80 1 SCR project, on December 9, 2010. Public Service Company of Colorado has
81 since received a Certificate of Public Convenience and Necessity ("CPCN") for
82 the SCR project from the Colorado Public Utilities Commission after having
83 demonstrated that the investment was in the best interests of customers.
84 PacifiCorp is a minority owner of Hayden Unit 1, with an interest of 24.5 percent.
85 The Participation Agreement governing that ownership interest mandates the
86 installation of capital improvements that are required by applicable law. The
87 Participation Agreement also places an independent obligation on Public Service
88 Company of Colorado, as Operating Agent, to operate Hayden Unit 2 in
89 accordance with applicable law. The applicable laws requiring the Hayden Unit 1
90 SCR investment are mentioned above and discussed in detail later in this
91 testimony.

92 In each case, installation of these major emissions control retrofit projects
93 have been aligned with scheduled major maintenance outages for the affected
94 units to mitigate replacement power cost impacts while benefiting from
95 overlapping major maintenance outage time frames. These environmental
96 compliance investments constitute approximately [REDACTED] (approximately [REDACTED]
97 [REDACTED]) of the total capital investments projected to be placed in service within
98 the Test Period. These environmental compliance investments will allow the
99 retrofitted facilities to continue to operate as low-cost generation resources for the
100 benefit of customers.

101 **Q. Please provide a general description of the other significant generation plant**
102 **projects being placed in service during the test period and the benefits gained**
103 **from the investments.**

104 A. The other significant generation plant projects being placed in service during the
105 test period include the Blundell geothermal resource well integration project and
106 the Naughton Unit 3 natural gas conversion project.

107 The Blundell geothermal resource well integration project integrates two
108 new geothermal resource wells into the Blundell generation system. One
109 production well and one injection well, along with associated appurtenances, have
110 been drilled and will be placed in service to support continued reliable electricity
111 production at the site.

112 The Naughton Unit 3 natural gas conversion project is being pursued as
113 the least cost compliance alternative to the state of Wyoming Regional Haze SIP
114 requirements for Naughton Unit 3. The natural gas conversion project was

115 identified as the least cost alternative to installing an SCR and baghouse on
116 Naughton Unit 3 via a CPCN docket in Wyoming. The Company is currently
117 awaiting EPA approval of the natural gas conversion project as part of EPA's
118 review and final action on the state of Wyoming Regional Haze SIP. EPA's final
119 action in this regard is currently expected by January 10, 2014.

120 These investments constitute approximately [REDACTED] (approximately [REDACTED]
121 [REDACTED]) of the total capital investments projected to be placed in service within
122 the test period for this docket.

123 **Lake Side 2 Generation Resource Addition**

124 Lake Side 2 Project Overview

125 **Q. Please describe the Lake Side 2 project.**

126 A. Lake Side 2 is located on a 63.6 acre site in Vineyard, Utah. It is a 645 MW
127 natural gas-fired electric generation facility, consisting of a 2x1 combined-cycle
128 configuration, using two combustion turbine generators and a single steam turbine
129 generator. More specifically, Lake Side 2 is nominally rated at 548 MW base load
130 and 97 MW of duct firing for a total net capacity of 645 MW at the average
131 ambient temperate of 52 degrees Fahrenheit. Each combustion turbine exhausts
132 into its own heat recovery steam generator which then commonly supply a single
133 steam turbine generator. The electrical energy generated by Lake Side 2 will be
134 delivered to a new 345 kV point of interconnection substation (Steel Mill) where
135 it will tie into the PacifiCorp transmission system. Lake Side 2 is currently
136 scheduled to reach substantial completion to generate and provide energy and
137 capacity to customers by June 2014.

138 **Q. Please describe the characteristics of Lake Side 2.**

139 A. Lake Side 2 is located in the Company's east balancing authority. The Company
140 can dispatch power and energy from Lake Side 2 on a forward, day-ahead basis,
141 with real-time optimization of the plant's usage. This dispatch flexibility will give
142 the Company an additional system resource with the ability to provide operating
143 reserves, load-following reserves, and automatic generation control. The added
144 system flexibility will provide increasing benefit to PacifiCorp as (1) load grows,
145 (2) PacifiCorp's existing flexible contracts expire, and (3) new wind and solar
146 resources are added to the system.

147 Total Currently Projected Cost of Lake Side 2

148 **Q. What was the total projected cost of Lake Side 2 as evaluated in the**
149 **Company's 2008 RFP?**

150 A. The total projected cost of Lake Side 2 as evaluated in the 2008 RFP was [REDACTED]
151 [REDACTED].

152 **Q. Please describe the components of the total projected cost associated with the**
153 **development and engineering, procurement, and construction of Lake Side 2**
154 **as evaluated in the 2008 RFP.**

155 A. The total estimated capital investment of [REDACTED] included the following
156 estimated costs:

- 157 • A transfer to in-service cost of [REDACTED] for the generation asset including:
- 158 ◦ [REDACTED] for engineering, procurement, and construction
 - 159 ◦ [REDACTED] for sales tax
 - 160 ◦ [REDACTED] for owner's cost

- 161 ◦ [REDACTED] for allowance for funds used during construction (“AFUDC”)
- 162 ◦ [REDACTED] for property taxes during construction
- 163 • [REDACTED]¹ for transmission upgrade costs required to integrate the plant into
- 164 the Company’s east balancing authority.

165 **Q. Have there been any changes in the Lake Side 2 generation asset cost forecast**
166 **to be placed in service in 2014?**

167 A. Yes, the Company has reduced its forecast of the generation asset’s costs to be
168 placed in service in 2014 by approximately [REDACTED]. This reduction is
169 primarily due to a restructuring of the water purchases required for the project
170 from the Central Utah Water Conservancy District (“CUWCD”). Instead of
171 purchasing all of the water needed to meet the long-term requirements of Lake
172 Side 2 during the construction period, the water purchases from the CUWCD
173 have been phased in to align with expected generation and cooling water needs of
174 Lake Side 2. This phasing in of water purchases is currently estimated to reduce
175 revenue requirement on a present value basis by approximately [REDACTED] due
176 to deferred capital payments and avoided fixed “take or pay” O&M costs for
177 water under the CUWCD water supply agreement. Future water purchases,
178 amounting to approximately [REDACTED], will be phased in over the 2015 to 2019
179 time period.

180 In addition to changes in the timing of water purchases, the Company’s
181 current Lake Side 2 generation asset cost forecast reflects reductions of

¹ PacifiCorp Transmission estimated the integration costs for each delivery point in Attachment 13 of the 2008 RFP. An initial estimate of [REDACTED] was updated on July 29, 2010, to [REDACTED] in 2010 dollars escalated at 1.89 percent annually through 2014 for a nominal cost of [REDACTED]. These two estimates are available at <http://www.oasis.pacificorp.com/oasis/ppw/main.htmlx>. The [REDACTED] estimate was used in the Final Shortlist evaluation process.

182 approximately [REDACTED] associated with changes in sales tax, owner's costs,
183 AFUDC, property taxes, and other internal costs. The combination of these
184 updates results in a reduction of the total capital investment forecast for Lake Side
185 2 from [REDACTED] to approximately [REDACTED].

186 **Q. Have there been any changes to the estimated transmission upgrade costs to**
187 **integrate the plant into the Company's east balancing authority from the**
188 **[REDACTED] used in the final shortlist evaluation process?**

189 A. Yes. The Company's forecast for the transmission upgrade costs is currently
190 estimated to be approximately [REDACTED].

191 **Q. What is the updated total forecasted capital investment for Lake Side 2?**

192 A. The combination of the updated forecast of generation asset to be placed in
193 service in 2014, the updated transmission upgrade costs to be placed in service
194 2014, and deferred water purchases results in reducing the total forecasted capital
195 investment for Lake Side 2 from [REDACTED] to approximately [REDACTED].

196 Contract Terms and Conditions

197 **Q. Please describe key engineering, procurement, and construction ("EPC")**
198 **contract terms and conditions related to contractor performance risk.**

199 A. If the EPC contractor does not achieve substantial completion of Lake Side 2 by
200 June 1, 2014, the EPC contract for the project provides for delay liquidated
201 damages. Any delay in achieving substantial completion that is greater than
202 [REDACTED] following June 1, 2014, will entitle the Company to terminate the
203 Agreement and to seek additional appropriate remedies. The EPC contractor's
204 performance is secured by a parent guarantee and retainage or a retainage letter of

205 credit equal to [REDACTED] percent of all payments made (other than the final payment).

