

Rocky Mountain Power
Docket No. 10-035-124
Witness: Chad A. Teply

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Direct Testimony of Chad A. Teply

New Generation Resources

January 2011

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

3 A. My name is Chad A. Teply. My business address is 1407 West North Temple,
4 Suite 210, Salt Lake City, Utah. 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 am a Registered Professional Engineer in the state of
12 Iowa. I joined MidAmerican Energy Company in November 1999 and held
13 positions of increasing responsibility within the generation organization,
14 including the role of project manager for the 790-megawatt Walter Scott Energy
15 Center Unit 4 completed in June 2007. In April 2008, I moved to Northern
16 Natural Gas Company as senior director of engineering. In February 2009, I
17 joined the PacifiCorp team as vice president of resource development and
18 construction, at PacifiCorp Energy. In my current role, I have responsibility for
19 development and execution of major resource additions and major environmental
20 projects.

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

22 A. The purpose of my testimony is to provide the Commission and parties with
23 information supporting the prudence of capital investments in pollution control

24 equipment, generation plant, and hydro projects being placed in service during the
25 test period. My testimony also supports the prudence of incremental generation
26 operations and maintenance costs associated with certain new resources, new
27 pollution control equipment, and other generation fleet operational changes
28 impacting this case.

29 **Background**

30 **Q. Please provide a general description of the pollution control equipment and**
31 **additional capital investments being placed in service, and the benefits**
32 **gained from the investments.**

33 A. The pollution control equipment investments included in this case primarily result
34 in the reduction of sulfur dioxide (“SO₂”), nitrogen oxides (“NO_x”), mercury
35 (“Hg”), and particulate matter (“PM”) emissions from the retrofitted facilities.
36 These investments are required to comply with current, proposed, and probable
37 environmental regulations. These investments constitute approximately 60 percent
38 of the generation related capital investments placed in service or projected to be
39 placed in service between July 2010 and June 2012, excluding the Dunlap I wind
40 energy project which was included and approved in the major plant addition case,
41 Docket no. 10-035-89.

42 Hydro generation plant investments, which constitute approximately 10
43 percent of the generation related capital investments placed in service or projected
44 to be placed in service between July 2010 and June 2012, excluding Dunlap I, are
45 primarily new license implementation measures required by the Federal Energy
46 Regulatory Commission to allow continued operation of these low-cost

47 generation assets.

48 Generation plant turbine upgrade investments enhance the Company's
49 overall generation capability and cycle efficiency without increasing emissions
50 for the large thermal units that receive this equipment.

51 Other generation plant investments support asset safety, reliability, and
52 cost effectiveness via reduced risk of equipment and component failures,
53 enhanced control systems, and improved security provisions.

54 **Justification of Pollution Control Investment**

55 **Q. Why has the Company invested in pollution control equipment?**

56 A. Through the 1977 amendments to the Clean Air Act, Congress set a national goal
57 for visibility to remedy impairment from manmade emissions in designated
58 national parks and wilderness areas; this goal resulted in development of the
59 Regional Haze Rules, adopted in 2005 by the U.S. Environmental Protection
60 Agency ("EPA"). The first phase of these rules trigger Best Available Retrofit
61 Technology ("BART") reviews for all coal-fired generation facilities built
62 between 1962 and 1977 that emit at least 250 tons of visibility-impairing pollution
63 per year. Visibility-impairing pollutants include sulfur dioxide SO₂, nitrogen
64 oxides NO_x and particulate matter PM. The Company has 14 units that meet the
65 construction and emissions threshold criteria and are, therefore, "BART-eligible
66 units." Pursuant to federal regulations at 40 CFR 51.308(e)(1)(ii), each state is
67 required to determine which BART-eligible sources are also "subject to BART."
68 BART-eligible sources are subject to BART if they emit any air pollutant that
69 may reasonably be anticipated to cause or contribute to impairment of visibility in

70 any designated national park or wilderness area. The investments in pollution
71 control equipment are at the Company's BART-eligible units that have been
72 determined by the state environmental regulators to be necessary after considering
73 available technology; costs of compliance; energy and non-air quality
74 environmental impacts; existing control equipment and the remaining useful life
75 of the facility; and the degree of improvement in visibility reasonably anticipated
76 to result from the use of such technology.

77 After considering these five factors, the respective state departments of
78 environmental quality for the units made their BART determinations and
79 incorporated the results of the above mentioned BART analyses into the operating
80 permits, construction permits and Approval Orders (defined below) for the
81 pollution control equipment contemplated by this case.

82 With respect to the Naughton Unit 2 low NO_x burners installation project
83 and Wyodak low NO_x burners and bag house installation projects described
84 below, the Wyoming Department of Environmental Quality ("WY DEQ") issued
85 BART permits for those units on December 31, 2009, incorporating the
86 equipment and installation schedules recommended via the BART review and
87 contemplated in this case. The conditions of the BART permits are currently in
88 the process of being incorporated into the Wyoming State Implementation Plan
89 ("SIP") for Regional Haze in support of its goals to reduce visibility impairing
90 emissions. The Wyoming SIP is subject to U.S. EPA review and approval. The
91 WYDEQ has also issued construction permits for the Jim Bridger, Naughton, and
92 Wyodak pollution control projects described below.

93 With respect to the Hunter Unit 2 and Huntington Unit 1 projects
94 described below, the Utah Department of Environmental Quality (“UT DEQ”) has
95 incorporated the results of BART reviews completed for those facilities into the
96 Utah SIP. The Utah SIP is subject to U.S. EPA review and approval. The state of
97 Utah has also issued Approval Orders (*i.e.*, permits to construct) for each of the
98 Hunter and Huntington pollution control projects described below.

99 In addition to the BART requirements under the regional haze rule,
100 increasingly more stringent National Ambient Air Quality Standards have been
101 and are being adopted for criteria pollutants, including SO₂, NO₂, ozone, and PM.
102 Implementation of the pollution control projects described herein assists in
103 meeting these more stringent standards, avoiding the negative consequences of an
104 area being declared to be a nonattainment area. Further, while the Clean Air
105 Mercury Rule, which would have required a reduction of mercury emissions of
106 approximately 70 percent by 2018 was overturned by the United States Court of
107 Appeals for the District of Columbia Circuit in February 2008, the U.S. EPA
108 plans to propose a new rule that will require coal-fired generating facilities to
109 reduce mercury, and potentially other emissions of hazardous air pollutants,
110 through a Maximum Achievable Control Technology standard. Under a consent
111 decree, the U.S. EPA must issue a proposed rule to regulate mercury emissions by
112 March 2011 and a final rule no later than November 2011; compliance with the
113 mercury standards would be required by November 2014. The bag house and
114 scrubber projects described herein will assist in meeting the forthcoming
115 Maximum Achievable Control Technology requirements.

