

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

3 A. My name is Darrell T. Gerrard. My business address is 825 N.E. Multnomah,
4 Suite 1600, Portland, Oregon. I am Vice President of Transmission System
5 Planning for PacifiCorp.

6 **Qualifications**

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

8 A. I have a Bachelor of Science degree in Electrical Engineering (Power Systems
9 Major) at the University of Utah and Certificate of Completion with Honors in
10 Electrical Technology from Utah Technical College at Salt Lake. My experience
11 spans more than 30 years in the electric utility business and electric power
12 industry in general. I have working experience and have had management
13 responsibility for a number of functional organizations at PacifiCorp including:
14 Area Engineering, Area Planning, Region Engineering, T&D Facilities
15 Management, Transmission, Substation and Distribution Engineering, System
16 Protection and Control, T&D Project Management and Delivery, Asset
17 Management, Electronic Communications, Hydro System Engineering,
18 Transmission Grid Operations, and most recently Transmission System Planning.

19 **Q. What are your responsibilities as Vice President of Transmission System**
20 **Planning?**

21 A. I am responsible for transmission planning activities required to support
22 PacifiCorp's existing and future bulk transmission system and to ensure a safe and
23 reliable transmission system provides adequate service to our customers

24 economically. I am also responsible for the conceptual and detailed system
25 planning and architecture associated with the Company's long-term Energy
26 Gateway transmission expansion strategy ("Energy Gateway").

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

28 A. The purpose of my testimony is to provide additional details and technical
29 information on the Company's decision to build the double-circuit 345kv Populus
30 to Terminal transmission line (constructed in two sections), which is part of
31 Segment B of the Energy Gateway Project (see Exhibit RMP____(JAC-1)).

32 **Overview of Transmission Project**

33 **Q. Please describe the scale and size of the Populus to Terminal transmission**
34 **segment.**

35 A. Populus to Terminal will add approximately 135 miles of new transmission line,
36 over 8,600,000 linear feet of conductor and approximately 900 poles will be
37 installed on new foundations. The Populus to Ben Lomond section specifically, is
38 approximately 90 miles and includes approximately 5,200,000 linear feet of
39 conductor and nearly 650 poles. This section of 345 kilovolt double-circuit
40 transmission line connects the new Populus substation, in Downey Idaho to the
41 existing Ben Lomond substation in Box Elder County, Utah. The first section of
42 the Populus to Terminal segment from Ben Lomond to Terminal was placed in-
43 service in March 2010. The remaining section included in this rate case, the
44 Populus to Ben Lomond section, is anticipated to be completed in November
45 2010. Exhibit RMP____(DTG-1) contains photos of assets in place for Ben
46 Lomond to Terminal and Populus to Ben Lomond sections of the transmission

47 line.

48 **Q. Please describe the transmission investment included in this rate case.**

49 A. In this Docket, the Company is seeking cost recovery for the Populus to Ben
50 Lomond section of the Populus to Terminal transmission segment B of Energy
51 Gateway, described in more detail in the direct testimony of Mr. John A.
52 Cupparo. A map showing the entire route of the Populus to Terminal segment is
53 shown in Exhibit RMP____(JAC-2). This remaining section between Populus and
54 Ben Lomond is critical to completion of the overall Populus to Terminal
55 transmission segment and is the remaining section to be constructed and placed in
56 service. The existing Ben Lomond Substation will be expanded to accommodate
57 the new 345 kV transmission lines and termination points. The Company expects
58 the total investment in the Populus to Ben Lomond section to be \$548 million,
59 based on project costs estimates detailed in Exhibit RMP____(DTG-2) and expects
60 the line to be fully in-service by November 2010, and used and useful to
61 customers at that time.

62 **Q. What is the purpose of the Populus to Terminal transmission segment?**

63 A. In addition to the project benefits described in the testimony of Mr. Cupparo, the
64 purpose of the Populus to Terminal line project is to:

- 65 • Increase the overall transmission capacity in the existing transmission
66 system between Southeast Idaho and Northern Utah where the existing
67 system has limited capacity and has demonstrated operational limitations;
- 68 • Meet the immediate need to improve system reliability in the area by
69 installing transmission capacity to ensure the system can sustain

70 transmission outages north of Ben Lomond and Terminal Substations
71 without curtailing loads, generation or impacting the PacifiCorp's East
72 Control Area and neighboring transmission balancing authority areas.

