

Exh. EL-3
Docket UE-19 ____
Witness: Etta Lockey

**BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION**

WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION,

Complainant,

v.

PACIFICORP dba
PACIFIC POWER & LIGHT COMPANY

Respondent.

Docket UE-19 ____

PACIFICORP

EXHIBIT OF ETTA LOCKEY

2020 PacifiCorp Inter-Jurisdictional Allocation Protocol

December 2019

2020 PacifiCorp Inter-Jurisdictional Allocation Protocol

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1. Introduction

This 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol Agreement (the “2020 Protocol” or this “Agreement”) reflects the agreement among PacifiCorp (or the “Company”), certain Commission¹ staff members, State regulatory agencies, customers, consumer advocates, conservation organizations, and other interested parties from California, Idaho, Oregon, Utah, Washington, and Wyoming (collectively referred to as the “States” or individually as a “State”) who have executed this Agreement (collectively referred to as the “Parties” or individually as a “Party”) on an interim allocation and assignment method and a process for determining a long-term replacement of existing inter-jurisdictional allocation and assignment methodologies.² The 2020 Protocol is intended to: (1) supersede the 2017 PacifiCorp Inter-Jurisdictional Allocation Protocol (the “2017 Protocol”) for California, Idaho, Oregon, Utah, and Wyoming; and (2) modify the West Control Area Inter-jurisdictional Allocation Methodology (“WCA”) for Washington. However, as part of the 2020 Protocol, the 2017 Protocol and the WCA allocation methodologies will continue to be used, with modifications explained herein, during an Interim Period, as defined below. Subject to the provisions set forth below, and with the acknowledgment that only the appropriate state body charged with issuing orders to establish rates can approve its use, the Parties agree that the 2020 Protocol can be used to set just and reasonable rates and agree to support its use in rate filings in California, Idaho, Oregon, Utah, Washington, and Wyoming during the Interim Period. The 2020 Protocol includes:

- The allocation and assignment policies, procedures, and methods to be used during the Interim Period (i.e., January 1, 2020 through December 31, 2023, as specified

¹ Capitalized terms in the 2020 Protocol are defined herein, in Appendix A, or in Appendix C.

² For purposes of this Agreement, use of the terms assign, assignment, and assigned generally refer to the generation, capacity, benefits, and risks associated with certain assets and use of the terms allocate, allocated, allocation generally refer to the treatment of costs associated with certain assets.

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22 in Section 2). The 2020 Protocol describes the way all components of PacifiCorp's
23 regulated service, including costs, revenues, and benefits associated with
24 generation, transmission, distribution, and wholesale transactions, should be
25 allocated and assigned among the six States during the Interim Period. During the
26 Interim Period, these inter-jurisdictional allocation policies, procedures, or
27 methods, if applied by each State as stated herein for rate proceedings filed during
28 the Interim Period, can provide PacifiCorp a reasonable opportunity to recover its
29 prudently incurred cost of service.

- 30 • An agreement on certain issues that are intended to be implemented during the
31 Interim Period and, assuming final resolution of all outstanding issues, incorporated
32 into a Post-Interim Period Method agreement ("Implemented Issues").
- 33 • A conditional agreement on certain issues intended to be implemented following
34 the Interim Period, subject to final resolution of all outstanding issues ("Resolved
35 Issues").
- 36 • A process and timeframe to address and attempt to resolve all outstanding issues
37 that the Parties intend to resolve after this 2020 Protocol has been filed with the
38 Commissions and during the Interim Period ("Framework"), including the
39 implementation or resolution of issues associated with a Nodal Pricing Model,
40 Resource planning and new Resource Assignment, Limited Realignment, Special
41 Contracts, post-Interim Period capital additions on coal-fueled Interim Period
42 Resources and other items ("Framework Issues"). The future resolution of
43 Framework Issues, combined with the Implemented Issues and the Resolved Issues,
44 would result in a new allocation methodology for PacifiCorp's six States ("Post-

45 Interim Period Method").

46 The proposed allocation of a particular expense or investment to a State under the 2020
47 Protocol is not intended to and will not prejudice the prudence of that cost or the extent to which
48 any particular cost may be reflected in rates. Nothing in the 2020 Protocol is intended to abrogate
49 any Commission's right or obligation to: (1) determine fair, just, and reasonable rates based upon
50 applicable laws and the record established in rate proceedings conducted by that Commission; (2)
51 consider the effect of changes in laws, regulations, or circumstances on inter-jurisdictional
52 allocation policies and procedures when determining fair, just, and reasonable rates; or (3) establish
53 different allocation policies and procedures for purposes of allocating costs and revenues within
54 that State to different customers or customer classes.

55 Parties support the 2020 Protocol, but their support will not, in any manner, affect or negate
56 their right to address changed or unforeseen circumstances, including changes in laws or
57 regulations. A Party's support of the 2020 Protocol will not bind or be used against that Party if a
58 Party concludes that the 2020 Protocol no longer produces results that are just, reasonable, or in
59 the public interest, or does not provide the Company with a reasonable opportunity to recover its
60 prudently incurred cost of service; provided, however, that in raising an objection to the 2020
61 Protocol the Parties agree to first raise any such objection by following the provisions of Section
62 8.4.

63 Support of the 2020 Protocol does not constitute an acknowledgment by any Party of the
64 validity or invalidity of any particular method, theory, or principle of regulation, cost recovery,
65 cost of service, or rate design. No Party will be deemed to have agreed that any particular method,
66 theory, or principle of regulation, Resource acquisition or Reassignment, cost recovery, cost of
67 service, or rate design employed in or implied by the 2020 Protocol is appropriate for resolving

68 any issues other than the inter-jurisdictional allocation of PacifiCorp's cost of service. The Parties
69 have made no effort to address or consider intra-state cost allocation issues and agree that using
70 the 2020 Protocol for inter-jurisdictional cost allocation purposes does not suggest or require
71 similar treatment be applied to intra-state cost allocations for class cost-of-service purposes for
72 any State. Parties may propose such methods of intra-state class cost-of-service allocations as they
73 deem appropriate.

74 The 2020 Protocol includes the following appendices described briefly below:

- 75 • Terms that are capitalized in the 2020 Protocol are defined herein, in Appendix A,
76 or in Appendix C.
- 77 • Appendix B includes tables identifying the allocation factor to be applied to each
78 component of PacifiCorp's revenue requirement calculation.
- 79 • Appendix C includes the definition and algebraic derivation of each allocation
80 factor, along with the FERC accounts to which the allocation factor will be applied.
- 81 • Appendix D is a Memorandum of Understanding among the Parties supporting the
82 Company's acquisition and implementation of a Nodal Pricing Model.
- 83 • Appendix E includes a table reflecting Commission-approved depreciable lives in
84 effect October 1, 2019, and the Company's proposed depreciable lives for coal-
85 fueled Interim Period Resources in pending depreciation dockets as filed in
86 September 2018.
- 87 • Appendix F is the Washington Inter-Jurisdictional Allocation Methodology
88 Memorandum of Understanding between the Company and the Washington Parties,
89 which modifies the WCA.

- 90 • Appendix G includes a description and numeric example of how Special Contracts
91 and related issues will be treated during the Interim Period.

92 **2. Timeframes and Effective Periods**

93 **2.1. Effective Period of the 2020 Protocol**

94 For the Interim Period, January 1, 2020 through December 31, 2023, subject to Section
95 2.2.4, the Parties agree to support before their respective Commissions the use of the 2020 Protocol
96 in PacifiCorp regulatory proceedings or filings, subject to exceptions for deferred amounts
97 including, but not limited to, Net Power Costs as set forth in this Agreement. The 2020 Protocol
98 includes an agreed-upon approach for cost allocations to each State that will be used by PacifiCorp
99 in proceedings or filings commenced during the Interim Period, except as provided in Section
100 2.2.5.

101 **2.2. Post-Interim Period**

102 **2.2.1. Commission Approvals for Post-Interim Period Method Obtained** 103 **Prior to December 31, 2023**

104 If each State’s Commission approves a Post-Interim Period Method agreement on or before
105 December 31, 2023, or in the first general rate case after the Post-Interim Period Method agreement
106 is reached,³ the Interim Period will terminate on December 31, 2023, and the Post-Interim Period
107 Method will take effect, subject to Section 2.2.2.

108 **2.2.2. Commission Approval Not Granted**

109 If any Commission denies PacifiCorp’s request for approval of the Post-Interim Period
110 Method agreement, PacifiCorp will propose an alternative allocation method for the Post-Interim
111 Period for consideration by all the Commissions. Parties are free to take any position regarding

³ The Parties understand the California and Washington Commissions will likely consider the Post-Interim Period Method in the first general rate case filed in either State after an agreement has been reached on the Post-Interim Period Method, and approval may occur after December 31, 2023.

112 PacifiCorp's proposal, including proposing alternative allocation methodologies, filing a
113 complaint, or requesting an investigation of PacifiCorp's proposal.

114 **2.2.3. Post-Interim Period Method Agreement Not Reached**

115 If the Company determines that it is unlikely that a Post-Interim Period Method agreement
116 will be reached before the end of the Interim Period, then the Company will propose an allocation
117 method for the Post-Interim Period for consideration by the Commissions. Parties are free to take
118 any position regarding PacifiCorp's proposal, including proposing alternative allocation
119 methodologies, or initiating a complaint or investigation of PacifiCorp's proposal.

120 **2.2.4. Early Commission Approvals of Post-Interim Period Method**

121 If a Post-Interim Period Method agreement is reached on or before December 31, 2022,
122 any Post-Interim Period Method agreement will address whether and the degree to which the
123 Company will use the Post-Interim Period Method in regulatory proceedings or filings commenced
124 after December 31, 2022.

125 **2.2.5. Regulatory Filings to Implement Post-Interim Period Method**

126 Any Post-Interim Period Method agreement will address whether and the degree to which
127 the Company may use the Post-Interim Period Method in regulatory proceedings or filings
128 commenced during the Interim Period while Commission approvals of the Post-Interim Period
129 Method agreement are pending but to be effective after the end of the Interim Period.

130 **3. Interim Period Allocation Method**

131 The 2017 Protocol expires December 31, 2019.⁴ The Parties representing interests in the
132 States of California, Idaho, Oregon, Utah, and Wyoming (collectively referred to as the "Five State
133 Parties" and the "Five States") agree that the methodology outlined in the 2017 Protocol being

⁴ As proposed in PacifiCorp's 2019 California general rate case filing, the 2017 Protocol does not expire in California on December 31, 2019.

134 used by the Company in 2019 should continue, as outlined and modified in Section 3, during the
135 Interim Period while the Parties continue to negotiate the Framework Issues necessary to develop
136 the Post-Interim Period Method. The Washington Parties agree that the methodology outlined in
137 the WCA being used in 2019 should, subject to the terms included in Appendix F, continue during
138 the Interim Period while the Parties continue to negotiate the Framework Issues necessary to
139 develop the Post-Interim Period Method.

140 For the Five States, the terms of the 2017 Protocol that will be used during the Interim
141 Period under the 2020 Protocol are provided in Section 3.1. The 2017 Protocol terms that are
142 being modified by this Agreement are provided in Section 3.2.

143 **3.1. Continuing Terms of the 2017 Protocol for the Five States Interim** 144 **Period Allocation Methodology⁵**

145 Items included in the Company's results of operations will be allocated on the factors set
146 forth below. The FERC account and allocation factor combinations are included in Appendix B.
147 The algebraic derivation and factor definitions are included in Appendix C.

148 **3.1.1. Classification of Interim Period Resources**

149 All Fixed Costs of Interim Period Resources will be classified as 75 percent Demand-
150 Related and 25 percent Energy-Related. All Non-Firm Purchases and Sales will be classified as
151 100 percent Energy-Related.

152 **3.1.2. Allocation of Interim Period Resource Costs and Wholesale Revenues**

153 Interim Period Resources will be allocated to one of two categories for inter-jurisdictional
154 allocation purposes: State Resources or System Resources. A complete description of allocation
155 factors to be used is set forth in Appendix B.

⁵ Terminology in Section 3.1 has been modified from the language in the 2017 Protocol to maintain consistency in the use of terms within the 2020 Protocol.

156 There are three types of State Resources. The remaining types of Interim Period Resources
157 are System Resources, which constitute the substantial majority of PacifiCorp's Resources.
158 Benefits and costs associated with each category and type of Interim Period Resource will be
159 assigned or allocated to States on the following basis.

160 **3.1.2.1. Interim Period State Resources**

161 Benefits and costs associated with the three types of State Resources will be assigned or
162 allocated as follows:

- 163 • Demand-Side Management (“DSM”) Programs: Costs associated with DSM
164 Programs, including Class 1 DSM Programs, will be allocated on a situs basis to
165 the State in which the investment is made. Benefits from these programs, in the
166 form of reduced consumption and contribution to Coincident Peak, will be reflected
167 in the Load-Based Dynamic Allocation Factors.
- 168 • Portfolio Standards: The portion of costs associated with Interim Period Resources
169 acquired to comply with a State's Portfolio Standard adopted, either through
170 legislative enactment or by a State's Commission, that exceed the costs PacifiCorp
171 would have otherwise incurred, will be allocated on a situs basis to the Jurisdiction
172 adopting the Portfolio Standard.
- 173 • State-Specific Initiatives: Costs and benefits associated with Interim Period
174 Resources acquired in accordance with a State-specific initiative will be allocated
175 and assigned on a situs basis to the State adopting the initiative. State-specific
176 initiatives include, but are not limited to, the costs and benefits of incentive
177 programs, net-metering tariffs, feed-in tariffs, capacity standard programs, solar

178 subscription programs, electric vehicle programs, and the acquisition of renewable
179 energy certificates.

180 **3.1.2.2. Interim Period System Resources**

181 All Interim Period Resources that are not State Resources are System Resources and will
182 be allocated as follows:

- 183 • Generally, all Fixed Costs associated with System Resources and all costs incurred
184 under Wholesale Contracts will be allocated based upon the System Generation
185 (“SG”) Factor.
- 186 • Generally, all Variable Costs associated with System Resources will be allocated
187 based upon the System Energy (“SE”) Factor.
- 188 • Revenues received by PacifiCorp under Wholesale Contracts will be allocated
189 based upon the SG Factor.

190 **3.1.3. Re-functionalization and Allocation of Transmission Costs and** 191 **Revenues**

192 Before filing any request to approve a reclassification of facilities as transmission or
193 distribution with FERC, PacifiCorp will submit filings seeking review and authorization of any
194 such reclassification with the Commissions. The cost responsibility for any assets reclassified
195 under FERC policy will be assigned or allocated consistent with other assets in the relevant
196 function.

197 Costs associated with transmission assets, and firm wheeling expenses and revenues, will
198 be classified as 75 percent Demand-Related, 25 percent Energy-Related, and allocated based upon
199 the SG Factor. Non-firm wheeling expenses and revenues will be allocated based upon the SE
200 Factor. In the event that PacifiCorp joins a regional independent system operator, the allocation
201 of transmission costs and revenues may be reevaluated and revised as provided for in Section 8.4.

202 **3.1.4. Allocation of Distribution Costs**

203 All distribution-related expenses and investment that can be directly allocated will be
204 directly allocated to the State where they are located. Those costs that cannot be directly allocated
205 will be allocated consistent with the factors set forth in Appendix B.

206 **3.1.5. Allocation of Administrative and General Costs**

207 Administrative and General Costs, General Plant costs, and Intangible Plant costs will be
208 allocated consistent with the factors set forth in Appendix B.

209 **3.1.6. Allocation of Special Contracts**

210 Revenues associated with Special Contracts will be included in State revenues, and loads
211 of Special Contract customers will be included in Load-Based Dynamic Allocation Factors as
212 appropriate (see Appendix G). Special Contracts may or may not include Customer Ancillary
213 Service Contract attributes. Load curtailments and buy-through arrangements will be handled as
214 appropriate (see Appendix G).

215 **3.1.7 Miscellaneous Costs and Taxes**

216 Miscellaneous costs described below will be allocated as follows:

- 217 • Generation-related dispatch costs and associated plant will be allocated on the SG
218 Factor.
- 219 • Miscellaneous regulatory assets and liabilities, and miscellaneous deferred debits
220 will be allocated with the appropriate allocation factor depending on the related
221 assets or underlying costs.

222 Taxes and fees will be allocated as follows:

- 223 • Income taxes will be calculated using the federal tax rate and PacifiCorp's
224 combined State effective tax rate. State-specific Schedule M and deferred income
225 tax amounts will be allocated using the Company's tax software system. Consistent

226 with prior system allocation methods, the Washington Public Utility Tax is
227 allocated using the SO Factor in lieu of a Washington income tax.

- 228 • Franchise taxes, revenue related taxes, Commission assessments and fees, and
229 usage related taxes are situs or a pass through.
- 230 • Property taxes are system allocated based on gross plant and allocated on a Gross
231 Plant System ("GPS") Factor.
- 232 • Generation and fuel-related taxes will be allocated using the SG Factor.
- 233 • Other taxes such as payroll taxes are embedded in expenses or capital costs.

234 Balances associated with the Trojan Decommissioning will be allocated using the Trojan
235 Decommissioning ("TROJD") Factor. This will not impact State-specific treatment of this item.

236 **3.1.8. State Programs Regarding Access to Alternative Electricity Suppliers**

237 **3.1.8.1. Treatment of Oregon Direct Access Programs**

238 This Section describes treatment of loads lost to Oregon Direct Access Programs during
239 the term of the 2020 Protocol.

240 **3.1.8.1.1. Customers Electing PacifiCorp's One- and** 241 **Three-Year Oregon Direct Access Programs**

242 Customer loads electing to be served on PacifiCorp's one- and three-year Oregon Direct
243 Access Programs will be included in the Load-Based Dynamic Allocation Factors for all Interim
244 Period Resources, and the transition cost payments from these customers will be situs assigned
245 and allocated to Oregon.

246 **3.1.8.1.2. Customers Electing PacifiCorp's Five Year Opt-** 247 **Out Program Under the Oregon Direct Access** 248 **Program**

249 The treatment will be consistent with Order No. 15-060, as clarified through Order No. 15-
250 067, of the Oregon Public Utility Commission in Docket UE 267, and Oregon Schedule 296, which

251 allow Oregon Direct Access Consumers to permanently opt-out of cost-of-service rates after
252 payment of ten years of transition costs in Oregon. If an Oregon Direct Access Consumer is paying
253 transition costs during the Interim Period, the Oregon Direct Access Consumer's load(s) will be
254 included in Load-Based Dynamic Allocation Factors, and the transition cost payments from these
255 consumers will be situs-assigned to Oregon. If any Oregon Direct Access Consumer reaches the
256 end of the 10-year period covered by the transition cost payments during the Interim Period, the
257 load(s) for that Oregon Direct Access Consumer will be excluded from Load-Based Dynamic
258 Allocation Factors. Thereafter, if an Oregon Direct Access Consumer elects to return to Oregon
259 cost-of-service rates by providing four-years notice under Schedule 296, its load will be treated as
260 new load and incorporated in PacifiCorp's Resource planning process.

261 **3.1.8.1.3. New Laws or Regulations**

262 To the extent Oregon adopts new laws or regulations regarding Oregon Direct Access
263 Programs, Oregon's treatment of loads lost to Oregon Direct Access Programs may be re-
264 determined in a manner consistent with the new laws and regulations. In the event Oregon adopts
265 such new laws or regulations, the Company will inform the Commissions and the Parties of the
266 same.

267 **3.1.8.2. Utah Eligible Customer Program**

268 If, pursuant to Utah Code Annotated Section 54-3-32, an eligible customer in Utah transfers
269 service to a non-utility energy supplier, the Public Service Commission of Utah will make
270 determinations under Utah law as contemplated therein. The Company will inform the
271 Commissions and the Parties of the Public Service Commission of Utah's determinations.