116 In short, the pollution control investments contemplated in this case are
117 required to maintain compliance with the environmental requirements described
118 above.

119 **Q. Please clarify the definition of a “presumptive BART emission limit” as it**
120 **pertains to established federal pollution control standards.**

121 A. The use of the term “presumptive BART emission limit” in the instance cited
122 does not mean that BART emission limits are uncertain future requirements.
123 Instead, the use of the term refers to emission rates identified in the Regional
124 Haze Rule, Code of Federal Regulations (CFR), Title 40, Sections 51.300 through
125 51.309, and Appendix Y. Electronic copies of the referenced CFRs can be found
126 at the following link:

127 http://www.access.gpo.gov/nara/cfr/waisidx_09/40cfr51_09.html

128 Presumptive BART emission limits come from Appendix Y cited above, and are
129 rates defined by the EPA. States use the rates defined by the EPA to assist in
130 determining whether a BART-eligible facility is presumed to meet the
131 requirement to install best available retrofit technology. For example, if the
132 installation of low-NO_x burners on a BART-eligible facility with cell-burners
133 firing sub-bituminous coal achieves an emission rate of 0.28 lb/MMBtu, which is
134 below the U.S. EPA presumptive BART rate of 0.45 lb/mmBtu (the presumptive
135 rate for a cell-burner unit burning sub-bituminous coal), it can be presumed that
136 the installation of low-NO_x burners on this unit meets federal best available
137 retrofit requirements with respect to NO_x control, and no additional controls
138 would be likely to be required. With respect to SO₂ control, the states of Utah and

139 Wyoming, along with New Mexico, are participating in a market-trading program
140 identified in the Regional Haze Rule, CFR, Title 40, Section 51.309. Under this
141 program the states have set SO₂ emission reduction milestones that must be
142 achieved. These milestones have been developed assuming that each coal-fired
143 generating unit meets the lower of its historic emission rate or the presumptive
144 SO₂ rate. The EPA has defined the presumptive SO₂ emissions rate as 0.15
145 lb/mmBtu or 90 percent removal. Here again, if the installation of pollution
146 control equipment on a BART-eligible facility achieves an emission rate less than
147 that presumptive limit and overall emission reduction goals are being met, it can
148 be presumed that the installation meets federal best available retrofit requirements
149 and no additional controls will be required.

150 **Q. What factors does the Company consider when determining which capital**
151 **investments to make in environmental equipment retrofit projects?**

152 A. As an initial matter, the Company assesses its environmental compliance
153 obligations and the timing of those compliance obligations; in that context, the
154 Company assesses the overall cost and availability of various control technologies
155 and alternatives. As the Company considers when, whether and what capital
156 investments to make in environmental controls, it takes several additional factors
157 into consideration, including: evaluation of current state and federal
158 environmental regulatory requirements; review of emerging environmental
159 regulations and rulemaking; and whether alternate compliance options exist, such
160 as purchasing allowances, that may result in lower costs to comply. As part of the
161 BART review of each facility, the Company evaluated several technologies on

162 their ability to economically achieve compliance and support an integrated
163 approach to control criteria pollutants (*e.g.* SO₂, NO_x, and PM for the facility), if
164 it were to continue to operate and to burn coal. The BART analyses reviewed
165 available retrofit emission control technologies and their associated performance
166 and cost metrics. Each of the technologies was reviewed against its ability to
167 meet a presumptive BART emission limit based on technology and fuel
168 characteristics. The BART analyses outlined the available emission control
169 technologies, the cost for each and the projected improvement in visibility which
170 can be expected by the installation of the respective technology. For each unit or
171 source subject to BART, the state environmental regulatory agencies identify the
172 appropriate control technology to achieve what the air quality regulators
173 determine are cost-effective emission reductions. Once the appropriate BART
174 technology was identified, the Company moved forward with its competitive
175 bidding process to evaluate and ultimately select the preferred provider for the
176 projects.

177 **Q. What process is in place to explore ongoing investment versus retirement of**
178 **the Company's coal units?**

179 A. The existing integrated resource planning (“IRP”) proceedings conducted in all
180 six of the states served by the Company provides the process to address ongoing
181 investment versus retirement of the Company's coal units. Future IRP
182 proceedings will increasingly focus upon the complexity in balancing factors such
183 as:

184 (1) pending environmental regulations and requirements to reduce emissions
185 in addition to addressing waste disposal and water quality concerns,
186 (2) avoidance of excessive reliance on any one generation technology,
187 (3) costs and trade-offs of various resource options including energy
188 efficiency, demand response programs, and renewable generation,
189 (4) state-specific energy policies, resource preferences, and economic
190 development efforts,
191 (5) additional transmission investment to reduce power costs and increase
192 efficiency and reliability of the integrated transmission system, and
193 (6) maintaining rates as affordable as possible.

194 **Q. Is the Company obligated to install pollution controls required by state**
195 **permits, regardless of whether final U.S. Environmental Protection Agency**
196 **review and approval of the respective regional haze state implementation**
197 **plans remains pending?**

198 A. Yes. The BART permits and construction permits issued by the respective state
199 agencies for the pollution control investments contemplated in this case include
200 stand-alone requirements enforceable by the laws of the respective states. These
201 requirements are enforceable independent of whether EPA has approved the
202 respective state implementation plans.

203 **Q. Does the Company anticipate that final U.S. Environmental Protection**
204 **Agency approval of the respective state implementation plans will require**
205 **alternate pollution control equipment to be installed, making the equipment**
206 **contemplated in this case obsolete?**

207 A. No. While it is possible that the EPA will require more stringent emission limits
208 to be achieved, the pollution control technology selections completed to date
209 apply best available retrofit technology, comply with existing state and federal
210 regulations, and support Regional Haze Rule objectives. The Company also
211 incorporates into its pollution control equipment contract specifications design
212 considerations intended to provide appropriate levels of operating margin,
213 equipment redundancy, and system maintainability and reliability provisions to
214 support an expected range of process inputs, operating conditions, and system
215 performance. Although the Company cannot predict future pollution control
216 regulations and associated emissions limits, the Company does take steps to
217 procure a prudent level of design flexibility to accommodate potential changes in
218 system performance requirements, where practical.

219 **Q. Does the Company anticipate that final U.S. Environmental Protection**
220 **Agency approval of the respective state implementation plans will require**
221 **additional pollution control equipment to be installed on the facilities**
222 **contemplated in this case?**

223 A. That is a possibility; however, the pollution control equipment investments
224 contemplated in this proceeding would be required in any event. Should the EPA
225 require additional emissions reductions, the incremental reductions would likely

226 be accomplished via additional projects that build on or enhance the capabilities
227 of installed pollution control projects, otherwise act independently of installed
228 pollution control projects, or via facility operating changes. The Company
229 includes the following considerations in its planning efforts in order to best meet
230 the Company's future emissions reductions obligations: facility operations
231 compliance options, available control technologies, cost of compliance; proposed
232 compliance deadlines, and emerging environmental regulations and rulemaking.