73 • Improve the Company's ability to perform maintenance on transmission
74 facilities between Populus and Terminal by having alternative
75 transmission paths that allow facilities to be taken off-line and maintained;

76 • Integrate with future Energy Gateway segments to increase transfer
77 capability between PacifiCorp's east and west control areas in order to
78 balance generating resources and loads, enable commercial energy
79 purchases or sales while allowing integration of new renewable generation
80 resources;

81 • Provide PacifiCorp with options and greater flexibility when considering
82 future planned resources to meet customers' growing demands for energy
83 service requirements while meeting current and future energy
84 requirements that may be mandated by state and federal regulation;

85 • Facilitate the integration of potential new energy resources in Wyoming,
86 Utah and Idaho, and help support economic development planned in those
87 states; and

88 • In the long-term, provide an incremental increase in transmission capacity
89 and reliability benefits for future Energy Gateway transmission segments
90 planned between Wyoming, Idaho, Utah, Oregon and Washington, and
91 interconnecting the region in general.

92 **Need for and Benefit of Additional Transmission**

93 **Q. What information has been used in determining the need and justification**
94 **for this investment?**

95 A. PacifiCorp's Open Access Transmission Tariff ("OATT"), approved by the
96 Federal Energy Regulatory Commission ("FERC"), describes PacifiCorp's
97 requirements and obligations to provide transmission service. Section 28.2 defines
98 PacifiCorp's responsibilities, which include the requirement to "plan, construct,
99 operate and maintain the system in accordance with good utility practice." Section
100 31.6 defines the requirement for network customers to supply annual load and
101 resource updates for inclusion in planning studies. The Company solicits this data
102 annually in order to determine future load and resource requirements for all
103 transmission network customers including PacifiCorp's network customers and
104 customers of third parties under our FERC-approved OATT. The Company's
105 retail loads comprise the bulk of the transmission network customer needs
106 including those in Utah. Section 28.3 includes the requirement for PacifiCorp to
107 provide "firm service over the system so that designated resources can be
108 delivered to designated loads." These future requirements and needs will be met
109 via Energy Gateway and its segments, including Populus to Terminal. Populus to
110 Ben Lomond is the remaining section of that segment, all of which is an important
111 part of PacifiCorp's overall transmission plan for Utah and the region.

112 **Q. Are other transmission performance requirements besides growing customer**
113 **energy demand driving the need for this system investment?**

114 A. Yes. In meeting the current and future customer energy needs described above,
115 the Company must maintain a level of system reliability in order to provide
116 adequate transmission service. The North American Electric Reliability
117 Corporation (“NERC”) and the Western Electricity Coordinating Council
118 (“WECC”) have recently adopted and enacted a significant number of standards
119 and guidelines that specify in detail the levels of system performance that entities
120 like PacifiCorp must maintain during the planning, operation and ongoing
121 maintenance of their bulk electric system. NERC’s reliability standards have been
122 approved by FERC and are mandatory for all FERC-jurisdictional entities. These
123 reliability standards are targeted at improving the security and reliability of the
124 nation’s electric infrastructure and, specifically in our case, in the WECC region.
125 Investments being made via this transmission project will help PacifiCorp meet
126 reliability requirements. Further, the investment will provide reliability benefits to
127 future planned high-voltage transmission additions interconnecting Wyoming,
128 Utah and Idaho and the region.

129 **Q. Are there examples where these new reliability standards and guidelines**
130 **have resulted in changes to the system and its operation? If so, how is that**
131 **change driving investments required in transmission?**

132 A. Yes. In early 2008, PacifiCorp performed an operational analysis of the
133 transmission system north of Ben Lomond substation. As a result of this analysis
134 and reflective of NERC and WECC reliability standards and guidelines, the

135 system firm transmission capacity was reduced from approximately 775MW to
136 430MW during heavy load hours and reduced from approximately 900MW to
137 620MW during light load hours. This reduction in firm capacity was a result of
138 NERC and WECC standards and guidelines that require transmission capacity to
139 be reduced due outage risks and system impacts associated with outages of
140 multiple transmission lines located adjacent to each other in common corridors.
141 The investment in the Populus to Terminal segment is required to improve the
142 firm capacity in this part of the transmission system.