206 The warranty under the EPC contract is effective for [REDACTED] beginning
207 June 1, 2014; provided that any repairs (other than the power generation
208 equipment) made during the warranty period will be warranted for a period that is
209 the greater of one year or the balance of the warranty period. The EPC contractor
210 has agreed to obtain insurance and assume risk of loss at the customary levels
211 requested by the Company. The EPC contractor will not be liable for
212 consequential damages; but, with a few exceptions, will be liable for losses under
213 the EPC contract up to the aggregate amount of 100 percent of the contract price.

214 In addition, the Company has secured an additional warranty on the power
215 generation equipment (the combustion turbines, steam turbine and associated
216 generators) for the earlier of the [REDACTED] of the substantial
217 completion date, [REDACTED] equivalent operating hours, or [REDACTED] months following
218 delivery of the equipment.

219 Lake Side 2 Project Implementation

220 **Q. What is the current status of Lake Side 2 project construction?**

221 A. Construction of Lake Side 2 plant facilities and installation of plant equipment is
222 complete. Piping, electrical, instrumentation and control systems installation work
223 is approximately 85 percent complete. Commissioning of major equipment and
224 systems has begun and will continue through the first quarter of 2014. First fire of
225 Combustion Turbine 21 (the first combustion turbine in the commissioning
226 queue) is expected in January 2014, followed by commissioning of the heat
227 recovery steam generators and finally the steam turbine and all supporting

228 systems. Tuning and testing of the plant is currently scheduled for April and May
229 2014 to support commercial operation by June 2014.

230 **Pollution Control Investment Projects - Hunter Unit 1**

231 Hunter Unit 1 Projects Overview

232 **Q. Please describe the Hunter facility and Hunter Unit 1 in particular.**

233 A. The Hunter plant is a three-unit coal-fueled power plant with a net generation
234 capacity of approximately 1,320 MW and a currently approved depreciable life
235 for ratemaking purposes of 2042 in Utah. The plant is located approximately 158
236 miles south of Salt Lake City, Utah near the town of Castle Dale, Utah, and is
237 operated under a base load generation regime. Unit 1 is 93.8 percent owned by the
238 Company and 6.2 percent owned by the Utah Municipal Power Agency, with the
239 Company responsible for operation and maintenance of the unit and the Hunter
240 plant as a whole. The Hunter plant site includes the main power station buildings
241 for Units 1 through 3, water storage reservoirs, coal stock piles, ash disposal, and
242 a small research farm to reclaim wastewater and a portion of storm water.

243 Units 1 and 2 are basically identical units when considering their base
244 design and originally installed boiler and steam turbine generator equipment. Unit
245 3 is identical in layout to Units 1 and 2 except the boiler and turbine are from
246 different manufacturers.

247 Water for plant use is released into the Cottonwood Creek from Joe's
248 Valley and conveyed by a direct pipeline from the Millsite Reservoir to the plant.
249 Potable water is piped from the cities of Castle Dale, Utah or Clawson, Utah.
250 Hunter is a zero discharge plant. The balance of water is evaporated from a pond

251 or used for irrigation of hay crops on the adjacent research farm. Plant sewage is
252 treated and discharged to the evaporation pond.

253 Coal is supplied by truck from the nearby Sufco, Cottonwood, Dugout,
254 and Deer Creek mines. Hunter has a blending facility in the fuels preparation
255 facility, which allows for combustion of various coal types.

256 The Hunter plant currently employs approximately 220 personnel,
257 including approximately 170 union craft personnel represented by the
258 International Brotherhood of Electrical Workers Local 57.

259 **Q. Please describe the Hunter Unit 1 baghouse conversion project and**
260 **associated equipment.**

261 A. The Hunter Unit 1 baghouse conversion project replaces the originally installed
262 particulate matter (“PM”) control equipment (electrostatic precipitator) on the unit
263 with a best available retrofit technology baghouse to meet the Company’s
264 emissions compliance obligations required by the Regional Haze Rules and
265 incorporated into the state of Utah’s Regional Haze SIP and associated permits by
266 spring 2014. The baghouse will capture PM and mercury from the flue gas stream
267 as it passes through the equipment. Capturing mercury in the baghouse allows the
268 unit to comply with the EPA’s MATS requirements for mercury capture by the
269 prescribed deadline of April 16, 2015, without installing incremental stand-alone
270 mercury emissions control equipment. The dry particulate waste stream captured
271 in the baghouse is transported to an on-site landfill for disposal.

272 An additional emissions control benefit that the baghouse brings to Unit 1
273 is the ability to close the scrubber bypass currently installed on the unit, which

274 when considered in conjunction with the Hunter Unit 1 scrubber, reagent
275 preparation, and waste handling projects completed on the unit in 2012 allows the
276 unit to meet a reduced SO₂ emissions limit required by the state of Utah Regional
277 Haze SIP and associated permits by spring 2014.

278 Other equipment to be installed as part of the baghouse project includes
279 upgraded booster fans, boiler reinforcement, new ductwork, modifications to the
280 existing chimney, relocation of the stack opacity monitors, electrical
281 infrastructure, controls, and other miscellaneous appurtenances and support
282 systems.

283 The Company's share of the capital investment for the baghouse
284 conversion project included in this case is approximately [REDACTED].
285 Construction of the project began in 2013, and the baghouse conversion is
286 scheduled to be completed and placed in service following a planned major
287 maintenance outage on the unit in spring 2014. The project cost is trending
288 favorably to the cost initially assessed during the economic analysis and
289 authorization for expenditure stage of the project.

290 **Q. Please describe the Hunter Unit 1 LNB installation project.**

291 A. The LNB installation project on Hunter Unit 1 includes the installation of NO_x
292 combustion controls that replace originally installed equipment. The new burners
293 utilize improved combustion characteristics and a separated over-fire air supply to
294 the boiler to reduce NO_x emissions.

295 The Company's share of the capital investment for the project is
296 approximately [REDACTED]. The project is scheduled to be completed and placed

297 in service following the same spring 2014 planned major maintenance outage on
298 the unit referenced above. The project cost is trending favorably to the cost
299 initially assessed during the economic analysis and authorization for expenditure
300 stage of the project.

301 **Q. Have Hunter Units 2 and 3 been equipped with LNB and baghouse retrofit**
302 **technologies that provide emissions reductions consistent with those being**
303 **installed on Hunter Unit 1?**

304 A. Yes. Pursuant to Utah Regional Haze SIP requirements, Unit 2 was equipped in
305 2011 with the same LNB and baghouse retrofit technologies contemplated in this
306 docket for Hunter Unit 1. The same post-retrofit emissions limits for NO_x (0.26
307 pounds per million Btu) and particulate matter (“PM”) (0.015 pounds per million
308 Btu) are required for each unit. The Commission reviewed the Unit 2 emissions
309 control equipment investments for ratemaking purposes in a past general rate case
310 docket. The Unit 2 equipment is included in the Company’s rate base.

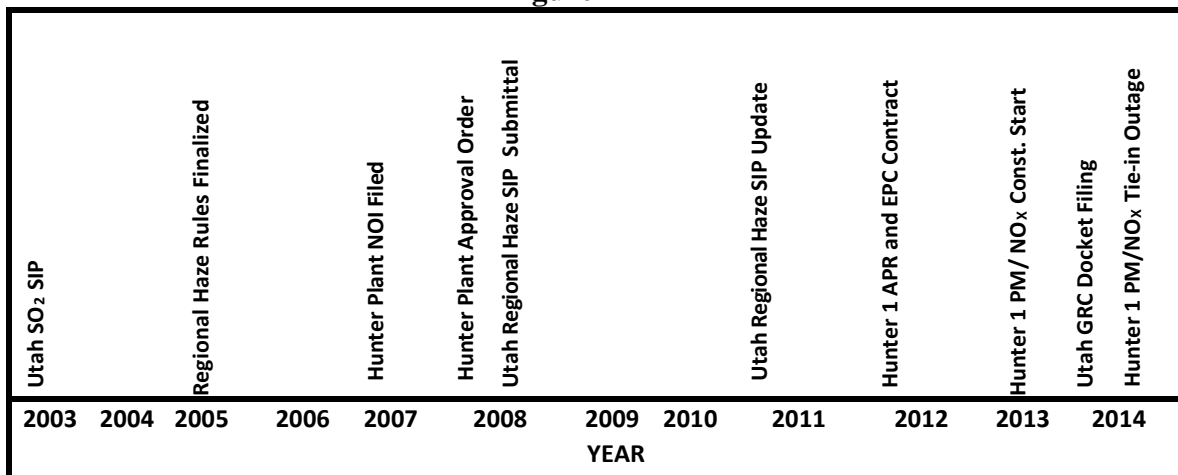
311 Unit 3 was equipped with a fabric filter baghouse (1983) when the unit
312 was originally constructed and was retrofitted with LNB technology in 2007. The
313 Commission reviewed the Unit 3 LNB investment for ratemaking purposes in a
314 past general rate case docket. The Unit 3 LNB equipment is included in the
315 Company’s rate base.