272 **3.1.8.3. Other State Actions**

273 In the event any State adopts laws or regulations governing customer access to alternative
274 electricity suppliers, the Company will inform the Commissions and the Parties of the same.

275 **3.1.9. Loss or Increase in Load**

276 Any loss or increase in retail load occurring as a result of condemnation or
277 municipalization, sale or acquisition of new service territory that involves less than five percent of
278 system load, realignment of service territories, changes in economic conditions, or gain or loss of
279 large customers will be reflected in changes in the Load-Based Dynamic Allocation Factors. The
280 allocation or assignment of costs and benefits arising from merger, sale, or acquisition transaction
281 proposed by the Company involving more than five percent of system load will be considered on
282 a case-by-case basis in the course of Commission approval proceedings.

283 **3.1.10. Commission Regulation of Interim Period Resources**

284 PacifiCorp will plan and acquire new Interim Period Resources on a system-wide risk-
285 adjusted, least-cost basis. Prudently incurred investments in Interim Period Resources will be
286 reflected in rates consistent with the laws and regulations in each State, as approved by individual
287 Commissions.

288 **3.2. Modifications to the 2017 Protocol During the Interim Period**

289 **3.2.1. Net Power Costs Filings**

290 For Net Power Costs (“NPC”) filings, Parties agree to support use of the allocation
291 methodology in place when the NPC were or will be incurred, to align the timing of the actual
292 costs incurred with the applicable allocation method for cost recovery for that period. The table
293 below summarizes the transition from the 2017 Protocol to the 2020 Protocol for NPC filings. If
294 a Post-Interim Period Method agreement is reached between the Parties, a similar table will be
295 included to summarize the transition for NPC filings from the 2020 Protocol to the subsequent
296 agreement.

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Allocation Methodology Used for NPC Filings			
Filing	2017 Protocol	2020 Protocol	Notes
California ECAC (Balancing Rate)	2021 ECAC for the CY2020 Deferral Period	2022 ECAC for the CY2021 Deferral Period	1
California ECAC (Offset Rate)	2020 ECAC for the CY2020 Forecast Period	2021 ECAC for the CY2021 Forecast Period	1
Idaho ECAM	2020 ECAM for the CY2019 Deferral Period	2021 ECAM for the CY2020 Deferral Period	
Oregon TAM	2020 TAM for the CY2019 Forecast Period	2021 TAM for the CY2020 Forecast Period	
Oregon PCAM	2020 PCAM for the CY2019 Deferral Period	2021 PCAM for the CY2020 Deferral Period	
Utah EBA	2020 EBA for the CY2019 Deferral Period	2021 EBA for the CY2020 Deferral Period	
Washington PCAM	2019 PCAM for the CY2019 Deferral Period	2020 PCAM for the CY2020 Deferral Period	2
Wyoming ECAM	2020 ECAM for the CY2019 Deferral Period	2021 ECAM for the CY2020 Deferral Period	
Net Power Costs included in General Rate Cases (GRC) - All States		GRC with rate effective date on or after January 1, 2020	3
Notes:			
1. The 2020 Protocol will not be implemented in California until approved by the Commission in a general rate case. The dates included in the table are subject to change based on the California general rate case schedule, the next general rate case is currently scheduled to use a 2022 test period.			
2. Washington will use the modified WCA allocation methodology per Appendix F of the 2020 Protocol.			
3. This also applies to any other NPC filing that resets base NPC rates.			

297 **3.3.2. Embedded Cost Differential (“ECD”) and Equalization Adjustment**

298 **3.3.2.1. ECD**

299 The Fixed ECD will continue for Idaho through the end of the Interim Period. The
300 Dynamic ECD for Oregon will continue through the end of the Interim Period, capped at
301 \$11,000,000. No ECD adjustment exists for Utah or California.

302 The Wyoming ECD will terminate December 31, 2020. Beginning January 1, 2021, for
303 purposes of the Wyoming energy cost adjustment mechanism (“ECAM”), actual ECD will be zero
304 and the true-up of the Wyoming ECD will not be subject to sharing bands in the Wyoming ECAM.
305 This treatment will continue until the ECD is removed from base rates.

306 **3.3.2.2. Equalization Adjustment**

307 The Equalization Adjustment addressed in Section XIV of the 2017 Protocol will terminate
308 on December 31, 2019, and no additional Equalization Adjustment amounts will be deferred after
309 that date. The method PacifiCorp will use to collect deferred Equalization Adjustment balances
310 and any related carrying charges has been or will be addressed in appropriate State regulatory
311 proceedings.

312 **3.3.3. Costs and Benefits of Qualifying Facilities**

313 Costs and benefits of Qualifying Facilities will be treated consistent with the provisions
314 specified in Section 4.4.

315 **3.3.4. Allocation of Gain or Loss from Sale of Assets**

316 The allocation of any gain or loss from the Company's sale of assets will be treated
317 consistent with the provisions specified in Section 7.

318 **3.3.5. Interpretation and Governance**

319 This Agreement will be interpreted and PacifiCorp's Multi-State Process ("MSP") will be
320 governed by the provisions specified in Section 8.

321 **4. Implemented Issues**

322 The Parties agree that the following items, described later in this Section 4, will be
323 implemented and effective during the Interim Period:

- 324 • The process and timing for States' decisions to exit coal-fueled Interim Period
325 Resources;
- 326 • The process for potential Reassignment of coal-fueled Interim Period Resources
327 among States without Exit Orders;
- 328 • The process for the allocation of Decommissioning Costs; and
- 329 • The allocation and assignment of Qualifying Facility Power Purchase Agreements

330 ("QF PPAs").

331 These issues are more thoroughly explained below.

332 **4.1. States' Decisions to Exit Coal-Fueled Interim Period Resources**

333 PacifiCorp will continue to conduct operational and economic analyses in accordance with
334 applicable regulatory requirements and good utility practice to maintain reliable service on a risk-
335 adjusted, least-cost basis for its customers. PacifiCorp anticipates continuing to conduct integrated
336 resource planning, at least biennially. PacifiCorp also anticipates continuing to undertake
337 depreciation studies on a five-year cycle. If these analyses affect the depreciable lives or
338 operational lives of Interim Period Resources in the future, Parties may address such effects
339 through appropriate regulatory proceedings before the Commissions. Nothing in this Agreement
340 affects PacifiCorp's rights and obligations to make prudent decisions regarding operation of its
341 assets and system in accordance with applicable law. The Parties further agree that PacifiCorp's
342 coal-fueled Interim Period Resource Closure dates may be informed by new information that
343 becomes available as a result of other regulatory filings or actions, including integrated resource
344 plans or State and federal energy policies. Nothing in this Agreement affects or limits any Party's
345 ability to raise any prudence issues with regards to PacifiCorp's decisions regarding Closure of an
346 Interim Period Resource.

347 Subject to the possible effects of Limited Realignment, the Parties agree to the following
348 procedures for the Company's coal-fueled Interim Period Resources.

349 **4.1.1. Allocation of Costs at Closure**

350 Upon Closure of a coal-fueled Interim Period Resource, each State that is receiving benefits
351 and is allocated costs associated with the coal-fueled Interim Period Resource at the time of
352 Closure shall continue to be allocated its share of the remaining costs of the coal-fueled Interim

353 Period Resource in accordance with this 2020 Protocol, which may include the remaining net book
354 value and Commission-approved Decommissioning Costs. The existence of an Exit Order does
355 not change this allocation, and all States assigned benefits and allocated costs from the coal-fueled
356 Interim Period Resource at the time of Closure will be allocated actual costs. Therefore, if every
357 State is being assigned benefits and allocated costs from a coal-fueled Interim Period Resource at
358 the time of Closure, every State will be allocated, in accordance with the method set forth in this
359 Agreement, all the actual costs associated with that coal-fueled Interim Period Resource and its
360 Closure. This can occur, for example, if every State (excepting Washington as discussed in Section
361 4.1.4) issues an Exit Order with the same Exit Date for a particular coal-fueled Interim Period
362 Resource. This can also occur, for example, if PacifiCorp pursues Closure of a coal-fueled Interim
363 Period Resource prior to a State Exit Date. No Party, by virtue of this Agreement, waives its right
364 to investigate and analyze whether the Company's decision to continue operation or continue an
365 ownership interest is prudent, regardless of the anticipated Closure dates in the tables in Section
366 4.1.3.

367 **4.1.2 Exit Orders**

368 The Parties, representing diverse and varied interests, have worked in good faith to create
369 a process that allows for States to pursue differing resource portfolios in the future, including
370 decisions to transition out of coal-fueled Interim Period Resources while mitigating resulting
371 effects to the Company and other States. A Commission may issue an Exit Order specifying an
372 Exit Date in a proceeding for approval of this Agreement, a depreciation docket, a rate case, or any
373 other appropriate proceeding.⁶ A Commission Order or other determination that a coal-fueled
374 Interim Period Resource will reach the end of its depreciable life without a specific determination

⁶ An Exit Order is not required from a Commission if a coal-fueled Interim Period Resource is not included in PacifiCorp's rates in that State.

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375 that the State will exit the Interim Period Resource shall not constitute an Exit Order. Provided
376 PacifiCorp secures all applicable approvals, a Company decision to close a coal-fueled Interim
377 Period Resource earlier than previously anticipated does not require the issuance of an Exit Order.
378 An Exit Order does not, by itself, result in Reassignment of shares of a coal-fueled Interim Period
379 Resource to other States or affect an Exiting State's responsibility for its share of the then-
380 remaining net book value of the Interim Period Resource that is being exited.

381 To provide the Company and States without Exit Orders time to consider the options and
382 address the potential Reassignment of the coal-fueled Interim Period Resource, as set forth in
383 Section 4.2, under this Agreement an Exit Order should provide at least four-years of notice⁷ from
384 the date of the Exit Order to the Exit Date. After an Exit Date, the Exiting State will no longer be
385 allocated any new costs⁸ and will no longer be assigned any benefits associated with that coal-
386 fueled Interim Period Resource, and no other State will be allocated the Exiting State's share of
387 costs nor receive the Exiting State's assigned benefits associated with that coal-fueled Interim
388 Period Resource, unless the costs and benefits are accepted through a Commission Order on
389 Reassignment. Until the Exit Date, an Exiting State shall continue to be assigned the benefits of
390 that coal-fueled Interim Period Resource and shall be allocated costs associated with that coal-
391 fueled Interim Period Resource in accordance with this 2020 Protocol or as determined through
392 the Framework process, which may include costs associated with any remaining net book value,
393 prudently incurred capital additions, prudently incurred Operations and Maintenance ("O&M")
394 expense, and prudently incurred or reasonably estimated Decommissioning Costs.

⁷ Subject to the provisions in Sections 4.1.3 and 4.1.4.

⁸ New costs are costs incurred after the Exit Date to maintain or operate the coal-fueled Interim Period Resource beyond that date. Any costs associated with the operation of a coal-fueled Interim Period Resource and incurred prior to the Exit Date that are allocated to the Exiting State as determined through the 2020 Protocol and that have not yet been collected from customers in that State are still that State's responsibility.

395 An Exit Order establishes the Exit Date that PacifiCorp will use to propose the allocation
396 of Decommissioning Costs, allocation of capital additions costs, and any other associated costs
397 related to the exit from a coal-fueled Interim Period Resource as outlined in the 2020 Protocol.
398 PacifiCorp will timely propose to Parties from an Exiting State a method to address the treatment
399 of these costs for ratemaking, such that costs and benefits remain matched in customer rates.

400 Following receipt of an Exit Order, the Company will file in accordance with Section 4.2
401 to allow States without Exit Orders the opportunity to evaluate the potential Reassignment of the
402 coal-fueled Interim Period Resource. For regulatory efficiency, Section 4.1.3 establishes
403 timeframes for addressing Exit Orders from coal-fueled Interim Period Resources by Oregon and
404 the potential Reassignment of those resources to other States.

405 **4.1.3 Oregon Exit Dates**

406 The Oregon Parties and the Company agree to recommend that the dates shown in the
407 tables in this Section 4.1.3 be used in Oregon for service and depreciable lives, and for establishing
408 Oregon's Exit Dates for all coal-fueled Interim Period Resources.

409 **4.1.3.1 Coal-Fueled Interim Period Resources Not Operated by** 410 **PacifiCorp Subject to Common Closure Dates, Oregon** 411 **Exit 2023-2027**

412 PacifiCorp anticipates that Cholla Unit 4, Craig Unit 1, Craig Unit 2, Colstrip Unit 3, and
413 Colstrip Unit 4 will have common Closure dates for all States. If PacifiCorp effectuates Closure
414 at Cholla Unit 4, Craig Unit 1, Craig Unit 2, Colstrip Unit 3, or Colstrip Unit 4 on or before the
415 applicable dates identified in the table below, each State will be allocated its share of the costs and
416 benefits of that coal-fueled Interim Period Resource with no transfer of cost responsibility or
417 decommissioning liability among States, in accordance with Section 4.1.1.

418 PacifiCorp and the Oregon Parties agree to recommend to the Oregon Commission that the
419 dates shown in the table below be used for establishing Oregon's Exit Dates and Oregon

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420 depreciable lives for Cholla Unit 4, Craig Unit 1, Craig Unit 2, Colstrip Unit 3, and Colstrip Unit
421 4.

Coal-Fueled Interim Period Resource Name	Anticipated Closure Date
Cholla Unit 4	January 1, 2023
Craig Unit 1	December 31, 2025
Craig Unit 2	December 31, 2026
Colstrip Unit 3	December 31, 2027
Colstrip Unit 4	December 31, 2027

422 PacifiCorp and the Oregon Parties agree that PacifiCorp will make best efforts to effectuate
423 Closure of the units identified above by the anticipated Closure dates, but the Company may need
424 additional time for Closure of Craig Units 1 and 2 and Colstrip Units 3 and 4 due to its joint-owner
425 agreements, and Cholla Unit 4 due to other contractual requirements.

426 If PacifiCorp has received an Exit Order from Oregon for Craig Unit 1, Craig Unit 2,
427 Colstrip Unit 3, or Colstrip Unit 4 with the same Exit Date as the date set forth in the table above
428 and PacifiCorp does not effectuate Closure by such date, Oregon may elect, at its option, to:

- 429 • Continue to take an allocation and assignment of the costs and benefits of such unit
430 for one additional year following the specified Exit Date; or
- 431 • Discontinue taking an allocation and assignment of the costs and benefits of such
432 unit as of the specified Exit Date.

433 Under either election, Oregon will continue to be subject to an allocation of actual
434 Decommissioning Costs if Closure of the unit is effectuated within such one-year period. If
435 Closure of the unit is not effectuated within such one-year period, Oregon will be allocated
436 Decommissioning Costs based on the estimates established pursuant to Section 4.3.

437 Oregon will be allocated actual Decommissioning Costs if Closure of Cholla Unit 4 occurs
438 on or before January 1, 2023. If Cholla Unit 4 operates beyond January 1, 2023, Oregon will be
439 allocated only estimated Decommissioning Costs as of January 1, 2023.

440 **4.1.3.2. Coal-Fueled Interim Period Resources Operated by**
441 **PacifiCorp, Oregon Exit Through 2027**

442 The Oregon Parties and the Company agree to recommend to the Oregon Commission that
443 the Exit Date for each coal-fueled Interim Period Resource shown in the following table should be
444 used in Oregon for establishing Oregon's Exit Dates and Oregon depreciable lives for these coal-
445 fueled Interim Period Resources, subject to the other provisions of this Section 4.1.

Coal-Fueled Interim Period Resource	Recommended Oregon Exit Date
Jim Bridger 1	December 31, 2023
Jim Bridger 2	December 31, 2025
Jim Bridger 3	December 31, 2025
Jim Bridger 4	December 31, 2025
Naughton 1	December 31, 2025
Naughton 2	December 31, 2025
Dave Johnston 1	December 31, 2027
Dave Johnston 2	December 31, 2027
Dave Johnston 3	December 31, 2027
Dave Johnston 4	December 31, 2027

446 Oregon Parties and the Company will strive to have Exit Orders issued on or before
447 December 15, 2020, for the coal-fueled Interim Period Resources reflected in the table above to
448 allow the Company to make filings in the other States in accordance with Section 4.2. If
449 PacifiCorp effectuates Closure for any of the units no later than the dates in the table above, then
450 the provisions of 4.1.1 will apply.

451 **4.1.3.3. Coal-Fueled Interim Period Resources, Oregon Exit**
452 **Date 2028 - 2029**

453 The Oregon Parties and the Company agree that the recommended Exit Dates for the coal-
454 fueled Interim Period Resources shown in the following table should be used in Oregon for
455 establishing Oregon's Exit Dates and Oregon depreciable lives for these coal-fueled Interim Period
456 Resources for purposes of this Agreement, subject to the other provisions of this Section 4.1.

Coal-Fueled Interim Period Resource Name	Recommended Oregon Exit Date
Hunter 1	December 31, 2029
Hunter 2	December 31, 2029
Hunter 3	December 31, 2029
Huntington 1	December 31, 2029
Huntington 2	December 31, 2029
Wyodak	December 31, 2029

457 Oregon Parties and the Company will strive to have Exit Orders issued by the Oregon
458 Commission issued by December 31, 2023, for the coal-fueled Interim Period Resources reflected
459 in the table above to allow the Company to make the necessary filings in other States in accordance
460 with Section 4.2. If PacifiCorp effectuates Closure for any of the units no later than the dates in
461 the table above, then the provisions of 4.1.1 will apply.

462 **4.1.4. Washington Exit Orders**

463 The Washington Clean Energy Transformation Act ("CETA") requires coal-fueled Interim
464 Period Resources to be out of Washington rates by December 31, 2025. Section 6.4 of the
465 Framework Issues addressing Limited Realignment is intended to facilitate the removal of coal-
466 fueled Interim Period Resources from Washington rates and address the Washington-allocated
467 share, per the System Generation-Fixed ("SGF") Factor, as defined in Appendix C, of all coal-
468 fueled Interim Period Resources whether or not those resources are included in Washington rates.

469 Washington Commission approval of the 2020 Protocol will constitute an Exit Order for

470 Washington, unless modified by Reassignment or Limited Realignment, with an Exit Date of
471 December 31, 2023, for Jim Bridger Unit 1, and December 31, 2025, for Jim Bridger Units 2-4
472 and Colstrip Unit 4. PacifiCorp and the Washington Parties agree that an Exit Order is not required
473 from the Washington Utilities and Transportation Commission for any coal-fueled Interim Period
474 Resources not currently in Washington rates, and PacifiCorp can evaluate seeking Reassignment
475 upon approval of the 2020 Protocol by the Washington Commission.

476 **4.1.5. Establishment of Exit Dates for Hayden Units 1 and 2**

477 On or before February 1, 2021, the Company will make State-specific recommendations
478 to Commissions for the treatment of Hayden Units 1 and 2. If PacifiCorp effectuates Closure for
479 Hayden Units 1 and 2, then the provisions of 4.1.1 will apply, subject to applicable legal
480 requirements.

481 **4.2. Reassignment of Coal-Fueled Interim Period Resources**

482 **4.2.1 Company Proposals for Reassignment**

483 After receipt of any Exit Order, PacifiCorp shall analyze whether it is reasonable to
484 continue to operate the affected coal-fueled Interim Period Resource for customers in one or more
485 of the States without Exit Orders. PacifiCorp may propose Reassignment of a greater share of the
486 coal-fueled Interim Period Resource to such State(s) to match State load and resource balance, or
487 request issuance of an Exit Order.⁹ PacifiCorp shall provide its analysis to Parties in each
488 applicable State and may make a filing with the Commission in each State that, as yet, has not
489 entered an Exit Order for such coal-fueled Interim Period Resource consistent with the timeframes
490 set forth in Sections 4.1 and this Section. If PacifiCorp seeks Reassignment, the analysis shall be
491 accompanied by recommendations as to an anticipated Closure date if Reassignment is accepted

⁹ Provided PacifiCorp secures all applicable approvals, PacifiCorp may effectuate Closure of a Resource without requesting issuance of any Exit Order.