143 **Q. How did the Company determine that additional transmission capacity was**
144 **needed?**

145 A. The Company utilizes its Integrated Resource Plan (“IRP”) to review whether
146 additional transmission capacity is needed. The IRP uses a public process to
147 develop a framework for the prudent future actions required to ensure the
148 Company continues to provide reliable and least-cost electric service to its
149 customers, while striking an expected balance between cost and risk over the
150 planning horizon and taking into consideration environmental issues and the
151 energy policies of our states. As stated in the 2008 IRP, “PacifiCorp’s IRP
152 mandate is to assure, on a long-term basis, adequate and reliable electricity supply
153 at a reasonable cost and in a manner consistent with the long-run public interest.”

154 **Q. Did the Company make any commitments to add transmission capacity?**

155 A. Yes. During the MidAmerican Energy Holdings Company (“MEHC”) acquisition
156 of PacifiCorp in 2006, the Company committed to increase the transmission
157 capacity by 300 MW from southeast Idaho to northern Utah. The objectives of the

158 transaction commitment were to:

- 159 • Enhance the reliability of the only high use commercial path between
160 Idaho and Utah;
- 161 • Provide for increased transfer capability between PacifiCorp's east and
162 west control areas; and
- 163 • Facilitate the delivery of future power from wind projects in Wyoming
164 and Idaho, and provide PacifiCorp with greater flexibility and the
165 opportunity to consider additional options regarding future planned
166 generation capacity additions.

167 **Q. Describe how the Populus to Terminal transmission segment complies with**
168 **the IRP and MEHC commitment.**

169 A. The Populus to Terminal transmission line segment is designed to meet load
170 growth, future customer energy service requirements and improve overall system
171 reliability. Based on the Company's 2008 IRP, as amended by the 2008 IRP
172 update, forecasts, PacifiCorp's network load obligation is expected to grow during
173 the next 10 to 20 years. In addition, system operational reserve obligations
174 required to balance and maintain system reliability will increase over time as they
175 are a function of load served. The existing transmission capacity from
176 southeastern Idaho into Utah is fully subscribed and no additional capacity can be
177 made available without the addition of new transmission lines. The Populus to
178 Terminal line will add significant new incremental transmission capacity (1,400
179 MW planned) to this area of the system and will help integrate other future
180 planned resources, market purchases and sales as necessary to help control energy

181 costs. The investment also improves the system reliability as needed, which I
182 discuss later in my testimony. All of the above support PacifiCorp's IRP and the
183 commitments made by MEHC.

184 **Q. Has the Company performed other studies and analyses that demonstrate the**
185 **need to improve the reliability of the transmission system in this area?**

186 A. Yes, in addition to the long-term energy resource needs identified in PacifiCorp's
187 IRP mentioned above, the Company performed specific analysis in late 2007 and
188 2008 addressing several system disturbance events that severely impacted
189 generation, customers, and the operation of the transmission system affecting
190 Wyoming, Utah and Idaho. These events also impacted other utilities
191 interconnected to PacifiCorp's transmission system. It is evident from these
192 disturbances and the resulting analysis that the transmission system in this area
193 does not have the necessary capacity and reliability to meet all of the system
194 operating conditions expected. NERC electric system reliability standards require
195 that the system demonstrate adequate performance for all expected operating
196 conditions expected including multiple contingencies. There have been five
197 system disturbances since September 2007 for which the Populus to Terminal line
198 directly mitigates the risk of reoccurrence. Three of these disturbances occurred
199 on the system north of Ben Lomond substation and two occurred south in the Ben
200 Lomond to Terminal section. These disturbances resulted in system overloads,
201 curtailments of schedules, repeated curtailments of interruptible loads and
202 generation reductions in Wyoming, Utah and other surrounding states. The three
203 disturbances occurred on September 27, October 15 and October 21, 2007, during

204 periods of heavy flow northbound from the Terminal Substation towards Ben
205 Lomond and into Idaho. As a result, over 1,450 customers were affected by the
206 first outage, and Nucor and Monsanto loads were either interrupted and/or
207 reduced during all three outages. Generation curtailments and adjustments of
208 more than 1,000 MW had to be requested for all three incidents including reduced
209 generation from Dave Johnston and Naughton plants in Wyoming. Details and
210 analysis of the system performance during the events and transmission limitations
211 are detailed in PacifiCorp System Disturbance Report dated November 11, 2007,
212 and PacifiCorp's Abbreviated System Disturbance Report to WECC dated
213 January 28, 2008.