316 All three Hunter units are equipped with wet lime scrubbers to control
317 sulfur dioxide emissions to a rate of 0.12 pounds per million Btu.

319 **Q. What are the key permits and/or regulations requiring the Hunter Unit 1**
 320 **baghouse and LNB projects to be installed?**

321 A. To continue compliant operation of Hunter Unit 1, the Company must install the
 322 projects described herein to control emissions of NO_x, PM, and SO₂ criteria
 323 pollutants as required by Regional Haze Rules, the state of Utah’s §309(g)
 324 Implementation Plan, the state of Utah’s Best Available Retrofit Technology
 325 (“BART”) review process, and the state of Utah’s Approval Order (DAQE-
 326 AN0102370012-08) dated March 2008. Figure 1 below is a general timeline of
 327 the significant regulatory actions and regulations that have established the course
 328 of events.

329 **Figure 1**



330 The state of Utah Regional Haze SIP and permit requirements for the Hunter Unit
 331 1 projects were finalized in 2008; detailed economic assessment of compliance
 332 alternatives and competitive procurement activities were completed in 2012;
 333 construction of the project began in 2013; and the baghouse conversion project is
 334 scheduled to be completed and placed in service following a planned major

335 maintenance outage on the unit in spring 2014. Additional background regarding
336 the Regional Haze compliance obligations facing Hunter Unit 1 is provided in
337 Exhibit RMP____(CAT-1).

338 **Q. What are the Company’s specific obligations under the Hunter Unit 1 permit**
339 **conditions?**

340 A. The Utah Regional Haze SIP and associated permit for the projects require that
341 emissions control equipment for the unit be installed and operated in compliance
342 with the following emissions limits.

Pollutant	Emissions Limit (lb per MMBtu)^(b)
NO _x	0.26 (30-day rolling)
SO ₂	0.12 (30-day rolling)
PM/PM ₁₀ ^(a)	0.015 (annual testing)
CO	0.34 (30-day rolling)

(a) Filterable portion only

(b) See Permit DAQE-AN102370012-08, Article 10

343 **Q. Did the Company consider alternative technologies to the Hunter Unit 1**
344 **control projects included in this case when working with the state of Utah to**
345 **assess Regional Haze compliance requirements incorporated into the Utah**
346 **Regional Haze SIP?**

347 A. Yes. The Company completed two technical studies of note to evaluate NO_x,
348 SO₂, and PM control technology alternatives for Hunter Units 1. In October 2002,
349 Sargent and Lundy completed a coal fleet-wide *Multi-Pollutant Control Report*
350 (under attorney work product privilege); and in January 2005, Sargent and Lundy
351 completed the *NO_x Emission Reduction Technologies Study*, and in November

352 2003, EPSCO International Inc. completed a *Phase III Recommendations* study of
353 the original PM control equipment on the unit. See Exhibit RMP___(CAT-2) for
354 additional discussion regarding study details.

355 The *Multi-Pollutant Control Report* investigated the cost and necessity of
356 NO_x controls including both boiler in-combustion and post-combustion controls,
357 PM controls including upgraded electrostatic precipitators, polishing baghouses
358 and full-scale fabric filter replacements.

359 The *NO_x Emission Reduction Technologies Study* compared emission
360 control technologies, status of the technology development, performance,
361 approximate initial capital costs, and approximate fixed and variable operational
362 and maintenance costs.

363 The *Phase III Recommendations* study of the electrostatic precipitators
364 (“ESP”) and was used as the basis for the decision to convert the Hunter Unit 1
365 ESP to a baghouse. The decision making process began when the same type of
366 conversion was made at Huntington Unit 2 (2004-2006). The ESP at Hunter Unit
367 1 and Unit 2 and Huntington Unit 1 and Unit 2 are identical, and in 2003 it had
368 become apparent that the Huntington Unit 1 and Unit 2 ESP’s were having
369 operational difficulties. EPSCO International, Inc. was retained to study the
370 situation, identify options and make recommendations for the Huntington and
371 Hunter units.

372 **Q. Has the Company updated its review of alternative technologies to the**
373 **Hunter Unit 1 control projects included in this case to support the state of**
374 **Utah with its ongoing assessment of Regional Haze compliance requirements**
375 **in the Utah Regional Haze SIP?**

376 A. Yes. In 2012, the Company contracted with CH2M Hill to complete updated
377 BART analyses for Hunter Units 1, 2 and 3 for criteria pollutants NO_x, PM₁₀ and
378 SO₂. In completing these BART analyses, technology alternatives were
379 investigated and potential reductions in emissions were quantified.

380 **Q. Did the Company explore compliance flexibility, if any, with the**
381 **environmental agencies having jurisdiction (i.e. state of Wyoming and/or**
382 **EPA)?**

383 A. Yes. As a result of negotiations with the Utah Division of Air Quality, the
384 Company was allowed to delay the installation of the emission control equipment
385 included in this case until the unit's planned major maintenance overhaul in 2014,
386 in lieu of attempting to complete the project during the unit's 2010 planned major
387 maintenance overhaul (which fell within the 2008 to 2013 Regional Haze
388 planning period originally prescribed by the state of Utah). Please refer to Exhibit
389 RMP___(CAT-1) for additional information regarding the Company's efforts to
390 explore compliance timeline flexibility for the Hunter Unit 1 Regional Haze
391 compliance projects.

392 **Q. Has the Company evaluated whether the risk-adjusted, least-cost alternative**
393 **to comply with environmental requirements was to invest in the emissions**
394 **control equipment included in this case or to idle Hunter Unit 1?**

395 A. Yes. Prior to executing the EPC contract for the baghouse project in June 2012,
396 the Company evaluated alternatives to comply with environmental requirements
397 other than to complete the project. The Company used its System Optimizer
398 Model to evaluate multiple alternatives. In brief, the major alternatives reviewed
399 are:

- 400 (1) Continue to operate and incur operating expenses and capital revenue
401 requirement expenses inclusive of incremental environmental investments;
402 (2) Retire Hunter Unit 1 and replace with resource alternatives; or;
403 (3) Convert to natural gas as a compliance alternative to the incremental
404 environmental investments planned for the unit as a coal-fueled facility.

405 The results of the comparison of various alternatives resulted in a PVRR(d) of
406 [REDACTED] favorable to proceeding with the project to the next best alternative as
407 selected by the System Optimizer Model. The next best alternative was to convert
408 Hunter Unit 1 to a natural gas fueled facility. Confidential Exhibit RMP___(CAT-
409 3) provides detailed discussion of the Company's analyses and results.

410 **Q. Are the methods and tools used to assess the compliance alternatives for**
411 **Hunter Unit 1 consistent with those utilized to support the Company's recent**
412 **2013 Integrated Resource Plan filings, as well as the Company's Jim Bridger**
413 **Units 3 and 4 CPCN filing in Wyoming and its Jim Bridger Units 3 and 4**
414 **Voluntary Procurement Pre-approval filing in Utah?**

415 A. Yes. The Company utilized consistent methods and tools (e.g. System Optimizer
416 Model) to assess compliance alternatives for Hunter Unit 1 as has been done in
417 the Company's other recent major filings regarding environmental compliance
418 investments in coal-fueled resources. In fact, the Company has included the
419 results of its Hunter Unit 1 analyses in its 2013 Integrated Resource Plan
420 Confidential Volume III filing.

421 **Q. Does the Hunter Unit 1 baghouse conversion project provide emissions**
422 **compliance benefits beyond those required by the Utah Regional Haze SIP?**

423 A. Yes. The Hunter Unit 1 baghouse conversion project provides emissions
424 compliance benefits associated with the EPA's MATS regulations.

425 **Q. Beyond directly reducing mercury emissions, how is the Hunter Unit 1**
426 **baghouse project expected to allow Hunter Unit 1 to meet other EPA's**
427 **MATS regulations?**

428 A. In addition to specific emissions requirements for mercury, MATS includes
429 requirements for emissions of non-mercury metals. MATS non-mercury metals
430 emissions compliance can be demonstrated via a surrogate PM emissions limit of
431 0.030 pounds filterable PM per million Btu. Installation of the baghouse with

432 performance requirements described above will allow Hunter Unit 1 to comply
433 with that portion of MATS.

