

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

Rebuttal Testimony of Chad A. Teply

Environmental Controls Investments

June 2011

1 **Introduction and Purpose of Testimony**

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

3 A. My name is Chad A. Teply. My business address is 1407 West North Temple,
4 Suite 210, Salt Lake City, Utah.

5 **Q. Are you the same Chad A. Teply who submitted pre-filed direct testimony in**
6 **this proceeding on behalf of Rocky Mountain Power (“RMP” or**
7 **“Company”)?**

8 A. Yes.

9 **Q. What is the purpose of your rebuttal testimony in this proceeding?**

10 A. My testimony provides information explaining the prudence of individual
11 pollution control projects called into question by the intervening parties. The
12 pollution control projects included in this case are required to comply with
13 existing regulations. Furthermore, maintaining the ability to operate our coal-
14 fueled units by retrofitting them with current-technology emissions control
15 equipment represents the least-cost option for our customers. Information
16 comparing the cost of retrofitted coal-fueled generation units to other generation
17 resource classes, including combined-cycle natural gas fueled generation and
18 conversion of coal-fueled units to natural gas, is provided below. I will also
19 provide testimony regarding the Company’s ongoing business planning efforts
20 and the Company’s coal utilization case studies included in its integrated resource
21 planning (“IRP”) process that were designed to investigate the impacts of CO₂
22 cost and gas price scenarios on the Company’s existing coal fleet after accounting
23 for coal plant incremental costs.

24 In doing so, my testimony will respond to the direct testimony of Mr.
25 Howard Gebhart and Mr. Kevin C. Higgins on behalf of Utah Association of
26 Energy Users Intervention Group (“UAE”), Ms. Nancy Kelly on behalf of
27 Western Resource Advocates (“WRA”), Dr. William Steinhurst, Ph. D. and Dr.
28 Jeremy Fisher, Ph. D. on behalf of Sierra Club, Ms. Michele Beck on behalf of the
29 Utah Office of Consumer Services (“OCS”), and Mr. Matthew Croft on behalf of
30 the Utah Division of Public Utilities (“DPU”) regarding prudence of the
31 Company’s pollution control expenditures for coal-fueled power generation
32 facilities.

33 **Q. How is your testimony organized?**

34 A. My testimony is organized as follows:

- 35 • Introduction and Purpose of Testimony
- 36 • Summary of Parties’ Concerns and Recommendations
- 37 • Need and Basis for the Projects
- 38 • Alternatives and Cost Effectiveness
- 39 • Planning

40 **Q. Will the testimony of other Company rebuttal witnesses also respond to**
41 **intervener testimony and discuss the prudence of the Company’s pollution**
42 **control investments in its coal-fueled generation facilities?**

43 A. Yes. In addition to my testimony, the Company has provided rebuttal testimony
44 from three other witnesses regarding pollution control investments.

45 1. Ms. Cathy Woollums provides an overview of the national and associated
46 state issues that support the Company’s decisions to invest in

47 environmental controls at the coal-fueled generation facilities at issue in
48 this case. Ms. Woollums' testimony addresses (1) the key regulatory and
49 compliance drivers for the environmental control projects, (2) the
50 Company's approach to assessing future regulatory requirements and how
51 those requirements may factor into its environmental controls decisions,
52 and (3) the overlap of the Regional Haze program with other air quality
53 regulations and how the environmental controls installed under the
54 Regional Haze program position the Company for future compliance with
55 environmental requirements.

56 2. Mr. Richard W. Sprott provides a third-party testimony regarding the
57 history and development of the Western Regional Haze program from the
58 perspective of an agency representative in that process and the specific
59 application of that process to the Company. Mr. Sprott worked in the Utah
60 Department of Environmental Quality from 1994 through 2008, and
61 served as the Executive Director of the Department of Environmental
62 Quality from May 2007 until his retirement in December 2008.

63 3. Dr. Howard Ellis provides an independent, third-party review and
64 verification of the Company's environmental compliance planning
65 strategies and decision-making based on 40 years of experience in the air
66 quality field. Dr. Ellis' experience base during that period includes air
67 quality modeling, emissions inventory development, development of air
68 pollution compliance strategies, air pollution permitting, and air quality
69 and meteorological monitoring.

70 **Summary of Parties' Concerns and Recommendations**

71 **Q. Please summarize Mr. Gebhart's concerns regarding the Company's**
72 **pollution control equipment investments.**

73 A. Mr. Gebhart has developed his testimony to evaluate whether the Company's
74 pollution control equipment investments are necessary or appropriate to meet the
75 regulatory requirements of the Clean Air Act. He focuses his concerns primarily
76 on the Company's scrubber (sulfur dioxide ("SO₂") control) projects included in
77 the case, and confined his analysis to those projects. It should be noted; however,
78 that Mr. Gebhart has taken issue with one of the Company's projects that has been
79 previously reviewed for rate base treatment under a separate Major Plant
80 Additions docket, namely the Company's Dave Johnston Unit 3 scrubber and
81 baghouse project. That project only has close-out costs included in this case.

82 Mr. Gebhart's primary concerns are that the Company has voluntarily
83 offered to install pollution control equipment that would otherwise not have been
84 required by existing regulations, that the appropriate metrics of cost effectiveness
85 have not been applied as part of the Company's decision-making processes, and
86 specifically that costs associated with the Company's Dave Johnston Unit 3
87 scrubber and baghouse project and the Company's Hunter Unit 1, Hunter Unit 2,
88 and Huntington Unit 1 scrubber projects should be disallowed. Mr Gebhart's
89 arguments related to Hunter Units 1 and 2 and Huntington Unit 1 are largely
90 based on his summary of an arbitration award that was applied to the Company's
91 jointly owned Hunter Unit 2 facility.

92 **Q. Please summarize Mr. Higgins' concern regarding the Company's pollution**
93 **control equipment investments.**

94 A. Mr. Higgins has adopted the cost effectiveness argument of Mr. Gebhart and
95 recommends that the revenue requirements associated with the Company's
96 scrubber projects at Dave Johnston Unit 3, Hunter Unit 1, Hunter Unit 2, and
97 Huntington Unit1 be disallowed. Consistent with Mr. Gebhart, Mr. Higgins also
98 takes issue with one of the Company's projects that has been previously reviewed
99 for rate base treatment under a separate Major Plant Additions docket, namely the
100 Company's Dave Johnston Unit 3 scrubber and baghouse project with only
101 project close-out costs included in this case. Mr. Higgins argues that the revenue
102 requirement associated with this project is subject to challenge before the
103 Commission in this docket.

104 **Q. Please summarize Ms. Kelly's concern regarding the Company's pollution**
105 **control equipment investments.**

106 A. Ms. Kelly's primary concern is that impending regulations will cause coal-fueled
107 generation to cease to be a "low-cost resource" and suggests that a comprehensive
108 analysis of the economic viability of further investment in the Company's coal-
109 fueled fleet be undertaken as part of the integrated resource planning (IRP)
110 process. Ms. Kelly further suggests that Commission acknowledgment of future
111 IRPs complete with the requested comprehensive analysis could relieve the
112 Company of its affirmative obligation to otherwise demonstrate prudence.

113 **Q. Please summarize Dr. Steinhurst's concern regarding the Company's**
114 **pollution control equipment investments.**

115 A. Dr. Steinhurst's primary contention is that the Company has failed to determine
116 whether pollution control investments contemplated in the case would be cost
117 effective in light of known and likely environmental regulations; and that the
118 Company has failed to properly reflect those known and likely environmental
119 regulations or their potential costs in its resource planning. Dr. Steinhurst suggests
120 that the Commission consider establishing a comprehensive and consistent
121 process for considering utility proposals for major investments in its existing
122 generating units to ensure coordination between the Company's rate requests and
123 its IRP planning processes and principles.

124 **Q. Please summarize Dr. Fisher's concern regarding the Company's pollution**
125 **control equipment investments.**

126 A. Dr. Fisher's primary concerns are aligned with those of Dr. Steinhurst. He
127 contends that the Company has failed to determine whether pollution control
128 investments presented in the case would be cost effective in light of current and
129 upcoming environmental regulations. Dr. Fisher has also submitted an exhibit
130 with varying degrees of specificity that depicts his perspective on future capital
131 expenditures associated with emerging environmental regulations that the
132 Company may be facing through the 2020 timeframe.

133 **Q. Please summarize Ms. Beck's concern regarding the Company's pollution**
134 **control equipment investments.**

135 A. Ms. Beck's primary contention is that the Company has invested in pollution

136 control equipment without first conducting a robust evaluation of all options for
137 compliance with new environmental regulations. Ms. Beck's recommendation is
138 that the Commission disallow costs associated with pollution control investments
139 that have not been justified as part of a rigorous analytical process that considers
140 various technology options, present and anticipated environmental regulations and
141 different resource options.

142 **Q. Please summarize Mr. Croft's recommendation regarding the Company's**
143 **pollution control equipment investments.**

144 A. Mr. Croft's recommendation is that the costs associated with the Company's
145 pollution control investments presented in the case are reasonable, are needed to
146 meet future emission limits, and are aligned with projects committed to by the
147 Company as part of its acquisition by MEHC. Mr. Croft notes that his
148 recommendation is based on review of the Company's filing, research of Regional
149 Haze Rules, review of the materials associated with the Company's recent
150 arbitration regarding Hunter Unit 2 investments, and discovery propounded by the
151 parties in the case.