492 for such coal-fueled Interim Period Resource. Recommended Reassignments, if proposed, should
493 include a range of options, including fallback options based on the potential that one Commission
494 may reject PacifiCorp's recommendation while another Commission may accept the primary
495 recommendation. Notwithstanding this Section 4.2.1, realignment of certain Interim Period
496 Resources serving Washington will be determined subject to resolution of the Limited Realignment
497 Framework Issue or Section 4.1.4 as applicable.

498 **4.2.2 Process and Timing**

499 Consistent with Section 4.1, for those coal-fueled Interim Period Resources, with an Exit
500 Date on or before December 31, 2027, the filings including the Company's analysis and
501 recommendations are targeted to occur by February 1, 2021. For those coal-fueled Interim Period
502 Resources with an Exit Date after December 31, 2027, and on or before December 31, 2029, the
503 filings including the Company's analysis and recommendations are targeted to occur by June 30,
504 2024, for Exit Orders that are received by December 31, 2023. Where possible, PacifiCorp will
505 make such filings concurrently in each State without an Exit Order so that each unit or plant can
506 be analyzed as a whole. To the extent a delay to these targeted filing dates is necessary, the
507 Company will provide notice to the Parties and Commissions explaining the reason and expected
508 filing dates. For coal-fueled Interim Period Resources with Exit Orders with different Exit Dates,
509 the Company will provide its analysis to the States without Exit Orders within six months after the
510 date any Exit Order is issued by any Commission, subject to the provisions of Section 4.1.4 for the
511 Washington Exit Orders.

512 If PacifiCorp makes filings pursuant to this Section in multiple States without Exit Orders,
513 then within 60 days from the date the last Commission issues an order pertaining to such filings,
514 PacifiCorp will submit a supplemental filing with each Commission in the State(s) without Exit

515 Orders summarizing the decisions made by each Commission and PacifiCorp's recommendations
516 regarding the implications.

517 **4.2.3 Effects of Commission Decisions Regarding Assignment**

518 If one or more Commissions have entered orders accepting, collectively, one-hundred
519 percent¹⁰ of the cost allocation of a coal-fueled Interim Period Resource beyond any Exit Date, the
520 costs and benefits of the coal-fueled Interim Period Resource after such Exit Date shall be
521 Reassigned to the States in accordance with the approved Reassignment as specified in the
522 applicable Commission Orders. Supplemental filings will reflect the final Reassignment of each
523 coal-fueled Interim Period Resource as a result of the Reassignment process and Commission
524 Orders.

525 If two or more Commissions have entered orders requesting, collectively, more than one-
526 hundred percent¹¹ of the cost allocation and associated benefits of a coal-fueled Interim Period
527 Resource beyond any Exit Date, the Company will recommend a pro-rata Reassignment up to one
528 hundred percent in accordance with the approved Reassignment as specified in the applicable
529 Commission Orders. Supplemental filings will reflect this pro-rata treatment of each coal-fueled
530 Interim Period Resource as a result of the pro-rata Reassignment process for further review and
531 approval by the Commissions.

532 If Commissions do not agree to accept one-hundred percent cost allocation, collectively, of
533 a coal-fueled Interim Period Resource beyond an Exit Date, as part of its supplemental filings, the
534 Company will provide its recommendations on the treatment of any shortfall in the Reassignment

¹⁰ Based on PacifiCorp's ownership interest in the coal-fueled Interim Resource, whether wholly-owned or jointly-owned.

¹¹ Based on PacifiCorp's ownership interest in the coal-fueled Interim Resource, whether wholly-owned or jointly-owned.

535 of a coal-fueled Interim Period Resource or recommendations on capacity reductions through
536 Closures for further Commission consideration.

537 In the event of either common Exit Dates for all States or Closure as a result of the
538 Reassignment process or other appropriate regulatory proceedings, the provisions of Section 4.1.1
539 will apply.

540 **4.3. Decommissioning Costs**

541 **4.3.1. Process for Determining Decommissioning Cost Allocation**

542 **4.3.1.1. Decommissioning Studies**

543 The Company intends to undertake a contractor-assisted engineering study of
544 decommissioning costs and to make best efforts to complete the study by January 15, 2020, to
545 estimate appropriate Decommissioning Cost reserve requirements for the Jim Bridger, Dave
546 Johnston, Hunter, Huntington, Naughton, Wyodak, and Hayden coal-fueled Interim Period
547 Resources. Colstrip will also be included in the contractor-assisted engineering study of
548 decommissioning costs, and the Company will make best efforts to complete that portion of the
549 study by March 15, 2020. The Company will provide the information from the study to the States
550 as a supplemental filing in all applicable depreciation dockets. The study results will be used to
551 inform the Company's recommendation on the amount of Decommissioning Cost responsibility
552 to be allocated to States for coal-fueled Interim Period Resources that States exit at different times.
553 The Company will retain and make available the Decommissioning Studies in future regulatory
554 proceedings.

555 **4.3.1.2. Decommissioning Studies Update**

556 The Company intends to undertake the same process to complete an update to the
557 Decommissioning Studies by no later than June 30, 2024, to estimate appropriate
558 Decommissioning Cost reserve requirements for the Craig, Hunter, Huntington, and Wyodak coal-

559 fueled Interim Period Resources (collectively with the studies discussed in the paragraph above
560 constituting the Decommissioning Studies), which will be incorporated into a Company-sponsored
561 depreciation study. The Company will retain and make available the Decommissioning Studies
562 update in future regulatory proceedings.

563 **4.3.1.3. Commission Determination of Decommissioning Costs**

564 No Party will be bound by the Decommissioning Cost estimates in the Decommissioning
565 Studies undertaken pursuant to Paragraphs 4.3.1.1 and 4.3.1.2, and final determination of each
566 State's just and reasonable Decommissioning Cost allocation for each coal-fueled Interim Period
567 Resource will remain exclusively with each Commission and will be determined in the
568 depreciation dockets in which the Decommissioning Costs are included.¹²

569 **4.3.1.4. Decommissioning Costs Allocation**

570 For coal-fueled Interim Period Resources having a common operating life across all States,
571 each State shall be allocated its share of actual Decommissioning Costs based on either an SG
572 Factor (if closed during the Interim Period) or an Assigned Production ("AP") Factor, adjusted for
573 any Reassignment or Limited Realignment effects (if closed after the Interim Period). For coal-
574 fueled Interim Period Resources that do not have a common operating life across all States, each
575 Exiting State shall be allocated, using either an SG Factor (if closed during the Interim Period) or
576 an AP Factor, adjusted for any Reassignment or Limited Realignment effects (if closed after the
577 Interim Period), that State's share of estimated Decommissioning Costs based on the
578 Decommissioning Studies described in Sections 4.3.1.1 and 4.3.1.2. If the Decommissioning
579 Costs ordered to be included in the reserve balance established for an Exiting State are less than
580 the estimated Decommissioning Costs allocated to that Exiting State as specified above, such

¹² For California, Decommissioning Costs will be addressed in PacifiCorp's next general rate case.

581 difference shall not be allocated to any other State under any circumstance. If PacifiCorp
582 effectuates Closure of a coal-fueled Interim Period Resource after one or more States have exited
583 from the Resource, the Company may, with the burden of proof and subject to PacifiCorp
584 supporting its proposal in testimony,¹³ propose to allocate to and collect from each State that is
585 participating in that Resource at the time of Closure that State's share, based on either an SG Factor
586 (if closed during the Interim Period) or an AP Factor, adjusted for any Reassignment or Limited
587 Realignment effects (if closed after the Interim Period), of actual Decommissioning Costs less the
588 regulatory liabilities for Exiting States including interest as described in Section 4.3.2 and less any
589 difference between the reserve balance established for each Exiting State and the estimated costs
590 allocated to each Exiting State as described above. Parties in such State(s) may take any position
591 regarding a Company request to recover Decommissioning Costs.

592 **4.3.2. Accounting for Decommissioning Costs Reserve Balances when All**
593 **States Do Not Exit a Unit**

594 After an Exit Date by some but not all States, the estimated Decommissioning Costs
595 reserves allocated to the Exiting State(s) associated with a coal-fueled Interim Period Resource
596 unit, from which that State is exiting, will be accounted for as a regulatory liability that is excluded
597 from rate base. Interest will be accrued on that regulatory liability at the Company's then-
598 authorized weighted average cost of capital¹⁴ for each State that continues to participate in that
599 coal-fueled Interim Period Resource after an Exit Date until the decommissioning work on that
600 unit is completed.

¹³ PacifiCorp's testimony will identify and explain the variances between estimated and actual Decommissioning Costs.

¹⁴ Not to exceed the maximum carrying charge allowed by applicable law or Commission Order.

601 **4.3.3. Accounting for Interim and Final Retirements**

602 Before any State exits a coal-fueled Interim Period Resource, but no later than December
603 31, 2021, the Company shall propose to the Parties a process for separately accounting for removal
604 costs associated with interim retirements and final Decommissioning Costs in its accounting
605 system. Each State may determine the regulatory treatment for such removal costs in appropriate
606 proceedings.

607 **4.3.4. Individual State Review Process**

608 Any Party, at its discretion and cost, may pursue actions it deems necessary or appropriate
609 to review and evaluate the Decommissioning Studies or Decommissioning Costs and may take any
610 positions based on its review and findings. If a Commission issues an order identifying an
611 independent evaluator for the Decommission Studies, and the Commission Order provides for the
612 deferral and later recovery in rates of the cost of the independent evaluator, the Company agrees
613 to initially pay for this independent evaluation.

614 **4.4. Qualifying Facilities**

615 The allocation of QF PPAs shall be treated in accordance with Sections 4.4.1 and 4.4.2 of
616 this 2020 Protocol, superseding Section (IV)(A)(3) of the 2017 Protocol. For Washington, QF
617 PPAs will be assigned and allocated consistent with the terms of Appendix F during the Interim
618 Period. Other than addressing the allocation of the costs and assignment of benefits of QF PPAs
619 among the States, this 2020 Protocol does not restrict or affect any Commission's jurisdiction over
620 any agreement or interaction between QFs and the Company. QF PPAs shall be treated in the
621 following manner for allocation and assignment purposes.

622 **4.4.1. Existing QF PPAs**

623 QF PPAs fully executed¹⁵ or as to which a legally enforceable obligation exists¹⁶ on or
624 before December 31, 2019 ("Existing QF PPAs") will remain system assigned and allocated,
625 subject to any Limited Realignment in Section 6.4, until the end of 2029, after which time they
626 will be situs assigned and allocated to the State having jurisdiction over the QF PPA for avoided
627 cost pricing ("State of Origin").

628 **4.4.1.1. Wyoming QF Adjustment**

629 The Company agrees to include: (1) a \$5 million adjustment, annually, to reduce Net Power
630 Costs in Wyoming customer rates¹⁷ beginning January 1, 2021, until December 31, 2022; and (2)
631 a \$7.175 million adjustment, annually, to reduce Net Power Costs in Wyoming customer rates from
632 January 1, 2023, until December 31, 2029.¹⁸ This adjustment will terminate on or before
633 December 31, 2029, or upon issuance of any order by the Wyoming Commission that changes
634 Wyoming's treatment of the Implemented Issues or the Resolved Issues from the terms of the 2020
635 Protocol. The adjustment shall be made solely at the Company's expense and not allocated to any
636 other States.

637 **4.4.2. New QF PPAs**

638 QF PPAs fully executed or as to which a legally enforceable obligation exists after
639 December 31, 2019, ("New QF PPAs") will be situs assigned and allocated for ratemaking
640 proceedings pertaining to periods beginning on or after January 1, 2020, to the State of Origin.

¹⁵ Fully executed means executed and delivered by each party to the other party.

¹⁶ Any such legally enforceable obligation date must be confirmed by an order from the applicable Commission issued prior to the end of the Interim Period.

¹⁷ The Wyoming QF adjustment will be included in the base ECAM costs forecasted in a general rate case with rates effective on or after January 1, 2021. The Wyoming QF adjustment will be trued up in the ECAM at 100% (sharing-bands do not apply).

¹⁸ The Wyoming QF adjustment shall be removed from base ECAM costs on December 31, 2029, or as otherwise specified in Section 4.4.1.1, so that no adjustment flows through to customers in rates after that date unless it was deferred in the ECAM prior to December 31, 2029.

641 **4.4.2.1. Interim Period Treatment – Pre-Nodal Pricing Model**

642 For the Interim Period, the energy output of New QF PPAs will be dynamically allocated
 643 per this agreement using the SG Factor, priced at a forecasted reasonable energy price defined
 644 below, and any cost of a New QF PPA above the forecasted reasonable energy price will be situs
 645 assigned and allocated to the State of Origin. The forecasted reasonable energy price is a single
 646 blended market price derived from the Company's Official Forward Price Curve ("OFPC"), scaled
 647 for hourly prices, that was used for setting QF pricing for the New QF PPA. The single blended
 648 market price is calculated by applying the appropriate weighting to the hourly scaled prices from
 649 the OFPC for each market hub. The weightings per market hub are identified in the table below.
 650 The weighting will be applied by month and by heavy load hours ("HLH") and light load hours
 651 ("LLH"). The forecasted reasonable energy price, used for allocation purposes, shall be
 652 established at the time a QF PPA is fully executed.

Market Hub Weighting by Month - HLH												
Market	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
COB	0.00%	0.55%	1.34%	0.82%	3.45%	4.01%	8.41%	3.69%	8.58%	0.97%	1.79%	1.20%
Mid Columbia	24.42%	30.21%	55.74%	63.22%	70.84%	87.39%	81.05%	83.85%	75.88%	42.27%	34.30%	40.74%
Palo Verde	1.52%	2.53%	1.07%	0.66%	0.54%	0.03%	0.76%	1.89%	1.85%	2.55%	3.45%	0.30%
Four Corners	64.72%	58.68%	35.94%	27.40%	16.15%	5.75%	4.12%	2.17%	3.82%	45.79%	52.88%	44.47%
Mead	0.18%	0.13%	1.23%	1.46%	1.52%	1.74%	1.95%	3.30%	6.64%	0.33%	0.12%	0.57%
Mona	9.16%	7.90%	2.94%	2.03%	1.79%	0.74%	0.01%	0.18%	1.82%	7.82%	7.46%	2.18%
NOB	0.00%	0.00%	1.75%	4.40%	5.72%	0.33%	3.70%	4.92%	1.41%	0.27%	0.00%	10.54%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Market Hub Weighting by Month - LLH												
Market	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
COB	0.00%	0.99%	5.17%	3.53%	15.50%	15.16%	5.97%	1.21%	0.31%	2.43%	3.44%	1.16%
Mid Columbia	58.74%	60.10%	76.58%	66.36%	71.82%	80.41%	85.52%	92.26%	83.27%	62.78%	66.30%	59.09%
Palo Verde	0.00%	1.12%	0.42%	0.04%	0.39%	0.40%	2.71%	3.04%	0.00%	0.92%	1.91%	2.30%
Four Corners	33.45%	34.66%	13.63%	26.49%	10.44%	3.30%	5.35%	2.39%	11.60%	27.69%	26.36%	29.65%
Mead	0.00%	0.06%	0.94%	0.44%	0.93%	0.47%	0.25%	0.00%	0.00%	0.57%	0.00%	0.00%
Mona	7.81%	3.07%	1.54%	2.41%	0.92%	0.27%	0.00%	1.11%	4.82%	5.61%	1.99%	7.80%
NOB	0.00%	0.00%	1.71%	0.73%	0.00%	0.00%	0.20%	0.00%	0.00%	0.00%	0.00%	0.00%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

653 **4.4.2.2. Post-Interim Period Treatment**

654 After the conclusion of the Interim Period, assuming resolution and Commission approval
 655 of all Framework Issues, the Parties agree that New QF PPAs will be situs assigned and the costs

656 and benefits will be allocated and assigned per the methodology developed through the Framework
657 process in Section 6.2.

658 **5. Resolved Issues - Post-Interim Period Implementation**

659 The Parties agree, conditioned upon reaching agreement on a Post-Interim Period Method
660 on the future allocation treatment described in this Section 5 for certain benefits, revenues, costs,
661 and investments. As stated in Section 2, these Resolved Issues of the 2020 Protocol are intended
662 to take effect with the implementation of the Post-Interim Period Method. Parties acknowledge
663 that conditions may change materially in unforeseen ways during the Interim Period and that it
664 may be necessary to re-evaluate Resolved Issues as part of the Post-Interim Period Method. The
665 Resolved Issues are identified below.

666 **5.1. Generation Costs**

667 Following the Interim Period, a fixed share of the Interim Period Resources will be
668 assigned to serve load in each State. The costs and benefits, including environmental attributes,
669 associated with each Interim Period Resource will be allocated and assigned in accordance with
670 the Interim Period Resources fixed allocation provisions (Section 5.1.1), Reassignment of coal-
671 fueled Interim Period Resources (Section 4.2), and Limited Realignment (Section 6.4).

672 **5.1.1. Interim Period Resources Fixed Allocation**

673 Interim Period Resources will be assigned and allocated to States based on the SGF Factor
674 for each State as defined in Appendix C. The load information used to determine the SGF Factor
675 is subject to modification for the inclusion or exclusion of Special Contract loads as determined
676 through the Framework process for resolution of issues addressed in Section 6.3. The SGF Factor
677 is used to develop the AP Factor for each unit. Additionally, Interim Period Resources will be
678 subject to the Limited Realignment as outlined in Section 6.4 and the Reassignment of Interim

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679 Period Resources as outlined in Section 4.2. Any such Assignment of Interim Period Resources,
680 along with the Limited Realignment and the Reassignment of Interim Period Resources, will be
681 subject to the following:

- 682 • Accumulated depreciation for Interim Period Resources will be allocated per the
683 AP Factor. State-specific accumulated depreciation that has been tracked by the
684 Company due to increased depreciation expenses will be treated as situs to the State
685 and offset its Resource costs until that State exits from an Interim Period Resource.
- 686 • Accumulated deferred income taxes and excess deferred income taxes will be
687 allocated per the Company's tax software system, using the AP Factor. State-
688 specific accumulated deferred income taxes and excess deferred income taxes that
689 have been tracked by the Company due to increased depreciation expense will be
690 treated as situs to the State and offset that State's Resource costs until that State
691 exits from an Interim Period Resource.
- 692 • All O&M expenses that are associated with a specific Interim Period Resource will
693 be allocated per the AP Factor.
- 694 • All generation-related O&M expenses that cannot be allocated to a specific Interim
695 Period Resource through an AP Factor, such as general office generation
696 management expenses, will be allocated to States based on an Assigned Production
697 Operations and Maintenance ("APOM") Factor, calculated as each States' relative
698 share of direct-allocated generation O&M expenses. There will be three separate
699 APOM factors based on FERC classifications, with the APOMS used for steam
700 generation (FERC accounts 500 - 514), APOMH used for hydro generation (FERC
701 accounts 535-545) and APOMO used for other generation (FERC accounts 546 -

702 554). The APOM factor calculations are shown in Appendix C and also included
703 in Appendix B, Column 5.

- 704 • Property tax will continue to be allocated based on gross plant using the GPS Factor
705 as calculated in Appendix C and included in Appendix B, Column 5.
- 706 • All other rate-base items associated with Interim Period Resources will be allocated
707 consistent with the Interim Period Resource allocations using the AP Factor.