434 With respect to mercury emissions control, the Company expects that the
435 Hunter 1 baghouse will allow Hunter Unit 1 to comply with MATS mercury
436 emissions limits without the need for a coal supply additive (and associated costs)
437 to oxidize mercury as the coal is burned in the furnace or the need to install
438 activated carbon injection equipment for mercury removal purposes, avoiding
439 those incremental costs as well.

440 Hunter Unit 1 Projects Emerging Environmental Regulations Considerations

441 **Q. Has the Company assessed the potential costs of emerging environmental**
442 **regulations in its economic analyses of the Hunter Unit 1 emissions**
443 **compliance projects included in this case?**

444 A. Yes. The Company has assessed potential costs of reasonably foreseeable
445 emerging environmental regulations including coal combustion residuals (“CCR”)
446 regulations, Clean Water Act Section 316(b) regulations, effluent limitation
447 guidelines, and various CO₂ cost scenarios in its Hunter Unit 1 analyses.
448 Confidential Exhibit RMP___(CAT-3) provides additional detail regarding the
449 Company's analyses in this regard.

450 **Q. Has the Company developed emerging CCR regulations compliance costs for**
451 **the Hunter facility?**

452 A. Yes. Although information regarding the currently emerging CCR regulations was
453 not available at the time of development of the Utah Regional Haze SIP and
454 planning of the multi-year Hunter Unit 1 projects, the Company is committed to

455 understanding and anticipating the effect of emerging environmental regulations
456 in its economic evaluations and environmental plans. As the Company assesses
457 options regarding continued investment in its coal fueled generation assets, the
458 Company will be faced with certain CCR storage, handling, and long-term
459 management costs at its existing facilities whether the facilities continue to
460 operate or not. Therefore, the Company periodically updates its CCR-related costs
461 and asset retirement obligations in its planning processes. In response to the
462 rulemaking regarding CCR proposed by EPA in June 2010, the Company has
463 updated its CCR-related costs and asset retirement obligations on a preliminary
464 basis to incorporate proposed Subtitle D or near-Subtitle D infrastructure
465 requirements in its business planning processes, which serve as a planning proxy
466 for the Company until such time as EPA completes its CCR rulemaking process.
467 It is currently anticipated that compliance with final CCR rules will be required
468 five years after final rulemaking, or by 2019. Until a final rule is promulgated, the
469 cost, timing, equipment, monitoring, and recordkeeping to comply with the rule
470 cannot be fully ascertained. However, the costs of the Company's proxy CCR
471 Subtitle D compliance projects have been incorporated into the Company's
472 business plans and the economic analyses of the Hunter Unit 1 emissions control
473 investments in this case.

474 **Q. Has the Company developed emerging 316(b) regulations compliance costs**
475 **for the Hunter facility?**

476 A. Yes. Although information regarding the currently emerging 316(b) regulations
477 was not available at the time of development of the Utah Regional Haze SIP and

478 planning of the multi-year Hunter Units 1 projects included in this case, the
479 Company has applied the same principles as those discussed above for emerging
480 CCR regulations and has incorporated 316(b) compliance costs into the
481 Company's economic analyses and those costs did not alter the outcome.

482 **Q. Has the Company developed emerging effluent limitation guidelines**
483 **compliance costs for Hunter?**

484 A. The Hunter plant is a zero discharge facility and it is currently not anticipated that
485 it will be materially impacted by the proposed EPA effluent limitation guidelines.
486 As such no proxy compliance costs for emerging effluent limitation guidelines
487 were incorporated into the Company's economic analyses.

488 **Q. How has the Company assessed potential CO₂ regulation outcomes?**

489 A. As further described in Confidential Exhibit RMP___(CAT-3), the Company's
490 Hunter Unit 1 baghouse and LNB investments were assessed over a range of CO₂
491 and natural gas forward price scenarios.

492 Hunter Unit 1 Projects Implementation

493 **Q. Did the Company competitively and prudently procure the Hunter Unit 1**
494 **baghouse project EPC contract, as well as the Hunter Unit 1 LNB project?**

495 A. Yes. In 2012, the Company issued a competitive EPC contract request for
496 proposals package to over 20 market participants for supply of the Hunter Unit 1
497 baghouse conversion project. Three viable proposals were received and evaluated
498 on a technical and commercial basis. The best evaluated proposal was identified
499 and an EPC contract awarded following the procurement process.

500 **Q. What emissions performance guarantees are provided via the Hunter 1**
501 **baghouse project EPC contract?**

502 A. The baghouse project was specified with contractually guaranteed performance
503 emission threshold at the following limits to provide an appropriate compliance
504 margin over the operating life of the equipment with established maintenance
505 cycles:

Pollutant	Emissions Limit (lb per MMBtu)
PM/PM₁₀^(a)	0.012

(a) Filterable portion only

506 **Q. What emissions performance guarantees are provided via the Hunter 1 LNB**
507 **supply contract?**

508 A. The LNB supply contract includes guaranteed performance emission thresholds at
509 the following limits to provide an appropriate compliance margin over the
510 operating life of the equipment with established maintenance cycles:

Pollutant	Emissions Limit (lb per MMBtu)
NO_x	0.24

511 **Q. What is the current status of the Hunter 1 baghouse project?**

512 A. Engineering and procurement for the baghouse EPC contract are complete, and
513 the major components of the baghouse have been fabricated and delivered to the
514 site. The EPC contractor is currently assembling baghouse components into
515 modules which are installed during the outage. The induced draft booster fans
516 rotors and motors are scheduled for delivery in January 2014. The only remaining
517 material deliveries are the bags and cages for the baghouse which will be received

518 on site by mid-February 2014. Pre-outage construction work began in May 2013
519 and will be ongoing until the outage starts. Major construction work and baghouse
520 tie-in will be completed during the planned major maintenance outage period. The
521 project is currently forecasted to be completed at or slightly below the approved
522 budget amount, thus ensuring ratepayers will realize the value indicated by the
523 economic analysis.

524 **Q. What is the current status of the Hunter 1 LNB project?**

525 A. Engineering and procurement are complete for the LNB project, and the new
526 burners, ancillary equipment and ductwork are scheduled to start arriving at the
527 Hunter plant in January 2014, and deliveries will be complete by the end of
528 February 2014. Pre-outage construction work began in November 2013 and will
529 be ongoing until the outage starts. Major construction work and LNB tie-in will
530 be completed during the planned major maintenance outage. The project is
531 currently forecasted to be completed at or slightly below the approved budget
532 amount, thus ensuring ratepayers will realize the value indicated by the economic
533 analysis.

534 **Pollution Control Investment Project - Hayden Unit 1**

535 Hayden Unit 1 Project Overview

536 **Q. Please describe the Hayden facility.**

537 A. The Hayden plant is a 446 megawatt, two-unit coal-fired electrical generating
538 facility located in Routt County, Colorado. Unit 1 is jointly owned by Public
539 Service Company of Colorado (“PSCo”) and PacifiCorp (PacifiCorp owns 24.5

540 percent). Unit 2 is jointly owned by PSCo, Salt River Project, and PacifiCorp
541 (PacifiCorp owns 12.6 percent). PSCo operates the plant.

542 Hayden Unit 1 Project Drivers and Alternatives Assessments

543 **Q. What are the key permits and/or regulations requiring the Hayden Unit 1**
544 **SCR project to be installed?**

545 A. To continue compliant operation of Hayden Unit 1, the PSCo must install the
546 SCR project described herein to control NO_x emissions. In December 2010, the
547 Colorado Air Quality Control Commission (“AQCC”) promulgated new BART
548 determinations and emissions control requirements for the Hayden units in the
549 Colorado Regional Haze SIP. These BART determinations set emissions limits of
550 0.08 lbs NO_x/MMBtu for Hayden Unit 1, and 0.07 lbs NO_x/MMBtu for Hayden
551 Unit 2. Although the BART determinations did not specify how these limits were
552 to be achieved, installation of SCRs is the only technically feasible method
553 currently available. The Unit 1 SCR is expected to enter service in 2015, and the
554 Unit 2 SCR is expected to enter service in 2016.

555 EPA published its approval of the Colorado Regional Haze SIP in in the
556 Federal Register on December 31, 2012.

557 **Q. Are the Colorado Regional Haze SIP requirements for Hayden Unit 1**
558 **currently being litigated?**

559 A. Environmental groups National Parks Conservation Association and WildEarth
560 Guardians filed petitions for review before the U.S. 10th Circuit Court of Appeals
561 challenging the legality of EPA approving some aspects of the Colorado Regional
562 Haze SIP. In general, the environmental groups are asking the court to require

563 EPA to make the Colorado Regional Haze SIP more stringent by requiring SCR
564 controls at more units at a faster pace. PacifiCorp, the state of Colorado and other
565 utilities have intervened in the appeal in support of EPA's approval of the
566 Colorado Regional Haze SIP and against the proposition of making it more
567 stringent.