152 **Need and Basis for the Projects**

153 **Q. Do the issues raised in the testimony referenced above exemplify the**
154 **complexity in balancing stakeholder interests that the Company faces in**
155 **making prudent pollution control project capital investment decisions?**

156 A. Yes. The perspectives presented in the testimony referenced above include:
157 (1) ardent environmental opposition to continued investment in coal fueled
158 generation in the face of ever evolving environmental regulations,

159 (2) recommendations for deferred decision-making while awaiting regulatory
160 certainty and final EPA action, and
161 (3) support of the Company's pollution control investments, based on
162 regulation of its obligation to reliably and cost-effectively serve its
163 customers, while balancing compliance with current and anticipated likely
164 environmental requirements and regulations.

165 **Q. Are the pollution control investments presented in this case required to**
166 **comply with existing regulations?**

167 A. Yes. The pollution control investments presented in this case are required to
168 comply with existing regulations including Regional Haze Rules and the Regional
169 SO₂ Milestone and Backstop Trading Program developed in alignment with
170 existing federal regulations and administered in Utah and Wyoming, National
171 Ambient Air Quality Standards, New Source Review requirements, state issued
172 construction and operating permits, and state implementation plans. Confidential
173 Exhibit RMP___(CAT-1R) attached to this testimony provides an overview of
174 existing regulations with which the projects presented in this case will be in
175 compliance.

176 **Q. Is the Company obligated to install the pollution controls required by state**
177 **permits, regardless of whether final U.S. Environmental Protection Agency**
178 **("EPA") review and approval of the respective Regional Haze state**
179 **implementation plans remain pending?**

180 A. Yes. The state implementation plans, BART permits and construction permits
181 issued by the respective state agencies for the pollution control investments

182 presented in this case include independent requirements, enforceable by the laws
183 of the respective states. These requirements are enforceable irrespective of
184 whether the EPA has approved or ever does approve the respective state
185 implementation plans.

186 **Q. What factors does the Company consider when determining which capital**
187 **investments to make in pollution control projects?**

188 A. My direct testimony described how the Company considered state and federal
189 environmental regulatory requirements and associated compliance deadlines;
190 review of emerging environmental regulations and rulemaking; and analyses of
191 alternate compliance options, among other factors, while considering these
192 projects.

193 **Q. Are each of these factors focused solely on compliance with environmental**
194 **regulations?**

195 A. No. As part of the Company's coal fueled units compliance planning efforts,
196 consideration is given to the selection of appropriate pollution control
197 technologies as well as alternate compliance options such as market purchases of
198 replacement power, converting facilities to natural gas fuel sources, and the
199 procurement of replacement generation. Examples of these analyses are discussed
200 further in my testimony below.

201 **Q. Do the factors mentioned in your direct testimony form the entire basis for**
202 **the Company's pollution control investment decisions?**

203 A. No. Other factors such as ongoing compliance with existing operating
204 requirements, fuel supply flexibility, equipment end of life considerations, and

205 operational efficiencies are also factors included in the Company's investment
206 decisions.

207 **Naughton Units 1 and 2 Scrubbers**

208 **Q. What is the primary justification for the Company's Naughton Units 1 and 2**
209 **scrubber installation projects?**

210 A. In support of the Regional Haze program being administered by the State of
211 Wyoming, and the associated Regional SO₂ Milestone and Backstop Trading
212 Program, the Company completed detailed analyses of the appropriate technology
213 to be applied to these BART-eligible Naughton facilities to achieve established
214 emissions control objectives. Naughton Units 1 and 2 were previously unscrubbed
215 units with permitted SO₂ emission limits of 1.2 pounds per million British thermal
216 units ("Btu"). When completed, the Naughton scrubber projects included in this
217 case will remove approximately 30,000 tons of SO₂ per year and will support the
218 continued operation of these cost effective generation facilities, while maintaining
219 compliance with permitted SO₂ emissions limits consistent with presumptive
220 BART limits (0.15 pounds per million Btu) and supporting established regional
221 compliance milestones. Additional information supporting the post-project cost
222 effectiveness of these units is provided in testimony below.

223 **Q. Are operational capabilities afforded by the Naughton Units 1 and 2**
224 **scrubber installation projects also expected to support compliance with the**
225 **Utility Maximum Achievable Control Technology ("MACT") requirements**
226 **for hazardous air pollutants ("HAPs") proposed in March 2011?**

227 A. Yes. As proposed in general terms, the Utility MACT establishes an emission

228 limit for mercury HAPs of 1.2 pounds per trillion Btu, a surrogate emission limit
229 for acid gases HAPs compliance via a SO₂ emission limit of 0.20 pounds per
230 million Btu, and a surrogate emission limit for non-mercury metallic HAPs
231 compliance via a particulate matter (PM) emission limit of 0.030 pounds per
232 million Btu. Based on the Utility MACT emission limits currently proposed, the
233 operational capabilities afforded by the Naughton Units 1 and 2 scrubber
234 installation projects are expected to directly support acid gases HAPs MACT
235 compliance and benefit both mercury and non-mercury metallic HAPs
236 compliance.

237 **Wyodak Baghouse**

238 **Q. What is the primary justification for the Company's Wyodak baghouse**
239 **installation project?**

240 A. In support of the Regional Haze program being administered by the State of
241 Wyoming, and the associated Regional SO₂ Milestone and Backstop Trading
242 Program, the Company completed detailed analyses of the appropriate technology
243 to be applied to this BART-eligible Wyodak facility to achieve established
244 emissions control objectives. Wyodak was previously configured with a dry
245 scrubber and electrostatic precipitator with permitted SO₂ emission limits of 0.50
246 pounds per million Btu and permitted PM emission limits of 0.10 pounds per
247 million Btu. The internal components of the electrostatic precipitator had reached
248 the end of their useful life as a direct result of corrosion caused by moisture
249 carryover from the existing upstream dry scrubber. Without the benefit of a
250 downstream baghouse, the existing dry scrubber was required to operate in a

251 lower temperature range to improve SO₂ removal, which results in moisture
252 carryover. The Wyodak baghouse project included in this case results in the
253 removal of approximately 6,000 tons of SO₂ emissions per year and allows the
254 facility to meet a PM emission limit of 0.015 pounds per million Btu. The project
255 supports continued operation of this cost effective generation facility, while
256 maintaining compliance with permitted SO₂ emissions limits consistent with
257 presumptive BART limits and supporting established regional compliance
258 milestones. Additional information supporting the post-project cost effectiveness
259 of these units is provided in testimony below.

260 **Q. Are operational capabilities afforded by the Wyodak baghouse installation**
261 **project also expected to support compliance with the Utility HAPs MACT**
262 **requirements proposed in March 2011?**

263 A. Yes. Based on the Utility MACT emission limits currently proposed, the
264 operational capabilities afforded by the Wyodak baghouse installation project are
265 expected to directly support acid gases and non-mercury metallic HAPs MACT
266 compliance, and benefit mercury HAPs compliance.

267 **Dave Johnston Units 3 and 4 Scrubbers and Baghouses**

268 **Q. What is the primary justification for the Company's Dave Johnston Units 3**
269 **and 4 scrubber and baghouse installation projects?**

270 A. In support of the Regional Haze program being administered by the State of
271 Wyoming, and the associated Regional SO₂ Milestone and Backstop Trading
272 Program, the Company completed detailed analyses of the appropriate technology
273 to be applied to the BART-eligible Dave Johnston Units 3 and 4 facilities to

274 achieve established emissions control objectives. The Dave Johnston Unit 3
275 facility was previously configured as an unscrubbed unit with an electrostatic
276 precipitator. With that configuration, the unit was permitted with an SO₂ emission
277 limit of 1.20 pounds per million Btu and a PM emission limit of 0.23 pounds per
278 million Btu. It should be noted that the Dave Johnston Unit 3 scrubber and
279 baghouse project has been previously considered for rate base treatment under a
280 separate Major Plant Additions docket. The Dave Johnston Unit 4 facility was
281 previously configured as an unscrubbed unit with wet particulate removal
282 equipment, although the wet particulate scrubber was able to achieve a marginal
283 level of SO₂ reduction via lime injection. With that configuration, the unit was
284 permitted with SO₂ emission limits of 0.50 pounds per million Btu and PM
285 emission limits of 0.21 pounds per million Btu. When completed, the Dave
286 Johnston scrubber and baghouse addition projects included in this case will result
287 in the removal of approximately 13,000 tons of SO₂ emissions per year and will
288 allow the affected units to meet PM emission limits of 0.015 pounds per million
289 Btu. The projects will support continued operation of these cost effective
290 generation facilities, while maintaining compliance with permitted SO₂ emissions
291 limits consistent with presumptive BART limits and supporting established
292 regional haze milestones. Additional information supporting the post-project cost
293 effectiveness of these units is provided in testimony below.

294 **Q. Outside of the BART review process, what other considerations led to the**
295 **Company's selection of a dry scrubber and baghouse installation on Dave**
296 **Johnston Unit 3 as the most cost effective option for continued plant**
297 **operation?**

298 A. As discussed in the testimony of Mr. Gebhart, the Company evaluated SO₂
299 removal options for Dave Johnston Unit 3 that included cases that would have
300 utilized the existing electrostatic precipitator for that unit, rather than installing a
301 baghouse. The Company also included that option in its requests for proposals
302 package that was issued to the competitive market soliciting bids for the Dave
303 Johnston Units 3 and 4 projects. Unfortunately, none of the bidders in the
304 competitive market chose to base their proposal on that option. As Mr. Gebhart
305 notes, the dry scrubber and electrostatic precipitator option does not provide the
306 same level of emissions control as a dry scrubber and baghouse option, and in the
307 case of the Dave Johnston facility, that option suffered from physical site
308 constraints, equipment layout concerns, and constructability concerns as
309 evidenced by the lack of competitive market bid interest.