233 **Q. Would the Company's decision to make these incremental investments in**
234 **environmental controls at these units change if limitations were placed on**
235 **carbon dioxide emissions, such as in the Waxman-Markey bill in the U.S.**
236 **House of Representatives or the Kerry-Lieberman bill in the U.S. Senate?**

237 A. No. The Company is engaged in assessing its existing generation resources, its
238 planned supply and demand-side resources and its 10-year capital budget with
239 respect to the impact of potential carbon dioxide emissions restrictions. While
240 other planned investments may change, the Company's plans regarding the
241 emission control investments included in this case would not change as a result of
242 carbon-emission restrictions. The current controls are required under existing
243 regulations and the units have depreciation lives for ratemaking purposes that
244 provide sufficient remaining time to depreciate the investments in the
245 environmental controls. While carbon restrictions may ultimately affect the cost
246 of generating electricity at these units, they are still anticipated to be utilized as
247 part of the company's overall generating fleet that will be necessary to provide
248 baseload electricity at a reasonable cost to customers.

249 **Q. What efforts are being taken by the Company to understand and evaluate**
250 **impacts of potential future environmental regulations on the Company's**
251 **business?**

252 A. PacifiCorp and its parent, MidAmerican Energy Holdings Company, are very
253 active in the current Congressional, state legislative, and EPA activities regarding
254 environmental controls affecting virtually all emissions from coal and natural gas
255 generating units, as well as other environmental issues. The Company is very
256 cognizant that some potential restrictions on greenhouse gas emissions (“GHGs”)
257 could require coal (and potentially natural gas) units to adjust the depreciation
258 lives for ratemaking purposes. The Company considers this possibility when
259 determining whether to proceed with investments to control emissions other than
260 GHGs.

261 PacifiCorp has been a participant in the Oregon regulatory proceedings
262 regarding the potential early closure or installation of emission controls at
263 Portland General Electric’s Boardman plant. PacifiCorp and its parent are also
264 closely following similar proceedings in Colorado in which regulated utilities are
265 required to comply with a statute enacted in 2010. That statute primarily focused
266 on reductions in nitrogen oxides and facilitated the conversion of 1000 MW of
267 coal-fired generation to natural gas generation in that state. While the Boardman
268 proceeding has largely been concluded by the state agencies, Oregon’s state
269 implementation plan that incorporates requirements leading up to an early closure
270 of the Boardman facility is still subject to approval by the EPA. The regulatory
271 proceedings in Colorado are still pending.

272 **Q. Is the Company undertaking reasonable efforts to ensure that environmental**
273 **regulators consider the uncertainty created by requiring investments in**
274 **certain emissions controls prior to knowing the nature and extent of controls**
275 **on other emissions?**

276 A. Yes. The Company filed an appeal of the Regional Haze requirements in
277 Wyoming for this exact reason. Wyoming was the first state to make the
278 determination that BART required the installation of selective catalytic reduction
279 (SCR) controls for nitrogen oxides. The Company disagreed with that
280 determination and asserted that Appendix Y of 40 CFR Part 51 did not
281 contemplate the installation of post-combustion controls. Additionally, the
282 Company was concerned that other environmental laws and/or regulations could
283 impact the Company's facilities affected by Wyoming's BART determinations in
284 a way that that impacted the economic analysis associated with the installation of
285 the contemplated controls. These requirements not only include greenhouse gas
286 reduction requirements, but also a host of regulatory initiatives underway by the
287 U.S. EPA, including the outcome of pending coal combustion waste disposal
288 regulations and maximum achievable control technology (MACT) standards for
289 mercury and non-mercury hazardous air pollutants. Due to the uncertainty
290 associated with the potential impact of these rules on the Company's facilities, the
291 Company appealed the BART permits issued by the Wyoming Department of
292 Environmental Quality to ensure that these and other issues were considered in
293 the agency's decision and, to the extent these issues had an impact on long-term
294 viability of the facilities, the economic analysis of adding emission reduction

295 equipment was properly reflected. Since the time that the Company filed its
296 appeal, the U.S. EPA issued a BART determination for the Four Corners Power
297 Plant in Arizona, requiring the installation of SCR at all five units operated by
298 Arizona Public Service within a five-year period, without regard to other
299 environmental requirements or their associated uncertainties. Likewise, the U.S.
300 EPA recently proposed to require the installation of four SCR within three years
301 at the San Juan Generating Station in New Mexico.

302 In November 2010, PacifiCorp settled the Wyoming BART appeal to
303 resolve the matter in a way that did not require more controls and impose
304 additional costs earlier than originally proposed in the Department of
305 Environmental Quality's BART determinations. To provide maximum flexibility
306 in the event that other environmental requirements or uncertainties arose,
307 PacifiCorp and the Wyoming Department of Environmental Quality included
308 terms in the settlement agreement to address a modification if future changes in
309 either federal or state requirements or technology would materially alter the
310 emissions controls and rates that would otherwise be required.

311 **Q. Did the Company provide the Wyoming Department of Environmental**
312 **Quality additional information regarding the Company's overall emission**
313 **reduction plans through 2023 in connection with the settlement discussed**
314 **above?**

315 A. Yes. The Company provided additional information including an overview of the
316 Company's long-term emission reduction commitment, project installation
317 schedules and compliance deadlines, emission reduction priorities, anticipated

318 customer impacts, and brief descriptions of other environmental initiatives that
319 are also expected to impact future operating costs of the Company. A copy of this
320 additional information is provided for reference in Exhibit RMP___(CAT-1).

321 **Timing of Investment**

322 **Q. Why is PacifiCorp installing pollution control equipment at this time?**

323 A. As discussed above, the Company is installing pollution control equipment at this
324 time to comply with the Regional Haze Rules, as well as in response to more
325 stringent National Ambient Air Quality Standards, the impending mercury
326 requirements, and a number of existing and emerging emission reduction
327 requirements. Final installation activities and tie-in of the pollution control
328 equipment described above can only be accomplished when the units are off-line.
329 Meeting the timing requirements of construction permits and Approval Orders
330 and reducing plant outage time necessitated completion of final installation
331 activities and tie-in of the pollution control equipment during the scheduled
332 overhauls within this test period. Installation of the pollution control equipment
333 and associated systems included in this case represent a significant step for
334 PacifiCorp's coal-fueled power plant fleet toward meeting the SO₂ and NO_x
335 reductions required by the Regional Haze Rules and established by the respective
336 states' emissions reduction milestones.