568 **Q. If litigation regarding Hayden Unit 1 environmental compliance**
569 **requirements were to result in changes to current compliance requirements**
570 **for the unit, would the Participation Agreement dictate that PSCo re-assess**
571 **the SCR investment?**

572 A. The environmental groups who filed the litigation are not seeking less stringent
573 controls at Hayden Unit 1. Without that issue specifically before the court, it is
574 highly unlikely that the court's decision will result in a relaxation of the SCR
575 compliance requirements for Hayden Unit 1. If, for some reason, litigation did
576 result in a change in SCR compliance requirements for Hayden Unit 1, the PSCo
577 and the Company would re-assesses such changes pursuant to the terms of the
578 Participation Agreement.

579 Hayden Unit 1 Ownership Agreement Considerations

580 **Q. What are the primary ownership agreement considerations regarding the**
581 **Company's investment in the Hayden Unit 1 SCR project?**

582 A. The Participation Agreement requires Hayden Unit 1 to be operated in
583 compliance with all environmental laws. The Participation Agreement also places
584 an independent obligation on Public Service Company of Colorado, as the
585 Operating Agent, to operate Hayden Unit 1 in accordance with all environmental

586 laws. Considerations under the agreement fall into two primary classes. First,
587 PacifiCorp must consider the applicable law (e.g., the Colorado Regional Haze
588 SIP and the Colorado Clean Air Clean Jobs Act). Second, PacifiCorp must
589 consider its contractual rights and obligations under the Participation Agreement
590 in regard to the applicable law.

591 **Q. Following its assessment of applicable law and its rights and obligations**
592 **under the Participation Agreement for Hayden Unit 1, what position has the**
593 **Company taken with respect to the SCR emissions control investment for the**
594 **unit.**

595 A. Following its assessment of applicable law and its rights and obligations under the
596 Participation Agreement, the Company approved investment in the SCR for
597 Hayden Unit 1 because: (i) it is required by applicable law; and (ii) Hayden Unit 1
598 is required to be operated in accordance with applicable law.

599 **Q. What is the status of applicable law that applies to the Hayden Unit 1 SCR**
600 **emissions control investment?**

601 A. The state of Colorado promulgated, and the U.S. EPA approved, a Regional Haze
602 SIP for the state of Colorado. Failure to comply with the requirements of a state
603 and EPA approved SIP will likely result in state and/or federal enforcement
604 action, substantial penalties, and a requirement to close the unit until it is brought
605 into compliance.

606 Further, the state of Colorado has adopted the Clean Air Clean Jobs Act
607 that required PSCo to submit a plan to reduce NO_x emissions by 70 to 80 percent
608 by 2017. PSCo's NO_x reduction plan, reviewed and approved by the Colorado

609 Public Utilities Commission, includes installation of SCR retrofits on Hayden
610 Units 1 and 2. To comply with the Colorado Regional Haze SIP and PSCo's
611 approved Clean Air Clean Jobs Act NOx reduction plan, PSCo as Operating
612 Agent for the Hayden facility, is pursuing installation of SCR on Hayden Units 1
613 and 2.

614 **Q. Please provide a general description of the terms and conditions of the**
615 **Hayden Unit 1 Participation Agreement that governs the Company's rights**
616 **and obligations regarding major capital expenditures at this jointly owned**
617 **plant.**

618 A. The Participation Agreement mandates the installation of capital improvements
619 that are required by applicable law. The Participation Agreement also places an
620 independent obligation on PSCo, as Operating Agent, to operate Hayden Unit 2 in
621 accordance with applicable law. Also, the Participation Agreement requires the
622 unanimous consent of all owners to proceed with a capital improvement. If the
623 Operating Agent proposes a capital improvement (e.g. the installation of SCR
624 equipment) to meet applicable law, as has occurred at Hayden Unit 1, a non-
625 consenting owner has the option to assert that the Operating Agent (and other
626 owners) are in default under the Participation Agreement if it cannot be
627 demonstrated that applicable law requires the investment. In that case, whether or
628 not a default has occurred will be decided by arbitration.

629 **Q. Does the Company assert that the Operating Agent for Hayden Unit 1 is in**
630 **default as it pertains to its proposed capital investment in the installation of**
631 **SCR equipment on the unit?**

632 A. No. The basis for the Company's position in that regard is provided above.

633 **Q. Did the Hayden Unit 1 Operating Agent and joint owner, PSCo, and the state**
634 **of Colorado determine that installation of the SCR on the unit was in the best**
635 **interests of customers?**

636 A. Yes. PSCo has found the installation of SCR on Unit 1 to be in the best interests
637 of customers and has received approval of a CPCN from the Colorado Public
638 Service Commission for the project.

639 **Q. Considering the terms and conditions of the Hayden Unit 1 Participation**
640 **Agreement, did the Company pursue arbitration of the Hunter Unit 1 SCR**
641 **investment decision?**

642 A. No, for the reasons explained above.

643 Hayden Unit 1 Projects Implementation

644 **Q. What is the current status of the Hayden Unit 1 SCR project?**

645 A. Engineering and procurement of the Hayden Unit 1 SCR project are underway,
646 and the SCR equipment supply contract has been awarded. PSCo is completing
647 the Hayden Unit 1 SCR project on a multiple lump sum contracts basis with PSCo
648 staff and PSCo's owner's engineer providing engineering, procurement, and
649 construction management. Major construction work and SCR tie-in will be
650 completed during the planned major maintenance outage period for the unit in
651 spring 2015.

652 **Blundell Geothermal Well Integration Project**

653 **Q. Please describe the Blundell facility.**

654 A. The Blundell plant is a 34-megawatt geothermal facility near Milford, Utah.
655 Blundell Unit 1 was commissioned in 1984 and is a 24 megawatt facility using
656 single “flash” technology. Blundell Unit 2 was commissioned in 2007 and is a 10
657 megawatt “bottoming” cycle which uses a binary heat-recovery process to extract
658 additional energy from the hot geothermal brine left over from Blundell Unit 1
659 prior to returning the brine to the geothermal reservoir. The renewable energy
660 source for the Blundell plant is the Roosevelt Hot Springs Reservoir which spans
661 approximately 30,000 acres and lays thousands of feet below surface. The
662 reservoir contains groundwater heated by magma to approximately 500°F and at a
663 pressure of approximately 500 pounds per square inch. There are four existing
664 supply wells that bring the high-pressure, heated liquid to the surface, where it
665 “flashes” to steam in steam separators. The steam is separated from the
666 geothermal liquid called “brine” and the steam is transported by above ground
667 pipeline to Blundell Unit 1 which uses a Rankine Cycle steam turbine generator to
668 produce electricity.

669 Blundell Unit 2 is a “bottoming” cycle. The steam exiting Blundell Unit 1
670 flows through heat exchangers to heat iso-pentane, a fluid similar to propane, to
671 expand through a separate turbine to generate electricity in a closed-loop, binary
672 process. The geothermal fluid, after passing through the iso-pentane heat
673 exchangers, is further condensed and returned to the geothermal reservoir via
674 three existing injection wells. The plant has approximately two miles of steam

675 piping and six miles of brine piping, tying the existing seven-well geothermal
676 supply and injection system together. With the exception of the geothermal brine,
677 Blundell is a zero-discharge facility.

678 **Q. Please describe the Blundell well integration project.**

679 A. The two wells included in the Blundell well integration project were originally
680 drilled in 2008 as part of a project to prove the Roosevelt Hot Springs Reservoir's
681 capacity and capability to support construction on an incremental generation
682 resource at the facility (Blundell Unit 3). The wells were drilled and tested under
683 the premise that they could ultimately be incorporated into the existing
684 geothermal supply and injection system for Blundell Units 1 and 2, or could
685 ultimately be incorporated into a series of new wells required for an incremental
686 resource at Blundell. Pursuit of an incremental generation resource at Blundell
687 was deferred and later canceled due to cost, inability to commercially mitigate
688 geothermal resource performance risk, and uncertainty regarding renewal of
689 production tax credits for geothermal resources. However, these two new wells
690 represent viable assets that are available to be placed into service for the benefit of
691 customers. The wells will supply additional steam and injection capacity for
692 Blundell Units 1 and 2 and improve operational reliability and flexibility.