708 **5.1.2. New Resources Fixed Assignment**

709 New Resources include any Resources that are not in commercial operation before the end
710 of the Interim Period. All costs and benefits associated with new Resources, subject to the
711 qualification below, will be allocated and assigned to States based on a fixed assignment under the
712 process to be determined in Section 6.1 – Resource Planning and New Resource Assignment. The
713 Parties agree that a transitional period is necessary to change the cost allocation for future new
714 Resources that are planned for by the Company, and that any new Resource reaching commercial
715 operation before the end of the Interim Period will be treated the same as Interim Period Resources
716 for allocation purposes under the terms of this Agreement.

717 **5.2. Transmission Costs**

718 The costs associated with transmission assets, except as addressed in Section 6.1, will be
719 dynamically allocated among States on the System Transmission (“ST”) Factor, generally
720 calculated based on a classification of costs as 75 percent Demand-Related and 25 percent Energy-
721 Related, and based on twelve monthly Coincident Peaks, using weather-normalized retail peak and
722 energy data, as more thoroughly defined in Appendix C.

723 All revenues recovered through PacifiCorp's Open Access Transmission Tariff or other
724 transmission rate schedules approved by the FERC will be allocated based on the ST Factor.

725 The 2020 Protocol does not preclude PacifiCorp from participating in any independent
726 transmission organization, regional transmission organization, or other similar wholesale
727 transmission market subject to the jurisdiction and oversight of the FERC.

728 **5.3. Distribution Costs**

729 All distribution-related expenses and capital costs that can be directly allocated will be
730 directly allocated to the States where the related distribution facilities are located. Those
731 distribution expenses that cannot be directly allocated will be allocated among States on a System
732 Net Plant Distribution ("SNPD") factor, as shown in Appendix B.

733 **5.4. System Overhead Costs**

734 Costs that support more than one function, such as generation, transmission, or distribution
735 plant, will continue to be allocated on the System Overhead ("SO") Factor after the Interim Period
736 but will be calculated based on an equal one-third weighting of the System Capacity ("SC") Factor,
737 System Energy Factor, and System Gross Plant Distribution ("SGPD") Factor, as shown in
738 Appendix B.

739 **5.5. Administrative and General Costs**

740 Administrative and General Costs, General Plant costs, and Intangible Plant costs, both
741 expenses and investments, which can be directly allocated will be directly allocated to the
742 appropriate State(s). Those costs that cannot be directly allocated will be allocated among States
743 consistent with the factors set forth in Appendix B.

744 **5.6. Other Allocation Issues**

745 Items included in the Company's results of operations, other than those that are specifically
746 called out herein, will continue to be allocated on the same factors used in the 2017 Protocol. The

747 FERC account and allocation factor combinations are included in Appendix B. The algebraic
748 derivation and factor definitions are included in Appendix C.

749 The following miscellaneous changes will be made to be consistent with the other
750 allocation changes:

- 751 • Communication equipment allocated on the System Generation Factor during the
752 Interim Period will change to either the SE Factor (generation-related) or ST Factor
753 (transmission-related) depending on the nature of the equipment for which the
754 communication equipment is utilized.
- 755 • Contributions In Aid of Construction (“CIAC”) currently allocated on the SG
756 Factor will change to either the AP factor for generation-related CIAC or the ST
757 Factor for transmission related CIAC.
- 758 • Generation-related dispatch costs and associated plant will be allocated on the SE
759 Factor.
- 760 • Miscellaneous regulatory assets and liabilities, and miscellaneous deferred debits
761 will be allocated with the appropriate allocation factor depending on the related
762 assets or underlying costs. Miscellaneous regulatory assets and liabilities, and
763 miscellaneous deferred debits currently allocated on the SG Factor, will change to
764 the AP Factor for generation-related and ST Factor for transmission-related items.

765 Taxes and fees will be allocated as follows:

- 766 • Income taxes will be calculated using the federal tax rate and PacifiCorp’s
767 combined State effective tax rate. State specific Schedule M and deferred income
768 tax amounts will be allocated using the Company’s tax software system. Consistent

769 with prior system allocation methods, the Washington Public Utility Tax is
770 allocated using the SO Factor in lieu of a Washington income tax.

- 771 • Franchise taxes, revenue related taxes, Commission assessments and fees, and
772 usage related taxes are situs or a pass through.
- 773 • Property taxes are system allocated based on gross plant and allocated on the GPS
774 Factor.
- 775 • Generation and fuel related taxes will follow the assignment of the Resource.
- 776 • Other taxes such as payroll taxes are embedded in the cost of expense or capital.

777 Balances associated with the Trojan Decommissioning will be allocated using the Trojan
778 Decommissioning Fixed ("TROJDF") Factor. This will not affect State-specific treatment of this
779 item.

780 **5.7. Demand-Side Management Programs**

781 Costs associated with DSM Programs, including Class 1 DSM Programs, will continue to
782 be allocated on a situs basis to the State in which the investment is made. The benefits from these
783 programs will flow back to the State through Net Power Costs or through reduced or delayed future
784 capacity needs that will be addressed in the development and implementation of the process
785 identified in Section 6.1.

786 **5.8. State-Specific Initiatives**

787 Costs and benefits resulting from a State-specific initiative will continue to be allocated
788 and assigned on a situs basis to the State adopting the initiative. Historically, these have included,
789 but are not limited to, programs such as incentive programs and customer and community energy
790 generation programs, but have not included local fees or taxes related to the ongoing operation of
791 existing transmission and generation facilities within a State. As new issues arise, PacifiCorp will

792 bring each issue to the MSP Workgroup to discuss whether each issue is a State-specific initiative,
793 and, if not, whether a different allocation method is appropriate.

794 **6. Framework Issues**

795 The Parties acknowledge that certain components of the Post-Interim Period Method are
796 not resolved by this Agreement, including Resource Planning and new Resource Assignment, Net
797 Power Costs / Nodal Pricing Model, the treatment of Special Contracts, post-Interim Period capital
798 additions, and other issues related to the transition from a dynamically-allocated system generation
799 portfolio to fixed generation portfolios. As part of the 2020 Protocol, the Parties agree to the
800 following processes and timeframes to address remaining, unresolved Framework Issues and to
801 request approval of a new Post-Interim Period Method agreement by the Commissions. The
802 Company will file for Commission consideration and approval of a new Post-Interim Period
803 Method in accordance with Section 2. The general understanding reached by the Parties as to
804 process and timelines for Framework Issues is as follows.

805 **6.1. Resource Planning and New Resource Assignment**

806 Continued operation, planning, and dispatch of the Company's system as an integrated six-
807 State system, to the greatest extent practicable, will likely be beneficial to PacifiCorp's customers.
808 However, because of differing State policies requiring or excluding certain generation resources,
809 it appears infeasible to continue serving customers with a common generation portfolio and
810 dynamically allocating system costs. Continued dynamic allocation of all system costs in this
811 environment could result in increased costs for some States, if not all. Accordingly, allocating
812 costs and assigning benefits associated with generation capacity will require assignment of specific
813 Resources, and potentially certain transmission assets, to a specific State or States. The goal is to

814 allow PacifiCorp to meet its legal requirements as a public utility in each State in a risk-adjusted,
815 least-cost manner, while striving to mitigate cost impacts to other States.

816 PacifiCorp will continue to plan for capacity and operating needs, both for the entire
817 interstate system and for each State. PacifiCorp will work with Parties to develop:

- 818 • A planning process that optimizes risk-adjusted, least-cost resource portfolios on a
819 system basis to the extent practicable, while meeting individual State requirements
820 and maintaining system reliability; and
- 821 • A process that assigns benefits and allocates costs of specific new Resources added
822 in order to meet an individual State's needs.

823 Parties will evaluate these processes in light of existing or new Commission regulatory
824 processes governing Resource planning, procurement, and investment approval.

825 **6.2. Net Power Costs / Nodal Pricing Model (“NPM”)**

826 A method to track the costs and benefits of Resource portfolios which may differ for each
827 State will be necessary in the future to maintain the benefits of system dispatch as much as
828 practicable. Specifically, after the Interim Period when States may no longer participate in a
829 common Resource portfolio, a NPM may be used to track cost causation and receipt of benefits by
830 each State for rate-making purposes.

831 Consistent with and in consideration of the Nodal Pricing Model Memorandum of
832 Understanding in Appendix D, the Company agreed to begin the development of an NPM with a
833 third-party vendor and will use best efforts to implement the NPM by the end of January 2021, for
834 purposes of total-Company day-ahead scheduling. Parties intend for this to provide some time and

835 experience with the NPM before it may be used for rate making as part of the Post-Interim Period
836 Method.¹⁹

837 The Company will also use best efforts to implement a model that can forecast NPC based
838 on the NPM concept. During the Interim Period, this model may be used by the Company for
839 forecast analysis of NPC. After the Interim Period, the Company intends to propose the use of this
840 model for NPC forecasts in applicable rate-making proceedings.

841 **6.3. Special Contracts**

842 The Company will continue to work in good faith with the Special Contract customers to
843 develop one or more proposals for consideration by the Parties on the treatment of Special
844 Contracts' loads, costs, and benefits as part of the Framework Issues and will make best efforts to
845 present a proposal to Parties by September 1, 2021, with the intention of incorporating such
846 proposal into the Post-Interim Period Method.

847 **6.4. Limited Realignment**

848 The Parties agree to investigate during the Interim Period the potential Limited
849 Realignment of Interim Period Resources among the States. Limited Realignment is intended to
850 address, among other potential issues, the transition of Washington retail customers away from
851 coal-fueled Interim Period Resource in compliance with the Washington CETA by realigning
852 Interim Period Resources, including natural gas-fueled Interim Period Resources.

853 **6.5. Post-Interim Period Capital Additions – Coal-Fueled Interim** 854 **Period Resources**

855 For a coal-fueled Interim Period Resource for which one or more States have an Exit Date
856 that differs from the depreciable life or Exit Date ordered in any other State, a process is needed

¹⁹ NPM is intended to be used for total Company system dispatch when it is fully functional and operational and will impact system Net Power Costs that flow through State NPC balancing accounts.

857 for determining the cost allocation for capital investments made in the Resources subsequent to
858 the Interim Period and prior to the Exit Date for each State. The Parties have agreed to evaluate,
859 but have not accepted, the following Company straw proposal for post-Interim Period capital
860 investments, information about which is provided here not for Commission approval but to inform
861 future discussions.

862 **6.5.1. PacifiCorp Straw Proposal - Post-Interim Period Capital Investment**
863 **Allocation Exceptions**

864 For post-Interim Period incremental capital investments that are made primarily for the
865 purpose of extending the life of a coal-fueled Interim Period Resource beyond a State's Exit Date
866 for that Resource, including but not limited to those associated with achieving compliance with
867 environmental requirements or those necessitated by catastrophic failure, such investments would
868 not be allocated to States that have issued such Exit Orders and would be allocated based on the
869 percentage shares of the coal unit Reassignment process addressed in Section 4.2 or as otherwise
870 determined for States that continue to participate in the coal-fueled Interim Period Resource.

871 For these incremental capital investments made primarily for the purpose of repairing a
872 coal-fueled Interim Period Resource following a catastrophic failure of the Interim Period
873 Resource, such investments would not be allocated to and no generation or benefits will be
874 assigned to States that have issued Exit Orders for that Resource. Parties in States not allocated
875 costs for such investments would support recovery of any remaining net book value and
876 Decommissioning Costs.

877 **6.5.2. PacifiCorp Straw Proposal - Incremental Capital Investments Made**
878 **Between 2024 and the Exit Date Where Exit Date is On or Before**
879 **December 31, 2027**

880 For States with Exit Orders for a coal-fueled Interim Period Resource specifying an Exit
881 Date on or before December 31, 2027, capital investments made in such Interim Period Resource

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882 after the Interim Period and prior to the Exit Date, would be allocated to an Exiting State based on
883 the AP Factor, adjusted for any Limited Realignment impacts agreed to, and pro-rated for the
884 number of years remaining based on the longest life ordered in any State's depreciation docket or
885 rate case by December 31, 2020, for such Interim Period Resource. States without Exit Orders in
886 such Interim Period Resource would be allocated the remaining amount of capital investment
887 based on proportional shares of the AP factor for the States that will be participating in the coal-
888 fueled Interim Period Resource after an Exit Date. For example, if a State's Exit Order establishes
889 an Exit Date four years from the date the capital investment is in-service, and the Interim Period
890 Resource has the longest remaining life in another State of ten years, the State with the Exit Order
891 would be allocated four-tenths of that State's share of the cost of the qualifying capital investment.
892 Each State's allocation of such capital investments would be subject to a prudence review based
893 on the cost to be allocated to each State consistent with this Section.

894 **6.5.3. PacifiCorp Straw Proposal - Incremental Capital Investments Made**
895 **in 2024 and 2025 Where Exit Date is After 2027**

896 For States with Exit Orders for a coal-fueled Interim Period Resource specifying an Exit
897 Date after 2027, capital investments made in such Interim Period Resource after the Interim Period
898 and through December 31, 2025, would be allocated to all States based on the AP Factor, adjusted
899 for any Limited Realignment impacts agreed to, and prudence of such capital investments for
900 States with Exit Orders would be determined based on the life established for such Interim Period
901 Resource in the Exit Order. This would allow for the reasonable allocation of capital and operating
902 costs for the Interim Period Resource during a period of time while PacifiCorp pursues the process
903 established in Section 4.2.

904 **6.5.4. PacifiCorp Straw Proposal - Incremental Capital Investments Made**
905 **Between 2026 and the Exit Date Where the Exit Date is After 2027**

906 For States with Exit Orders for a coal-fueled Interim Period Resource specifying an Exit
907 Date after 2027, capital investments made in such Interim Period Resource after December 31,
908 2025, and until the Exit Date, would be allocated to an Exiting State based on the AP Factor,
909 adjusted for any Limited Realignment impacts agreed to, and pro-rated for the number of years
910 remaining based on the longest life ordered in any State's depreciation docket, Reassignment
911 proceeding, or rate case as of December 31, 2025. States that will be participating in the coal-
912 fueled Interim Period Resource after an Exit Date would be allocated the remaining amount of any
913 capital investment based on the AP Factor calculated for that coal-fueled Interim Period Resource.

914 **7. Allocation of Gain or Loss from Sale of Assets**

915 Any gain or loss from the sale of Company-owned assets will be allocated among or to
916 States based upon the proportional allocation or assignment of the asset at the time of the execution
917 date of the sale agreement. Each Commission will determine the appropriate allocation of the gain
918 or loss allocated to that State as between PacifiCorp's customers and shareholders. For assets that
919 have been Reassigned for less than one calendar year as of the execution date of the sale agreement,
920 States will be allocated the gain or loss as if the asset had remained a System Resource.

921 **8. Interpretation and Governance**

922 **8.1. Issues of Interpretation**

923 Parties will attempt, consistent with their legal obligations, to resolve questions of
924 interpretation of the 2020 Protocol, in good faith in light of the language of the 2020 Protocol and
925 the intent of the Parties.

926 **8.2. Workgroups**

927 **8.2.1. Framework Issues Workgroup**

928 PacifiCorp will schedule and convene meetings with Parties to continue negotiations of the
929 Framework Issues, which may occur in person or remotely.

930 **8.2.2. Multi-State Process Workgroup**

931 Consistent with Sections 8.4 or 8.5 of this Agreement, the Company will notify Parties and
932 other MSP participants if it determines a need exists to convene the MSP Workgroup to address
933 general allocation issues or complaints related to the 2020 Protocol. Any Party to this Agreement,
934 State utility regulatory agency, or other stakeholder can participate in the MSP Workgroup. The
935 MSP Workgroup may create sub-committees to investigate or evaluate or make recommendations
936 as to specified issues. MSP Workgroup meetings may be held in person or remotely.

937 **8.3. Commissioner Forum**

938 The 2017 Protocol included a mandatory requirement to hold an annual Commissioner
939 Forum each January during the pendency of that agreement. Under this 2020 Protocol,
940 Commission Forums are not required. A Commission or the MSP Workgroup may request such a
941 meeting of Commissioners. If a Commissioner Forum is requested, all seated commissioners from
942 each State will be invited to participate. Commissioner Forums will be public meetings, and all
943 interested parties will be allowed to attend. Before attending a Commissioner Forum, each
944 Commission can take such steps and provide such process for public input as the Commission
945 determines is necessary or appropriate under applicable State laws.

946 **8.4. Proposals to Change the 2020 Protocol during the Interim Period**

947 The Parties agree not to propose or support changes to the 2020 Protocol applicable to the
948 Interim Period based on a Party's dissatisfaction with a reasonably foreseeable outcome from
949 implementation of the 2020 Protocol. Before proposing an alternative or modification to the 2020

950 Protocol based primarily on changed or unforeseen circumstances, each Party agrees to first make
951 the proposal to the Parties and attempt in good faith to resolve the concern before asking a
952 Commission to change the 2020 Protocol. The provisions of this Section 8.4 will apply to any
953 State agency only to the extent consistent with the State agency's statutory obligations.

954 Proposals for modifications to the 2020 Protocol may be submitted to the Company by any
955 Party. Proposals received by the Company shall be circulated in a timely manner to the other
956 Parties and the Company shall initiate discussions to attempt to address and resolve specific
957 concerns.

958 **8.5. Replacement of the 2020 Protocol**

959 If any stakeholder that is not a Party to this Agreement objects to the use of the 2020
960 Protocol after approval by the Commissions or proposes a new inter-jurisdictional allocation
961 procedure, PacifiCorp may convene the MSP Workgroup and hold discussions to attempt to
962 address and resolve the concerns at an MSP Workgroup meeting(s).

963 **8.6. Interdependency Among Commission Approvals**

964 The 2020 Protocol has been developed and negotiated by the Parties as an integrated,
965 interdependent whole. Support by any Party of the 2020 Protocol is expressly conditioned upon
966 approval without material alteration of the 2020 Protocol by all Commissions in the States that
967 PacifiCorp has sought approval.²⁰ If any Commission disapproves, alters, or conditions approval
968 of the 2020 Protocol, Parties shall promptly meet and discuss the implications of that Commission's
969 action. PacifiCorp shall report to the Parties any Commission Order of another State concerning
970 the 2020 Protocol. Parties agree to recommend to each Commission that approval of the 2020
971 Protocol be conditioned on other Commissions approving the 2020 Protocol without change.


²⁰ California has historically reviewed allocation methodologies in conjunction with a general rate case. PacifiCorp's next regulatory-mandated general rate case will not be filed until 2021 at the earliest.

973 **9. Compliance with Resource Laws**

974 PacifiCorp asserts that the 2020 Protocol complies with the requirements of current
975 resource laws of all of the States and will not shift risk of compliance among PacifiCorp's States.
976 If a future change in law, court decision, or Commission decision results in the Company's
977 reasonable belief that compliance with all applicable laws cannot be achieved, the Company will
978 raise its concerns with the Parties and/or convene an MSP Workgroup meeting to address the issue.

