

1 **Q. Are you the same K. Ian Andrews that submitted direct testimony in this**
2 **proceeding?**

3 A. Yes.

4 **Purpose of Testimony**

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

6 A. The purpose of my rebuttal testimony is to address testimony filed by the Utah
7 Division of Public Utilities (“DPU”), Utah Office of Consumer Services (“OCS”) and
8 the Utah Association of Energy Users Intervention Group (“UAE”) related to:

- 9 • Extending the life of the Craig coal-fired units 1 & 2,
- 10 • Extending the life of the Gadsby gas-fired steam units 1, 2 & 3,
- 11 • Extending the life of the James River Plant,
- 12 • Extending the life of certain hydro electric facilities,
- 13 • Extending the life of gas-fired combined cycle generation facilities,
- 14 • Estimated decommissioning costs of the Carbon Plant,
- 15 • Terminal net salvage of coal-fired steam generation facilities,
- 16 • Terminal net salvage of gas-fired combined cycle generation facilities,
- 17 and
- 18 • Terminal net salvage of wind generation.

19 **Extending the Life of Craig units 1 and 2**

20 **Q. What did the DPU and UAE recommend regarding the stipulated life of the**
21 **Craig units 1 and 2?**

22 A. The DPU proposes that the retirement year of Craig units 1 and 2 be extended from
23 the current retirement year of 2034 to 2040, an increase of seven years from the

24 currently stipulated life. The DPU proposes that by extending the life to 2040, the life
25 span of the two units will be 61 and 60 years, respectively. DPU states these lives are
26 more consistent with the other (coal-fired) steam plants in this case. The UAE
27 recommends that the retirement year of Craig units 1 and 2 be extended from the
28 current retirement year of 2034 to 2051, an increase of 17 years. The UAE did not
29 explicitly provide a basis for its recommendation, but the Company assumes it is
30 based on the study prepared by RW Beck for Tri-State Generation and Transmission
31 Association, the operator and one of the majority owners of the plant that was
32 provided in response to data request DPU 8.1.

33 **Q. Do you agree that the stipulated life of the Craig units 1 and 2 should be**
34 **extended?**

35 A. No. Even though it is accurate that the DPU's observation that extending the life of
36 Craig to 2040 would be more consistent with the lives of the other (coal-fired) steam
37 plants in this case, the Craig units are tied to other ancillary contracts and therefore
38 the Craig units should not be depreciated beyond 2034. If these factors cannot be
39 successfully resolved, there may be a need to accelerate the current established
40 retirement year of 2034. In order to minimize ratepayer impacts associated with an
41 accelerated retirement date, the Company recommends that the currently stipulated
42 retirement year of 2034 be retained and the retirement year of the Craig units not be
43 extended.

44 **Extending the life of the Gadsby gas-fired steam units 1, 2 and 3**

45 **Q. What did the DPU recommend regarding the retirement year of the Gadsby gas-**
46 **fired steam units 1, 2 and 3?**

47 A. The DPU proposes that the retirement year of Gadsby units 1, 2 and 3 be extended
48 from the proposed retirement year of 2022 to 2033, an increase of 16 years from the
49 currently stipulated life and 11 years greater than the retirement year that the
50 Company proposed in this case (2022). The basis for the DPU's position is that
51 Gadsby units 1, 2 and 3 are included in the most recent 2013 PacifiCorp Integrated
52 Resource Plan ("IRP") throughout the 20-year time planning horizon.

53 **Q. Do you agree that the stipulated life of the Gadsby units 1, 2 and 3 should be**
54 **extended through 2032?**

55 A. No. The IRP is a planning tool and the Gadsby steam units were kept throughout the
56 IRP planning horizon on the assumption that these units could continue to be operated
57 and maintained at historical operating and maintenance costs with minimal
58 investments required to keep them operational. It is also expected these units will
59 continue to be operated both infrequently and at reduced load. Costly failures of
60 major equipment become more likely as these units continue to age. The Company
61 can support extending these units to 2022 given their current condition and intended
62 operating profile. In the event the lives of these units were extended beyond 2022, the
63 probability of a major event increases. If the cost to repair/replace the equipment
64 renders the resource uneconomic to continue to operate, it would be necessary to
65 accelerate the retirement of that particular unit.