337 **Customer Considerations**

338 **Q. What are the benefits to customers of installing the pollution control**
339 **equipment and why should Utah customers pay the costs related to this**
340 **project?**

341 A. Customers directly benefit from the continued availability of low-cost generation
342 produced at the facilities while also achieving environmental improvements from
343 these resources, resulting in cleaner air. In addition, the tie-in of these necessary
344 controls is being accomplished during planned maintenance outages, as opposed
345 to scheduling separate outages for this work, which reduces replacement power
346 costs. The Company has ten BART-eligible units in Wyoming and four in Utah.
347 The BART controls for each of these units must be installed as expeditiously as
348 possible, but no later than five years from the date the respective SIPs are
349 approved and prior to the compliance dates specified in the permits. Postponing
350 installation of the pollution control equipment included in this case to later
351 planned maintenance outages would make it virtually impossible for the Company
352 to effectively ensure that all of its affected units meet compliance deadlines and
353 would place the Company at risk of not having access to necessary capital,
354 materials, and labor while attempting to perform these major equipment
355 installations in a compressed timeframe. As the deadlines for environmental
356 requirements across the country draw closer, the demand for equipment and
357 skilled labor is likely to increase, making timely compliance more difficult
358 without incurring significant additional cost.

359 **Description of Pollution Control Investment Projects**

360 **Q. Please describe the Naughton Unit 2 scrubber addition project and**
361 **associated equipment.**

362 A. The scrubber addition project at the Naughton Unit 2 power plant includes the
363 installation of sulfur dioxide controls. The capital investment for the project being
364 placed in service during the test period is approximately \$157 million.
365 Construction began in 2010, and the project is expected to be placed in service by
366 November 2011. The new pollution control equipment will be tied into the
367 existing unit during a scheduled plant maintenance outage. The project will
368 install a flue gas desulfurization (“FGD”) system. The FGD system injects reagent
369 slurry containing sodium carbonate and sodium bicarbonate in the top of an
370 absorber vessel (scrubber) with a network of spray nozzles. The distribution of
371 spray nozzles and trays causes the sodium carbonate slurry to intermix with the
372 flue gas passing through the absorber vessel. The SO₂ in the flue gas reacts with
373 the sodium carbonate in the slurry to form a waste slurry of sodium sulfite and
374 sodium sulfate. The liquid waste slurry is then captured and transported to a
375 scrubber waste pond for disposal. The scrubber waste will ultimately be
376 dewatered and retained in a closed and capped scrubber waste cell on the
377 Naughton plant site.

378 Other equipment to be installed as part of the project includes induced
379 draft fans, boiler reinforcement, new ductwork and a new chimney, sodium
380 carbonate slurry reagent preparation systems, waste material handling systems,

381 electrical infrastructure, controls, and other miscellaneous appurtenances and
382 support systems.

383 **Q. Is the Company also installing scrubber facilities at the Naughton Unit 1**
384 **power plant?**

385 A. Yes. The Naughton Unit 1 scrubber project is being constructed concurrently
386 with the Naughton Unit 2 scrubber project, but on a different schedule. The
387 description of the Naughton Unit 1 scrubber project is for the most part identical
388 to that provided above.

389 **Q. Will the Naughton Unit 1 scrubber addition project also be placed in service**
390 **during the test period used in this case?**

391 A. Yes. The Naughton Unit 1 scrubber addition project is expected to be placed in
392 service during the next planned major maintenance outage for that unit. The
393 capital investment for the project being placed in service during the test period is
394 approximately \$120 million. The project is expected to be complete by May 2012.
395 The planned major maintenance outages for the Company's generation assets are
396 scheduled on a control area basis, considering optimal frequency between
397 overhauls and to minimize the number of major units off line at any one time.
398 The Company completed its most recent overhaul to Naughton Unit 1 in 2008 and
399 is scheduled for its next overhaul in the spring of 2012. The Company's intent in
400 establishing the tie-in schedules for the Naughton Unit 1 and Naughton Unit 2
401 pollution control equipment was to balance the aggregated construction costs and
402 schedules for the pollution control equipment projects against the established

403 planned maintenance overhaul schedules, work plans, and budgets for the
404 respective units.

405 **Q. Are common facilities costs associated with the Naughton Unit 1 and**
406 **Naughton Unit 2 scrubber addition projects included in this case?**

407 A. Yes. The cost of all common facilities that are required to be placed in service to
408 allow prudent operation of either unit's new emission control equipment are
409 incorporated into the Naughton Unit 2 capital investment being placed in service
410 by November 2011. Common facilities include reagent preparation, waste
411 disposal, electrical supply, and ancillary utility systems, as well as site preparation
412 and the chimney.

413 **Q. Please describe the Wyodak power plant stand-alone bag house project and**
414 **associated equipment.**

415 A. A stand-alone bag house will be installed at the Wyodak power plant for control
416 of PM, SO₂, and Hg emissions consistent with requirements. In order to increase
417 the SO₂ removal efficiency of the unit above 90 percent as required to comply
418 with environmental requirements, a bag house must be utilized in conjunction
419 with the existing dry spray dryer absorbers ("SDAs"). Without a bag house, the
420 best SO₂ removal efficiency an SDA on the unit can achieve with Wyodak coal is
421 between 70 and 80 percent. Adding the bag house is necessary to achieve the
422 permitted SO₂ removal requirements.

423 The PacifiCorp share of the capital investment for the Wyodak bag house
424 project being placed in service during the test period is approximately \$103
425 million. Construction began in 2010, and the project is expected to be placed in

426 service by April 2011. The new pollution control equipment will be tied into the
427 existing unit during a scheduled plant maintenance outage.

428 The bag house will capture particulate matter from the flue gas stream as it
429 passes through the bag house and will improve the unit's efficiency in removing
430 SO₂ and Hg from the flue gas. The dry particulate waste stream containing both
431 fly ash and scrubber waste will then be transported to an ash collection pond on
432 adjacent coal mine property for disposal by the mine operator.

433 Other equipment to be installed as part of the project includes induced
434 draft fans, boiler reinforcement, new ductwork, waste material handling systems,
435 electrical infrastructure, controls, and other miscellaneous appurtenances and
436 support systems.

437 **Q. Please describe the Dave Johnston Unit 4 pollution control project and**
438 **associated equipment.**

439 A. The pollution control project being undertaken at the Dave Johnston Unit 4 power
440 plant will upgrade and improve the unit's particulate matter controls to comply
441 with environmental requirements and will also install required SO₂ controls. The
442 capital expenditure for the project during the test period is approximately \$101
443 million.