214 On November 27 and November 30, 2007, two disturbances occurred on
215 the Ben Lomond to Terminal section (refer to Exhibit RMP__JAC-2) of the
216 system, causing overloads on three WECC designated and monitored transmission
217 paths. The disturbances impacted more than 400 MW of PacifiCorp generation
218 along with generation interconnected to three other utilities in surrounding states.

219 Based on the system performance, studies and analysis it is clear that the
220 existing system requires new capacity to meet expected operating conditions and
221 reliability requirements on both a short and long-term basis. The investment in the
222 Populus to Ben Lomond project is a critical remaining step in providing the
223 needed capacity.

224 **Q. What is the transmission capacity and limitations on this system today?**

225 A. The existing transmission capacity in the area between Salt Lake City and
226 Southeast Idaho is fully subscribed for firm service and has limited transfer

227 capability between several key transmission substations (Terminal, Ben Lomond,
228 and new Populus) connecting generation facilities in Idaho, Wyoming and Utah.
229 No new capacity will be available until new transmission facilities are
230 constructed.

231 **Q. Does the investment in the Populus to Ben Lomond Project provide**
232 **reliability and capacity benefits to future planned transmission additions in**
233 **the area?**

234 A. Yes. Without investment in the Populus to Ben Lomond, the full transfer
235 capability on both of the Gateway West and Gateway South Segments would not
236 be possible. To obtain the full capacity of the Gateway West and Gateway South
237 segments, both segments must be electrically interconnected. This interconnection
238 is achieved by building the Populus to Terminal transmission line as part of
239 Gateway Central.

240 **Q. What alternatives to the Populus to Terminal project did PacifiCorp**
241 **consider?**

242 A. The Company considered, but rejected four alternatives. The first alternative was
243 to not build the line or to upgrade other existing paths or seek additional
244 transmission corridors into Utah. The Company rejected this alternative because it
245 did not improve existing system reliability, did not provide any new incremental
246 transmission capacity required and precluded the ability of new resources to be
247 delivered into Utah from Wyoming, Idaho, or the Northwest in general. New
248 incremental transmission capacity is needed for both load service and for
249 contingencies.

250 The second alternative considered was to rebuild the majority of the
251 existing 138 kV lines interconnecting Utah and Southeast Idaho and continue
252 operation of these lines at 138 kV. This alternative would have provided only a
253 small incremental increase of 300 MWs or less in transmission capacity across the
254 currently constrained path between Southeast Idaho and Utah. It also would not
255 have provided adequate interconnection capacity between the future Energy
256 Gateway West and Energy Gateway South segments or offer any additional
257 capacity for the future. In addition to the marginal increase in transmission
258 capacity, this alternative had serious constructability issues as it required large
259 segments of the path to be completely removed from service for extended periods,
260 a year or more, as these existing 138 kV facilities were rebuilt. This would have
261 placed significant reliability exposure on the transmission system serving the area
262 to Rocky Mountain Power customers during construction. This alternative did not
263 allow the Company to meet its current firm transmission obligations nor did it
264 meet the long-range resource plans and network load service requirements.

265 The third option considered was to construct a new single circuit 345 kV
266 transmission line from the future Populus Substation near Downey, Idaho to the
267 Ben Lomond Substation in Utah, which would have provided some capacity
268 increase from Idaho to Ben Lomond. The alternative included an upgrade of the
269 existing 138 kV line between Ben Lomond and Terminal required to realize a
270 minimum increase in capacity of 300 MW from Ben Lomond to Terminal
271 substation. However, this alternative would not have provided the necessary
272 future system capacity between Energy Gateway West and Energy Gateway

273 South and would have failed to take advantage of maximizing transmission
274 capacity installed in the new corridor between Populus and Ben Lomond and our
275 existing corridor between Ben Lomond to Terminal transmission corridor.