66 **Extending the Life of the James River Camas Co-generation Plant**

67 **Q. What did the DPU recommend regarding the retirement year of the James River**
68 **Camas Co-generation Plant?**

69 A. The DPU proposes that the retirement year of the James River Camas Co-generation
70 Plant (now owned by Georgia-Pacific instead of James River) is extended by 10
71 years. The basis for the DPU's position is that under the terms of the current lease
72 agreement there are other options besides termination of the lease. As a result, DPU
73 theorizes that an additional 10 years of life is achievable. No calculation for the
74 10-year increase was provided other than the 10 years "is the middle of the range of a
75 0-year additional life and 20-year additional life."

76 **Q. Do you agree that the stipulated life of the James River Camas Co-generation**
77 **Plant should be extended?**

78 A. No. On May 29, 2013, the Company sent notice to Georgia Pacific that the agreement
79 would be terminated at the end of the existing lease period and would not be
80 extended. Since the lease will not be extended, the lease will expire on December 30,
81 2015, per the terms of the lease agreement. Under the terms of the lease agreement in
82 the event the lease is not extended, the only available options are to sell the asset to
83 Georgia-Pacific under the definition of fair market value set forth in the lease
84 agreement, or in the event Georgia-Pacific chooses not to purchase the assets, the
85 Company is obligated to remove the generation facility. No values for fair market
86 value as defined in the lease agreement have been established at this time. It is
87 expected that this will be a protracted process. In any event, the stipulated life of the
88 Camas co-generation facility should not be extended beyond December 30, 2015. In

89 Mr. Henry E. Lay’s rebuttal testimony, Mr. Lay is proposing that the depreciation rate
90 be adjusted to align with this date.

91 **Extending the life of certain hydro electric facilities**

92 **Q. What did the DPU recommend regarding extending the life of certain hydro**
93 **electric facilities?**

94 A. The DPU recommended extending the lives of the Prospect 3, Bend, Paris, Santa
95 Clara (which, includes the other hydro projects on the Santa Clara River, Veyo and
96 Gunlock), Wallowa Falls and Weber hydro facilities by 30 years beyond the proposed
97 retirement lives proposed by the Company.

98 **Q. Do you concur with DPU’s recommendation to extend the life of the Prospect 3,**
99 **Wallowa Falls and Weber facilities?**

100 A. No. Of these facilities, the Prospect 3, Wallowa Falls and Weber facilities require
101 licenses from Federal Energy Regulatory Commission (“FERC”) to operate. The
102 current FERC licenses for the Wallowa Falls, Prospect 3, and Weber facilities expire
103 in 2016, 2018, and 2020, respectively.

104 **Q. Is the DPU recommendation industry standard?**

105 A. No. It is industry practice to match the depreciable life of a hydro project to the end of
106 FERC license date. The DPU recommendation to extend the Wallowa, Prospect 3 and
107 Weber facilities based on an assumption that they will be economically viable to re-
108 license those projects for an additional 30 years following their current license
109 expiration dates is unjustified.

110 **Q. Why is it industry standard to match the depreciable life of a hydro project to**
111 **the end FERC license date?**

112 A. It is unknown whether accepting the conditions of a new license will be in the best
113 interests of customers. The economic viability of each project is determined on a
114 case-by-case basis. Requirements of a new license may include recreational facilities,
115 fish passage facilities, operational restrictions or other measures. The term of a new
116 license is partially determined by, among other things, the level of investment
117 required to implement the new license conditions.