979 **10. Signatures of Parties to the 2020 Protocol**

980 This 2020 Protocol is entered into by each Party on the date entered below such Party's
981 signature.

<p>PACIFICORP</p> <p>By:  Senior Vice President, Title: <u>Strategic Business Planning</u></p> <p>Date: <u>November 22, 2019</u></p>	<p>ALLIANCE OF WESTERN ENERGY CONSUMERS</p> <p>By: _____ Title: _____ Date: _____</p>
<p>IDAHO CONSERVATION LEAGUE</p> <p>By: _____ Title: _____ Date: _____</p>	<p>IDAHO PUBLIC UTILITIES COMMISSION STAFF</p> <p>By: _____ Title: _____ Date: _____</p>

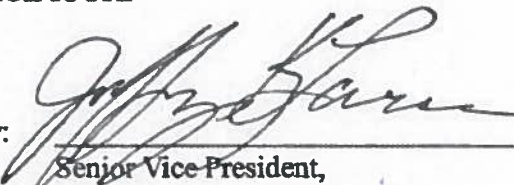
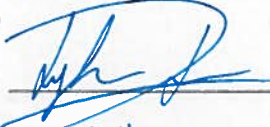
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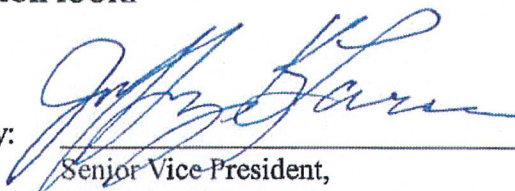

<p>PACIFICORP</p> <p>By:  Title: <u>Senior Vice President, Strategic Business Planning</u> Date: <u>November 22, 2019</u></p>	<p>ALLIANCE OF WESTERN ENERGY CONSUMERS</p> <p>By:  Title: <u>Attorney</u> Date: <u>11/25/19</u></p>
<p>IDAHO CONSERVATION LEAGUE</p> <p>By: _____ Title: _____ Date: _____</p>	<p>IDAHO PUBLIC UTILITIES COMMISSION STAFF</p> <p>By: _____ Title: _____ Date: _____</p>

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<p>IDAHO CONSERVATION LEAGUE</p> <p>By: </p> <p>Title: <u>Energy Associate</u></p> <p>Date: <u>November 27 2019</u></p>	<p>IDAHO PUBLIC UTILITIES COMMISSION STAFF</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>

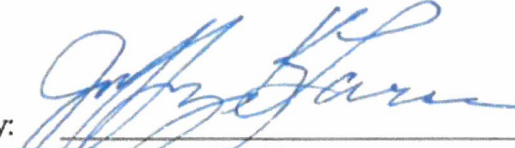
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978 raise its concerns with the Parties and/or convene an MSP Workgroup meeting to address the issue.

979 **10. Signatures of Parties to the 2020 Protocol**


980 This 2020 Protocol is entered into by each Party on the date entered below such Party's
981 signature.

<p>PACIFICORP</p> <p>By: </p> <p>Title: <u>Senior Vice President, Strategic Business Planning</u></p> <p>Date: <u>November 22, 2019</u></p>	<p>ALLIANCE OF WESTERN ENERGY CONSUMERS</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>
<p>IDAHO CONSERVATION LEAGUE</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>IDAHO PUBLIC UTILITIES COMMISSION STAFF</p> <p>By: <u>Jerri Carlock</u></p> <p>Title: <u>Administrator Utilities Division</u></p> <p>Date: <u>11/26/2019</u></p>

EXECUTION VERSION

<p>IDAHO IRRIGATION PUMPERS ASSOCIATION</p> <p>By: <u><i>Eric J. Olsen</i></u></p> <p>Title: <u><i>Attorney</i></u></p> <p>Date: <u><i>12/2/19</i></u></p>	<p>INTERWEST ENERGY ALLIANCE</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>
<p>MONSANTO COMPANY</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>NORTHWEST & INTERMOUNTAIN POWER PRODUCERS</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>
<p>NORTHWEST ENERGY COALITION</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>_____</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>
<p>OREGON CITIZENS' UTILITY BOARD</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>OREGON PUBLIC UTILITY COMMISSION STAFF</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>

EXECUTION VERSION

<p>IDAHO IRRIGATION PUMPERS ASSOCIATION</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>INTERWEST ENERGY ALLIANCE</p> <p></p> <p>By: <u>Lisa Tormoen Hickey</u></p> <p>Title: <u>Regulatory Attorney</u></p> <p>Date: <u>Tormoen Hickey LLC</u> <u>12/2/19</u></p>
<p>MONSANTO COMPANY</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>NORTHWEST & INTERMOUNTAIN POWER PRODUCERS</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>
<p>NORTHWEST ENERGY COALITION</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>_____</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>
<p>OREGON CITIZENS' UTILITY BOARD</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>OREGON PUBLIC UTILITY COMMISSION STAFF</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>


EXECUTION VERSION

<p>IDAHO IRRIGATION PUMPERS ASSOCIATION</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>INTERWEST ENERGY ALLIANCE</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>
<p>MONSANTO COMPANY</p> <p>By: <u>Randall C. Budge</u></p> <p>Title: <u>Attorney for Monsanto</u></p> <p>Date: <u>11/26/2019</u></p>	<p>NORTHWEST & INTERMOUNTAIN POWER PRODUCERS</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>
<p>NORTHWEST ENERGY COALITION</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>_____</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>
<p>OREGON CITIZENS' UTILITY BOARD</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>OREGON PUBLIC UTILITY COMMISSION STAFF</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>

EXECUTION VERSION

<p>IDAHO IRRIGATION PUMPERS ASSOCIATION</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>INTERWEST ENERGY ALLIANCE</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>
<p>MONSANTO COMPANY</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>NORTHWEST & INTERMOUNTAIN POWER PRODUCERS</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>
<p>NORTHWEST ENERGY COALITION</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>_____</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>
<p>OREGON CITIZENS' UTILITY BOARD</p> <p>By: <u>Bl. Aebler</u></p> <p>Title: <u>Executive Director</u></p> <p>Date: <u>11/26/2019</u></p>	<p>OREGON PUBLIC UTILITY COMMISSION STAFF</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>


EXECUTION VERSION

<p>IDAHO IRRIGATION PUMPERS ASSOCIATION</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>INTERWEST ENERGY ALLIANCE</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>
<p>MONSANTO COMPANY</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>NORTHWEST & INTERMOUNTAIN POWER PRODUCERS</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>
<p>NORTHWEST ENERGY COALITION</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>_____</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>
<p>OREGON CITIZENS' UTILITY BOARD</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>OREGON PUBLIC UTILITY COMMISSION STAFF</p> <p>By:  _____</p> <p>Title: <u>Assistant Attorney General</u></p> <p>Date: <u>11/25/19</u></p>

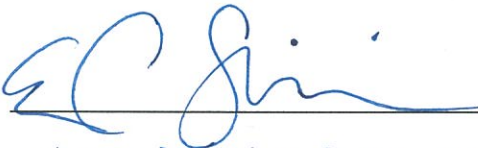
EXECUTION VERSION

<p>PACIFICORP IDAHO INDUSTRIAL CUSTOMERS</p> <p>By: <u>Rand L. Willis</u></p> <p>Title: <u>Attorney</u></p> <p>Date: <u>11-29-2019</u></p>	<p>PACKAGING CORPORATION OF AMERICA</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>
<p>POWDER RIVER BASIN RESOURCE COUNCIL</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>RENEWABLE NORTHWEST</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>
<p>SIERRA CLUB</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>UTAH ASSOCIATION OF ENERGY USERS</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>
<p>UTAH CLEAN ENERGY</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>UTAH DIVISION OF PUBLIC UTILITIES</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>

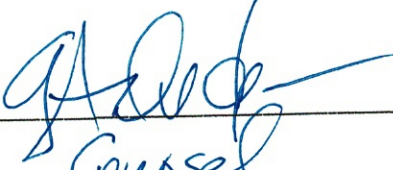
EXECUTION VERSION

<p>PACIFICORP IDAHO INDUSTRIAL CUSTOMERS</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>PACKAGING CORPORATION OF AMERICA</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>
<p>POWDER RIVER BASIN RESOURCE COUNCIL</p> <p>By:  _____</p> <p>Title: Staff Attorney</p> <p>Date: November 26, 2019</p>	<p>RENEWABLE NORTHWEST</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>
<p>SIERRA CLUB</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>UTAH ASSOCIATION OF ENERGY USERS</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>
<p>UTAH CLEAN ENERGY</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>UTAH DIVISION OF PUBLIC UTILITIES</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>

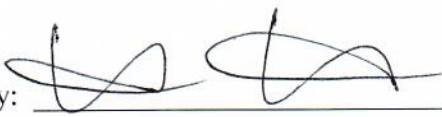
EXECUTION VERSION

<p>PACIFICORP IDAHO INDUSTRIAL CUSTOMERS</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>PACKAGING CORPORATION OF AMERICA</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>
<p>POWDER RIVER BASIN RESOURCE COUNCIL</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>RENEWABLE NORTHWEST</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>
<p>SIERRA CLUB</p> <p>By:  _____</p> <p>Title: <u>Western Director, Beyond Coal</u></p> <p>Date: <u>12/3/19</u></p>	<p>UTAH ASSOCIATION OF ENERGY USERS</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>
<p>UTAH CLEAN ENERGY</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>UTAH DIVISION OF PUBLIC UTILITIES</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>


EXECUTION VERSION

<p>PACIFICORP IDAHO INDUSTRIAL CUSTOMERS</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>PACKAGING CORPORATION OF AMERICA</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>
<p>POWDER RIVER BASIN RESOURCE COUNCIL</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>RENEWABLE NORTHWEST</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>
<p>SIERRA CLUB</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>UTAH ASSOCIATION OF ENERGY USERS</p> <p>By:  _____</p> <p>Title: <i>Counsel</i> _____</p> <p>Date: <i>11/27/19</i> _____</p>
<p>UTAH CLEAN ENERGY</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>UTAH DIVISION OF PUBLIC UTILITIES</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>

EXECUTION VERSION

<p>PACIFICORP IDAHO INDUSTRIAL CUSTOMERS</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>PACKAGING CORPORATION OF AMERICA</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>
<p>POWDER RIVER BASIN RESOURCE COUNCIL</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>RENEWABLE NORTHWEST</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>
<p>SIERRA CLUB</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>UTAH ASSOCIATION OF ENERGY USERS</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>
<p>UTAH CLEAN ENERGY</p> <p>By:  _____</p> <p>Title: <i>Staff Attorney</i> _____</p> <p>Date: <i>11/27/19</i> _____</p>	<p>UTAH DIVISION OF PUBLIC UTILITIES</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>

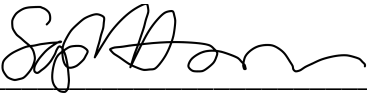
EXECUTION VERSION

<p>PACIFICORP IDAHO INDUSTRIAL CUSTOMERS</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>PACKAGING CORPORATION OF AMERICA</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>
<p>POWDER RIVER BASIN RESOURCE COUNCIL</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>RENEWABLE NORTHWEST</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>
<p>SIERRA CLUB</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>UTAH ASSOCIATION OF ENERGY USERS</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>
<p>UTAH CLEAN ENERGY</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>UTAH DIVISION OF PUBLIC UTILITIES</p> <p>By:  _____</p> <p>Title: <u>DIRECTOR</u> _____</p> <p>Date: <u>11/25/19</u> _____</p>

EXECUTION VERSION

<p>UTAH INDUSTRIAL ENERGY CONSUMERS</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>UTAH OFFICE OF CONSUMER SERVICES</p> <p>By: <u>Richard Seer</u></p> <p>Title: <u>Director</u></p> <p>Date: <u>11-27-19</u></p>
<p>VOTE SOLAR</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>WASHINGTON PUBLIC COUNSEL</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>
<p>WASHINGTON UTILITIES & TRANSPORTATION COMMISSION STAFF</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>WESTERN RESOURCE ADVOCATES</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>
<p>WOLVERINE FUELS</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>WYOMING INDUSTRIAL ENERGY CONSUMERS</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>

EXECUTION VERSION

<p>UTAH INDUSTRIAL ENERGY CONSUMERS</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>UTAH OFFICE OF CONSUMER SERVICES</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>
<p>VOTE SOLAR</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>WASHINGTON PUBLIC COUNSEL</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>
<p>WASHINGTON UTILITIES & TRANSPORTATION COMMISSION STAFF</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>WESTERN RESOURCE ADVOCATES</p> <p>By:  _____</p> <p>Title: <u>Senior Staff Attorney</u></p> <p>Date: <u>November 27, 2019</u></p>
<p>WOLVERINE FUELS</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>WYOMING INDUSTRIAL ENERGY CONSUMERS</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>

EXECUTION VERSION

<p>UTAH INDUSTRIAL ENERGY CONSUMERS</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>UTAH OFFICE OF CONSUMER SERVICES</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>
<p>VOTE SOLAR</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>WASHINGTON PUBLIC COUNSEL</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>
<p>WASHINGTON UTILITIES & TRANSPORTATION COMMISSION STAFF</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>WESTERN RESOURCE ADVOCATES</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>
<p>WOLVERINE FUELS</p> <p>By: <u>RB</u></p> <p>Title: <u>Chief Administrative officer</u></p> <p>Date: <u>11/26/19</u></p>	<p>WYOMING INDUSTRIAL ENERGY CONSUMERS</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>

EXECUTION VERSION

<p>UTAH INDUSTRIAL ENERGY CONSUMERS</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>UTAH OFFICE OF CONSUMER SERVICES</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>
<p>VOTE SOLAR</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>WASHINGTON PUBLIC COUNSEL</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>
<p>WASHINGTON UTILITIES & TRANSPORTATION COMMISSION STAFF</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>WESTERN RESOURCE ADVOCATES</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>
<p>WOLVERINE FUELS</p> <p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>WYOMING INDUSTRIAL ENERGY CONSUMERS</p> <p>By:  _____</p> <p>Title: <u>Attorney for WIEC</u></p> <p>Date: <u>November 25, 2019</u></p>

EXECUTION VERSION

<p>WYOMING OFFICE OF CONSUMER ADVOCATE</p> <p>By: <u>Ann H. Williams</u></p> <p>Title: <u>Senior Counsel</u></p> <p>Date: <u>11/25/2019</u></p>	<p>WYOMING PUBLIC SERVICE COMMISSION STAFF</p> <p>By: <u>[Signature]</u></p> <p>Title: <u>Staff Attorney</u></p> <p>Date: <u>11.25.2019</u></p>
<p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>
<p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>
<p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>	<p>By: _____</p> <p>Title: _____</p> <p>Date: _____</p>

APPENDIX A

Definitions

1 For purposes of this Agreement, the following terms will have the following meanings:

- 2 • **“2017 Protocol”** refers to the 2017 PacifiCorp Inter-Jurisdictional Allocation Protocol.
- 3 • **“2020 Protocol”** refers to the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol.
- 4 • **“Administrative and General Costs”** means costs included in FERC accounts 920 through 935.
- 5 • **“Assigned Production Factor” or “AP”** means States' assigned share of a Resource (see Appendix
6 C for more details).
- 7 • **“Assigned Production - Operations and Maintenance Factor” or “APOM Factor”** means the
8 State allocated share of all generation related operating and maintenance expenses that cannot be
9 associated with a specific Resource, such as general office generation management expenses, that
10 will be allocated to States calculated as each State's relative share of directly allocated generation
11 operating and maintenance expenses for steam, hydro, and other generation functions (see Section
12 5.1.1 and Appendix C for more details).
- 13 • **“Class 1 Demand-Side Management” or “Class 1 DSM”** means dispatchable or scheduled firm
14 DSM resources, sometimes referred to as direct load control programs.
- 15 • **“Closure”** means either PacifiCorp’s termination of ownership interest in a Resource, permanent
16 cessation of operations of a Resource, permanent cessation of receipt of energy from a Resource, or
17 otherwise retirement of a Resource.
- 18 • **“Coincident Peak”** means the hour each month that the combined demand of all PacifiCorp retail
19 customers is greatest, adjusted for normal weather conditions. The hour of coincident peak is
20 calculated assuming weather normalized retail load, and as it relates to generation allocation factors,
21 it includes adjustments for Class 1 DSM and Special Contract curtailments. In calculating the

EXECUTION VERSION

- 22 coincident peak for the System Transmission Factor, the only adjustment will be for weather
23 normalization.
- 24 • **“Commission”** means a utility regulatory commission in a State.
 - 25 • **“Commissioner Forum”** means the meeting of Commissioners from all States, the goal of which
26 is to provide an update from the MSP Workgroup. Such a forum is not required by the 2020 Protocol.
 - 27 • **“Commission Order”** means a formal determination issued by a State Commission consistent with
28 its authority as provided by a State's statutes or administrative rules.
 - 29 • **“Company”** means PacifiCorp.
 - 30 • **“Contributions in Aid of Construction” or “CIAC”** means contributions from customers to pay
31 their share of a capital construction project above the amount their retail rates justify. CIAC is a
32 reduction to rate base, (see Appendix C for more detail).
 - 33 • **“Customer Ancillary Services”** means products or services that may be provided by a customer to
34 the Company, such as in which the Company has the right to curtail electric service to the customer
35 so as to lower the costs of operating the Company’s system.
 - 36 • **“Customer Ancillary Service Contracts”** means contracts between the Company and a retail
37 customer pursuant to which the Company pays the customer for Customer Ancillary Services
 - 38 • **“Decommissioning Costs”** means the costs of removal and environmental remediation or
39 reclamation - net of any salvage value realized - required at the time a generation resource is
40 physically retired.
 - 41 • **“Decommissioning Studies”** means the engineering studies carried out in advance of planned coal-
42 fueled Interim Period Resource Reassignment filings in February of 2021 and June of 2024, in order
43 to identify the final Decommissioning Cost liabilities of Exiting States, as specifically identified in
44 Section 4.3.1.
 - 45 • **“Demand-Related”** describes capital and other fixed costs incurred by the Company in order to be
46 prepared to meet the maximum demand imposed upon its system.

- 47 • **“Demand-Side Management Programs” or “DSM Programs”** means programs intended to
48 reduce electricity use through activities or programs that promote electric energy efficiency or
49 conservation, more efficient management of electric energy loads, or reductions in peak demand.
- 50 • **“Embedded Cost Differential” or “ECD”** means the sum of PacifiCorp’s production costs of pre-
51 2005 resources as defined in the 2010 Protocol, excluding west side hydro, Mid-Columbia Contracts,
52 and Qualified Facility contracts, referred to as "all other generation resources" expressed in dollars
53 per megawatt-hour compared to west hydro-electric resources production costs expressed in dollars
54 per megawatt-hour with the difference multiplied by the hydro-electric resources megawatt-hours
55 of production, and the differential between the all other generation resources dollars per megawatt-
56 hour compared to Mid-Columbia Contracts costs dollars per megawatt-hour multiplied by the Mid-
57 Columbia Contracts megawatt-hours.
- 58 ○ **“Dynamic Embedded Cost Differential” or “Dynamic ECD”** means the ECD components
59 are updated to the test period utilized in the filing.
 - 60 ○ **“Fixed Embedded Cost Differential” or “Fixed ECD”** means the ECD amount for a State
61 is set at a point of time and not updated.
- 62 • **“Energy Imbalance Market” or “EIM”** means the multi-Balancing Authority Area (BAA) real-
63 time market operated by the California Independent System Operator (CAISO) that balances
64 electricity supply and demand every five minutes by choosing the least-cost resource to serve system
65 load.
- 66 • **“Energy-Related”** means variable costs incurred by the Company in order to deliver the energy
67 required to serve customers.
- 68 • **“Existing QF PPAs”** is defined in Section 4.4.1 of the agreement.
- 69

- 70 • **“Exit Date”** means the date, established in an Exit Order entered by a Commission, on which
71 PacifiCorp intends to discontinue the allocation of costs and assignment of benefits of a coal-fueled
72 Interim Period Resource to the State issuing the Exit Order.
- 73 • **“Exiting State”** means a State with a final order from a State Commission approving the exit from
74 a coal-fueled Interim Period Resource on a date certain.
- 75 • **“Exit Order”** means an order entered by a Commission establishing an Exit Date consistent with
76 the 2020 Protocol.
- 77 • **“Extended Day-Ahead Market” or “EDAM”** means a market currently still in development that
78 will address ramping needs between intervals and uncertainty that can occur between the day-ahead
79 and real-time markets.
- 80 • **“FERC”** means the Federal Energy Regulatory Commission.
- 81 • **“Five States”** means the States of California, Idaho, Oregon, Utah, and Wyoming.
- 82 • **“Fixed Costs”** means costs incurred by the Company that do not vary with the amount of energy
83 delivered by the Company to its customers during any hour.
- 84 • **“Framework”** is defined in Section 1 of the Agreement.
- 85 • **“Framework Issue”** is defined in Section 1 of the Agreement.
- 86 • **“General Plant”** means capital investment included in FERC accounts 389 through 399.
- 87 • **“Implemented Issues”** is defined in Section 1 of the Agreement.
- 88 • **“Intangible Plant”** means capital investment included in FERC accounts 301 through 303.
- 89 • **“Interim Period”** is defined in Section 2 of the Agreement.
- 90 • **“Interim Period Resource”** means Resource in commercial operation, or with a contract delivery
91 date, as applicable, during the Interim Period.
- 92 • **“Limited Realignment”** means the assignment of Interim Period Resources among PacifiCorp
93 States that differ from assignment using the SGF Factor.