310 **Q. Are operational capabilities afforded by the Dave Johnston Units 3 and 4**
311 **scrubber and baghouse installation projects also expected to support**
312 **compliance with the Utility HAPs MACT requirements proposed in March**
313 **2011?**

314 A. Yes. Based on the Utility MACT emission limits currently proposed, the
315 operational capabilities afforded by the Dave Johnston Units 3 and 4 scrubbers
316 and baghouse installation projects are expected to directly support acid gases and

317 non-mercury metallic HAPs MACT compliance, and benefit mercury HAPs
318 compliance.

319 **Huntington Unit 1 and Hunter Unit 2 Baghouses**

320 **Q. What is the primary justification for the Company's Huntington Unit 1 and**
321 **Hunter Unit 2 baghouse projects?**

322 A. The Huntington Unit 1 and Hunter Unit 2 facilities were previously configured
323 with electrostatic precipitators with PM emission limits of 0.10 pounds per
324 million Btu and 0.05 pounds per million Btu, respectively. The internal
325 components of the electrostatic precipitator on each of these units had reached the
326 end of their useful life. The Huntington Unit 1 and Hunter Unit 2 baghouse
327 projects included in this case allow the facilities to meet a PM emission limit of
328 0.015 pounds per million Btu. The baghouse projects at Huntington Unit 1 and
329 Hunter Unit 2 are also key contributors to the ability to scrub 100% of the flue gas
330 and operate wet stacks, by effectively allowing the opacity monitors for those
331 units to be relocated upstream of the wet scrubbers. Although the scrubber and
332 baghouse projects on Huntington Unit 1 and Hunter Unit 2 are not necessarily
333 dependent on or caused by each other; they are interrelated. The projects support
334 continued operation of these cost effective generation facilities, while maintaining
335 compliance with permitted emissions limits. Additional information supporting
336 the post-project cost effectiveness of these units is provided in testimony below.

337 **Q. How has ongoing compliance with existing operating requirements factored**
338 **into planning of the Huntington Unit 1 and Hunter Unit 2 baghouse**
339 **projects?**

340 A. The Huntington Unit 1 and Hunter Unit 2 baghouse will significantly reduce
341 particulate matter emissions and improve the respective facility's ability to
342 comply with existing opacity standards.

343 **Q. Are operational capabilities afforded by the Huntington Unit 1 and Hunter**
344 **Unit 2 baghouse installation projects also expected to support compliance**
345 **with the Utility HAPs MACT requirements proposed in March 2011?**

346 A. Yes. Based on the Utility MACT emission limits currently proposed, the
347 operational capabilities afforded by the Huntington Unit 1 and Hunter Unit 2
348 baghouse installation projects are expected to directly support mercury and non-
349 mercury metallic HAPs MACT compliance. It is anticipated that these projects
350 will obviate the need for additional mercury emissions controls capital projects
351 and the associated reagent costs on these units.

352 **Huntington Unit 1 Scrubber**

353 **Q. What is the primary justification for Company's Huntington Unit 1 scrubber**
354 **project?**

355 A. In support of the Regional Haze program being administered by the State of Utah,
356 and the associated Regional SO₂ Milestone and Backstop Trading Program, the
357 Company completed detailed analyses of the appropriate technology to be applied
358 to this BART-eligible facility to achieve established emissions control objectives.
359 Huntington Unit 1 was previously configured with a wet scrubber with permitted

360 SO₂ emission limits of 0.21 pounds per million Btu (or a minimum of 80%
361 removal, whichever is more stringent). The Huntington Unit 1 scrubber project
362 included in this case will result in the removal of approximately 5,100 tons of SO₂
363 per year. The project will support the continued operation of this cost effective
364 generation facility, while maintaining compliance with permitted SO₂ emissions
365 limits with better than presumptive BART performance and supporting
366 established regional compliance milestones. Additional information supporting
367 the post-project cost effectiveness of these units is provided in testimony below.

368 **Q. What are the key subcomponents of the Huntington Unit 1 scrubber project?**

369 A. As further described in my pre-filed direct testimony, there are three key
370 subcomponents of the Huntington Unit 1 scrubber project; namely:

371 (1) scrubber vessel, recycle pumps, and reagent injection system upgrades
372 intended to improve SO₂ removal efficiency within the flue gas
373 desulfurization (FGD) system,

374 (2) scrubber waste handling system replacement intended to increase waste
375 handling capacity of the system to remove free liquids from the waste
376 stream and to replace certain end-of-life equipment and components that
377 were no longer operating to original design specifications or otherwise
378 unreliable, and

379 (3) closure of the scrubber bypass duct and wet stack conversion activities. It
380 is important to note that the costs associated with subcomponent (3) are
381 included in the Huntington Unit 1 baghouse project contract due primarily
382 to site work area logistics, and are included in this case as such.

383 **Q. How has ongoing compliance with existing operating requirements factored**
384 **into planning of the Huntington Unit 1 scrubber project?**

385 A. The Huntington Unit 1 scrubber waste handling system replacement will ensure
386 that the final scrubber waste product will not contain any free liquids and can
387 properly be disposed in the onsite landfill. The discussion pertaining to Figure 3
388 below for Hunter Units 1 and 2 provides additional detail in this regard and is also
389 applicable to Huntington Unit 1. The Huntington Unit 1 scrubber waste thickener
390 system had reached the end of its useful life and was otherwise unreliable.

391 **Q. Are costs for both key subcomponents of the Huntington Unit 1 scrubber**
392 **project included in this case?**

393 A. Yes. The FGD removal efficiency subcomponent was placed in service in
394 November 2010 and the scrubber waste handling subcomponent was placed in
395 service in March 2011.

396 **Q. Are operational capabilities afforded by the Huntington Unit 1 scrubber**
397 **project also expected to support compliance with the Utility HAPs MACT**
398 **requirements proposed in March 2011?**

399 A. Yes. Based on the Utility MACT emission limits currently proposed, the
400 operational capabilities afforded by the Huntington Unit 1 scrubber project are
401 expected to directly support acid gases HAPs MACT compliance.

402 **Hunter Unit 2 Scrubber**

403 **Q. What is the primary justification for Company's Hunter Unit 2 scrubber**
404 **project?**

405 A. In support of the Regional Haze program being administered by the State of Utah,

406 and the associated Regional SO₂ Milestone and Backstop Trading Program, the
407 Company completed detailed analyses of the appropriate technology to be applied
408 to this BART-eligible facility to achieve established emissions control objectives.
409 Hunter Unit 2 was previously configured with a wet scrubber with permitted SO₂
410 emission limits of 0.21 pounds per million Btu (or a minimum of 80% removal,
411 whichever is more stringent). The Hunter Unit 2 scrubber project included in this
412 case will result in the removal of approximately 9,200 tons of SO₂ per year. The
413 project will support the continued operation of this cost effective generation
414 facility, while maintaining compliance with permitted SO₂ emissions limits with
415 better than presumptive BART performance and supporting established regional
416 compliance milestones. Additional information supporting the post-project cost
417 effectiveness of these units is provided in testimony below.

418 **Q. What are the key subcomponents of the Hunter Unit 2 scrubber project?**

419 A. As further described in my pre-filed direct testimony, there are four key
420 subcomponents of the Hunter Unit 2 scrubber project; namely:

421 (1) scrubber vessel, recycle pumps, and reagent injection system upgrades
422 intended to improve SO₂ removal efficiency within the FGD system,

423 (2) reagent preparation system replacement intended to increase reagent
424 preparation capacity of the system to accommodate increased coal sulfur
425 content and to replace certain end-of-life equipment and components that
426 were no longer operating to original design specifications or otherwise
427 unreliable,

428 (3) scrubber waste handling system replacement intended to increase waste

429 handling capacity of the system to accommodate increased coal sulfur
430 content and to replace certain end-of-life equipment and components that
431 were no longer operating to original design specifications or otherwise
432 unreliable, and

433 (4) closure of the scrubber bypass duct and wet stack conversion activities. It
434 is important to note that the costs associated with subcomponent (4) are
435 included in the Hunter Unit 2 baghouse project contract due primarily to
436 site work area logistics, and are included in this case as such.

437 **Q. How has ongoing compliance with existing operating requirements factored**
438 **into planning of the Hunter Unit 2 scrubber project?**