118 **Q. Do you agree with DPU's recommendation to extend the life of the Bend, Paris**
119 **and Santa Clara hydro facilities?**

120 A. No. The Bend, Paris and Santa Clara hydro facilities are very small (3.88 megawatts
121 total) and aged facilities. Based on the Company's proposed life, each of these small
122 facilities will be over one hundred years old at the end of their depreciable life. Given
123 their size and age, it is unknown whether it will be cost effective to continue to
124 operate and maintain these facilities beyond the retirement dates proposed by the
125 Company or if an unplanned event will occur in the interim to cause one of these
126 projects to no longer be economic. The assumption that it will be economic to operate
127 these facilities for an additional 30 years beyond the retirement date proposed by the
128 Company is not supportable.

129 **Extending the life of gas-fired combined cycle generation facilities**

130 **Q. What did the Office of Consumer Services ("OCS") recommend regarding**
131 **extending the life of gas-fired combined cycle generation facilities?**

132 A. The OCS recommends that the life of gas-fired combined cycles be extended from the

133 Company's recommended life of 40 years to 45 years. OCS makes this
134 recommendation based on the following:

- 135 • historically, the lives of other types of generating assets have been
136 increased compared to their original estimated design lives,
- 137 • the higher efficiency and environmental characteristics of combined
138 cycle plants relative to coal-fired resources will result in the concept
139 which was summarized in testimony as follows: "maximization of
140 capital intensive investments should be the guiding factor for the
141 establishment of useful life,"
- 142 • the assumption there will be a demand to extend the lives of combined
143 cycle resources since the Company is not proposing to extend the lives
144 of its existing coal-fired resources, and
- 145 • some combined cycle plants have operated longer than 40 years.

146 **Q. Do you concur with OCS's recommendation that the lives of gas-fired combined**
147 **cycle generation facilities should be extended?**

148 A. No. The Company provided, through discovery, multiple documents indicating that
149 the design lives of both the plants themselves and the major equipment comprising
150 the combined cycle plants in the Company's fleet from 25 to 30 years. The Company
151 recognized that, historically, resource lives have been extended from their original
152 design lives to longer periods; this was a major consideration in increasing the
153 economic life to the current stipulated life of 40 years; this equates to a life 33 percent
154 longer than the design life. However, there is a limit as to how much historical life
155 extension for coal-fired plants designed in the 1950-1970s can be extrapolated to gas-

156 fired combined cycle plants designed in the 2000-2010 time frame. The design
157 margins and engineering tools between these two time frames and the expected
158 operating regimes are significantly different. The operating conditions of
159 state-of-the-art combustion turbines are significantly different than the operating
160 conditions of coal-fired furnaces which have remained principally unchanged.
161 Current combined cycle plants are operated in moderate to severe cycling service
162 which has a significant effect on equipment life. Coal-fired plants, on the other hand,
163 were designed and have been operated as baseload resources. Many years of
164 operating experience will be needed to determine if extending the life of a combined
165 cycle plant by 50 percent of its design life is warranted.

166 **Q. How does the efficiency and environmental characteristics of a combined cycle**
167 **plant influence the estimated life?**

168 A. Current natural gas-fired combined cycle plants are more efficient and have lower
169 criteria emissions than coal-fired resources. However, from a cost of energy basis,
170 due to the underlying cost of fuel, the cost of energy from coal-fired resources is
171 typically lower than from combined cycle plants. Therefore, the position advanced by
172 OCS that combined cycle resources are more efficient and thus more valuable does
173 not support a conclusion that a combined cycle resource should have an economic life
174 of 45 years.

175 Material improvements have been made and continue to be made in the
176 operating and emissions performance of gas-fired combined cycle resources. It is
177 reasonable to expect further advances in combined cycle performance and emissions
178 rates and that new gas-fueled technologies will continue to emerge and be developed.

179 It is reasonable to expect that resources built in the 2040-2050 timeframe will be
180 more efficient and have less environmental impact than today's combined cycle
181 plants. Therefore it is unknown what the economic value will be of combined cycle
182 that are currently being built will be in the 2040-2050 time frame.