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- 94 • **“Load-Based Dynamic Allocation Factor”** means an allocation factor that is calculated using
95 States’ monthly energy usage and/or States’ contribution to monthly system Coincident Peak.
- 96 • **“Mid-Columbia Contracts”** means the various power sales agreements between PacifiCorp and
97 Public Utility District No. 2 of Grant County, PacifiCorp and Douglas County Public Utility District,
98 and PacifiCorp and Chelan County Public Utility District, specifically: the Power Sales Contract
99 with Public Utility District No. 2 of Grant County dated May 22, 1956; the Power Sales Contract
100 with Public Utility District No. 2 of Grant County dated June 22, 1959; the Priest Rapids Project
101 Product Sales Contract with Public Utility District No. 2 of Grant County dated December 31, 2001;
102 the Additional Products Sales Agreement with Public Utility District No. 2 of Grant County dated
103 December 31, 2001; the Priest Rapids Project Reasonable Portion Power Sales Contract with Public
104 Utility District No. 2 of Grant County dated December 31, 2001; the Power Sales Contract with
105 Douglas County Public Utility District dated September 18, 1963; the Power Sales Contract with
106 Chelan County Public Utility District dated November 14, 1957, and all successor contracts thereto.
- 107 • **“MSP Workgroup”** means a group of regulators, the Company, and other interested stakeholders
108 that convenes to discuss the assignment or allocation of PacifiCorp revenues, costs, and investments
109 among the States.
- 110 • **“Multi-State Process” or “MSP”** means the ongoing Company-led convening of Parties from all
111 six States in which it operates to consider issues related to fair cost allocations among the States.
- 112 • **“Net Power Costs” or “NPC”** means PacifiCorp’s fuel and wheeling expenses and costs and
113 revenues associated with long-term Wholesale Contracts, Short-Term Purchases and Sales and Non-
114 Firm Purchases and Sales.
- 115 **“New QF PPA”** is defined in Section 4.4.2 of the Agreement.
- 116 • **“Nodal Pricing Model” or “NPM”** means a method for pricing electricity proposed by the
117 Company that is based on the marginal cost (\$/MWh) of serving the next increment of demand at a

- 118 given pricing node consistent with existing transmission constraints and the performance
119 characteristics of resources.
- 120 • **“Nodal Pricing Model Memorandum of Understanding” or “NPM MOU”** means the agreement
121 among the Parties on the prudence of the Company's proceeding to implement the Nodal Pricing
122 Model that may be adopted for the calculation of net power costs (NPC) through a new inter-
123 jurisdictional cost-allocation methodology.
 - 124 • **“Non-Firm Purchases and Sales”** means transactions at wholesale that are not Wholesale Contracts
125 or Short-Term Purchases and Sales.
 - 126 • **“Open Access Transmission Tariff”** means PacifiCorp's Open Access Transmission Tariff on file
127 with FERC.
 - 128 • **“Operations and Maintenance” or “O&M”** means costs incurred by the Company to maintain its
129 assets that are expensed as defined by FERC.
 - 130 • **“Oregon Direct Access Consumer”** means Oregon retail electricity consumers that procure
131 electricity from a supplier other than PacifiCorp under an Oregon Direct Access Program.
 - 132 • **“Oregon Direct Access Program”** means Oregon laws, regulations, and orders that permit
133 PacifiCorp's Oregon retail consumers to purchase electricity directly from a supplier other than
134 PacifiCorp.
 - 135 • **“Party” or “Parties”** means certain State Commission staff members, regulatory agencies,
136 customers, consumer advocates, conservation organizations, and other interested parties from
137 California, Idaho, Oregon, Utah, Washington, and Wyoming who have executed this Agreement.
 - 138 • **“Portfolio Standard”** means a law or regulation that requires PacifiCorp to acquire: (a) a particular
139 type of Resource, (b) a particular quantity of Resources, (c) Resources in a prescribed manner or (d)
140 Resources located in a particular geographic area.

- 141 • **“Post-Interim Period Method”** means the resolution of the Framework Issues combined with the
142 Implemented Issues and the Resolved Issues are all intended to result in the new allocation
143 methodology for PacifiCorp's six States.
- 144 • **“Post-Interim Period Resources”** means Resources that begin commercial operation, or with a
145 contract or delivery date, as applicable, after the end of the Interim Period.
- 146 • **“Qualifying Facility” or “QF”** means small power production or cogeneration facilities developed
147 under the Public Utility Regulatory Policies Act of 1978 (PURPA) and related State laws and
148 regulations.
- 149 • **“Qualifying Facility Power Purchase Agreement” or “QF PPA”** means contracts to purchase the
150 output of a Qualifying Facility by the Company.
- 151 • **“Reassignment”, “Reassign”, or “Reassigned”** means assigning benefits from an Exiting State's
152 share of a coal-fueled Interim Period Resource to those States with Commission orders to accept the
153 cost responsibility allocation for the Exiting State’s portion of the coal-fueled Resource.
- 154 • **“Resolved Issues”** is defined in Section 1 of the Agreement.
- 155 • **“Resource”** means a Company-owned generating unit, plant, mine, long-term Wholesale Contract,
156 Short-Term Purchase and Sale, Non-firm Purchase and Sale, or QF contract.
- 157 • **“Short-Term Firm Purchases and Firm Sales”** means physical or financial contracts pursuant to
158 which PacifiCorp purchases, sells, or exchanges firm power at wholesale and Customer Ancillary
159 Service Contracts that are less than one year in duration.
- 160 • **“Short-Term Purchases and Sales”** means physical or financial contracts pursuant to which
161 PacifiCorp purchases, sells, or exchanges firm power at wholesale and Customer Ancillary Service
162 Contracts that are less than one year in duration.
- 163 • **“Special Contract”** means a contract entered into between PacifiCorp and one of its retail customers
164 with prices, terms, and conditions different from otherwise-applicable tariff rates. Special Contracts

- 165 may provide for a value consideration to the customer to reflect attributes of Customer Ancillary
166 Service Contracts.
- 167 • **“State”** means California, Oregon, Idaho, Utah, Washington, or Wyoming.
 - 168 • **“State Resources”** means Interim Period Resources whose costs are assigned to a single
169 jurisdiction to accommodate jurisdiction-specific policy preferences.
 - 170 • **“System Energy Factor”** or **“SE Factor”** is defined in Appendix C.
 - 171 • **“System Generation-Fixed Factor”** or **“SGF Factor”** is defined in Appendix C.
 - 172 • **“System Gross Plant Distribution Factor”** or **“SGPD Factor”** is defined in Appendix C.
 - 173 • **“System Net Plant-Distribution Factor”** or **“SNPD Factor”** is defined in Appendix C.
 - 174 • **“System Overhead Factor”** or **“SO Factor”** is defined in Appendix C.
 - 175 • **“System Resources”** means Interim Period Resources that are not State Resources and whose
176 associated costs and revenues are allocated among all States on a dynamic basis.
 - 177 • **“System Transmission Factor”** or **“ST Factor”** is defined in Appendix C.
 - 178 • **“Trojan Decommissioning”** means costs associated with decommissioning the Trojan Plant.
 - 179 • **“Trojan Decommissioning Fixed Factor”** or **“TROJDF”** is defined in Appendix C.
 - 180 • **“Trojan Plant”** means the now-decommissioned nuclear plant for which the Company is still
181 recovering costs.
 - 182 • **“Variable Costs”** means costs incurred by the Company that vary with the amount of energy
183 delivered by the Company to its customers during any hour.
 - 184 • **“Washington Public Utility Tax”** means a Washington tax on public service businesses, including
185 businesses that engage in transportation, communications, and the supply of energy, natural gas, and
186 water. The tax is in lieu of the business and occupation (B&O) tax.
 - 187 • **“West Control Area Inter-jurisdictional Allocation Methodology”** or **“WCA”** means the
188 allocation protocol methodology used by Washington to allocate costs consistent with its Balancing
189 Area Authority-based principles governing the assets deemed to serve Washington.

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- 190 • **“Wholesale Contracts”** means physical or financial contracts pursuant to which PacifiCorp
191 purchases, sells, or exchanges firm power at wholesale and Customer Ancillary Service Contracts.

APPENDIX B

Allocation Factors by Account by Revenue Requirement Components

2020 Protocol - Appendix B

Allocation Factors by Account by Revenue Requirement Components

1	2	3	4	5
<u>FERC ACCT</u>	<u>ACCT NAME</u>	<u>REVENUE REQUIREMENT COMPONENTS ASSIGNED TO FACTOR</u>	<u>INTERIM PERIOD FACTOR</u>	<u>POST INTERIM PERIOD FACTOR</u>
Sales to Ultimate Customers				
440	Residential Sales	Retail Revenues Direct assigned - Jurisdiction	S	S
442	Commercial & Industrial Sales	Retail Revenues Direct assigned - Jurisdiction	S	S
444	Public Street & Highway Lighting	Retail Revenues Direct assigned - Jurisdiction	S	S
445	Other Sales to Public Authority	Retail Revenues Direct assigned - Jurisdiction	S	S
448	Interdepartmental	Retail Revenues Direct assigned - Jurisdiction	S	S
447	Sales for Resale	Wholesale Sales Direct assigned - Jurisdiction	S	S
		Non-Firm	SE	AP, NP
		Firm	SG	AP, NP
449	Provision for Rate Refund	Direct assigned - Jurisdiction	S	S
		Transmission	SG	ST
Other Electric Operating Revenues				
450	Forfeited Discounts & Interest	Retail Revenues Direct assigned - Jurisdiction	S	S
451	Misc Electric Revenue	Retail Revenues Direct assigned - Jurisdiction	S	S
		Other - Common	SO	SO
453	Water Sales	Retail Revenues Direct assigned - Jurisdiction	SG	AP
454	Rent of Electric Property	Retail Revenues Direct assigned - Jurisdiction	S	S
		Common	SG	ST
		Other - Common	SO	SO
456	Other Electric Revenue	Retail Revenues Direct assigned - Jurisdiction	S	S
		Wheeling Non-firm, Other	SE	ST
		Common	SO	SO
		Wheeling - Firm, Other	SG	ST
		Customer Related	CN	CN

Allocation Factors by Account by Revenue Requirement Components

1	2	3	4	5
<u>FERC ACCT</u>	<u>ACCT NAME</u>	<u>REVENUE REQUIREMENT COMPONENTS ASSIGNED TO FACTOR</u>	<u>INTERIM PERIOD</u> <u>FACTOR</u>	<u>POST INTERIM PERIOD</u> <u>FACTOR</u>
Miscellaneous Revenues				
41160	Gain on Sale of Utility Plant - CR			
		Distribution	S	S
		Production	SG	AP
		Transmission	SG	ST
		General Office	SO	SO
41170	Loss on Sale of Utility Plant			
		Distribution	S	S
		Production	SG	AP
		Transmission	SG	ST
		General Office	SO	SO
4118	Gain from Emission Allowances			
		SO2 Emission Allowance sales	SE	AP
41181	Gain from Disposition of NOX Credits			
		NOX Emission Allowance sales	SE	AP
421	(Gain) / Loss on Sale of Utility Plant			
		Distribution	S	S
		Production	SG	AP
		Transmission	SG	ST
		General Office	SO	SO
		Customer Related	CN	CN
Miscellaneous Expenses				
4311	Interest on Customer Deposits			
		Customer Service Deposits	CN	CN
		Direct assigned - Jurisdiction	S	S
Steam Power Generation				
500, 502, 504-514	Operation Supervision & Engineering			
		Steam Plants O&M	SG	AP, APOMS
501	Fuel Related			
		Steam plants Fuel	SE	AP, APOMS
503	Steam From Other Sources			
		Steam Royalties	SE	AP, APOMS
Nuclear Power Generation				
517 - 532	Nuclear Power O&M			
		Nuclear Plants O&M	SG	AP
Hydraulic Power Generation				
535 - 545	Hydro O&M			
		Pacific Hydro O&M	SG	AP, APOMH
		East Hydro O&M	SG	AP, APOMH
Other Power Generation				
546, 548-554	Operation Super & Engineering			
		Other Production Plant	SG	AP, APOMO
547	Fuel			
		Other Fuel Expense	SE	AP, APOMO

Allocation Factors by Account by Revenue Requirement Components

1	2	3	4	5
<u>FERC ACCT</u>	<u>ACCT NAME</u>	<u>REVENUE REQUIREMENT COMPONENTS ASSIGNED TO FACTOR</u>	<u>INTERIM PERIOD</u> <u>FACTOR</u>	<u>POST INTERIM PERIOD</u> <u>FACTOR</u>
Other Power Supply				
555	Purchased Power	Tracking Mechanisms	S	S
		Firm	SG	AP, NP
		Non-firm	SE	AP, NP
556	System Control & Load Dispatch	Other Expenses	SG	SE
557	Other Expenses	Direct assigned - Jurisdiction	S	S
		Other Expenses	SE	SE
		Other Expenses	SG	APOMS, APOMH, APOMO
		Cholla Transaction	SGCT	AP
TRANSMISSION EXPENSE				
560-564, 566-573	Transmission O&M	Transmission Plant O&M	SG	ST
565	Transmission of Electricity by Others	Firm Wheeling	SG	ST
		Non-Firm Wheeling	SE	ST
		GRID Management Charge	SG	SE
DISTRIBUTION EXPENSE				
580 - 598	Distribution O&M	Direct assigned - Jurisdiction	S	S
		Other Distribution	SNPD	SNPD
CUSTOMER ACCOUNTS EXPENSE				
901 - 905	Customer Accounts O&M	Direct assigned - Jurisdiction	S	S
		Total System Customer Related	CN	CN
CUSTOMER SERVICE EXPENSE				
907 - 910	Customer Service O&M	Direct assigned - Jurisdiction	S	S
		Total System Customer Related	CN	CN
SALES EXPENSE				
911 - 916	Sales Expense O&M	Direct assigned - Jurisdiction	S	S
		Total System Customer Related	CN	CN
ADMINISTRATIVE & GEN EXPENSE				
920-935	Administrative & General Expense	Direct assigned - Jurisdiction	S	S
		Customer Related	CN	CN
		Mine	SE	AP
		FERC Regulatory Expense	SG	ST
		General	SO	SO

Allocation Factors by Account by Revenue Requirement Components

1	2	3	4	5
<u>FERC ACCT</u>	<u>ACCT NAME</u>	<u>REVENUE REQUIREMENT COMPONENTS ASSIGNED TO FACTOR</u>	<u>INTERIM PERIOD FACTOR</u>	<u>POST INTERIM PERIOD FACTOR</u>
DEPRECIATION EXPENSE				
403SP	Steam Depreciation	Steam Plants	SG	AP
403NP	Nuclear Depreciation	Nuclear Plant	SG	AP
403HP	Hydro Depreciation	Pacific Hydro	SG	AP
		East Hydro	SG	AP
403OP	Other Production Depreciation	Other Production Plant	SG	AP
403TP	Transmission Depreciation	Transmission Plant	SG	ST
403	Distribution Depreciation Direct assigned - Jurisdiction	Land & Land Rights	S	S
		Structures	S	S
		Station Equipment	S	S
		Storage Battery Equipment	S	S
		Poles & Towers	S	S
		OH Conductors	S	S
		UG Conduit	S	S
		UG Conductor	S	S
		Line Trans	S	S
		Services	S	S
		Meters	S	S
		Inst Cust Prem	S	S
		Leased Property	S	S
		Street Lighting	S	S
403GP	General Depreciation	Distribution	S	S
		Steam Plants	SG	AP
		Mining	SE	AP
		Pacific Hydro	SG	AP
		East Hydro	SG	AP
		Transmission	SG	ST
		Customer Related	CN	CN
		General	SO	SO
403MP	Mining Depreciation	Mining Plant	SE	AP

Allocation Factors by Account by Revenue Requirement Components

1	2	3	4	5
<u>FERC ACCT</u>	<u>ACCT NAME</u>	<u>REVENUE REQUIREMENT COMPONENTS ASSIGNED TO FACTOR</u>	<u>INTERIM PERIOD</u> <u>FACTOR</u>	<u>POST INTERIM PERIOD</u> <u>FACTOR</u>
AMORTIZATION EXPENSE				
404GP	Amort of LT Plant - Capital Lease Gen	Direct assigned - Jurisdiction	S	S
		General	SO	SO
		Customer Related	CN	CN
404SP	Amort of LT Plant - Cap Lease Steam	Steam Production Plant	SG	AP
404IP	Amort of LT Plant - Intangible Plant	Distribution	S	S
		Production	SG	AP
		Transmission	SG	ST
		General	SO	SO
		Mining Plant	SE	AP
		Customer Related	CN	CN
404MP	Amort of LT Plant - Mining Plant	Mining Plant	SE	AP
404HP	Amortization of Other Electric Plant	Pacific Hydro	SG	AP
		East Hydro	SG	AP
405	Amortization of Other Electric Plant	Direct assigned - Jurisdiction	S	S
406	Amortization of Plant Acquisition Adj	Direct assigned - Jurisdiction	S	S
		Production Plant	SG	AP
407	Amort of Prop Losses, Unrec Plant, etc.	Direct assigned - Jurisdiction	S	S
		Production,	SG	AP
		Transmission	SG	ST
Taxes Other Than Income				
408	Taxes Other Than Income	Direct assigned - Jurisdiction	S	S
		Property	GPS	GPS
		System Taxes	SO	SO
		Misc Energy	SE	AP
		Misc Production	SG	AP
DEFERRED ITC				
41140	Deferred Investment Tax Credit - Fed	ITC	DGU	DGUF
41141	Deferred Investment Tax Credit - Idaho	ITC	DGU	DGUF

Allocation Factors by Account by Revenue Requirement Components

1	2	3	4	5
<u>FERC ACCT</u>	<u>ACCT NAME</u>	<u>REVENUE REQUIREMENT COMPONENTS ASSIGNED TO FACTOR</u>	<u>INTERIM PERIOD FACTOR</u>	<u>POST INTERIM PERIOD FACTOR</u>
Interest Expense				
427	Interest on Long-Term Debt			
		Direct assigned - Jurisdiction	S	S
		Interest Expense	SNP	SNP
428	Amortization of Debt Disc & Exp			
		Interest Expense	SNP	SNP
429	Amortization of Premium on Debt			
		Interest Expense	SNP	SNP
431	Other Interest Expense			
		Interest Expense	SNP	SNP
432	AFUDC - Borrowed			
		AFUDC	SNP	SNP
Interest & Dividends				
419	Interest & Dividends			
		Interest & Dividends	SNP	SNP
DEFERRED INCOME TAXES				
41010	Deferred Income Tax - DR			
		Direct assigned - Jurisdiction	S	S
		Non-Coal and Gas Production	SG	AP
		Coal and Gas Production	SG	AP
		Transmission	SG	ST
		Customer Related	CN	CN
		General	SO	SO
		Property Tax related	GPS	GPS
		Miscellaneous	SNP	SNP
		Trojan	TROJD	TROJDF
		Distribution	SNPD	SNPD
		Mining Plant	SE	AP
		Bad Debt	BADDEBT	BADDEBT
		Tax Depreciation	TAXDEPR	TAXDEPR