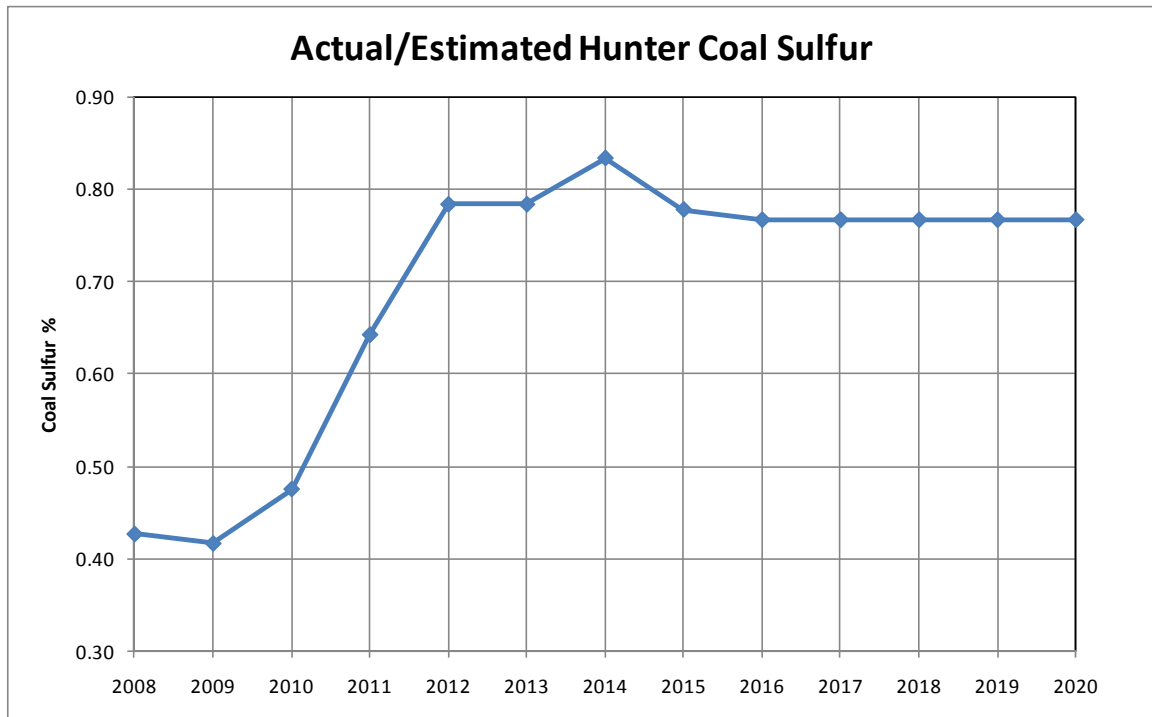
439 A. The Hunter Unit 2 scrubber waste handling system replacement will ensure that
440 the final scrubber waste product will not contain any free liquids and can properly
441 be disposed in the onsite landfill. The discussion pertaining to Figure 3 below
442 provides additional detail in this regard. The Hunter Unit 2 scrubber waste
443 thickener system had reached the end of its useful life and was otherwise
444 unreliable.

445 **Q. How has fuel supply flexibility factored into planning of the Hunter Unit 2**
446 **scrubber project?**

447 A. As the Company developed its final project scoping requirements for the Hunter
448 Units 1 and 2 scrubber projects, the Company became aware of anticipated
449 changes in fuel quality for the Hunter facility that needed to be integrated into the
450 Company's project plans. The fuel quality forecasts received include an increase
451 in coal sulfur content that will exceed the capacities of the existing reagent

452 preparation system and the existing scrubber waste handling system. Testimony
453 regarding the Hunter facility's coal quality forecasts is provided in the rebuttal
454 testimony of Ms. Cindy Crane. The following figure provides an overview of the
455 expected coal sulfur content trend.

Figure 1



456 **Q. Did this change in forecasted fuel quality increase the scope and cost of the**
457 **Hunter Unit 2 scrubber project?**

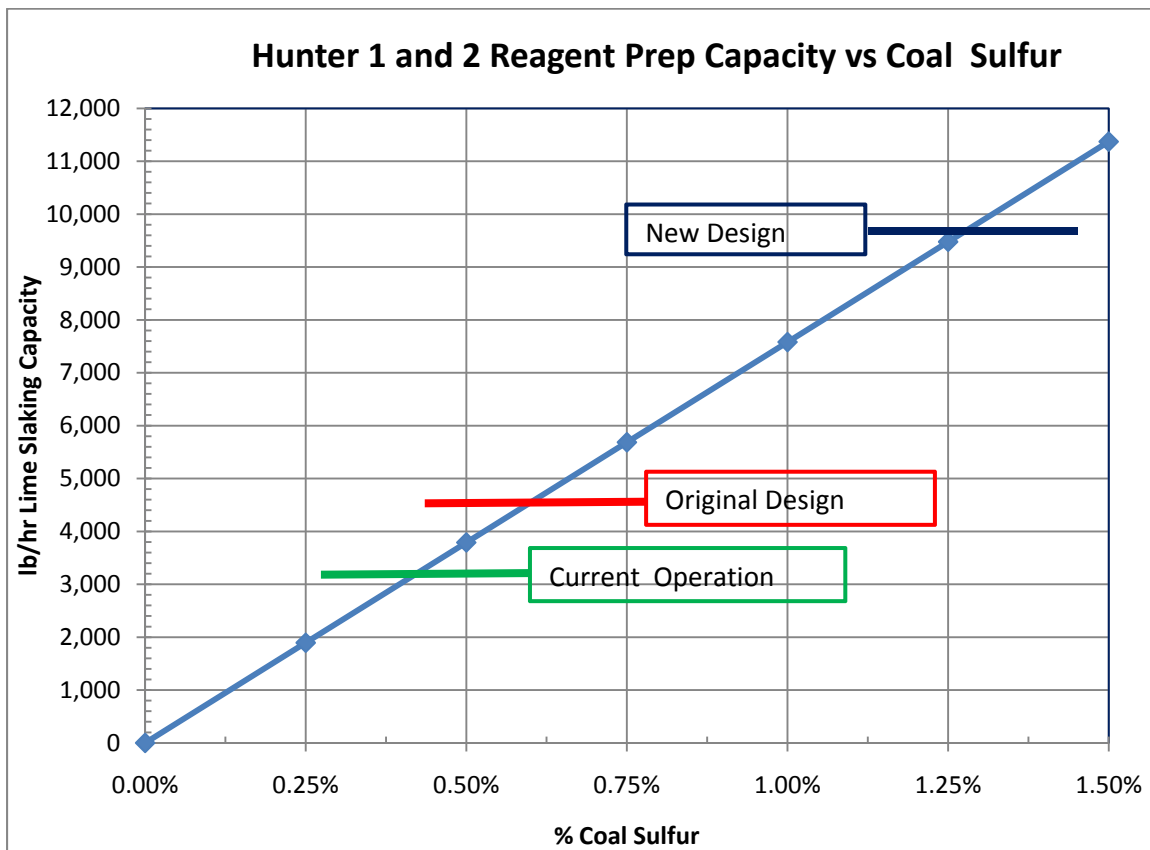
458 A. Yes. The scope of the Hunter Unit 2 scrubber project as originally defined and
459 reviewed was primarily limited to scrubber vessel, recycle pumps, and reagent
460 injection system upgrades, as well as wet stack conversion related activities,
461 intended to improve SO₂ removal efficiency within the FGD system. The change
462 in forecasted fuel quality is a primary driver for reagent preparation system
463 replacement costs and scrubber waste handling system replacement costs, which

464 are two of the three key subcomponents of the final scrubber project scope of
465 work. The Company's share of project costs associated with those project
466 subcomponents is approximately \$11 million and approximately \$19 million,
467 respectively, compared to the Company's share of project costs associated with
468 FGD system efficiency and wet stack conversion related activities of
469 approximately \$22 million.

470 **Q. How does the forecasted change in fuel quality impact the scope and cost of**
471 **the scrubber project subcomponents discussed above?**

472 A. Forecasted fuel quality changes result in almost twice the amount of sulfur being
473 introduced into the Hunter units on an annual average basis across the 10-year
474 planning horizon, when compared to historical averages for delivered coal sulfur
475 content. The expectation is that individual coal seams may produce as much as
476 three times the amount of sulfur on a spot basis, when compared to historical
477 averages for delivered coal sulfur content. The ability to produce enough reagent
478 to chemically react with this increased sulfur in the units' flue gas requires larger
479 equipment, upsized infrastructure such as piping and power distribution, and more
480 efficient scrubber performance. Figure 2 below provides a graphical
481 representation of the reagent preparation capacity of the original Hunter scrubbers
482 versus the equipment installed as part of the respective scrubber projects at
483 permitted emissions limits. The new design allows the units to accept and control
484 significantly higher sulfur content in the coal supplied, and supports the ability of
485 the units to receive coal from the various cost competitive mines serving the
486 Company's Utah facilities, as further discussed in Ms. Crane's rebuttal testimony.