444 Construction began in 2008, and the project is expected to be operational
445 by April 2012. The new equipment will be tied into the existing equipment
446 during a scheduled plant maintenance outage. The project will install a dry flue
447 gas desulfurization ("DFGD") system and a fabric filter bag house. A DFGD
448 system injects lime slurry in the top of an absorber vessel (scrubber) with a

449 rapidly rotating atomizer wheel. The rapid rotation of the atomizer wheel causes
450 the lime slurry to separate into very fine droplets that intermix with the flue gas.
451 The SO₂ in the flue gas reacts with the calcium in the lime slurry to form calcium
452 sulfate in the form of particulate matter. The dry particulate matter is then
453 captured in the downstream bag house along with fly ash from the boiler. The
454 DFGD system will produce a nonhazardous dry waste product suitable for landfill
455 disposal.

456 Other equipment to be installed as part of the project includes induced
457 draft fans, boiler reinforcement, new ductwork, lime slurry reagent preparation
458 systems, waste material handling systems, electrical infrastructure, controls, and
459 other miscellaneous appurtenances and support systems.

460 **Q. Has the Company also installed scrubber and associated facilities at the Dave**
461 **Johnston Unit 3?**

462 A. Yes. The Company placed a scrubber and associated facilities at the Dave
463 Johnston Unit 3 power plant in service in May 2010. The majority of the costs
464 associated with the Dave Johnston Unit 3 scrubber and all common facilities
465 required to be placed in service to allow prudent operation of either unit's new
466 emission control equipment were included in Utah Major Plant Addition Docket
467 10-035-13 filings by the Company. Approximately \$9.5 million of additional
468 investment associated with the Dave Johnston Unit 3 scrubber and associated
469 facilities has been made subsequent to the project's in service date, which was not
470 included in the major plant addition docket. That investment is included in this

471 case. Common facilities include reagent preparation, waste disposal, electrical
472 supply, and ancillary utility systems, as well as site preparation and the chimney.

473 **Q. Please describe the Huntington Unit 1 power plant bag house conversion**
474 **project, scrubber upgrade project, and associated equipment.**

475 A. The bag house conversion project at the Huntington Unit 1 plant converted an
476 existing electrostatic precipitator to a bag house for PM and Hg emissions control
477 consistent with requirements described earlier in my testimony. The capital
478 investment for the bag house conversion project being placed in service during the
479 test period is approximately \$93 million. Construction began in 2009, and the
480 project was placed in service in November 2010. The bag house conversion was
481 completed during a scheduled plant maintenance outage. The bag house will
482 capture PM and help remove Hg from the flue gas stream as it passes through the
483 bag house. The dry particulate waste stream is then transported to an on-site
484 landfill for disposal.

485 Other equipment to be installed as part of the project includes upgraded
486 scrubber booster fans, boiler reinforcement, new ductwork, modifications to the
487 existing chimney to accommodate wet operation, relocation of the stack opacity
488 monitors, scrubber waste material handling systems, electrical infrastructure,
489 controls, and other miscellaneous appurtenances and support systems.

490 The scrubber project at the Huntington Unit 1 power plant is for required
491 SO₂ controls for the unit and a new scrubber waste material handling system. The
492 new waste handling equipment will be designed to manage the increase in waste

493 product from the higher removal efficiency and increased throughput of the
494 scrubber.

495 The capital investment for the scrubber upgrade and waste material
496 handling project being placed in service during the test period is approximately
497 \$41 million. Construction began in 2010, and the scrubber upgrade portion of the
498 project was placed in service in November 2010. The scrubber waste handling
499 portion of the project is expected to be placed in service by March 2011. The
500 scrubber equipment upgrade will be completed during a scheduled plant
501 maintenance outage. Installation of the waste handling portion of the project will
502 be completed with the plant in service.

503 The scrubber project includes installation of new pumps to increase the
504 capacity of the slurry delivery system of the unit's existing flue gas
505 desulfurization ("FGD") system,, effectively increasing the liquid (slurry) to flue
506 gas ratio within the absorber vessels (scrubbers), and expanding waste material
507 handling system capacity. The FGD system injects lime slurry in the top of a
508 scrubber with a network of spray nozzles and trays. The distribution of spray
509 nozzles and trays causes the lime slurry to intermix with the flue gas passing
510 through the absorber vessel. The SO₂ in the flue gas reacts with the calcium in
511 the slurry to form a waste slurry of calcium sulfite and calcium sulfate. The
512 project will add oxidation air blowers to the system to ensure conversion of the
513 calcium sulfite to calcium sulfate. Calcium sulfate is easier to dewater and the
514 change will allow the slurry waste stream to be more effectively dewatered, and
515 transported to a scrubber waste landfill for disposal.

516 Other equipment to be installed as part of the project includes waste
517 material handling system hydroclones as a replacement for the existing thickener,
518 vacuum drum filters, electrical infrastructure, controls, and other miscellaneous
519 appurtenances and support systems.

520 **Q. Please describe the Hunter Unit 2 power plant bag house conversion project,**
521 **scrubber upgrade project, and associated equipment.**

522 A. The bag house conversion project at the Hunter Unit 2 power plant will convert an
523 existing electrostatic precipitator to a bag house to meet PM and Hg emissions
524 control requirements. The bag house will capture PM and help remove Hg from
525 the flue gas stream as it passes through the bag house. The dry particulate waste
526 stream is then transported to an on-site landfill for disposal. Other equipment to
527 be installed as part of the project includes upgrading the scrubber booster fans,
528 boiler reinforcement, new ductwork, modifications to the existing chimney to
529 accommodate wet operation, relocation of the stack opacity monitors, waste
530 material handling systems, electrical infrastructure, controls, and other
531 miscellaneous appurtenances and support systems.

532 The PacifiCorp share of the capital investment for the bag house
533 conversion project being placed in service during the test period is approximately
534 \$55 million. Construction began in 2010, and the project is expected to be placed
535 in service by May 2011. The bag house conversion will be completed during a
536 scheduled plant maintenance outage. The scrubber project at the Hunter Unit 2
537 power plant will install upgraded SO₂ controls for the unit and an improved
538 scrubber waste material handling system to meet environmental requirements.

539 The scrubber project will upgrade the unit's existing FGD system by increasing
540 the capacity of the slurry delivery system utilizing new pumps, effectively
541 increasing the liquid (slurry) to flue gas ratio within the absorber vessels
542 (scrubbers), and expanding waste material handling system capacity. The FGD
543 system injects lime slurry in the top of a scrubber with a network of spray nozzles
544 and trays. The distribution of spray nozzles and trays causes the lime slurry to
545 intermix with the flue gas passing through the absorber vessel. The SO₂ in the
546 flue gas reacts with the calcium in the slurry to form a slurry waste of calcium
547 sulfite and calcium sulfate. The project will add oxidation air blowers to the
548 system to ensure conversion of the calcium sulfite to calcium sulfate. Calcium
549 sulfate is easier to dewater and the change will allow the slurry waste stream to be
550 more effectively dewatered, and transported to a scrubber waste landfill for
551 disposal.