693 **Q. Please describe the assets that will be placed into rates.**

694 A. This project will place into service one new steam production well drilled to a
695 depth of approximately 5,000 feet and associated ancillary equipment including a
696 well head, steam/brine separator, emergency backup generator, brine transfer
697 pump, control system, disposal pond, air compressors, well site control/equipment

698 building and security fencing. It will also place into service one new injection
699 well drilled to a depth of approximately 7,000 feet deep and associated ancillary
700 equipment including a wellhead, disposal pond, local instrumentation and valves
701 for operation. The wells are interconnected with Blundell Unit 1 and 2 by three
702 new overland pipelines. One pipeline will connect the production well to the Unit
703 1 main steam supply line. A second pipeline will connect the production well to
704 the Blundell Unit 2 brine supply line, and the third pipeline will connect Blundell
705 Unit 2 brine return line to the new injection well. In addition, plant control system
706 modifications are required to operate the new production and injection wells from
707 the Blundell Unit 1 control room.

708 **Q. What is the total value of the assets described above and when will they be**
709 **placed in service?**

710 A. The forecasted costs of the project, including AFUDC, are approximately [REDACTED]
711 [REDACTED] and are expected to be placed in service by September 2014.

712 **Q. How does this project benefit customers?**

713 A. The project will benefit customers by improving the reliability and operational
714 flexibility of Blundell Units 1 and 2.

715 **Q. How has the Company assessed the benefit to customers?**

716 A. The four active production wells at Blundell have an average age of over 30
717 years. The three active injection wells at Blundell have an average age of over 35
718 years. Production and injection wells have a finite life which is very difficult to
719 model and predict; however, a statistical analysis of Roosevelt Hot Springs
720 Reservoir well histories indicate a 10 percent per year probability of a well

721 failure. While statistically, an event can happen any time, it has been over 10
722 years since a significant well event has occurred at Blundell.

723 Since 1984, two production wells have failed and been abandoned. During
724 that timeframe, three other production wells have developed issues that, while not
725 immediately impairing their serviceability, are being monitored. With the
726 remaining wells in service, reserve steam supply capability at Blundell is
727 currently estimated to be less than eight percent based upon current well
728 conditions and performance assumptions and will continue to decline as the
729 condition of the wells continues to deteriorate. However, during peak demand
730 months in the summer and early fall, the Company has experienced lost
731 production due to lack of steam supply, leading to the conclusion that the reserve
732 margin reported as less than eight percent may be overly optimistic depending
733 upon specific operating conditions. During May through October 2012, Blundell
734 Unit 1 operated at 6,195 megawatt-hours below nameplate capacity as a result of
735 low steam pressure across the four production wells. This realized loss of
736 production capability is a key driver to pursuing incremental production well
737 capacity tie-in at this point in time.

738 If one of the four wells were to fail, there is insufficient capacity in the
739 remaining three production wells to maintain rated plant output. In fact, two of the
740 four production wells deliver approximately 70 percent of the steam for Blundell.
741 If one of those wells were to fail, output would be severely curtailed until the well
742 could be replaced.

743 Regarding injection wells, the continued production of high pressure

744 geothermal fluid from the Roosevelt resource is contingent on injection of the
745 used geothermal brine back into the aquifer to maintain the fluid balance. The
746 brine cools as it travels down the injection wells, and as it cools the silica
747 suspended in the brine solution turns solid and can plug and ultimately close off
748 the injection capability of the well. While the rate of plugging is difficult to
749 measure, maintaining margin in total system injection well capacity to
750 accommodate individual well performance degradation is prudent.

751 Of the three existing injection wells, one well is suspected to be re-
752 injecting fluid near or just outside the limit of the geothermal field due to
753 gradually changing subsurface characteristics of the resource, one has a partially
754 collapsed casing and the third injection well is used to re-inject most of the fluid.
755 Thus plant production is currently heavily dependent on a single injection well.

756 Based on the approximate 20-year remaining life of Blundell and a range
757 of probabilities and circumstances, the benefit for integration of the two wells
758 ranges from [REDACTED] to [REDACTED] on an annualized basis, with a total benefit
759 over the remaining life of Blundell of [REDACTED] to [REDACTED].

760 **Q. Can the Company wait to complete the Blundell well integration project?**

761 A. No. With the increasing risk of failure due to deteriorating condition of the
762 production and injection wells described above, as well as the realization of loss
763 of available energy production in 2012 due to existing well conditions, pursuing
764 integration of the production and injection wells available at Blundell is
765 appropriate at this time. As noted above, if the Company were to wait until
766 ultimate failure of a well prior to commencing procurement of ancillary

767 equipment supply and installation contracts, it is reasonable to assume that the
768 lost production and/or injection well capacity would extend 12 months or more,
769 based upon the competitively procured equipment supply lead times and
770 installation contract schedules currently being negotiated by the Company.

771 While accelerated equipment supply and installation agreements may
772 ultimately be available in an “emergency” condition, such contracts would be
773 reasonably expected to be significantly more costly and would not address
774 ongoing loss of energy generation during the delivery and installation period.

775 **Naughton Unit 3 Natural Gas Conversion Project**

776 **Q. Please describe the Naughton plant and the Naughton Unit 3 facility, in**
777 **particular.**

778 A. The Naughton plant consists of three coal fueled units that are all 100 percent
779 owned and operated by PacifiCorp. PacifiCorp also owns 100 percent of the Viva
780 Naughton reservoir which stores water for consumptive use at the Naughton plant
781 and provides regional recreation opportunities. Water for plant use flows from the
782 Viva Naughton reservoir into the Ham’s Fork River, where it is diverted
783 approximately five miles downstream and then conveyed approximately nine
784 miles via a pipeline to an onsite raw water storage pond. National Pollutant
785 Discharge Elimination System (“NPDES”) permit WY0020311 allows release of
786 small flows from CCR clearwater ponds. Plant sewage is treated on site in a
787 general biosolids permitted package wastewater treatment facility that discharges
788 effluent into a CCR pond under NPDES permit WY0020311. Potable water for
789 plant use is obtained from the town of Kemmerer, Wyoming.

790 The Naughton plant property is adjacent to the Westmoreland Kemmerer
791 Mine that supplies approximately 2.8 million tons per year of sub-bituminous coal
792 to the plant via an overland belt conveyor. CCR are disposed of on plant property
793 in surface impoundments.

794 Naughton Unit 3 began commercial operation in 1971. It has a currently
795 approved depreciable life for ratemaking purposes of 2029, and a net reliable
796 generation capacity of 330 megawatts (“MW”). The boiler was retrofitted in 1999
797 with LNB for NO_x removal. The unit configuration also includes: a closed-loop
798 cooling water system, with a mechanical draft cooling tower; an electrostatic
799 precipitator (“ESP”) for PM removal; and a sodium-based wet flue gas
800 desulfurization system (“FGD”) for SO₂ removal that was retrofitted in 1981.

801 The Naughton plant currently employs approximately 140 personnel,
802 including approximately 105 union craft personnel represented by the
803 International Brotherhood of Electrical Workers Local 57.

804 **Q. Please describe the Naughton Unit 3 natural gas conversion project and the**
805 **associated equipment.**

806 A. As part of the Naughton Unit 3 natural gas conversion project, the steam electric
807 unit will be converted from a base-loaded 100 percent coal fueled unit to a 100
808 percent natural gas fueled slow-start peaking unit. Coal fueling equipment will be
809 left in place except where it interferes with new natural gas fuel supply
810 equipment. It is anticipated that natural gas supply piping to the converted
811 Naughton Unit 3 can be modified with a new pipeline, approximately 16 inches in
812 diameter, from the existing natural gas supplier metering station located

813 approximately 1.8 miles east of the plant.

814 New boiler natural gas fuel supply equipment will include igniters, flame
815 scanners, LNBS, and natural gas distribution piping. Five levels of LNBS will be
816 installed in existing air compartments on each of the four corners of the boiler and
817 will have the capability to sustain unit operation over a net reliable load range
818 from approximately 85 to 330 MW. Modifications to the boiler burner
819 management control systems will be completed. New process control instruments,
820 control wiring and high performance controller modules will be installed and
821 integrated into the plant's existing distributed control system.

822 A 15 to 20 percent flue gas recirculation system ("FGR") will be installed
823 to enable the boiler to attain required operating temperatures and to provide NOx
824 emissions reductions. Flue gas will be recirculated from the existing ductwork
825 between the economizer outlet and the air preheater inlet. Flue gas will be re-
826 injected into the boiler wind box. The FGR will consist of two by 50 percent
827 capacity fans; including lubricating oil systems, fan motors, foundations, vibration
828 monitoring, controls and interconnecting ductwork.