183 **Q. What is your position regarding the assumption there will be a demand to**
184 **extend the lives of combined cycle resources since the Company is not proposing**
185 **to extend the lives of its existing coal-fired resources?**

186 A. OCS states there will be a demand to extend the lives of combined cycle plants since
187 the Company is not proposing to extend the lives of existing coal-fired resources.
188 However, since the coal fired resources are expected to retire many years earlier than
189 the combined cycle plants, it will first be necessary to replace the coal-fired resources
190 with other resources, and there may be no impact on the lives of existing combined
191 cycle resources.

192 **Q. What is your position regarding the "U.S. Energy Information Administration**
193 **("EIA") data that indicates that some combined cycle plants are still in operation**
194 **after 40 years?**

195 A. Combined cycle plants that were designed and built 40 years ago or more are not the
196 same as the combined cycle plants built recently. The EIA data does not support a
197 conclusion of widespread operation of combined cycle plants beyond 40 years. A
198 resource reported as "not retired" in the EIA data does not mean that the plant is
199 operating. According to EIA 860 data, 96 percent of the combined cycle plants that
200 have been retired are 34 years or younger at the time of retirement. The mere
201 incidence of longer lived assets that were designed and constructed more than 40

202 years ago says little or nothing about the lives of new combined cycle plants. The
203 Company's recent experience with its Little Mountain plant supports a 40-year life.
204 The Little Mountain Plant, a cogeneration plant consisting of a combustion turbine
205 and heat recovery steam generator and operated at high capacity factors, was retired
206 after a 40-year life (March 1971 to December 2011).

207 **Estimated decommissioning costs of the Carbon Plant**

208 **Q. What did the DPU and OCS recommend regarding the decommissioning costs to**
209 **use for the Carbon Plant?**

210 A. DPU recommends that a decommissioning cost of \$40 per kilowatt be used for the
211 Carbon Plant. OCS recommends that a decommissioning cost of \$30 per kilowatt be
212 used for the Carbon Plant.

213 **Q. Do you agree that a decommissioning cost of either \$30 or \$40 should be used for**
214 **the Carbon Plant?**

215 A. No. Many of the issues that DPU and OCS raise are valid; however, a detailed
216 discussion of each issue would not be constructive. Ultimately, the Company will
217 seek to recover its prudently incurred costs associated with the decommissioning of
218 the Carbon Plant. To the extent practicable, earlier collection of the expected costs for
219 that decommissioning will reduce rate impacts at a later date.

220 The underlying message from both DPU and OCS testimony on this issue is
221 that the Commission should not rely on the overall cost estimate based on the analysis
222 of the demolition cost estimate presented by the Company. By only focusing on the
223 power plant demolition estimate, other major contributors of cost are ignored.

224 The Company has expressed on a number of occasions that the Carbon Plant
225 demolition estimate was preliminary and that the Company cost estimate will be
226 refined as the demolition planning and development process proceeds through
227 competitive bid pricing. This process is ongoing. Notably, both DPU and OCS
228 testimony focuses only on the demolition methodology, labor costs and estimated
229 salvage value; they do not address other major cost contributors such as removal of
230 all coal from the coal pile and remediation of the coal pile site. This coal pile is
231 immediately adjacent to Willow Creek that feeds into the Price River. The wastewater
232 retention ponds must be drained, filled and the site remediated. Significant quantities
233 of asbestos must be removed and abated. The water retention basin must be drained,
234 filled and remediated. The ash landfill must be re-contoured, capped and seeded.
235 These important and significant steps must be considered in determining the overall
236 cost of decommissioning the plant.

237 **Q. Are DPU's and OCS's remarks accurate regarding demolition of the boiler and**
238 **steam turbine building?**

239 A. In some respects. Both DPU and OCS propose that there are other demolition
240 methods currently used in the demolition industry. Furthermore, OCS indicates that
241 the Company scrap values are not current.

242 The Company acknowledges that when a contractor is finally selected to raze
243 the Carbon Plant, the contractor may employ a different demolition approach than
244 that assumed in the Company's third-party estimate. Also, different scrap values may
245 reduce the cost of the demolition; as driven by then-current scrap market values.