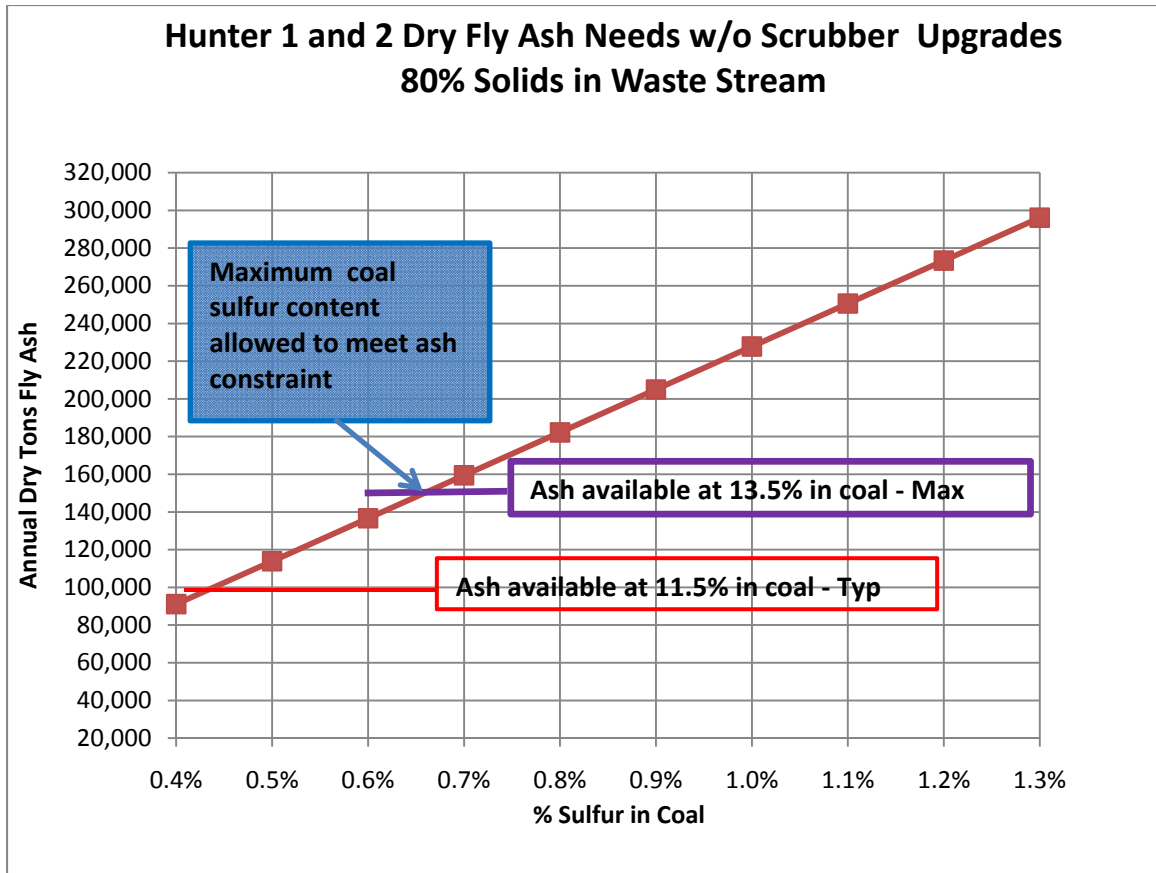
Figure 2



487 The ability to receive and dewater the increased waste streams associated with
488 higher sulfur coal has the same effect on waste handling system capacity
489 requirements. Figure 3 below provides a graphical representation of the
490 limitations of the original scrubber waste handling systems regarding ash and
491 sulfur content of the coal supplied to the units. As shown, at typical coal ash
492 content the original waste handling system capacity was capable of effectively
493 processing coal limited to 0.4% to 0.5% sulfur, without the need to manage
494 blending via additional measures, which could include sourcing and manually
495 blending off-site fly ash. At maximum coal ash content, the original waste
496 handling system capacity could accommodate up to approximately 0.65% sulfur

497 coal. Neither of these scenarios will support protected fuel quality changes for
498 these units. The waste handling system installed as part of the scrubber projects
499 does not rely on fly ash blending, and therefore also accommodates coal from the
500 various cost competitive mines serving the Company's Utah facilities.

Figure 3



501 Q. Why is the ability to accommodate the forecasted change in fuel quality
502 important?

503 A. The ability to fuel the Hunter units on coal with higher sulfur content while
504 meeting new emission limits is fundamental to the Company's ability to maintain
505 competitive fuel and generation costs at this facility.

506 **Q. Is the Hunter Unit 2 scrubber project still cost effective when considering the**
507 **costs associated with this additional scope?**

508 A. Yes. Additional information supporting the post-project cost effectiveness of this
509 unit is provided in testimony below.

510 **Q. Are costs for all key subcomponents of the Hunter Unit 2 scrubber project**
511 **included in this case?**

512 A. Yes.

513 **Q. Are operational capabilities afforded by the Hunter Unit 2 scrubber project**
514 **also expected to support compliance with the Utility HAPs MACT**
515 **requirements proposed in March 2011?**

516 A. Yes. Based on the Utility MACT emission limits currently proposed, the
517 operational capabilities afforded by the Hunter Unit 2 scrubber project are
518 expected to directly support acid gases HAPs MACT compliance.

519 **Hunter Unit 1 Scrubber**

520 **Q. What is the primary justification for Company's Hunter Unit 1 scrubber**
521 **project?**

522 A. The primary justification of the Company's Hunter Unit 1 scrubber is the same as
523 that for the Hunter Unit 2 scrubber provided above. Hunter Unit 1 was previously
524 configured with a wet scrubber with permitted SO₂ emission limits of 0.21 pounds
525 per million Btu (or a minimum of 80% removal, whichever is more stringent).
526 The Hunter Unit 1 scrubber project included in this case will result in the removal
527 of approximately 9,200 tons of SO₂ per year. The project will support the
528 continued operation of this cost effective generation facility, while maintaining

529 compliance with permitted SO₂ emissions limits with better than presumptive
530 BART performance and supporting established regional compliance milestones.
531 Additional information supporting the post-project cost effectiveness of these
532 units is provided in testimony below.

533 **Q. What are the key subcomponents of the Hunter Unit 1 scrubber project?**

534 A. As further described in my pre-filed direct testimony, there are four key
535 subcomponents of the Hunter Unit 1 scrubber project; namely:

536 (1) scrubber vessel, recycle pumps, and reagent injection system upgrades
537 intended to improve SO₂ removal efficiency within the FGD system,

538 (2) reagent preparation system replacement intended to increase reagent
539 preparation capacity of the system to accommodate increased coal sulfur
540 content and to replace certain end-of-life equipment and components that
541 were no longer operating to original design specifications or otherwise
542 unreliable,

543 (3) scrubber waste handling system replacement intended to increase waste
544 handling capacity of the system to accommodate increased coal sulfur
545 content and to replace certain end-of-life equipment and components that
546 were no longer operating to original design specifications or otherwise
547 unreliable, and

548 (4) closure of the scrubber bypass duct and wet stack conversion activities.

549 **Q. Is your previous testimony regarding compliance with existing operating**
550 **requirements and fuel supply flexibility discussions for the Hunter Unit 1**
551 **scrubber project applicable to the Hunter Unit 2 scrubber project as well?**

552 A. Yes.

553 **Q. Are costs for all three key subcomponents of the Hunter Unit 1 scrubber**
554 **project included in this case?**

555 A. No. Only costs associated with the scrubber reagent preparation system are
556 included in this case. Costs for the FGD removal efficiency subcomponent, the
557 scrubber waste handling subcomponent, and the wet stack conversion related
558 activities are not included in this case.

559 **Q. Are operational capabilities afforded by the Hunter Unit 1 scrubber project**
560 **also expected to support compliance with the Utility HAPs MACT**
561 **requirements proposed in March 2011?**

562 A. Yes. Based on the Utility MACT emission limits currently proposed, the
563 operational capabilities afforded by the Hunter Unit 1 scrubber project are
564 expected to directly support acid gases HAPs MACT compliance.

565 **Huntington Unit 1 and Hunter Units 1 and 2 Scrubbers**

566 **Q. How have equipment end of life considerations factored into planning of the**
567 **Huntington Unit 1 and Hunter Units 1 and 2 scrubber projects?**

568 A. The replacement of various scrubber system elements at those facilities is an
569 example of how end of life of existing equipment is a partial driver for the
570 projects at issue. These elements include scrubber vessel work scope, scrubber
571 recycle pump replacements, and scrubber reagent injection nozzle replacements.

572 By planning the scrubber project tie-ins to coincide with planned maintenance
573 outage cycles for the units, the projects were able to replace equipment and
574 components that had exhausted their useful life, and at the same time address
575 system capacity and compliance requirements.

576 **Q. How have operational efficiency considerations factored into planning of**
577 **pollution control investments presented in this case?**

578 A. Operational efficiency considerations are included in the technical specifications
579 for each of the Company's pollution control projects. The material handling
580 phases of the Huntington Unit 1 and Hunter Units 1 and 2 scrubber projects are
581 key examples of the Company's efforts to create operational efficiencies. The
582 discussion regarding Figure 3 above is pertinent to each of these installations.
583 These projects result in the installation of scrubber waste dewatering equipment
584 that eliminates the inefficient manual management of fly ash blending processes.
585 Thus, in addition to addressing system capacity concerns and maintaining waste
586 disposal compliance, these projects increased operational efficiencies.

587 **Jim Bridger 3 Scrubber**

588 **Q. What is the primary justification for Company's Jim Bridger Unit 3**
589 **scrubber project?**

590 A. In support of the Regional Haze program being administered by the State of
591 Wyoming, and the associated Regional SO₂ Milestone and Backstop Trading
592 Program, the Company completed detailed analyses of the appropriate technology
593 to be applied to this BART-eligible facility to achieve established emissions
594 control objectives. Jim Bridger Unit 3 was previously configured with a wet

595 scrubber with permitted SO₂ emission limits of 0.30 pounds per million Btu. The
596 Jim Bridger Unit 3 scrubber project included in this case will result in the removal
597 of approximately 4,500 tons of SO₂ emissions per year and will support continued
598 operation of this cost effective generation facility, while maintaining compliance
599 with permitted SO₂ emissions limits consistent with presumptive BART
600 performance and supporting established regional compliance milestones.
601 Additional information supporting the post-project cost effectiveness of this unit
602 is provided in testimony below.

603 **Q. Are operational capabilities afforded by the Jim Bridger Unit 3 scrubber**
604 **project also expected to support compliance with the Utility HAPs MACT**
605 **requirements proposed in March 2011?**

606 A. Yes. Based on the Utility MACT emission limits currently proposed, the
607 operational capabilities afforded by the Jim Bridger Unit 3 scrubber project are
608 expected to directly support acid gases HAPs MACT compliance.

609 **Installation Schedules**

610 **Q. Are the pollution control investments contemplated in this case being**
611 **installed in an efficient manner?**

612 A. Yes. Emission reduction projects of the number and size described above take
613 many years to engineer, plan, and build. When considering a fleet the size of the
614 Company's, there is a practical limitation on available construction resources and
615 labor. There is also a limit on the number of units that may be taken out of service
616 at any given time, as well as the level of construction activities that can be
617 supported by the local infrastructures at and around these facilities. Additional

618 cost and construction timing limitations include the loss of large generating
619 resources during some parts of construction and the associated impact on the
620 reliability of the Company’s electrical system during these extended outages. In
621 other words, it is not practical, and it is unduly expensive, to expect to build these
622 emission reduction projects all at once or even in a compressed time period.