829 Flue gas will exit the unit by flowing through: (1) the de-energized
830 existing ESP, (2) the existing induced draft and booster fans, and (3) the FGD
831 bypass ductwork. It will discharge to the atmosphere through the existing wet
832 FGD chimney. All flue gas duct expansion joints between the induced draft fan
833 inlets and the FGD outlet duct will be replaced. Other demolition work will be
834 limited to interfering items only.

835 **Q. Why is natural gas conversion of Naughton Unit 3 being pursued?**

836 A. To comply with state of Wyoming Regional Haze SIP requirements, installation
837 of SCR and a baghouse to reduce emissions of NO_x and PM on Naughton Unit 3
838 was required by December 31, 2014. The Company assessed the economics
839 associated with these requirements in a CPCN docket in the state of Wyoming
840 and determined that natural gas conversion is in the best interests of the
841 Company's customers. A summary of the Company's CPCN filing and results is
842 included in Exhibit RMP___(CAT-4).

843 **Q. Please provide additional background regarding the Regional Haze**
844 **compliance obligations facing Naughton Unit 3.**

845 A. In 2007, the Company submitted required applications to the Wyoming
846 Department of Environmental Quality ("WDEQ") Air Quality Division ("AQD")
847 for BART permits at various BART-eligible electric generating units in
848 Wyoming, including Naughton Unit 3. On December 31, 2009, the WDEQ AQD
849 issued BART permit MD-6042 for the Naughton plant requiring, among other
850 things, the installation of a SCR and a baghouse as additional environmental
851 controls at Naughton Unit 3.

852 In February 2010, the Company appealed certain provisions of the
853 Naughton BART permit to the Wyoming Environmental Quality Council
854 ("WEQC"), including provisions requiring the installation of SCR and baghouse
855 on Naughton Unit 3. By settlement agreement dated November 3, 2010, the
856 Company and the WDEQ AQD resolved the appeal as to Naughton Unit 3 by the
857 Company agreeing to abide by the original terms of the Naughton BART permit.

858 The WDEQ AQD finalized its Regional Haze SIP on January 7, 2011,
859 including the requirement for the Company to install a SCR and baghouse at
860 Naughton Unit 3. It then submitted its Regional Haze SIP to the EPA for review
861 and approval. On June 4, 2012, EPA proposed to partially approve certain
862 portions of the Wyoming Regional Haze SIP, including those portions that require
863 the installation of SCR and baghouse at Naughton Unit 3 by December 31, 2014.

864 The EPA later determined that public comments received on its proposed
865 action on the SIP led it to *re-propose* its rule for a new round of public comment.
866 The EPA reported that it had conducted additional analysis on emissions control
867 costs and the associated visibility benefits between the Wyoming Regional Haze
868 SIP submittal and December 14, 2012, the anticipated EPA final action date. The
869 EPA approached the original litigants and, in an unopposed motion filed
870 December 10, 2012 with the U.S. Department of Justice on behalf of the EPA,
871 requested a new deadline for a re-proposed rule of March 29, 2013, and a final
872 action deadline of September 27, 2013. The court approved the EPA's request for
873 extension on December 13, 2012.

874 Subsequently, on March 27, 2013, the EPA received approval from the
875 U.S. District Court to again extend the deadlines previously agreed to for issuance
876 of actions on the Wyoming Regional Haze SIP. In a filing made in the U.S.
877 District Court, WildEarth Guardians, National Parks Conservation Association,
878 and the Environmental Defense Fund agreed to allow the EPA to extend the
879 previously extended deadlines for issuance of a re-proposal on the Wyoming
880 Regional Haze SIP from March 29, 2013 to May 23, 2013, and to revise final

881 action deadlines from September 27, 2013 to November 21, 2013.

882 The EPA re-proposed official draft rules on the Wyoming Regional Haze
883 SIP on June 10, 2013. In its re-proposed draft rules, the EPA supported SCR and
884 baghouse on Naughton Unit 3 and requested public comments on a natural gas
885 conversion alternative. The Company provided comments on the EPA's re-drafted
886 proposal on August 26, 2013, in support of the natural gas conversion alternative
887 for Naughton Unit 3 and extension of the operating timeframe of the unit as a
888 coal-fueled resource from December 31, 2014 to December 31, 2017.

889 Since August 26, 2013, EPA has again been granted an extension to take
890 final action on the Wyoming Regional Haze SIP to January 10, 2014. Until EPA
891 takes final action on the SIP, and the underlying state of Wyoming compliance
892 obligations, including the Wyoming Regional Haze SIP, are modified, the
893 Company remains obligated to comply the Wyoming Regional Haze SIP and the
894 associated WDEQ permit documents to install SCR and a baghouse at Naughton
895 Unit 3 by December 31, 2014.

896 **Q. Did the Company explore compliance flexibility, if any, with the**
897 **environmental agencies having jurisdiction (i.e. state of Wyoming and/or**
898 **EPA)?**

899 A. Yes. The topic of project timelines and technical requirements has been raised
900 with representatives of the state of Wyoming and EPA Region 8 given EPA's
901 continual extension motions regarding Wyoming Regional Haze SIP actions, and
902 consideration that final action is now not expected until January 10, 2014. The
903 Company has pointed out that re-proposed rules, after dates the Company must

904 enter into contracts for timely and compliant equipment procurement and
905 installation, affecting required emissions limits or compliance timelines make
906 cost-effective decision-making and planning extremely difficult both for the
907 Company and for competitive market participants. Further, due to EPA's
908 continually delayed action, it would be impossible for the Company to complete
909 an SCR and baghouse project within the originally prescribed compliance
910 deadline for Naughton Unit 3, should the EPA reject the alternative compliance
911 approach of natural gas conversion of the unit. EPA has acknowledged the
912 dilemma to the Company and competitive market faces.

913 Company representatives also met WDEQ representatives on January 4,
914 2013 and March 27, 2013, to further discuss EPA's delayed action along with
915 other environmental compliance planning topics. WDEQ's position regarding
916 EPA's pending actions is that the Company is currently bound by the
917 environmental compliance obligations included in the Wyoming Regional Haze
918 SIP, associated WDEQ AQD permits, and settlement stipulation pertaining to
919 Naughton Unit 3 and other Wyoming units. The WDEQ re-confirmed its position
920 in writing on March 6, 2013.

921 Company representatives also met with the Wyoming Attorney General's
922 office on January 4, 2013, to discuss deadlines and the agency's position on
923 extending the deadlines. The Company was advised that the state of Wyoming
924 views the deadlines as being independently legally enforceable under the
925 Wyoming Regional Haze SIP, the Settlement Agreement, and Chapters 6 and 9 of
926 the Wyoming Air Quality Standards and Regulations. The state's position was

927 confirmed at the WEQC's meeting on January 10, 2013.

928 **Q. Has the Company formally requested state of Wyoming approval of the**
929 **natural gas conversion alternate Regional Haze compliance approach for**
930 **Naughton Unit 3?**

931 A. Yes. Recognizing the complexity that attempting to modify Wyoming Regional
932 Haze SIP, Settlement Agreement, and other associated regulations and
933 agreements regarding Naughton Unit 3 presents; as well as the uncertainty
934 surrounding the timing and extent of EPA's final action in this regard, the
935 Company applied for and received a permit from the WDEQ to cease coal-fueled
936 operation of Naughton Unit 3 by December 31, 2017, and to convert the unit to
937 natural gas fueling by June 30, 2018. WDEQ AQD Permit MD-14506 is attached
938 as Exhibit RMP___(CAT-5) for reference.

939 It is expected that the terms of the natural gas conversion permit for
940 Naughton Unit 3 will ultimately be aligned with the other Regional Haze related
941 plans, permits, and agreements affecting the unit following final EPA action on
942 the Wyoming Regional Haze SIP.

943 **Q. Has the Company evaluated whether the least-cost alternative, accounting**
944 **for risk and uncertainty, to comply with environmental requirements was to**
945 **invest in the emissions control equipment or to idle Naughton Unit 3?**

946 A. Yes. As part of the CPCN process described above, the Company completed an
947 economic analysis that evaluated the trade-offs between making incremental
948 investments to comply with then-current and emerging environmental regulations
949 to a broad range of resource alternatives including: (1) natural gas conversion; (2)

950 early retirement and replacement with green field natural gas resources; (3) firm
951 market purchases; (4) demand-side management opportunities; and or (5)
952 renewable resources. Ultimately, the Company's evaluation established that
953 converting the unit to 100 percent natural gas fueling and operating the unit as a
954 slow-start peaking unit was the risk-adjusted and least-cost alternative for our
955 customers.