Allocation Factors by Account by Revenue Requirement Components

1	2	3	4	5
<u>FERC ACCT</u>	<u>ACCT NAME</u>	<u>REVENUE REQUIREMENT COMPONENTS ASSIGNED TO FACTOR</u>	<u>INTERIM PERIOD</u> <u>FACTOR</u>	<u>POST INTERIM PERIOD</u> <u>FACTOR</u>
41110	Deferred Income Tax -CR			
		Direct assigned - Jurisdiction	S	S
		Non-Coal and Gas Production	SG	AP
		Coal and Gas Production	SG	AP
		Transmission	SG	ST
		Customer Related	CN	CN
		General	SO	SO
		Property Tax related	GPS	GPS
		Miscellaneous	SNP	SNP
		Trojan	TROJD	TROJDF
		Distribution	SNPD	SNPD
		Mining Plant	SE	AP
		Contributions in Aid of Construction	CIAC	CIAC
		Production, Other	SGCT	AP
		Book Depreciation	SCHMDEXP	SCHMDEXP
SCHEDULE - M ADDITIONS				
SCHMAF	Additions - Flow Through			
		Direct assigned - Jurisdiction	S	S
SCHMAP	Additions - Permanent			
		Direct assigned - Jurisdiction	S	S
		Mining related	SE	AP
		General	SO	SO
		Non-Coal and Gas Production	SG	AP
		Coal and Gas Production	SG	AP
		Transmission	SG	ST
		Depreciation	SCHMDEXP	SCHMDEXP
SCHMAT	Additions - Temporary			
		Direct assigned - Jurisdiction	S	S
		Bad Debt	BADDEBT	BADDEBT
		Contributions in Aid of Construction	CIAC	CIAC
		Miscellaneous	SNP	SNP
		Trojan	TROJD	TROJDF
		Non-Coal and Gas Production	SG	AP
		Mining Plant	SE	AP
		Coal and Gas Production	SG	AP
		Transmission	SG	ST
		Property Tax	GPS	GPS
		General	SO	SO
		Depreciation	SCHMDEXP	SCHMDEXP
		Distribution	SNPD	SNPD
		Production, Other	SGCT	AP

Allocation Factors by Account by Revenue Requirement Components

1	2	3	4	5
<u>FERC ACCT</u>	<u>ACCT NAME</u>	<u>REVENUE REQUIREMENT COMPONENTS ASSIGNED TO FACTOR</u>	<u>INTERIM PERIOD</u> <u>FACTOR</u>	<u>POST INTERIM PERIOD</u> <u>FACTOR</u>
SCHEDULE - M DEDUCTIONS				
SCHMDF	Deductions - Flow Through			
		Direct Assigned - Jurisdiction	S	S
		Coal and Gas Production	SG	AP
		Transmission	SG	ST
		Non-Coal and Gas Production	SG	AP
SCHMDP	Deductions - Permanent			
		Direct Assigned - Jurisdiction	S	S
		Mining Related	SE	AP
		Depreciation	SCHMDEXP	SCHMDEXP
		Miscellaneous	SNP	SNP
		General	SO	SO
SCHMDT	Deductions - Temporary			
		Direct Assigned - Jurisdiction	S	S
		Bad Debt	BADDEBT	BADDEBT
		Miscellaneous	SNP	SNP
		Non-Coal and Gas Production	SG	AP
		Mining related	SE	AP
		Coal and Gas Production	SG	AP
		Transmission	SG	ST
		Property Tax	GPS	GPS
		General	SO	SO
		Depreciation	TAXDEPR	TAXDEPR
		Distribution	SNPD	SNPD
		Customer Related	CN	CN
State Income Taxes				
40911	State Income Taxes			
40911		Income Before Taxes	CALCULATED	CALCULATED
40911		Renewable Energy Tax Credit	SG	AP
40910		FIT True-up	S	S
40910		Renewable Energy / Production Tax Credit	SG	AP
40911		PacifiCorp Minerals Inc.	SE	AP
40911		Foreign Tax Credit	SO	SO
Steam Production Plant				
310 - 316	Steam Plants			
		Steam Plants	SG	AP
Nuclear Production Plant				
320-325	Nuclear Plant			
		Nuclear Plant	SG	AP
Hydraulic Plant				
330-336	Hydro Plant			
		Pacific Hydro	SG	AP
		East Hydro	SG	AP

Allocation Factors by Account by Revenue Requirement Components

1	2	3	4	5
<u>FERC ACCT</u>	<u>ACCT NAME</u>	<u>REVENUE REQUIREMENT COMPONENTS ASSIGNED TO FACTOR</u>	<u>INTERIM PERIOD FACTOR</u>	<u>POST INTERIM PERIOD FACTOR</u>
Other Production Plant				
340-346	Other Production Plant	Other Production Plant - Situs	S	S
		Other Production Plant	SG	AP
TRANSMISSION PLANT				
350-359	Transmission Plant	Transmission Plant	SG	ST
DISTRIBUTION PLANT				
360-373	Distribution Plant	Direct assigned - Jurisdiction	S	S
GENERAL PLANT				
389 - 398	General Plant	Distribution	S	S
		Pacific Hydro	SG	AP
		East Hydro	SG	AP
		Production	SG	AP, SE
		Transmission	SG	ST
		Customer Related	CN	CN
		General	SO	SO
		Mining	SE	AP
399	Coal Mine	Mining Plant	SE	AP
1011346	General Gas Line Capital Leases	Capital Lease	SG	AP
1011390	General Capital Leases	Direct assigned - Jurisdiction	S	S
		General	SO	SO
		Generation	SG	AP
		Transmission	SG	ST
INTANGIBLE PLANT				
301	Organization	Direct assigned - Jurisdiction	S	S
302	Franchise & Consent	Direct assigned - Jurisdiction	S	S
		Production	SG	AP
		Transmission	SG	ST
303	Miscellaneous Intangible Plant	Distribution	S	S
		Pacific Hydro	SG	AP
		East Hydro	SG	AP
		Production	SG	AP
		Transmission	SG	ST
		Customer Related	CN	CN
		General	SO	SO
		Mining	SE	AP
		Other	SG	SGF

Allocation Factors by Account by Revenue Requirement Components

1	2	3	4	5
<u>FERC ACCT</u>	<u>ACCT NAME</u>	<u>REVENUE REQUIREMENT COMPONENTS ASSIGNED TO FACTOR</u>	<u>INTERIM PERIOD FACTOR</u>	<u>POST INTERIM PERIOD FACTOR</u>
303	Less Non-Utility Plant	Direct assigned - Jurisdiction	S	S
Rate Base Additions				
105	Plant Held For Future Use	Direct assigned - Jurisdiction	S	S
		Production	SG	AP
		Transmission	SG	ST
		Mining Plant	SE	AP
114	Electric Plant Acquisition Adjustments	Direct assigned - Jurisdiction	S	S
		Production Plant	SG	AP
		Transmission	SG	ST
115	Accum Provision for Asset Acquisition Adjustments	Direct assigned - Jurisdiction	S	S
		Production Plant	SG	AP
		Transmission	SG	ST
124	Weatherization	Direct assigned - Jurisdiction	S	S
		General	SO	SO
128	Pensions	General	SO	SO
182W	Weatherization	Direct assigned - Jurisdiction	S	S
186W	Weatherization	Direct assigned - Jurisdiction	S	S
151	Fuel Stock	Steam Production Plant	SE	AP
152	Fuel Stock - Undistributed	Steam Production Plant	SE	AP
25316	UAMPS Working Capital Deposit	Mining Plant	SE	AP
25317	DG&T Working Capital Deposit	Mining Plant	SE	AP
25319	Provo Working Capital Deposit	Mining Plant	SE	AP

Allocation Factors by Account by Revenue Requirement Components

1	2	3	4	5
<u>FERC ACCT</u>	<u>ACCT NAME</u>	<u>REVENUE REQUIREMENT COMPONENTS ASSIGNED TO FACTOR</u>	<u>INTERIM PERIOD FACTOR</u>	<u>POST INTERIM PERIOD FACTOR</u>
154	Materials and Supplies	Direct assigned - Jurisdiction	S	S
		Production,	SG	AP
		Transmission	SG	ST
		Mining	SE	AP
		Production - Common	SG	AP
		General	SO	SO
		Distribution	SNPD	SNPD
		Production, Other	SG	AP
163	Stores Expense Undistributed	General	SO	SO
25318	Provo Working Capital Deposit	Provo Working Capital Deposit	SG	AP
165	Prepayments	Direct assigned - Jurisdiction	S	S
		Property Tax	GPS	GPS
		Production	SG	AP
		Transmission	SG	ST
		Mining	SE	AP
		General	SO	SO
182M	Misc Regulatory Assets	Direct assigned - Jurisdiction	S	S
		Production	SG	AP
		Transmission	SG	ST
		Mining	SE	AP
		General	SO	SO
		Production, Other	SGCT	AP
		Other	SG	SGF
186M	Misc Deferred Debits	Direct assigned - Jurisdiction	S	S
		Production	SG	AP
		Transmission	SG	ST
		General	SO	SO
		Mining	SE	AP
		Production - Common	SG	AP
		Other	SG	SGF
Working Capital				
CWC	Cash Working Capital	Direct assigned - Jurisdiction	S	S
OWC	Other Working Capital			
131	Cash		SNP	SNP
135	Working Funds		SG	AP
141	Notes Receivable		SO	SO
143	Other Accounts Receivable		SO	SO

Allocation Factors by Account by Revenue Requirement Components

1	2	3	4	5
<u>FERC ACCT</u>	<u>ACCT NAME</u>	<u>REVENUE REQUIREMENT COMPONENTS ASSIGNED TO FACTOR</u>	<u>INTERIM PERIOD</u>	<u>POST INTERIM PERIOD</u>
			<u>FACTOR</u>	<u>FACTOR</u>
232		Accounts Payable	SO	SO
232		Accounts Payable	SE	AP
232		Accounts Payable	SG	ST, AP, SGF
25330		Other Deferred Credits - Misc	SE	AP
230		Other Deferred Credits - Misc	SE	AP
254105		ARO Reg Liability	SE	AP
Rate Base Deductions				
235	Customer Service Deposits			
		Direct assigned - Jurisdiction	S	S
2281	Prov for Property Insurance			
		Prov for Property Insurance	SO	SO
2282	Prov for Injuries & Damages			
		Prov for Injuries & Damages	SO	SO
2283	Prov for Pensions and Benefits			
		Prov for Pensions and Benefits	SO	SO
22841	Accum Misc Oper Prov-Black Lung			
		Other Production	SG	AP
254105	FAS 143 ARO Regulatory Liability			
		ARO	S	S
		Trojan Plant	TROJD	TROJDF
230	Asset Retirement Obligation			
		Trojan Plant	TROJD	TROJDF
252	Customer Advances for Construction			
		Direct assigned - Jurisdiction	S	S
		Production	SG	AP
		Transmission	SG	ST
		Customer Related	CN	CN
25398	S02 Emissions			
		S02 Emissions	SE	AP
25399	Other Deferred Credits			
		Direct assigned - Jurisdiction	S	S
		Production	SG	AP
		Transmission	SG	ST
		General	SO	SO
		Mining	SE	AP
254	Regulatory Liabilities			
		Insurance Provision	SO	SO

Allocation Factors by Account by Revenue Requirement Components

1	2	3	4	5
<u>FERC ACCT</u>	<u>ACCT NAME</u>	<u>REVENUE REQUIREMENT COMPONENTS ASSIGNED TO FACTOR</u>	<u>INTERIM PERIOD</u> <u>FACTOR</u>	<u>POST INTERIM PERIOD</u> <u>FACTOR</u>
190	Accumulated Deferred Income Taxes			
		Direct assigned - Jurisdiction	S	S
		Bad Debt	BADDEBT	BADDEBT
		Non-Coal and Gas Production	SG	AP
		Coal and Gas Production	SG	AP
		Transmission	SG	ST
		Customer Related	CN	CN
		General	SO	SO
		Miscellaneous	SNP	SNP
		Trojan	TROJD	TROJDF
		Distribution	SNPD	SNPD
		Mining Plant	SE	AP
281	Accumulated Deferred Income Taxes			
		Non-Coal and Gas Production	SG	AP
		Coal and Gas Production	SG	AP
		Transmission	SG	ST
282	Accumulated Deferred Income Taxes			
		Direct assigned - Jurisdiction	S	S
		Depreciation	DITBAL	DITBAL
		Non-Coal and Gas Production	SG	AP
		Coal and Gas Production	SG	AP
		Transmission	SG	ST
		Customer Related	CN	CN
		General	SO	SO
		Miscellaneous	SNP	SNP
		Depreciation	TAXDEPR	TAXDEPR
		Depreciation	SCHMDEXP	SCHMDEXP
		System Gross Plant	GPS	GPS
		Contribution in Aid of Construction	CIAC	CIAC
		Mining	SE	AP
283	Accumulated Deferred Income Taxes			
		Direct assigned - Jurisdiction	S	S
		Depreciation	DITBAL	DITBAL
		Non-Coal and Gas Production	SG	AP
		Coal and Gas Production	SG	AP
		Transmission	SG	ST
		Customer Related	CN	CN
		General	SO	SO
		Miscellaneous	SNP	SNP
		Trojan	TROJD	TROJDF
		Production, Other	SGCT	AP
		Property Tax	GPS	GPS
		Mining Plant	SE	AP
255	Accumulated Investment Tax Credit			
		Direct assigned - Jurisdiction	S	S
		Investment Tax Credits	ITC84	ITC84
		Investment Tax Credits	ITC85	ITC85
		Investment Tax Credits	ITC86	ITC86
		Investment Tax Credits	ITC88	ITC88
		Investment Tax Credits	ITC89	ITC89
		Investment Tax Credits	ITC90	ITC90
		Investment Tax Credits	SG	SGF

Allocation Factors by Account by Revenue Requirement Components

1	2	3	4	5
<u>FERC ACCT</u>	<u>ACCT NAME</u>	<u>REVENUE REQUIREMENT COMPONENTS ASSIGNED TO FACTOR</u>	<u>INTERIM PERIOD</u> <u>FACTOR</u>	<u>POST INTERIM PERIOD</u> <u>FACTOR</u>
PRODUCTION PLANT ACCUM DEPRECIATION				
108SP	Steam Prod Plant Accumulated Depr	Steam Plants	SG	AP
108NP	Nuclear Prod Plant Accumulated Depr	Nuclear Plant	SG	AP
108HP	Hydraulic Prod Plant Accum Depr	Pacific Hydro	SG	AP
		East Hydro	SG	AP
108OP	Other Production Plant - Accum Depr	Other Production Plant	SG	AP
TRANS PLANT ACCUM DEPR				
108TP	Transmission Plant Accumulated Depr	Transmission Plant	SG	ST
DISTRIBUTION PLANT ACCUM DEPR				
108360 - 108373	Distribution Plant Accumulated Depr	Direct assigned - Jurisdiction	S	S
108D00	Unclassified Dist Plant - Acct 300	Direct assigned - Jurisdiction	S	S
108DS	Unclassified Dist Sub Plant - Acct 300	Direct assigned - Jurisdiction	S	S
108DP	Unclassified Dist Sub Plant - Acct 300	Direct assigned - Jurisdiction	S	S
GENERAL PLANT ACCUM DEPR				
108GP	General Plant Accumulated Depr.	Distribution	S	S
		Pacific Hydro	SG	AP
		East Hydro	SG	AP
		Production	SG	AP
		Transmission	SG	ST
		Customer Related	CN	CN
		General SO	SO	SO
		Mining Plant	SE	AP
108MP	Mining Plant Accumulated Depr.	Mining Plant	SE	AP
1081390	Accum Depr - Capital Lease	General	SO	SO
1081399	Accum Depr - Capital Lease	Direct assigned - Jurisdiction	S	S

Allocation Factors by Account by Revenue Requirement Components

1	2	3	4	5
<u>FERC ACCT</u>	<u>ACCT NAME</u>	<u>REVENUE REQUIREMENT COMPONENTS ASSIGNED TO FACTOR</u>	<u>INTERIM PERIOD</u> <u>FACTOR</u>	<u>POST INTERIM PERIOD</u> <u>FACTOR</u>
ACCUM PROVISION FOR AMORTIZATION				
111SP	Accum Prov for Amort-Steam	Steam Plants	SG	AP
111GP	Accum Prov for Amort-General	Distribution	S	S
		Pacific Hydro	SG	AP
		East Hydro	SG	AP
		Production	SG	AP
		Transmission	SG	ST
		Customer Related	CN	CN
		General SO	SO	SO
111HP	Accum Prov for Amort-Hydro	Pacific Hydro	SG	AP
		East Hydro	SG	AP
111IP	Accum Prov for Amort-Intangible Plant	Distribution	S	S
		Pacific Hydro	SG	AP
		Production	SG	AP
		Transmission	SG	ST
		General	SO	SO
		Mining	SE	AP
		Customer Related	CN	CN
111IP	Less Non-Utility Plant	Direct assigned - Jurisdiction	S	S
111390	Accum Prov Amort - Capital Leases	Distribution	S	S
		Production	SG	AP
		General	SO	SO

APPENDIX C

Definitions of Allocation Factors

Factors without an effective period will be used during and after the Interim Period.

i denotes count of jurisdictions. j denotes count of month in a year. N is the number of regulatory jurisdictions that the Company operates in and allocates costs to.

Assigned Production Factor (“AP”) – Effective after Interim Period

$$AP_i = \frac{SGF_i}{\sum_{i=1}^x SGF_i}$$

where:

AP_i	=	Assigned Production Factor for jurisdiction i .
SGF_i	=	System Generation – Fixed Factor for jurisdiction i .
x	=	Number of jurisdictions that are assigned the unit.

The AP factor may be calculated by unit of Resources, group of Resources, or for specific periods of capital investments. The AP factor may change over time as allocations change due to jurisdictions accepting a larger or smaller assignment in units that lead to the change in the value of x .

For example,

1. Assuming a unit is assigned to States A, B and C out of six jurisdictions in year 1, and their SGF factors are

$SGF_A = 25\%$, $SGF_B = 45\%$, and $SGF_C = 15\%$, respectively, then

$$AP_A = \frac{25\%}{25\% + 45\% + 15\%} = 29.4\%$$

$$AP_B = \frac{45\%}{25\% + 45\% + 15\%} = 52.9\%$$

$$AP_C = \frac{15\%}{25\% + 45\% + 15\%} = 17.6\%$$

2. Assuming the unit is later assigned to States B and C only, then the AP factors will change to

$$AP_A = 0\%$$

$$AP_B = \frac{45\%}{45\% + 15\%} = 75\%$$

$$AP_C = \frac{15\%}{45\% + 15\%} = 25\%$$

3. Assuming the unit is later assigned to C only, then the AP factors will change to

$$AP_A = 0\%$$

$$AP_B = 0\%$$

$$AP_C = \frac{15\%}{15\%} = 100\%$$

Accounts using AP factor: Sales for Resale (447), Water Sales (453), Miscellaneous Revenue (41160, 41170, 4118, 41181, 421), Generation (500-555, 557), Administrative and General Expense (920-935), Depreciation Expense (403SP, 403NP, 403HP, 403OP, 403GP, 403MP) Amortization Expense (404SP, 404IP, 404HP, 404MP 406-407), Taxes Other Than Income (408), Deferred Income Tax Expense (41010, 41110), Schedule M, Income Taxes (40910, 40911), Generation Plant (310-346), General Plant (389-399), Intangible Plant (302-303), Plant Held for Future Use (105), Electric Plant Acquisition Adjustments (114-115), Fuel Stock (151-152), Materials and Supplies (154), Mining Working Capital Deposits (25316-25319), Prepayments (165), Misc. Regulatory Assets (182M), Misc. Deferred Debits (186M), Working Capital (135, 232, 25330, 230, 245105), Accum Misc Oper Prov-Black Lung (22841), Customer Advances for Construction (252), SO2 Emissions (25398), Other Deferred Credits (25399), Regulatory Liabilities ARO Regulatory Liability (254105), Accumulated Deferred Income Taxes (190, 281-283), Accumulated Depreciation (108SP, 108NP, 108HP, 108OP, 108GP, 108MP), Accumulated Provision for Amortization (111SP, 111GP, 111HP, 111IP, 111390)

Assigned Production Factor of New Resources – Effective after Interim Period

Initial values of AP factors for all new resources will be addressed as part of the Framework discussions on Resource Planning.