623 **Q. Do the pollution control investments contemplated in this case meet the**
624 **“used and useful” standard?**

625 A. Yes. Each of these investments achieves its original intent, provides benefit to
626 customers, and allows the Company to maintain timely compliance with state
627 issued permits, state implementation plans, and regional SO₂ milestones and
628 backstop trading programs. They are both used and useful.

629 **Alternatives and Cost Effectiveness**

630 **Q. Does the Company agree that it has not presented sufficient information for**
631 **the Commission to be able to evaluate the prudence of the capital**
632 **investments in pollution control equipment contemplated in this case?**

633 A. No. Through the Company’s filings and participation in the discovery processes
634 in this Docket and other proceedings such as the IRP, the Company has provided
635 the Commission and parties with thorough and responsive information regarding
636 the prudence of its pollution control investments.

637 **Q. Has the Company provided cost information comparing the cost of continued**
638 **operation of the retrofitted coal fueled generation units contemplated in this**
639 **case to its other generation sources, including natural gas fueled generation?**

640 A. Yes. The Company has responded to several data requests in various dockets in

641 this regard. To compare the cost of retrofitted coal fueled generation units to other
642 generation resource classes, Confidential Exhibit RMP___(CAT-2R) was
643 developed to present the 2009 embedded generation bus bar cost per megawatt-
644 hour differences of the various generation resources within the Company's
645 generation fleet, including combined-cycle natural gas fueled generation and
646 conversion of coal-fueled units to natural gas. Confidential Exhibit
647 RMP___(CAT-3R) also provides the incremental revenue requirement associated
648 with the pollution control equipment retrofits presented in this case on a dollars
649 per megawatt-hour basis adjusted to 2009 dollars.

650 In general terms, the capital cost on a dollars per megawatt basis to retrofit
651 pollution controls on existing coal fueled generation is approximately the same
652 cost to build a new combined cycle natural gas generation unit, though it can be
653 less expensive to retrofit pollution controls depending on specific unit
654 requirements. However, fuel costs will overwhelm the capital cost
655 competitiveness of a combined cycle natural gas unit when compared to a
656 retrofitted coal fueled facility. Natural gas on a dollars per million Btu basis is
657 approximately triple the cost of coal, and even when considering the efficiency
658 differences, the cost of electricity generated by an emission controlled coal fueled
659 facility will be significantly less than the cost of electricity from a new combined
660 cycle unit.

661 These exhibits demonstrate that maintaining the ability to operate the
662 existing coal units by retrofitting the units with the pollution control equipment
663 represents the least-cost option for customers. This is even before considering

664 factors associated with retirement of the coal units prior to their ratemaking
665 depreciation lives, such as stranded depreciation expense, the economic impact on
666 Utah, the loss of fuel diversity in the generation portfolio, and the impact on
667 system reliability.

668 **Q. Has the Company applied least cost principles to selection of its pollution**
669 **control investments?**

670 A. Yes. Various project revenue requirement analyses have determined the lower
671 cost alternative to customers for achieving the target level of emission reduction
672 or control. These take the form of comparing the present value revenue
673 requirement impact of one technology to another and determining the present
674 value revenue requirement differential (PVRR(d)) benefit to customers. I will
675 further explain these analyses in the following testimony.

676 **Q. Has the Company assessed the costs of continuing to invest in individual coal**
677 **fuelled generation assets versus replacing the lost generation with market**
678 **purchases?**

679 A. Yes. The Company has developed economic analyses that provide an overview of
680 the PVRR(d) benefits associated with its pollution control investments, with
681 consideration given to potential CO₂ costs and resulting market pricing
682 assumptions. Confidential Exhibit RMP__(CAT-4R) and Confidential Exhibit
683 RMP__(CAT-5R) provide the results of said analyses at various points in time
684 and with various CO₂ costs and market pricing assumptions. Confidential Exhibit
685 RMP__(CAT-4R) provides a PVRR(d) view of the projects presented in this
686 case at the time of planning and approval of the pollution control investments,

687 utilizing the CO₂ cost and market pricing assumptions of the Company's then
688 current business plan. Confidential Exhibit RMP___(CAT-5R) provides a
689 PVRR(d) view of the units that received the pollution control investments
690 presented in this case on a going-forward basis, utilizing CO₂ cost and market
691 pricing assumptions consistent with the Company's current 10-year business plan
692 and the System Optimizer Coal Utilization Case Studies referenced below. These
693 PVRR(d) analyses provide positive results for the various scenarios presented and
694 further demonstrate prudence of the pollution control investments presented in
695 this case. These analyses also offer insight into the potential impacts of various
696 CO₂ cost and market pricing scenarios on investment recovery periods.

697 **Q. Has the Company assessed the costs of continuing to invest in individual coal**
698 **fueled generation assets versus the cost of converting the units to natural gas**
699 **as fuel source?**

700 A. Yes. The Company has developed economic analyses intended to provide an
701 overview of the PVRR(d) benefits associated with its pollution control
702 investments, with consideration given to potential CO₂ costs and resulting market
703 pricing assumptions, versus natural gas repowering scenarios. Confidential
704 Exhibit RMP___(CAT-6R) provides the PVRR(d) results of said natural gas
705 repowering analyses. The results of these PVRR(d) analyses provide positive
706 results for the various scenarios presented and further demonstrate prudence of
707 the pollution control investments presented in this case, and also offer insight into
708 the potential impacts of various CO₂ cost and market pricing scenarios on
709 investment recovery periods.

710 **Q. Does the Company believe that it has appropriately assessed the cost**
711 **effectiveness of the pollution control investments contemplated in this case?**

712 A. Yes. In assessing when and whether to proceed with pollution control
713 investments, the Company has considered cost effectiveness of reasonable
714 options. Measures of cost impacts on a bus bar dollars per mega-watt-hour basis
715 have been reviewed, as well as the cost to remove a ton of a pollutant, which is
716 typically applied specifically as part of BART determination processes.

717 **Q. Does the Company agree with Mr. Gebhart's assertion that any costs for**
718 **BART control on coal-fired electric generating unit SO₂ emissions control**
719 **projects that exceed \$2,000 per ton SO₂ removed should not be designated as**
720 **BART unless other regulatory factors in the analysis warrant a higher cost**
721 **level?**

722 A. No. While the Company has argued from a similar position as Mr. Gebhart in past
723 discussions with the EPA and state agencies regarding the appropriate cost
724 effectiveness criteria to apply to specific projects on a cost per ton removed basis,
725 the EPA and state agencies are not bound by the cost effectiveness
726 recommendations included in the EPA's preamble for BART rulemaking
727 referenced in Mr. Gebhart's testimony. In addition, cost effectiveness of specific
728 projects will most definitely be impacted by factors other than the "regulatory
729 factors" that Mr. Gebhart identifies as the only allowance that would warrant a
730 higher cost level for a project (see lines 179 through 183 of Mr. Gebhart's direct
731 testimony). Other project specific factors that have the potential to impact project
732 scoping and costs could include projected changes in fuel quality, operational

733 compliance issues with existing systems, equipment end-of-life issues, site
734 constraints, and market availability of equipment and labor.

735 **Q. Have agency actions supported the Company's assertion that the EPA and**
736 **state agencies have demonstrated wide-ranging discretion in assessing cost**
737 **effectiveness of pollution control projects?**

738 A. Yes. Recently, BART determinations issued by the state of New Mexico for
739 emission control projects have demonstrated that removal costs of \$7,500 per ton
740 are not considered cost prohibitive. Although this specific example is related to
741 NO_x emissions and not SO₂, it demonstrates the wide range of costs that states
742 have deemed acceptable, as well as the latitude that states have in setting the cost
743 effectiveness standards that they apply under the Regional Haze Rules. Although
744 the EPA has provided ranges of cost effectiveness for both SO₂ and NO_x, there
745 are numerous examples of states, including New Mexico, Colorado, Wyoming,
746 and Oregon, that have required facilities to install controls that significantly
747 exceed these costs. EPA itself has exceeded their own cost guidelines in making
748 BART determination for the Four Corners and Navajo Power stations.

749 **Q. Are particulate matter emissions reduction projects typically evaluated on**
750 **the same cost per ton removed standards?**

751 A. No. Particulate matter emission reductions cannot typically be compared to this
752 same cost per ton removal standard since the incremental emissions improvement
753 will be much smaller due to the relatively high removal efficiency level of
754 existing particulate matter removal equipment. It should also be noted that when
755 ongoing emissions compliance and/or equipment end-of-life issues must be

756 addressed, the dollar per incremental ton removed evaluation is not applicable.

757 **Q. Does the Company believe that Mr. Gebhart has appropriately assessed the**
758 **cost effectiveness of the pollution control investments that he recommends**
759 **for disallowance in this case?**

760 A. No. In assessing the cost effectiveness of the Huntington Unit 1 and Hunter Units
761 1 and 2 scrubber projects that he recommends for disallowance, Mr. Gebhart has
762 failed to consider key project specific planning inputs, including coal quality and
763 operational compliance, that must be considered when evaluating the cost
764 effectiveness of those projects. With respect to the Dave Johnston Unit 3 scrubber
765 and baghouse project that he recommends for disallowance, Mr. Gebhart failed to
766 consider project specific constraints and ultimate commercial viability of his
767 recommended solution.