956 **Q. Did the Company consider alternative technologies to the natural gas**
957 **conversion?**

958 A. Yes. Exhibit RMP___(CAT-2) is a summary of the technical studies and key
959 study points used in the Company's consideration and analysis of technical
960 alternatives to the Naughton Unit 3 Regional Haze compliance alternatives.

961 **Q. Please describe the currently anticipated Naughton Unit 3 natural gas**
962 **conversion project timeline from inception through final completion.**

963 A. This testimony has been prepared under the worst-case assumption that the
964 Naughton Unit 3 natural gas conversion will be completed and placed in service
965 by May 2015, pursuant to the currently established Wyoming Regional Haze SIP
966 compliance deadline for Naughton Unit 3 NO_x and PM reductions, and assuming
967 that EPA does not support the timeline for conversion approved under the state of
968 Wyoming construction permit discussed above. Under this scenario, the unit
969 would operate on coal through December 31, 2014, and subsequently enter into a
970 five-month construction and tie-in outage for conversion of the unit to natural gas
971 as its fuel supply. EPC contract provisions are being pursued that will guarantee

972 the project to be mechanically complete by June 1, 2015, and available thereafter
973 to generate as dispatched during the 2015 summer peak load season and beyond.

974 Exhibit RMP___(CAT-6) illustrates the overall project timeline from
975 inception to completion, including activities occurring during the early
976 development phase of the project that were focused toward planning a SCR and a
977 baghouse alternative instead of the natural gas conversion alternative.

978 **Q. Has the Company aligned its competitive procurement activities for the**
979 **conversion project with the emissions performance requirements of the**
980 **construction permit approved for the project?**

981 A. Yes. PacifiCorp is currently in the process of bidding the EPC contract for the
982 Naughton Unit 3 natural gas conversion. Proposals were received from bidders on
983 December 3, 2013. In its request for proposals, PacifiCorp requested the
984 following emissions performance guarantees:

Parameter	Guarantee
NOx Emission Rate	By Contractor (At least ≤ 0.080 lb NOx/mmBtu throughout the load range)
Long Term NOx Emission Rate	< 0.080 lb NOx/mmBtu AND < 250 lb NOx/hr (30-boiler day rolling arithmetic average)
CO	By Contractor (lb CO/mmBtu or ppm throughout the load range)
VOC Emission	< 0.0040 lb VOC/mmBtu
PM Limit	≤ 0.0070 lb PM₁₀/mmBtu

985 **Q. Did the Company consider all applicable emerging environmental**
986 **regulations that pose risk to continued operation of Naughton Unit 3 when**
987 **determining natural gas conversion was the preferred compliance**
988 **alternative?**

989 A. Yes. The Company considered MATS regulations; potential carbon dioxide
990 (“CO₂”) regulations; proposed CCR regulations; proposed Clean Water Act
991 316(b) regulations; and proposed effluent limitation guidelines rulemaking. Case-
992 by-case discussion of the impacts of those emerging environmental regulations on
993 the Company’s decision to convert Naughton Unit 3 to a natural gas fueled
994 generation resource is provided in Exhibit RMP___(CAT-7) for reference.

995 **Q. Does the Naughton Unit 3 natural gas conversion permit issued by Wyoming**
996 **address MATS compliance for the unit in the interim between April 15, 2015**
997 **and December 31, 2017?**

998 A. Yes. A critical consideration of the Naughton Unit 3 natural gas conversion
999 compliance schedule approved by WDEQ is the overlapping requirement to
1000 comply with MATS by April 16, 2015, through the December 31, 2017, coal-
1001 fueled operation window for the unit. In that interim period, WDEQ has
1002 prescribed enforceable operating restrictions and emissions limits on the unit
1003 consistent with MATS compliance requirements. It is proposed that the operating
1004 limits and permit conditions commence upon compliance dates required by the
1005 MATS rule (April 16, 2015), and terminate December 31, 2017.

1006 **Q. Has the EPA approved the alternate Regional Haze compliance approach of**
1007 **converting Naughton Unit 3 to natural gas fueling?**

1008 A. No. As discussed above, EPA is not currently expected to take final action on the
1009 Wyoming Regional Haze SIP until January 10, 2014. EPA has, however,
1010 requested public comment on the Naughton Unit 3 natural gas conversion and
1011 associated project timing approved by Wyoming. As such, the Company
1012 continues to prepare for the earlier conversion date discussed above to avoid
1013 placing the Company in a position of being unable to achieve the currently
1014 prescribed Wyoming Regional Haze SIP compliance timeline for the unit.

1015 **Q. Are the state of Wyoming compliance requirements enforceable absent final**
1016 **EPA action?**

1017 A. Yes. Company representatives met with WDEQ representatives on January 4,
1018 2013 and March 27, 2013, to further discuss the EPA's delayed Wyoming
1019 Regional Haze SIP rule making action along with other environmental
1020 compliance planning topics. WDEQ's position regarding EPA's pending actions
1021 is that the Company remains currently bound by the environmental compliance
1022 obligation included in the Wyoming Regional Haze SIP, associated WDEQ AQD
1023 permits, and settlement stipulation pertaining to Naughton Unit 3 and other
1024 Wyoming units. The WDEQ re-confirmed its position in writing on March 6,
1025 2013. See Exhibit RMP___(CAT-8).

1026 **Q. If EPA approves the revised compliance deadline for Naughton Unit 3**
1027 **consistent with the state of Wyoming's requirements, what actions does the**
1028 **Company intend to take?**

1029 A. If EPA approves the Naughton Unit 3 compliance conditions included in the
1030 construction permit issued by WDEQ discussed above and allows the unit to
1031 operate as a coal-fueled resource through December 31, 2017, the Company will
1032 revise its natural gas conversion project implementation schedule accordingly. In
1033 that instance, the Company would support an adjustment to the capital cost
1034 associated with the natural gas conversion project and removing the capital
1035 addition from the Test Period. The impact of such an adjustment is addressed in
1036 the direct testimony of Company witnesses Mr. Gregory N. Duvall and Mr.
1037 Steven R. McDougal. Exhibit RMP___(CAT-9) provides additional context
1038 regarding permitting activities associated with EPA's review and approval.

1039 **Q. Will Naughton Unit 3 remain a low cost generation resource following**
1040 **implementation of the project?**

1041 A. While the implementation phase of the Naughton Unit 3 natural gas conversion
1042 has not yet started, the EPC contract is currently being bid for an early 2015
1043 conversion. The competitive market respondents to the Company's request for
1044 proposals further inform the Company as to whether its cost estimates and
1045 performance assumptions for the project remain accurate and aligned with the
1046 assumptions used in its Naughton Unit 3 natural gas conversion alternative
1047 resource decision analysis.

1048 The Company's current economic analysis, including sensitivity analyses,
1049 for the proposed Naughton Unit 3 natural gas conversion project demonstrates
1050 that the unit remains a valuable low cost generation resource for peaking needs
1051 following unit conversion.

1052 **Conclusion**

1053 **Q. Please summarize your testimony.**

1054 A. The Lake Side 2 project was approved by the Commission as the lowest
1055 reasonable cost option to meet additional electricity needs of customers, taking
1056 into account costs and risks, in Docket No. 10-035-126. The Company's
1057 investment in and implementation of the new Lake Side 2 CCCT natural gas
1058 fueled resource project remains aligned with its original intent and is expected to
1059 deliver benefits to customers on schedule and at a lower capital cost than
1060 originally forecasted.

1061 Investments in emissions control investments at the Company's jointly
1062 owned Hunter Unit 1 and Hayden Unit 1 are required to meet the EPA's Regional
1063 Haze rules, and the resulting BART reviews, state implementation plans,
1064 permitting processes, and in the case of Hayden, Colorado Clean Air Clean Jobs
1065 Act. The investments in pollution control equipment at the Company's Hunter
1066 Unit 1 included in this case have been assessed in conjunction with potential
1067 compliance costs associated with emerging environmental regulations, including
1068 potential regulation of carbon dioxide emissions. The investment allows for the
1069 continued operation of low-cost coal-fueled generation resources, while achieving
1070 significant environmental improvements. The Company's support of the

1071 investment in the Hayden Unit 1 environmental compliance project included in
1072 this case has been administered pursuant to applicable law and the Partnership
1073 Agreement applicable to that unit.

1074 The Company's other major generation plant investments at Blundell and
1075 as currently planned at Naughton Unit 3 have been prudently managed and
1076 assessed as being in the best interests of customers; effectively maintaining safe,
1077 reliable, efficient, cost-effective generating resources and production facilities.

1078 The capital investments included in this case are reasonable and prudent,
1079 and the Company should be granted full cost recovery for these investments.

1080 **Q. Does this conclude your direct testimony?**

1081 A. Yes.