276 The fourth option considered was to build a new 500 kV line along the
277 route. The Company rejected this option because of its high cost, its potential for
278 significant siting and community impacts, its requirement for a completely new
279 corridor between Populus and Terminal stations, and its failure to use existing
280 vacant corridors and property rights that the Company previously obtained.

281 **Q. Please explain any further considerations that the Company made in**
282 **selecting the Populus to Terminal line.**

283 A. The Company selected this transmission line project based on several factors:

- 284 • It meets short-term and immediate reliability needs while prudently
285 planning for the future by adding significant long-term incremental
286 transmission capacity (planned rating 1,400 MWs) across the currently
287 constrained transmission system. There have been several transmission
288 outages since 2007 along this corridor that could have been mitigated with
289 additional transmission facilities. The risk of further unplanned
290 disturbances is too great if the current facilities are not improved.
- 291 • It allows additional imports into Utah of up to 1,400 MWs of forecast
292 resource capacity from Wyoming and Southern Idaho. This new capacity
293 is required based on long-term planning results.
- 294 • Construction benefits occur on a significant portion of the transmission
295 project due to existing corridors that were acquired by Utah Power many

296 years ago just for this purpose. The project optimizes use of limited and
297 scarce transmission corridor lands by maximizing installed transmission
298 capacity in new corridors.

299 • Construction could occur with minimum planned outages on existing
300 facilities remaining in service without increasing reliability exposure to
301 the current system.

302 • The Company's ability to perform required maintenance will be improved
303 without significant operational risk associated with taking existing lines
304 out of service.

305 **Bid Process**

306 **Q. Please describe the Company's typical procurement process used for major**
307 **transmission projects.**

308 A. The Company uses a competitive blind-sealed bid process to contract for the
309 development of each project unless certain defined conditions apply, such as a
310 restriction in the supply of technology or design solutions that prevent an open
311 competitive process. The form of contract tendered is a turnkey, fixed price, date
312 certain basis for delivery referred to as an engineer, procure and construct
313 approach. The Company identifies potential bidders that provide the capabilities
314 required to deliver the work scope within a boundary of project specific technical
315 specifications and commercial terms. The tender process includes a question and
316 answer period to clarify any outstanding issues and provides anonymity to the
317 requesting bidder and responses of a non-confidential nature are provided to all
318 bidders. Upon receipt of tender documents, the technical proposals are separated

319 from commercial proposals and a separate technical and commercial evaluation is
320 performed on all qualified bids using pre-established evaluation criteria (see
321 Exhibit RMP___(DTG-3) summary of bidder evaluation). The technical
322 evaluation is assisted by external consulting firms who have been pre-contracted
323 for such work based on their industry experience. Upon completion of technical
324 and commercial evaluations a recommendation is made to enter post-tender
325 negotiations to reach final terms, conditions and pricing to support contract
326 execution.

327 **Q. Was this typical procurement process applied to Populus to Terminal?**

328 A. Yes. Specifically for the project, the Company adopted an open competitive
329 tendering rather than a restrictive competitive tendering process where 75 vendors
330 were identified and received an invitation to bid. The competitive tendering
331 process began in October 2007 and provided two separate blind-sealed bidding
332 opportunities. During the October 2007 to May 2008 bidding period, four
333 communications were provided to bidders containing additional project-specific
334 information to assist bidders to refine their submissions specifically to remove
335 any bid qualifications associated with contingent and non-firm pricing. All bid
336 responses were due for submittal in May 2008 and again in July 2008 after
337 additional information was provided to bidders during May 2008 to July 2008
338 allowing a further refinement of previously submitted design solutions, terms and
339 conditions, including price. Three qualified bids were received and evaluated
340 resulting from the May 2008 proposal submissions. Two competing proposals
341 were received in July 2008. During the separate technical and commercial

342 evaluations, the Company and its consultants identified non-fixed price aspects of
343 the bidder's proposals affecting cost and schedule. The Company consultant
344 computed a cost associated with non-fixed price work scope submitted by each
345 bidder, which was estimated to range from approximately \$103 million to \$429
346 million. The Company engaged in negotiations to remove or cap the cost of non-
347 fixed priced work to mitigate post-contract award price escalation and schedule
348 change. The Company awarded the contract in October 2008 for \$584.6 million
349 after post-tender negotiation that reduced the contractor's price.