246 Regarding demolition method, the Carbon Plant has unique physical
247 constraints. It is located in a canyon on an extremely constrained footprint. The
248 Carbon Plant is situated between a 120-foot high rock bluff and Utah State Highway
249 191; the state highway bifurcates the coal pile from the power plant. The plant is
250 immediately adjacent to a natural waterway, Willow Creek that feeds the Price River
251 which is approximately 300 feet away from the plant. The plant is further bounded by
252 the mainline of the Union Pacific Railroad between Denver and Salt Lake City. The
253 corner of the main turbine building is less than 50 feet from Utah State Highway 191.
254 The boiler stacks are made of steel and are cantilevered off the boiler structure. The
255 stacks are not made of brick or concrete; the typical characteristic of candidates for
256 explosive demolition. Site conditions will be a critical issue in determining which
257 demolition methods can be safely and effectively used at the Carbon Plant.

258 In addition, the two cooling towers are at the top of the bluff; the only access
259 is via a narrow road. Access for heavy machinery and haul trucks is limited.

260 A site visit and thorough understanding of specific site conditions are critical
261 to determining the appropriate demolition method that will allow the facilities to be
262 efficiently demolished and removed while ensuring worker and public safety while
263 maximizing salvage value. Both DPU and OCS identify a variety of alternative
264 methods that are commonly used in demolition operation. However, they have not
265 demonstrated that these methods can be used at this location with its physical
266 constraints.

267 **Q. What do you recommend?**

268 **A. In an attempt to address the concerns of DPU and OCS, the Company has completed**

269 additional cost reviews since the Company's original testimony was filed. At the
270 current time, the estimated cost for demolition and site remediation of the Carbon
271 Plant is approximately \$117 per kilowatt. Major contributors to the revised cost
272 estimate include a reduction in the costs for demolition, a revised asbestos removal
273 estimate from Thermal West Industrial, Inc. and revisions to the project management
274 estimate. However, the actual costs will not be available until firm pricing is obtained
275 and the plant decommissioning is complete. The Company would expect recovery of
276 those costs prudently incurred in the decommissioning effort.

277 **Terminal net salvage of coal-fired steam generation facilities**

278 **Q. What does OCS recommend regarding the decommissioning costs for steam**
279 **generation?**

280 A. OCS recommends reducing the previously stipulated decommissioning cost from \$40
281 per kilowatt to \$30 per kilowatt.

282 **Q. What is the basis for OCS' recommendation?**

283 A. OCS arrives at the \$30 per kilowatt cost for decommissioning based on the
284 probability weighted cost/benefit of three outcomes. The probability and cost of each
285 outcome is as follows:

- 286 1. Eighty-nine percent probability of having to decommission the plant at
287 a cost of \$40 per kilowatt plus,
- 288 2. One percent probability of selling the asset with a net benefit of \$163
289 dollars per kilowatt; this benefit was derived from the proceeds of the
290 Centralia plant that was sold in June 2000; the two units were 29 and
291 30 years old, respectively when the plant was sold plus,

292 3. Ten percent probability of receiving a net benefit similar to the
293 decommissioning of the Hale Plant which received a positive net
294 salvage due to a sale of the underlying property.

295 **Q. Is the proposed adjustment of the OCS methodology supportable?**

296 A. In part. We support the use of the currently stipulated cost of \$40 per kilowatt for
297 decommissioning a steam plant.

298 However, the OCS adjustments based on a probabilistic outcome are not
299 supportable. The lives of the Company's steam plants will range in age from 54 to 68
300 years when they are retired and decommissioned. OCS' methodology assumes that
301 when these plants reach this retirement they can be: 1) sold, and, 2) sold at the same
302 price that a coal plant which was only 29-30 years old when it was sold to another
303 party who was going to operate the plant on coal for an extended period. First, the
304 probability that there will be a market for a coal-fired resource that is retired in the
305 2027-2046 timeframe is practically zero. The conditions that existed when the
306 Centralia Plant was sold in 2000 are materially different today. More and more
307 environmental regulations and standards have been and continue to be enacted that
308 result in utilities deciding that it is economically advantageous to either retire the
309 resource or convert to gas firing. It is estimated that 59 to 77 giga-watts of coal-fired
310 generating capacity will be retired by 2020 (recent estimates from the Brattle Group¹
311 and Black & Veatch²). In 2012, the United States Energy Information Administration
312 estimated that 27 giga-watts of coal-fired generating capacity will be retired by

¹ Potential Coal Plant Retirements: 2012 Update, Martin Celebi et al, Brattle Group, October 2012.