552 The PacifiCorp share of the capital investment for the scrubber upgrade
553 and material handling project being placed in service during the test period is
554 approximately \$34 million. Construction began in 2010, and the scrubber
555 upgrade and the scrubber waste material handling portions of the project are
556 expected to be completed by May 2011. The scrubber reagent preparation system
557 upgrade portion of the project is expected to be placed in service by March 2012.
558 The scrubber equipment upgrade will be completed during a scheduled plant
559 maintenance outage. Installation of the reagent preparation system upgrade and
560 the waste handling portion of the project will be completed while the plant is in
561 service, and will not require an extended plant maintenance outage for tie-in.

562 Other equipment to be installed as part of the project includes lime slurry
563 reagent preparation systems, waste material handling system hydroclones as a
564 replacement for the existing thickener, vacuum drum filters, electrical
565 infrastructure, controls, and other miscellaneous appurtenances and support
566 systems

567 **Q. Please describe the Hunter Unit 1 power plant scrubber upgrade project and**
568 **associated equipment.**

569 A. The scrubber project at the Hunter Unit 1 power plant will install upgraded SO₂
570 controls for the unit and an improved scrubber waste material handling system to
571 meet environmental requirements. The detailed description of the Hunter Unit 1
572 scrubber project is for the most part identical to that provided for Hunter Unit 2
573 above.

574 Costs associated with the capital investment for the scrubber upgrade and
575 material handling portions of the project ARE NOT included in the revenue
576 requirement in this case due to the projected in-service dates. Construction is
577 scheduled to begin in 2012, and the scrubber upgrade portion of the project is
578 expected to be placed in service by May 2014. The scrubber equipment upgrade
579 will be completed during a scheduled plant maintenance outage. The scrubber
580 waste material handling portion of the project is expected to be placed in service
581 by March 2013. Installation of the scrubber waste handling portion of the project
582 will be completed while the plant is in service, and will not require an extended
583 plant maintenance outage for tie-in.

584 However, costs associated with the scrubber reagent preparation system
585 upgrade portion of the project ARE included in the revenue requirement into this
586 case as this portion of the project is expected to be placed in service by March
587 2012. The reagent preparation portion of this project is being constructed
588 concurrently with the Hunter Unit 2 reagent preparation system to benefit from
589 installation and operational costs synergies achieved through the use of common
590 facilities between the two units. The capital investment associated with the
591 portion of the project being placed in service during the test period is
592 approximately \$19 million. Installation of the reagent preparation system upgrade
593 will be completed while the plant is in service, and will not require an extended
594 plant maintenance outage for tie-in.

595 **Q. Please describe the other major pollution control projects and associated**
596 **equipment contemplated in this case.**

597 A. The other major pollution control projects to be placed in service during the test
598 period include:

- 599 (1) the Naughton Unit 2 low NO_x burners installation project;
- 600 (2) the Naughton Unit 1 low NO_x burners installation project;
- 601 (3) the Wyodak low NO_x burners installation project;
- 602 (4) the Huntington Unit 1 low NO_x burners installation project;
- 603 (5) Hunter Unit 2 low NO_x burners installation project; and
- 604 (6) the Jim Bridger Unit 3 scrubber upgrade project.

605 The Jim Bridger Unit 3 scrubber upgrade will replace internal scrubber
606 parts (trays, piping and nozzles). This work will improve sulfur dioxide removal

607 efficiency while enabling the bypass dampers to bypass less flue gas. The low
608 NO_x burners projects referenced above will install new burners that utilize
609 improved combustion characteristics and a separated over-fire air supply to the
610 boiler to reduce NO_x emissions.

611 **Q. Does Jim Bridger Unit 3 currently have a scrubber?**

612 A. Yes. The scrubber project primarily includes the upgrade and replacement of
613 existing pumps, spray headers, trays, induced draft fans, and ancillary equipment
614 to improve the control of SO₂ emissions from the affected units.

615 **Q. Please describe the emissions improvements that will be achieved with the
616 pollution control projects described above.**

617 A. The pollution control equipment investments described above are required by the
618 permit terms and conditions issued in response to the environmental requirements
619 described herein and support the Company's ongoing commitment to reduce SO₂
620 emissions from the Company's generation fleet by approximately 50 percent
621 compared to 2005 levels. In addition to reducing SO₂ emissions, the projects
622 support the Company's ongoing commitment to reduce NO_x emissions from the
623 Company's generation fleet by approximately 40 percent compared to 2005
624 levels. These projects also meet the requirements of the Utah regional haze
625 requirements and the Wyoming best available retrofit technology permits issued
626 by the respective state agencies, which are intended to improve the visibility in
627 certain national parks and wilderness areas. The emission reductions that result
628 from these projects have been incorporated into the approved operating permits
629 for the subject units.

630 **Q. Have the costs of the projects been prudently managed by the Company?**

631 A. Yes. The scrubber and bag house projects described above have been contracted
632 under lump-sum, turnkey, engineer, procure and construct (“EPC”) contract terms
633 which resulted from competitive bidding processes. The burner replacement
634 projects have been contracted under multiple lump-sum contracts which resulted
635 from competitive bidding processes or job-specific work releases under
636 established service level agreement rate structures. PacifiCorp management
637 continues to provide oversight of the projects and closely manages any project
638 execution plan changes or potential contract scope changes.

639 **Q. Are there additional operating costs that will be incurred as a result of the
640 installation of the pollution control equipment?**

641 A. Yes. Unfortunately, but unavoidably, the operation of the new pollution control
642 equipment will result in increased operation and maintenance costs associated
643 with reagent, waste disposal, and equipment maintenance. These costs are
644 summarized in Mr. Steven R. McDougal’s direct testimony.

645 **Q. How are the pollution control investment costs and associated operating costs
646 being treated in the revenue requirement?**

647 A. The costs for the pollution control equipment have been included in this case as
648 explained in the revenue requirement testimony of Mr. McDougal.

649 **Description of Generation Plant Turbine Upgrade Investments**

650 **Q. Please describe the turbine upgrade projects.**

651 A. The turbine upgrade projects that will be placed in service during the test period
652 include:

- 653 (1) the Huntington Unit 1 high pressure (HP)/intermediate pressure (IP)/low
654 pressure (LP) turbine sections replacement,
655 (2) the Hunter Unit 2 HP/IP/LP turbine sections replacement,
656 (3) the Hunter Unit 3 HP/IP/LP turbine sections replacement, and
657 (4) the Jim Bridger Unit 1 HP/IP turbine sections replacement.