768 **Q. Has the Company assessed the cost effectiveness of the Hunter Units 1 and 2**
769 **scrubber projects in light of those key project specific planning inputs.**

770 A. Yes. The Hunter units are in a unique situation compared to the Company's other
771 units in that 1) the historic emission rates were driven by an 80% percent removal
772 requirement and not by a specific pounds per million Btu emission rate, 2) the low
773 sulfur fuel being burned historically resulted in low emission rates and typically
774 remained within original equipment design specifications and capacities on an
775 annual average basis, but 3) the sulfur content of the fuel is projected to increase
776 significantly and exceed the capabilities of existing scrubber infrastructure. The
777 typical dollar per ton analysis utilized by Mr. Gebhart simply evaluates the
778 historic emissions of a unit against the unit's projected future emissions based on

779 its permitted emissions limit to obtain the additional tons removed. In most cases
780 evaluated by Mr. Gebhart the coal quality is not changing, the difference in the
781 tons emitted before and after the project upgrades is equivalent to the difference
782 in the tons of SO₂ being removed. In fact, the Company has maintained
783 consistency with this cost effectiveness reporting methodology in its previous
784 filings and discovery requests in this case in attempt to directly respond to
785 questions asked. However, as a practical matter and because the coal quality is
786 changing at the Hunter units, this type of analysis does not provide the best
787 method for analyzing the cost effectiveness of the respective projects and appears
788 to be causing confusion amongst the Parties to this case. To properly identify the
789 additional tons of SO₂ removed with the new equipment, the evaluation needs to
790 be based on the changes between historic permit emission rates and new permitted
791 emission rates, as well as the changes in the fuel quality. Examples of this
792 approach are provided in the Table 1 below.

793 **Q. What are the results of the Company's cost effectiveness analyses?**

794 A. Table 1 below provides the Company's cost effectiveness analyses for the Hunter
795 Units 1 and 2 scrubber projects for which Mr. Gebhart recommends disallowance.
796 The results of the Company's analyses, incorporating appropriate inputs for
797 changes in fuel quality, further support the cost effectiveness of the scrubber
798 projects in question.

Table 1

	Hunter 1	Hunter 2
Unit Megawatt Rating, MWn	430	430
Unit Hourly Heat Input, mmBtu/hr	4,750	4,750
Annual Capacity Factor, percent	90.0%	90.0%
Unit Annual Heat Input, mmBtu/yr @ 90% CF	37,551,600	37,551,600
Baseline Coal Btu/lb	11,208	11,208
Baseline Coal Sulfur, % (historical):	0.5	0.5
Baseline uncontrolled emission rate, lb/mmBtu	0.892	0.892
Annual uncontrolled SO ₂ emissions, tons/yr	16,752	16,752
SO ₂ Baseline Emission Rate, lb/mmBtu	0.16	0.16
Baseline Emissions, tons/yr	3,004	3,004
Historic tons SO ₂ removed	13,748	13,748
Future Coal Btu/lb	11,425	11,425
Future Coal Sulfur, %	0.767	0.767
Future Uncontrolled emission rate (lb/mmBtu)	1.343	1.343
Annual uncontrolled SO ₂ emissions, tons/yr	25,210	25,210
New Permitted SO ₂ Rate, lb/mmBtu	0.12	0.12
Future SO ₂ Emissions, tons/yr	2,253	2,253
Reduction in Future SO ₂ emissions, tons/yr	751	751
Future tons SO ₂ removed, tons/yr	22,957	22,957
Net increase in the tons of SO₂ removed, tons/yr	9,209	9,209
Annual Cost of Control	\$9,885,000	\$8,982,000
Dollar per ton estimate based on tons of SO ₂ removed	\$1,073	\$975

799 **Q. Has Mr. Gebhart recommended disallowance of pollution control project**
800 **costs that are not included in case?**

801 A. Yes. The most significant of which are the costs associated with the Dave
802 Johnston Unit 3 scrubber and baghouse project which was previously placed in

803 service and reviewed for rate base treatment under a separate Major Plant
804 Additions docket. Notwithstanding the fact that the Company has requested
805 recovery of only approximately \$9.5 million of project close-out costs associated
806 with this project in this case, the UAE witnesses have submitted testimony
807 regarding their evaluation of that project in its entirety. Mr. Gebhart recommends
808 only costs associated with the baghouse portion of that project for disallowance,
809 and Mr. Higgins states that he has adopted Mr. Gebhart's position. However, Mr.
810 Higgins' recommended revenue adjustment appears to reflect disallowance of
811 what would be the equivalent revenue requirement of the entire Dave Johnston
812 Unit 3 scrubber and baghouse project, if it were included in this case. The
813 Company objects to the applicability of any of these analyses to this docket,
814 disagrees with the conclusions reached, and further objects to the recommended
815 actions. The Company is further perplexed by the inconsistency between the
816 testimony of the two UAE witnesses mentioned above.

817 **Q. Has Mr. Gebhart taken a similar approach with respect to the Hunter Unit 1**
818 **scrubber project?**

819 A. Yes. The Company has requested recovery in this case of approximately \$19
820 million of costs associated with placing in service the scrubber waste handling
821 subcomponent of the Hunter Unit 1 scrubber project. Mr. Gebhart's testimony
822 presents an evaluation of the costs of the Hunter Unit 1 scrubber project in its
823 entirety, with the same flaws in his evaluation as discussed above, and
824 recommends disallowance of the project in its entirety. The Company again
825 objects to the applicability of these analyses to this docket, disagrees with the

826 conclusions reached, and further objects to the recommended actions.

827 **Planning**

828 **Q. Has the Company accounted for pollution control investments in its forward-**
829 **planning cycles?**

830 A. Yes. The Company makes every effort to identify, quantify and include forward-
831 looking environmental compliance projects in its business planning processes and
832 associated filings.

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

836 A. PacifiCorp and its parent, MidAmerican Energy Holdings Company, are active in
837 current state and federal legislative and agency activities regarding environmental
838 controls affecting virtually all emissions from coal and natural gas generating
839 units, and other environmental issues. The Company is cognizant that some
840 potential restrictions on greenhouse gas ("GHG") emissions could require coal
841 (and potentially natural gas) units to adjust the depreciation lives for ratemaking
842 purposes. The Company considers this possibility when determining whether to
843 proceed with pollution control investments.

844 **Q. Has the Company communicated to the Commission its knowledge and**
845 **understanding of additional costs required to maintain compliance with**
846 **current and anticipated likely environmental regulations?**

847 A. Yes. As the Company becomes aware of known or anticipated likely
848 environmental regulations, the Company begins assessment of requirements and

849 incorporation of appropriate project completion timelines and cost estimates into
850 its business planning processes. The Company's IRP and IRP updates filed with
851 this Commission also include extensive discussion regarding the business
852 planning considerations given to current and anticipated likely environmental
853 regulations.

854 **Q. Does the Company continue to improve its analysis of market risk associated**
855 **with emerging environmental regulations, particularly risks associated with**
856 **greenhouse gases?**

857 A. Yes. In support of the Company's 2011 IRP development process, the Company
858 incorporated System Optimizer Coal Utilization Case Studies 20-24. These case
859 studies were designed to investigate the impacts of CO₂ cost and gas price
860 scenarios on the Company's existing coal fleet after accounting for coal plant
861 incremental costs. This study used new modeling functionality that enables
862 representation of existing plant repowering and retrofitting as future resource
863 options. Additionally, the Company acquired and used customized enhancements
864 to the model for estimating carbon dioxide emissions and regulatory costs
865 associated with spot market balancing sales and purchases. These case studies
866 include capital expenditures for planned and/or ongoing pollution control
867 equipment investments included in the Company's business plan, including
868 mercury HAPs MACT compliance costs. Due to the timing of these case studies
869 in 2010, the Company's preliminary capital cost estimates for compliance with
870 the EPA's proposed coal combustion residuals (CCR) rules and Clean Water Act
871 Section 316(b) cooling water intake rules were not incorporated. CCR compliance

872 costs have since been incorporated into the Company's business plan, and
873 preliminary estimates for future Clean Water Act Section 316(b) cooling water
874 intake compliance projects are being developed and will be incorporated into the
875 Company's next business plan cycle. These costs will be incorporated into future
876 updates of the coal utilization case studies.

877 **Q. Do the results of the Company's coal utilization case studies included in the**
878 **2011 IRP process result in the Company requesting accelerated depreciation**
879 **treatment of pollution control investments contemplated in this case?**

880 A. No. The results of the Company's coal utilization case studies do, however,
881 identify certain CO₂ cost and gas price scenarios that would lead the Company to
882 re-evaluate strategic asset planning for certain units. Re-evaluation of strategic
883 asset planning would be vetted via the Company's depreciable life studies that are
884 completed every five years, with the next due in 2013.

885 **Q. Does the Company agree with Ms. Kelly's assertion that the coal utilization**
886 **case studies produced no meaningful results?**

887 A. No. The coal utilization sensitivity cases included in the Company's 2011 IRP
888 were designed to investigate, as a modeling proof-of-concept, the impacts of CO₂
889 cost and gas price scenarios on the existing coal fleet. The sensitivity cases
890 included the Company's planned and/or ongoing pollution control project
891 investments, incorporating mercury HAPs MACT costs. As intended, the coal
892 utilization sensitivity case studies will provide the impetus for future refinement
893 of the modeling approach to be used for investigating coal plant operations.

894 **Q. Will the Company continue to include System Optimizer Coal Utilization**
895 **Case Studies in its IRP process?**

896 A. Yes. The Company will continue to include and refine System Optimizer Coal
897 Utilization Case Studies in its future IRP processes.

898 **Q. Does the Company support Ms. Kelly's recommendation to the Commission**
899 **to open a separate docket at the conclusion of this general rate case to**
900 **oversee the development of a comprehensive analysis of any significant new**
901 **coal plant investments?**

902 A. No. The Company's IRP proceedings conducted in all six of the states served by
903 the Company provides the process to address ongoing investment in the
904 Company's coal units. As noted above, the Company's intent is to continue to
905 include and refine its modeling and evaluation tools in this regard. As evidenced
906 by the testimony, exhibits and extensive discovery provided by the Company in
907 this docket, the Company will continue to apply least cost principals to its
908 pollution control investments and offer comparisons of compliance alternatives
909 including retrofitted coal fueled generation units to other generation resource
910 classes, such as combined-cycle natural gas fueled generation and conversion of
911 coal-fueled units to natural gas. Establishing a separate docket to oversee the
912 development of said analyses would be duplicative.