² "Black & Veatch slightly increases estimate of coal-fired power plant retirements," Power Engineering, February 11, 2013.

313 2016.³ Announcements of additional coal plant closures will likely follow. Coal
314 plants will be operated as long as they bring value to customers. Once it has been
315 determined that continued operation is not economically viable, the resource will be
316 retired. There won't be a market for a coal plant and especially for one that has
317 reached the end of its economic life. Second, if conversion to gas-firing was viable,
318 the value, if any, would be very small indeed, due to any limited remaining life and
319 the value that would result from the low levels of gas-fired generation from a highly
320 inefficient process. In short, the sale scenario after plant retirement as conjectured by
321 OCS is implausible and should be ignored.

322 OCS further suggests that the Company will receive a net positive salvage
323 similar to that received from the Hale Plant decommissioning. OCS assigns a 10
324 percent probability to this outcome. The Hale Plant was located on a highly desirable
325 property at the mouth of Provo Canyon in a scenic area adjacent to a highly populated
326 area. The proceeds from this land sale exceeded the cost of demolition of the Hale
327 Plant. Any proceeds from future land value would offset costs of decommissioning.
328 However, there is no basis to assume the proceeds from steam plant property sales
329 would be similar to the Hale Plant experience such that a positive net benefit would
330 result. The Company's coal-fired steam resources are remotely located. They are not
331 adjacent to populated areas. Property values at these sites would be worth
332 significantly less than the Hale Plant property. Furthermore, in his rebuttal testimony,
333 Mr. John J. Spanos indicates that it is not appropriate to include the value of non-
334 depreciable property in decommissioning costs.

³ "27 giga-watts of coal-fired capacity to retire over next five years," Today in Energy – U.S. Energy Information Administration, July 27, 2012.

335 In conclusion, OCS's adjustment mechanism to modify the currently
336 stipulated value for steam plant decommissioning from \$40 per kilowatt to \$30 per
337 kilowatt has no supportable basis.

338 **Terminal net salvage of gas-fired combined cycle generation facilities**

339 **Q. What does OCS recommend regarding the decommissioning costs for gas-fired**
340 **generation?**

341 A. OCS recommends reducing the previously stipulated decommissioning cost from \$20
342 per kilowatt to \$8 per kilowatt.

343 **Q. What is the basis for OCS' recommendation?**

344 A. OCS indicates that it relied on the updated and corrected values to Black & Veatch's
345 analysis in Nevada as adopted by the Nevada Public Service Commission. Though
346 not provided expressly, it appears that the \$8 per kilowatt was determined by
347 applying a factor of 40 percent to the amount of \$20 per kilowatt proposed by the
348 Company. The 40 percent value was reported by OCS to be the percentage of the
349 actual cost for decommissioning projects to original estimates prepared by Black &
350 Veatch in from a study completed in 2004/2005. Further OCS testimony indicates
351 that the ratio of actual costs to the original Black & Veatch estimate was closer to 28
352 percent, however, how that value was applied for gas-fired combined cycle plants
353 cannot be determined. In any event the derivation of the \$8 per kilowatt was not
354 evident based on the testimony provided.

355 **Q. Is the \$8 per kW value supportable?**

356 A. No. Applying a historical ratio of an actual cost of a single demolition to an
357 individual engineering estimate and then applying that factor is not a valid basis for
358 providing a cost estimate.

359 Subsequent to the Black and Veatch study, URS Corporation was
360 commissioned by Nevada Power Company (“NPC”) to perform an updated
361 demolition estimate. In this proceeding, the NPC approved costs, based on URS-
362 Cleveland Wrecking Company estimates, for the demolition for the two Sunrise gas-
363 fired units was \$5.13 million. The actual cost, net of salvage, was \$3.5 million.
364 Therefore, a more reasonable adjustment factor would be 68 percent, not 28 percent.