350 **Q. What process, if any, did the Company use to identify and implement cost**
351 **savings opportunities during the procurement process?**

352 A. During the tender evaluation process, bidders were requested to submit cost
353 savings opportunities for consideration. Each item was reviewed to assess savings
354 with respect to potential impact to operability, reliability and maintainability that
355 were included in the final contract price. In addition, post tender negotiation
356 included a reduction of \$25 million in consideration of commodity price
357 reductions, which occurred in the global market during the tender evaluation
358 period.

359 **Q. Specific to the Populus to Ben Lomond section, have there been any changes-**
360 **in-work identified as part of the overall estimated project costs?**

361 A. Yes. As shown in Exhibit RMP_(DTG-2), of the estimated total project cost of
362 \$548 million, approximately \$9 million is associated with Company approved
363 changes-in-work. Nearly half of the \$9 million total amount, or approximately
364 \$4.2 million, is associated with the Le Grande reroute which required agreement

365 on routing a portion of the line around a commercial gravel pit operation. It was
366 not possible to establish the exact line route in this case, prior to bidding and
367 award of the EPC contract. The majority of remaining costs associated with
368 changes-in-work were primarily due to subsurface geological conditions that
369 impacted line structure foundations and line location. The Company anticipated
370 the issues stated above and planned for them during EPC contract development
371 and award. The company controlled the cost risk of reroutes and subsurface
372 geology impacts through pricing mechanisms and work approval processes agreed
373 to as part of the EPC contract. Additionally several commodity price reduction
374 credits that benefited the project were applied as part of the total changes-in-work.

375 **Q. What is the current status of construction for the Populus to Ben Lomond**
376 **section of line?**

377 A. With regard to the transmission line section, all 646 foundations have been
378 installed along with 625 poles. Access road and right-of-way restoration is being
379 performed along the line route. Conductor has been installed to a point just south
380 of the Populus substation. Work continues on the Populus substation with final
381 cabling, terminations, security installation, grounding and landscaping efforts
382 ongoing. Main construction is scheduled to be complete by this summer cutover
383 of the new lines will occur during the fall.

384 **Q. Please state why you believe the project will be completed and in service by**
385 **November 16, 2010.**

386 A. The transmission line construction is more than 90% complete and the Substation
387 Construction is more than 80% complete at this time. Weekly project

388 management status reports and field verification confirm construction is on
389 schedule and will be completed by November 16, 2010 barring unforeseen events
390 at this point.

391 **Conclusion**

392 **Q. Please summarize your testimony.**

393 A. The existing transmission system capacity from southeastern Idaho into Utah is
394 fully subscribed and utilized, significant operational limitations exist on the
395 system in this area due to limited transmission capacity, and no additional
396 capacity can be made available without the addition of new transmission facilities.
397 The investment in Populus to Ben Lomond transmission facilities is prudent as it
398 meets short-term reliability requirements and meets longer term customer needs
399 by adding significant incremental transmission capacity between Southeast Idaho
400 and Northern Utah

401 Further the investment facilitates a stronger interconnection to systems in
402 Idaho, Utah, and Wyoming and to the Northwest in general. The Populus to Ben
403 Lomond transmission project, especially when integrated with the other proposed
404 Energy Gateway Segments, is fundamental to the development of new renewable
405 and other generation sources in Utah, Idaho and Wyoming. The completion of the
406 project will be an important step in strengthening the Western Interconnection's
407 transmission infrastructure, which is necessary based upon the projected future
408 energy service requirements of our customers including those in Utah.

409 The project was bid out through a competitive bid process followed by
410 negotiations with the best bidders that resulted in a total contract price of \$584.6

411 million. The project construction is significantly complete at this time and it is on
412 schedule to be in service by November 16, 2010.

413 **Q. Does this conclude your testimony?**

414 A. Yes.