658 The revenue requirement impact of these investments has been included in
659 Mr. McDougal's direct testimony.

660 **Q. Please describe the efficiency improvements that will be achieved with the**
661 **turbine upgrade projects described above.**

662 A. The Company expects the Huntington Unit 1 turbine upgrade to allow more
663 efficient turbine performance without increasing emissions, such that an
664 additional 18 megawatts of capacity can to be generated by the unit. The same
665 principles apply to the Hunter Unit 2 turbine upgrade, which is expected to
666 provide efficiency improvements, without increasing emissions, resulting in an
667 additional 10 megawatts of capacity to be generated by the unit. Applying the
668 same principals, the Hunter Unit 3 turbine upgrade is expected to result in an
669 additional 19 megawatts, and the Jim Bridger 1 turbine upgrade is expected to
670 result in an additional 4 megawatts. Mr. Gregory Duvall has included the net
671 power cost impact associated with these projects in his direct testimony.

672 **Q. What is the basis for justification of these investments?**

673 A. As part of the Company's efforts to meet the growing demand for generation, and
674 given the advancing technological improvements in steam turbine design and
675 manufacturing, the Company has initiated a turbine upgrade initiative. This

676 turbine upgrade initiative will further enhance PacifiCorp's overall generation
677 capability and cycle efficiency for the large thermal units being provided with this
678 equipment

679 **Description of Other Generation Plant Investments**

680 **Q. What other generation plant capital investments are included in this**
681 **application?**

682 A. Generation plant repair and replacement investments and a coal unloading facility
683 addition at the Hayden power plant are the remaining projects included in this
684 case. The repair and replacement projects fall primarily within three major
685 categories: (i) boiler section replacements; (ii) control system upgrades; and (iii)
686 other. The revenue requirement impact of these investments has been included in
687 Mr. McDougal's direct testimony.

688 **Q. How will customers benefit from the repair and replacement capital**
689 **expenditures contemplated in this case?**

690 A. These capital expenditures enable the Company to maintain safe, reliable, and
691 cost-effective operation of an aging generation fleet. The Company's plants
692 produce energy at costs lower than market prices, enabling the Company to serve
693 its customers at some of the lowest retail electricity prices in the United States.
694 Prudent investment in the Company's existing generating units increases the
695 probability of continued safe and reliable operation of these low-cost resources.

696 **Q. Please describe the Wyodak air cooled condenser replacement project.**

697 A. The Wyodak air cooled condenser (ACC) has been in service for 33 years and has
698 reached its end of useful life. This replacement project will replace all of the

699 ACC's tube bundles and headers, both of which are experiencing failures. Failed
700 tubes and welds are allowing air in-leakage to the ACC which increases turbine
701 backpressure, allows for accelerated corrosion of the carbon steel tubes and
702 headers in the ACC, and results in freeze/thaw damage during cold weather
703 operation. The project is planned to be placed in service by May 2011 and is
704 expected to cost approximately \$22 million.

705 **Q. How will customers benefit from the Wyodak air cooled condenser**
706 **replacement project?**

707 A. The Wyodak air cooled condenser replacement project is expected to result in
708 improved unit reliability and efficiency. From a unit reliability perspective,
709 continued operation of the ACC in its current condition has a high potential of
710 causing progressively more unit outages and/or derates. From a unit efficiency
711 perspective, during the winter months it is typical for the Wyodak plant to
712 increase turbine back pressure to ensure that the ACC does not freeze. During the
713 summer months, poor ACC performance also causes the plant to run with high
714 turbine back pressure. Increasing unit back pressure leads to increased fuel
715 consumption for given megawatt output. By proceeding with the ACC
716 replacement project, customers will benefit from improvements in the areas
717 discussed above as well as advancements in currently available ACC technology.
718 Technology improvements have resulted in increased equipment efficiency
719 without increasing the size of the ACC structure. This efficiency improvement
720 comes without increasing the power consumption of the existing cooling fans.

721 **Q. Please describe the Hayden power plant coal unloading facility project.**

722 A. Currently, the Hayden plant can only receive coal which is shipped by truck. The
723 new coal unloading facility will allow the Hayden plant to also receive coal that is
724 shipped by rail. The project includes construction of a new rail spur and loop,
725 bridges, unloading hopper, belts, transfer points, feeders, crushers and other
726 equipment. The project is expected to be ready for service in October 2011, at a
727 total loaded cost of approximately \$12 million (PacifiCorp share).

728 **Q. How will customers benefit from the Hayden power plant coal unloading**
729 **capital expenditure?**

730 A. Hayden Units 1 and 2 currently consume coal produced at Peabody Energy's
731 Twentymile mine. This coal is transported to the plant by truck over county roads.
732 The current contract with Peabody to supply coal for Hayden expires at the end of
733 2011. In order to ensure a reliable, long-term supply of low-cost fuel to the plant
734 after expiration of the Peabody contract, Hayden's owners (Public Service
735 Company of Colorado, Salt River Project Agricultural Improvement and Power
736 District, and PacifiCorp) requested bids from a number of regional mines that
737 have capability to supply suitable coal to Hayden. Many of these regional mines
738 are located too far from the Hayden plant to economically deliver coal to the
739 facility by truck. Construction of the rail unloading facility allows these suppliers
740 to ship coal to the plant at economic rates and to compete effectively with nearby
741 suppliers. Ratepayers will benefit from the continued supply of cost-effective fuel
742 to the plant.

743 **Description of Hydro Investments**

744 **Q. What hydro plant capital investments are included in this application?**

745 A. The hydro plant regulatory and new infrastructure investments contemplated in
746 this case are primarily associated with new license implementation measures for
747 the North Umpqua Hydroelectric Project; Federal Energy Regulatory Commission
748 No. 1927 issued November 18, 2003. The revenue requirement impact of these
749 investments has been included in Mr. McDougal's direct testimony.

750 **Q. Please describe the Soda Springs fish passage project.**

751 A. The Company's investment in the Soda Springs fish passage project is driven by
752 Settlement Agreement Sections 4.1.1 and 4.1.2 of the referenced FERC license.
753 The project will provide for the upstream and downstream volitional passage of
754 anadromous fish by the addition of a fish ladder, fish screens and a fish
755 observation/monitoring station. The facilities will provide for approximately six
756 miles of additional spawning and rearing habitat. The project is planned to be
757 placed in service by January 2012 and is expected to cost approximately \$65
758 million.