365 As part of the same docket, the Nevada Public Utilities Commission (“PSC”)
366 approved decommissioning costs for NPC’s large combined cycle plants. These
367 included a number of large combined cycle plants which are similar in size and
368 configuration to those in the Company’s fleet, the estimated costs ranged from \$9 to
369 \$22.1 per kilowatt with a weighted average cost of \$15.1 per kilowatt, on a 2013
370 dollar basis.

371 To date no demolition projects have actually been performed for the type and
372 size of combined cycle facility considered as part of this proceeding.

373 **Q. What is your recommendation with regard to the demolition cost for gas-fired**
374 **combined cycle plants?**

375 A. I recommend a demolition cost of \$20 per kilowatt be applied.

376 **Terminal net salvage of wind generation**

377 **Q. What does OCS recommend regarding the decommissioning costs for wind**
378 **generation?**

379 A. OCS recommends reducing the previously stipulated decommissioning cost from \$9
380 per kilowatt to \$5 per kilowatt.

381 **Q. What is the basis for OCS' recommendation?**

382 A. OCS does not provide any data to support the recommendation. OCS states they have
383 demolition costs are "conservatively estimated \$5 per kW."

384 **Q. Is the OCS' proposed decommissioning cost low?**

385 A. Yes. OCS fails to recognize that the Company's estimate of \$9 per kilowatt is to
386 decommission an *entire wind project*.

387 **Q. What is the decommissioning scope associated with a wind project?**

388 A. The scope to decommission a wind project includes removal of: the wind tower; the
389 wind turbine blades; the wind turbine generator major components (i.e., hub, gearbox,
390 generator); the nacelle and all its contents; the contents at the base of the wind tower;
391 removing all or a portion of the wind turbine generator foundations; removing access
392 roads; removing wind turbine generator transformers and pads; removing overhead
393 collector lines; removing underground collector lines that cannot be abandoned;
394 removing operation and maintenance facilities; removing the collector substation
395 (including the step-up transformer(s) breakers, metering, buss work, foundations and
396 grounding matt); removing meteorological towers; and removing the project-specific
397 transmission lines. In addition, decommissioning a wind project typically requires
398 that the site be reclaimed by re-grading and re-seeding the disturbed areas.
399 Decommissioning a wind project cannot proceed until the necessary regulatory

400 approvals and permits are received. The Company's cost estimate of \$9.00 per
401 kilowatt includes all of the above plus the cost to manage the project.

402 **Q. OCS also suggests a decommissioning cost, net of salvage, of zero may be**
403 **appropriate. Has the Company performed an analysis of decommissioning costs**
404 **based on the specific volume of salvageable materials present at a wind project?**

405 A. Yes. The Company utilized a decommissioning cost model provided by the Oregon
406 Energy Facility Siting Council ("OR EFSC") to calculate the net decommissioning
407 cost of the Leaning Juniper I wind project for the purpose of determining the amount
408 of a decommissioning bond required by the Leaning Juniper I permit. The OR EFSC
409 model relies on the specific volume of materials, including salvageable materials,
410 present at a wind project.

411 **Q. What was the net decommissioning cost for the Leaning Juniper I wind project**
412 **based on the OR EFSC model?**

413 A. The cost was \$2,443,624 for the entire 100.5 megawatt wind project or \$24.13 per
414 kilowatt. The Company's estimate of \$9.00 per kilowatt is significantly lower.

415 **Q. What is your recommendation with respect to OCS wind project**
416 **decommissioning cost?**

417 A. OCS offers no evidence to contradict the Company's decommissioning cost estimate
418 of \$9.00 per kilowatt to decommission an *entire wind project*. Indeed, the OR EFSC
419 model, which relies on the specific volume of materials present at a wind project,
420 indicates that the Company's estimate of \$9.00 per kilowatt may be too low.

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

422 A. Yes.