913 **Q. Do the pollution control investments presented in this case also support**
914 **compliance with anticipated likely regulations?**

915 A. Yes. In many cases the investments are also expected to support compliance with
916 anticipated likely regulations as currently proposed. Confidential Exhibit

917 RMP___(CAT-1R) attached to this testimony provides an overview of anticipated
918 likely regulations with which the projects presented in this case are anticipated to
919 support compliance.

920 **Q. Has the Company presented pollution control investments in this case based**
921 **on anticipated regulations that do not exist, may never be implemented, and**
922 **if implemented may require technologies other than those installed by the**
923 **Company?**

924 A. No. As discussed above, the Company maintains that the pollution control
925 investments presented in this case are required to comply with existing
926 regulations being administered by the respective state departments of
927 environmental quality.

928 **Q. Does the Company agree that Dr. Fisher has accurately forecasted the future**
929 **capital investment obligations associated with emerging environmental**
930 **regulations that the Company may be facing through the 2020 timeframe?**

931 A. No. The Company believes that Dr. Fisher has taken a generalized view of
932 emerging environmental regulations without any real certainty of agency action.
933 Where Dr. Fisher's forecast falls short is with respect to detailed evaluation of the
934 Company's individual units and installations as they may be affected by the
935 emerging environmental regulations considered.

936 **Q. Do you agree with Dr. Fisher's discussion regarding selective catalytic**
937 **reduction ("SCR") capital investments?**

938 A. No. With respect to the SCR investments identified by Dr. Fisher for Dave
939 Johnston Units 3 and 4, Naughton Units 1 through 3, Wyodak, Jim Bridger Units

940 1 through 4, Hunter Units 1 through 3, and Huntington Units 1 and 2, all with in-
941 service dates of 2015 (except Jim Bridger Unit 4 which is identified with a 2016
942 in-service date), the Company does not believe that Dr. Fisher’s plan represents a
943 likely outcome. The costs that Dr. Fisher proposed are generally understated and
944 the proposed installation schedule is overly optimistic, highly inefficient and
945 unfeasible. EPA is not expected to take action on the recently submitted Utah and
946 Wyoming Regional Haze state implementation plans (“SIPs”) until 2012, at the
947 earliest. Not accounting for potential appeals of final EPA action, if EPA requires
948 additional SCR as part of its approval of these SIPs, federal Regional Haze
949 regulations will require installation “as expeditiously as practicable”, but not later
950 than five years after EPA’s approval of the SIPs. Dr. Fisher’s schedule for
951 installation of SCR at 13 facilities by 2015 and one in 2016 is not consistent with
952 the Regional Haze Rules, and installation of 13 SCR in approximately 3 ½ years
953 is in no way “practicable.”

954 In addition, in Wyoming, the EPA is aware of the settlement reached with
955 respect to the timing of the Naughton and Jim Bridger SCRs following the
956 Company’s recent appeal of BART permits for those units. That settlement does
957 not call for the installation of SCR at the identified Wyoming units by 2015 as
958 suggested by Dr. Fisher, but instead requires installation of SCR at only five units
959 on a gradual basis over time beginning in 2014 and ending in 2022. This
960 settlement reflects the expectation of both PacifiCorp and the Wyoming
961 Department of Environmental Quality and is far more indicative of the timing for
962 installing SCR equipment than Dr. Fisher’s speculation. The Company’s out-year

963 business plan (beyond 2020) currently includes SCRs for three Utah units;
964 however, the Company has not been compelled to commit to those projects via
965 permit applications or other agency action. The Company will continue to
966 evaluate such investment plans with the appropriate inputs and considerations.
967 The Company will also remain engaged in the EPA SIP review process with the
968 intent of effectuating outcomes in the best interests of its customers and
969 stakeholders. The Company firmly believes that its current commitments
970 regarding SCR installations meet the letter and intent of the Regional Haze Rules,
971 including guidance provided by the EPA Appendix Y of 40 CFR Part 51.

972 **Q. Do you agree with Dr. Fisher's discussion regarding baghouse capital**
973 **investments?**

974 A. No. With respect to the baghouse investments identified by Dr. Fisher for
975 Naughton Units 1 and 2 and Jim Bridger Units 1 through 4 with various costs and
976 in-service dates through 2016, Dr. Fisher's plan does not represent a likely
977 outcome. Dr. Fisher identifies the underlying driver for each of the baghouses as
978 maximum achievable control technology ("MACT") compliance. Presumably, Dr.
979 Fisher's MACT reference is to the EPA's recently proposed non-mercury metallic
980 hazardous air pollutants ("HAPs") MACT rules, and the associated surrogate
981 particulate matter emissions compliance limits. Based on the Company's
982 evaluation of the proposed non-mercury metallic HAPs MACT rules at the
983 facilities identified, the Company expects to be able to comply with the surrogate
984 particulate matter emissions limit at each facility with existing equipment;
985 therefore, not requiring the baghouse investments Dr. Fisher identifies. In

986 addition, based on recently completed control technology demonstration testing,
987 the Company also expects to be able to comply with mercury HAPs MACT rules
988 via activated carbon injection (“ACI”) and supplemental reagent injection, as may
989 be required. Once again, not requiring the baghouse investments Dr. Fisher
990 identifies. The Company’s ACI plans are discussed further below. The baghouse
991 cost estimates provided by Dr. Fisher reflect costs that are not necessary for the
992 reasons discussed above.

993 **Q. Do you agree with Dr. Fisher’s observations regarding ACI investments?**

994 A. No. With respect to the ACI investments identified by Dr. Fisher with various in-
995 service dates and costs, the Company has incorporated a similar compliance plan
996 for mercury emission into its business planning process; however, specific project
997 costs and schedules are only generally aligned with Dr. Fisher’s proposal. The
998 Company’s plan deviates most significantly from Dr. Fisher’s proposal at Hunter
999 and Huntington, where the Company does not anticipate needing ACI systems to
1000 achieve mercury HAPs MACT compliance, as currently proposed.

1001 **Q. Do you agree with Dr. Fisher’s observations regarding coal ash remediation**
1002 **investments?**

1003 A. No. With respect to the coal ash remediation line item identified by Dr. Fisher
1004 with various in-service dates through 2017 and no cost estimates, the Company
1005 has incorporated preliminary coal combustion residuals (“CCR”) compliance
1006 plans that are generally aligned with the timing proposed into its business
1007 planning process. Management of the CCR is an integral part of the Company’s
1008 operations. With respect to Dr. Fisher’s correlation of future CCR compliance

1009 costs with the Company's decisions to continue to invest in its coal fueled
1010 generation assets, it is important to note that the Company will be faced with
1011 certain CCR storage, handling, and long-term management costs at its existing
1012 facilities whether the facilities continue to operate or not. Therefore, the Company
1013 continually updates its CCR-related costs and asset retirement obligations. In
1014 response to the recently proposed EPA rulemaking regarding CCR, the Company
1015 has updated its CCR-related costs and asset retirement obligations on a
1016 preliminary basis to incorporate proposed Subtitle D or near-Subtitle D
1017 infrastructure requirements, which will serve as a proxy until such time as EPA
1018 responds to the recently completed public comment period for CCR regulations.
1019 Dr. Fisher's implication that the Company has not included such considerations
1020 into its business planning process is inaccurate.

1021 **Q. Do you agree with Dr. Fisher's observations regarding effluent and**
1022 **remediation investments?**

1023 A. No. With respect to the effluent and impingement remediation line items
1024 identified by Dr. Fisher with various in-service dates through 2018 and no cost
1025 estimates other than for the proposed cooling tower addition at Dave Johnston
1026 Unit 3, the Company is in the process of evaluating these recently proposed rules.
1027 However, based on the Company's past investigations of its facilities, including
1028 Dave Johnston Unit 3, investments associated with compliance in these areas are
1029 expected to be limited and are not expected to result in investments in cooling
1030 tower additions, as Dr. Fisher speculates.

1031 **Q. Please provide a summary of your testimony.**

1032 A. The Company's pollution control projects included in this case and their timing
1033 appropriately balance compliance with environmental regulations, including
1034 Regional Haze programs administered by the states of Utah and Wyoming, with
1035 the costs and other concerns of our customers. The projects are required to
1036 comply with existing regulations, including stand-alone requirements in state
1037 implementation plans, BART permits and construction permits enforceable by the
1038 laws of the respective states, independent of whether EPA has approved the
1039 respective state implementation plans. The Company's considerations when
1040 making pollution control investments include evaluation of state and federal
1041 environmental regulatory requirements and associated compliance deadlines,
1042 review of emerging environmental regulations and rulemaking, and analyses of
1043 alternate compliance options. Considerations also include ongoing compliance
1044 with existing operating requirements, fuel supply flexibility, equipment end of life
1045 considerations, and operational efficiencies. The Company's analyses completed
1046 to date demonstrate that maintaining the ability to operate the coal-fueled units
1047 included in this case by retrofitting them with the pollution control equipment
1048 represents the least-cost option for our customers. PacifiCorp has compared the
1049 cost of retrofitted coal fueled generation units to other generation resource classes,
1050 including combined-cycle natural gas fueled generation and conversion of coal-
1051 fueled units to natural gas.

1052 **Q. Does this conclude your rebuttal testimony?**

1053 A. Yes.