759 **Q. Please describe the Lemolo Unit 2 reach pipe project.**

760 A. The Company's investment in the Lemolo Unit 2 reach pipe project is driven by
761 Settlement Agreement Section 6.1 of the referenced FERC license. These new
762 facilities will collect the outflow from the Lemolo 2 plant and transport the water
763 to Toketee Lake. The purpose of the project is to prevent significant increases
764 and decreases in the flow levels in the Umpqua River downstream of the plant
765 which could have detrimental impacts on the native fishery. The project is

766 planned to be placed into service in December 2011 and is expected to cost
767 approximately \$15 million.

768 **Q. What is the basis for justification of these investments?**

769 A. The Soda Springs hydroelectric project with a nameplate rating of 11 megawatts
770 and the Lemolo 2 hydroelectric project with a nameplate rating of 33 megawatts
771 are part of the eight project development comprising the North Umpqua
772 Hydroelectric Project. The economic evaluation for the entire development was
773 conducted in association with the Federal Energy Regulatory Commission re-
774 licensing process prior to the issuance of the current 2003 license. The analysis
775 indicated that the 35-year license would provide energy for customers at rates
776 substantially lower than market prices.

777 **Customer Benefits**

778 **Q. How will customers benefit from these capital expenditures?**

779 A. The capital expenditures described above and otherwise included in this case
780 enable the Company to maintain safe, reliable, and cost-effective operation of an
781 aging generation fleet. The Company's plants produce energy at costs lower than
782 market prices, enabling the Company to serve its customers at some of the lowest
783 retail electricity prices in the United States. Prudent investment in the Company's
784 existing generating units increases the probability of continued safe and reliable
785 operation of these low-cost resources.

786 **Description of Other Incremental O&M Costs**

787 **Q. Are there incremental O&M costs contemplated in this case associated with**
788 **recently completed wind projects?**

789 A. Yes. Incremental O&M costs for the Company's recently completed wind
790 projects are included in this case. The High Plains and McFadden Ridge I wind
791 projects achieved commercial operation during September 2009, and the Dunlap
792 wind project achieved commercial operation on October 1, 2010. The incremental
793 O&M costs included in this case are known and measurable costs associated with
794 ongoing operation of the facilities, including labor, contracts, parts, and
795 consumables. These costs are summarized in Mr. McDougal's direct testimony.

796 **Q. Are there incremental O&M reductions contemplated in this case associated**
797 **with the decommissioning of the Little Mountain facility?**

798 A. Yes. In March 2010, the Company was informed that the one customer served by
799 the Little Mountain substation has chosen to construct its own 138 kV substation
800 instead of continuing to receive service from the Company due to a better price
801 opportunity. Without this customer connection, further investment in the
802 deteriorating Little Mountain substation and continued operation of the Little
803 Mountain generation facility are no longer in the best interest of customers. As
804 such, the Company's Little Mountain facility is currently expected to be retired
805 and decommissioned in 2012. Planned decommissioning of the facility will result
806 in an incremental decrease in O&M costs contemplated in this case of
807 approximately \$0.9 million. These costs are summarized in Mr. McDougal's
808 direct testimony.

809 **Q. Are there incremental O&M costs contemplated in this case associated with**
810 **the Lake Side facility?**

811 A. Yes. In 2004, as part of the Lake Side 1 resource addition, the Company entered
812 into a Long Term Program (“LTP”) maintenance contract with Siemens Energy,
813 Inc., (“Siemens”) to provide parts and services to cover planned maintenance of the
814 two Siemens combustion turbines installed on that project over 100,000 equivalent
815 base hours (“EBH”) or 3,600 equivalent starts (“ES”). The scope of the contract
816 included combustion inspections, hot gas path inspections, and major inspections of
817 the covered equipment. In November 2010, the Company executed an amended and
818 restated LTP maintenance contract with Siemens, significantly amending and
819 extending the scope, commercial terms, and duration of the managed long term
820 parts and services program contract for the Lake Side 1 combined-cycle natural gas
821 plant. Key changes to the LTP maintenance contract include extension of the term
822 of the contract by an additional 50,000 EBH, or 1,800 ES; upgraded combustion
823 turbine hardware; upgrades to the two combustion turbine generators; improved
824 terms and conditions regarding warranty and indemnification; availability of two
825 replacement combustion turbine rotor assemblies at the 100,000 EBH overhauls;
826 and associated inspection intervals. The primary benefits expected to be realized
827 from the amended and restated LTP maintenance contract include increased
828 availability of the equipment associated with modified outage schedules; decreased
829 outage duration at 100,000 EBH due to availability of combustion turbine rotor
830 assemblies; avoided parts purchases and repair costs to self-perform services from
831 100,000 EBH to 150,000 EBH; and improved indemnity and warranty coverage.

832 Incremental costs of approximately \$1.2 million associated with said amended and
833 restated LTP maintenance contract are incorporated in this case. These costs are
834 summarized in Mr. McDougal's direct testimony.

835 **Q. Are there incremental O&M costs contemplated in this case associated with**
836 **operation of the Cholla Unit 4 power plant?**

837 A. Yes. The mine which historically supplied cost-effective coal to Cholla Unit 4
838 was completely mined out in early 2010. While also cost-effective, the new fuel
839 being supplied to the facility contains more sulfur and ash, and is more abrasive.
840 In order to continue to comply with environmental requirements while burning
841 the new fuel, a new scrubber and bag house were installed on the unit in 2008.
842 The new high-removal-rate scrubber and the higher sulfur coal have combined to
843 raise limestone consumption significantly. Also, the abrasive nature of the new
844 fuel has raised costs for pulverizer and boiler maintenance in the plant. Even with
845 these changes, Cholla Unit 4 continues to provide essential energy and system
846 regulation benefits to PacifiCorp's electric system at an attractive price.
847 Incremental costs of approximately \$2.3 million associated with the operational
848 changes described above are included in this case. These costs are summarized in
849 Mr. McDougal's direct testimony.

850 **Conclusion**

851 **Q. Please summarize your testimony.**

852 A. Investments in pollution control equipment are required to meet the Regional
853 Haze rules, enacted in 2005 by the EPA, and the resulting BART reviews, state
854 implementation plans, and permitting processes. The investment in pollution

855 control equipment included in this case would not change if additional
856 environmental requirements are imposed in the future, including restrictions upon
857 carbon dioxide emissions. The investment allows for the continued operation of
858 low-cost coal-fired generation facilities, while achieving significant
859 environmental improvements to air quality and regional haze issues.

860 The Company is also making other prudent capital expenditures in its
861 existing generation fleet, including hydro, which will benefit customers by
862 maintaining safe, reliable, efficient, cost-effective generating resources and
863 production facilities. The capital investments included in this case are reasonable
864 and prudent, and the Company should be granted full cost recovery for these
865 investments.

866 The Company continues to prudently manage O&M costs. The Company
867 should be granted full recovery of the incremental O&M costs contemplated in
868 this case.

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

870 A. Yes.