Assigned Production Hydro – O&M Factor (“APOMH”) – Effective after Interim Period

$$APOMH_i = \frac{PPOMH_i}{\sum_{i=1}^N PPOMH_i}$$

where:

$APOMH_i$	=	Assigned Production Hydro O&M Factor for jurisdiction i.
$PPOMH_i$	=	Sum of all hydro production plant O&M costs allocated to jurisdiction i using the AP factors.
N	=	Number of jurisdictions.

The APOMH factor is used to allocate hydro generation related O&M costs that cannot be allocated to a specific hydro resource through an AP factor, calculated as each States’ relative share of direct-allocated hydro generation and maintenance expenses.

Accounts using APOMH factor: Hydro (535-545, 557)

Assigned Production Other – O&M Factor (“APOMO”) – Effective after Interim Period

$$APOMO_i = \frac{PPOMO_i}{\sum_{i=1}^N PPOMO_i}$$

where:

$APOMO_i$	=	Assigned Production Other O&M Factor for jurisdiction i.
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$PPOMO_i$ = Sum of all other production plant O&M costs allocated to jurisdiction i using the AP factors.
 N = Number of jurisdictions.

The APOMO factor is used to allocate other generation related O&M costs that cannot be allocated to specific other production Resource through an AP factor, calculated as each States’ relative share of directly-allocated other production generation and maintenance expenses.

Accounts using APOMO factor: Other Generation (546-554, 557)

Assigned Production Steam – O&M Factor (“APOMS”) – Effective after Interim Period

$$APOMS_i = \frac{PPOMS_i}{\sum_{i=1}^N PPOMS_i}$$

where:

$APOMS_i$ = **Assigned Production Steam O&M Factor** for jurisdiction i.
 $PPOMS_i$ = Sum of all steam production plant O&M costs allocated to jurisdiction i using the AP factors.
 N = Number of jurisdictions.

The APOMS factor is used to allocate steam generation related O&M costs that cannot be allocated to specific steam resource through an AP factor, calculated as each States’ relative share of direct-allocated steam generation and maintenance expenses.

Accounts using APOMS factor: Generation (500-514, 557)

Bad Debt Expense Factor (“BADDEBT”)

$$BADDEBT_i = \frac{ACCT904_i}{\sum_{i=1}^N ACCT904_i}$$

where:

$BADDEBT_i$ = **Bad Debt Expense Factor** for jurisdiction i.
 $ACCT904_i$ = Balance in FERC Account 904 for jurisdiction i.
 N = Number of jurisdictions.

The BADDEBT Factor is calculated by dividing the FERC account 904 Uncollectible Accounts amount for a jurisdiction by the total 904 amount for all jurisdictions. The factor allocates tax related costs for bad debt related expenses.

Accounts using BADDEBT factor: Deferred Income Tax Expense (41010), Schedule M, Accumulated Deferred Income Taxes (190)

Contributions in Aid of Construction Factor (“CIAC”)

$$CIAC_i = \frac{CIACNA_i}{\sum_{i=1}^N CIACNA_i}$$

where:

$CIAC_i$ = **Contributions in Aid of Construction Factor** for jurisdiction i.
 $CIACNA_i$ = Contributions in aid of construction – net additions for jurisdiction i.

N = Number of jurisdictions.

The CIAC Factor is calculated by dividing the contribution in aid of construction net additions for a jurisdiction by the total contribution in aid of construction net additions for all jurisdictions. The factor allocates tax related costs for contributions in aid of construction.

Accounts using CIAC factor: Deferred Income Tax Expense (41110), Schedule M, Accumulated Deferred Income Taxes (282)

Customer Number Factor (“CN”)

$$CN_i = \frac{CUST_i}{\sum_{i=1}^N CUST_i}$$

where:

CN_i = **Customer Number Factor** for jurisdiction i.
 $CUST_i$ = Total electric customers for jurisdiction i.
 N = Number of jurisdictions.

The Customer Number Factor is calculated using the ratio of number of customers for a jurisdiction to the total number of electric customers for all jurisdictions. The factor is used to allocate customer related costs.

Accounts using CN factor: Gain / Loss on Sale of Utility Plant (421), Customer Service Deposits (4311), Other Electric Revenue (456), Customer Account Expense (901-905), Customer Service Expense (907-910), Sales Expense (911-916), Administrative and General Expense (920-935), General Plant Depreciation (403GP), Amortization Intangible Plant (404IP), Deferred Income Tax Expense (41010, 41110), Schedule M, General Plant (389-398), Intangible Plant (303), Customer Advances for Construction (252), Accumulated Deferred Income Taxes (190, 282-283), General Plant Accumulated Depreciation (108GP), Accumulated Provision for Amortization (111IP)

Deferred Tax Balance Factor (“DITBAL”)

$$DITBAL_i = \frac{DITBALA_i}{\sum_{i=1}^N DITBALA_i}$$

where:

$DITBAL_i$ = **Deferred Tax Balance Factor** for jurisdiction i.
 $DITBALA_i$ = Deferred tax balance allocated to jurisdiction i.
 (Deferred tax balance is allocated by a run of PowerTax based upon the above factors. PowerTax is a computer software package used to track deferred tax expense & deferred tax balance.)
 N = Number of jurisdictions.

The DITBAL Factor is used to allocate deferred tax balances to jurisdictions.

Accounts using DITBAL factor: Accumulated Deferred Income Taxes (282, 283)

Division Generation – Pacific Factor (“DGP”)

$$DGP_i = \frac{SG^*_i}{\sum_{i=1}^N SG^*_i}$$

where:

DGP_i	=	Division Generation – Pacific Factor for jurisdiction i.
SG^*_i	=	SG_i if i is a pre-merger Pacific Power jurisdiction, otherwise 0.
SG_i	=	System Generation Factor for jurisdiction i.
N	=	Number of jurisdictions.

The DGP Factor is calculated as the ratio of the pre-merger Pacific Division’s SG factor for a jurisdiction divided by the sum of the pre-merger Pacific Division’s SG factors.

The DGP factor is only used in calculating the dynamic ECD

Division Generation – Utah Factor (“DGU”)

$$DGU_i = \frac{SG^*_i}{\sum_{i=1}^N SG^*_i}$$

where:

DGU_i	=	Division Generation – Utah Factor for jurisdiction i.
SG^*_i	=	SG_i if i is a pre-merger Utah Power jurisdiction, otherwise 0.
SG_i	=	System Generation Factor for jurisdiction i.
N	=	Number of jurisdictions.

After the Interim Period, the factor is determined by the average of the four-year historical value from 2018 to 2021, or 2019 to 2022 if the Interim Period is extended.

The DGU Factor is calculated as the ratio of the pre-merger Utah Power jurisdiction’s SG factor for a jurisdiction divided by the sum of the pre-merger Utah Power jurisdiction’s SG factors.

The only accounts using DGU factor are Deferred Investment Tax Credits (41140, 41141)

Gross Plant System Factor (“GPS”)

$$GPS_i = \frac{PP_i + PT_i + PD_i + PG_i + PI_i}{\sum_{i=1}^N (PP_i + PT_i + PD_i + PG_i + PI_i)}$$

where:

GPS_i	=	Gross Plant System Factor for jurisdiction i.
PP_i	=	Production plant for jurisdiction i.
PT_i	=	Transmission plant for jurisdiction i.
PD_i	=	Distribution plant for jurisdiction i.
PG_i	=	General plant for jurisdiction i.
PI_i	=	Intangible plant for jurisdiction i.
N	=	Number of jurisdictions.

The GPS Factor is used to allocate property taxes. It is calculated using the ratio of gross plant for a jurisdiction divided by the total gross plant for all jurisdictions.

The accounts using GPS factor: Taxes Other Than Income Taxes (408), Deferred Income Tax Expense (41010, 41110), Schedule M, Prepayments (165), Accumulated Deferred Income Taxes (282, 283)

Nodal Pricing Assignment of Net Power Costs (“NP”)

Costs listed as allocated by NP in Appendix B are costs that will be allocated through the Nodal Pricing Model.

Accounts using NP factor: Sales for Resale (447), Purchased Power (555)

Schedule M – Depreciation Expense Factor (“SCHMDEXP”)

$$SCHMD_i = \frac{DEPRC_i}{\sum_{i=1}^N DEPRC_i}$$

where:

- $SCHMD_i$ = **Schedule M – Depreciation Expense Factor** for jurisdiction i.
- $DEPRC_i$ = Depreciation in FERC Accounts 403.1 - 403.9 for jurisdiction i.
- N = Number of jurisdictions.

The SCHMDEXP factor is used to allocate Schedule M items related to depreciation expense. The accounts using SCHMDEXP factor: Deferred Income Tax Expense (41110), Schedule M, Accumulated Deferred Income Taxes (282)

System Capacity Factor (“SC”)

$$SC_i = \frac{\sum_{j=1}^{12} TAP_{ij}}{\sum_{i=1}^N \sum_{j=1}^{12} TAP_{ij}}$$

where:

- SC_i = **System Capacity Factor** for jurisdiction i.
- TAP_{ij} = Weather-normalized peak load of jurisdiction i at the time of the system peak in month j. During the Interim Period, the peak load is further adjusted to exclude the peak load of Class 1 Demand Side Management programs and interruptible peak load of the special contracts as defined in the 2017 Protocol.
- N = Number of jurisdictions.

The SC factor is calculated based on the relative capacity requirements of each State as determined based on 12 monthly Coincident Peaks that is used to calculate the System Generation and System Transmission factors

System Energy Factor (“SE”)

$$SE_i = \frac{\sum_{j=1}^{12} TAE_{ij}}{\sum_{i=1}^N \sum_{j=1}^{12} TAE_{ij}}$$

where:

- SE_i = **System Energy Factor** for jurisdiction i.
- TAE_{ij} = Weather-normalized energy at input of jurisdiction i in month j.
- N = Number of jurisdictions.

The SE factor is used to allocate energy-related costs and is calculated as the ratio of the weather-normalized energy at input for a jurisdiction divided by the total weather-normalized energy at input for all jurisdictions.

Accounts using SE factor for Interim period: Sales for Resale (447), Other Electric Revenue (456), Miscellaneous Revenue (4118, 41181), Steam Plants Fuel (501), Steam from Other Sources (503), Other Fuel Expense (547), Purchased Power (555), Transmission of Electricity by Others (565), Administrative and General Expense (920-935), Depreciation Expense (403MP), Amortization Expense (404IP, 404MP), Taxes Other Than Income (408), Deferred Income Tax Expense (41010, 41110), Schedule M, Federal Income Tax True-Up (40910), General Plant (389-399), Intangible Plant (303), Plant Held for Future Use (105), Fuel Stock (151, 152), Working Capital – Mining related (25316, 25317, 25319), Materials and Supplies (154), Prepayments – Mining related (165), Misc. Regulatory Assets – Mining Related (182M), Misc. Deferred Debits – Mining related (186M), Accounts Payable (232), Other Deferred Credits Misc. (25330, 230, 25399), ARO Regulatory Liability (254105), SO Emissions (25398), Regulatory Liabilities (254), Accumulated Deferred Income Taxes (190, 282-283), General Plant Accumulated Depreciation 108GP, Accumulated Provision for Amortization (111IP, 111MP)

Accounts using SE factor after Interim period: System Control & Load Dispatch (556), Other Expenses (557), Transmission of Electricity by Others - GRID Management Charge (565)

System Generation Factor (“SG”) – Effective during the Interim Period

$$SG_i = 0.75 * SC_i + 0.25 * SE_i$$

where:

SG_i	=	System Generation Factor for jurisdiction i.
SC_i	=	System Capacity Factor for jurisdiction i.
SE_i	=	System Energy Factor for jurisdiction i.

The SG factor is used to allocate generation and transmission costs. It is calculated using a weighting of 75% of the SC factor and 25% of the SE factor for a jurisdiction.

Accounts using the SG factor: Sales for Resale (447), Provision for Rate Refund (449), Other Electric Operating Revenue (453, 454, 456), Miscellaneous Revenue (41160, 41170, 421), Generation Expense (500, 502, 504-514, 517-532, 535-545, 546, 548-554, 555, 556, 557), Transmission Expense (560-564, 566-573, 565), Administrative and General Expense (920-935), Depreciation Expense (403SP, 403NP, 403HP, 403OP, 403TP, 403GP), Amortization Expense (404SP, 404HP, 404IP 406, 407), Taxes Other Than Income (408), Deferred Income Tax Expense, (41010, 41110), Schedule M, Renewable Energy Tax Credit (40911), Federal Income Tax True-Up (40910), Generation Plant (310-316, 320-325, 330-336, 340-346), Transmission Plant (350-359), General Plant (389-398, 1011390), Intangible Plant (302-303), Plant Held for Future Use (105), Electric Plant Acquisition Adjustments (114-115), Materials and Supplies (154), Working Capital Deposit (25318), Prepayments (165), Misc. Regulatory Assets (182M), Misc. Deferred Debits (186M), Working Capital (135, 232), Accumulated Misc. Operating Provision Other (22841), Customer Advances for Construction (252), Other Deferred Debits (25399), Accumulated Deferred Income Taxes (190, 281-283), Accumulated Investment Tax Credit (255), Accumulated Depreciation (108SP, 108HP, 108OP, 108TP, 108GP), Accumulated Provision for Amortization (111SP, 111GP, 111HP, 111IP, 111390)

System Generation Factor – Fixed (“SGF”) – Effective after Interim Period

Based on actual SG allocation factors for the most recent four calendar years available prior to the end of the Interim Period. The SG_i factor is as defined above.)

$$SGF_i = \frac{PY1SG_i + PY2SG_i + PY3SG_i + PY4SG_i}{4}$$

where:

SGF _i	=	System Generation – Fixed Factor for jurisdiction i.
Prior Year (PY) 1 SG _i	=	PY1 System Generation Factor for jurisdiction i.
Prior Year (PY) 2 SG _i	=	PY2 System Generation Factor for jurisdiction i.
Prior Year (PY) 3 SG _i	=	PY3 System Generation Factor for jurisdiction i.
Prior Year (PY) 4 SG _i	=	PY4 System Generation Factor for jurisdiction i.

For Example: If the Interim Period ends December 31, 2023, then (PY) 1 = calendar year 2022, (PY) 2 = calendar year 2021, (PY) 3 = calendar year 2020, and (PY) 4 = calendar year 2019.

Accounts using SGF factor: Intangible Plant (303), Misc. Regulatory Assets (182M), Misc. Deferred Debits (186M), Working Capital (232), Accumulated Investment Tax Credit (255)

System Gross Plant Distribution Factor (“SGPD”) – Effective after Interim Period

$$SGPD_i = \frac{GPD_i}{\sum_{i=1}^N GPD_i}$$

where:

SGPD _i	=	System Gross Plant Distribution Factor for jurisdiction i.
GPD _i	=	Gross plant distribution for jurisdiction i.
N	=	Number of jurisdictions.

This factor is calculated by taking the ratio of gross distribution plant for a jurisdiction by the total gross distribution plant for all jurisdictions.

There are no accounts allocated using the SGPD factor. This factor is used to calculate the SO factor after the Interim period.

System Net Plant - Distribution Factor (“SNPD”)

$$SNPD_i = \frac{PD_i + ADPD_i}{\sum_{i=1}^N (PD_i + ADPD_i)}$$

where:

SNPD _i	=	System Net Plant – Distribution Factor for jurisdiction i.
PD _i	=	Distribution plant – for jurisdiction i.
ADPD _i	=	Accumulated depreciation distribution plant - for jurisdiction i.
N	=	Number of jurisdictions.

The SNPD factor is used to allocate non situs distribution costs. The factor is calculated as the ratio of net distribution plant for a jurisdiction by the total net distribution plant for all jurisdictions.

Accounts using the SNP factor: Distribution O&M (580-598), Deferred Income Tax Expenses (41010, 41110), Schedule M, Materials and Supplies – Distribution (154), Accumulated Deferred Income Taxes (190)

System Net Plant Factor (“SNP”)

$$SNP_i = \frac{PP_i + PT_i + PD_i + PG_i + PI_i + ADPP_i + ADPT_i + ADPD_i + ADPG_i + ADPI_i}{\sum_{i=1}^N (PP_i + PT_i + PD_i + PG_i + PI_i + ADPP_i + ADPT_i + ADPD_i + ADPG_i + ADPI_i)}$$

where:

SNP_i	=	System Net Plant Factor for jurisdiction i.
PP_i	=	Production plant for jurisdiction i.
PT_i	=	Transmission plant for jurisdiction i.
PD_i	=	Distribution plant for jurisdiction i.
PG_i	=	General plant for jurisdiction i.
PI_i	=	Intangible plant for jurisdiction i.
$ADPP_i$	=	Accumulated depreciation production plant for jurisdiction i.
$ADPT_i$	=	Accumulated depreciation transmission plant for jurisdiction i.
$ADPD_i$	=	Accumulated depreciation distribution plant for jurisdiction i.
$ADPG_i$	=	Accumulated depreciation general plant for jurisdiction i.
$ADPI_i$	=	Accumulated depreciation intangible plant for jurisdiction i.
N	=	Number of jurisdictions.

The SNP factor is used to allocate interest expense and miscellaneous deferred tax treatment. The factor is calculated by taking the ratio of the system net plant balance for a jurisdiction divided by the total system net plant balance for all jurisdictions.

Accounts using SNP factor: Interest Expense (427-429, 431, 432), Deferred Income Tax Expenses (41010, 41110), Schedule M, Working Capital – Cash (131), Accumulated Deferred Income Taxes (190, 282, 283)

System Overhead Factor (“SO”) – Effective after Interim Period

$$SO_i = \frac{SC_i + SE_i + SGPD_i}{3}$$

where:

SO_i	=	System Overhead Factor for jurisdiction i.
SC_i	=	System Capacity Factor for jurisdiction i.
SE_i	=	System Energy Factor for jurisdiction i.
$SGPD_i$	=	System Gross Plant Distribution for jurisdiction i.

The SO factor is used to allocate system overhead costs. The SO factor used after the Interim period is calculated by taking the sum of the SC, SE and SGPD factor for a jurisdiction and dividing by three.

Accounts using SO factor after Interim period: Other Electric Operating Revenue (451, 454, 456), Miscellaneous Revenue (41160, 41170, 421), Administrative and General Expense (920-935), Depreciation Expense (403GP), Amortization Expense (404GP, 404IP), Deferred Income Tax Expenses (41010, 41110), Schedule M, Federal Income Tax True-Up (40910), General Plant (389-398, 1011390), Intangible Plant (303), Materials and Supplies (154), Stores Expense Undistributed (163), Prepayments (165), Misc. Regulatory Assets (182M), Misc. Deferred Debits (186M), Working Capital (141, 232), Rate Base Deduction Provisions (2281-2283), Other Deferred Credits (25399), Regulatory Liabilities (254),

Accumulated Deferred Income Taxes (190, 282, 283), Accumulated Depreciation (108GP, 1081390),
Accumulated Provision for Amortization (111GP, 111IP)

System Overhead Factor (“SO”) – Effective during the Interim Period

$$SO_i = \frac{PP_i + PT_i + PD_i + PG_i + PI_i - PP_{oi} - PT_{oi} - PD_{oi} - PG_{oi} - PI_{oi}}{\sum_{i=1}^N (PP_i + PT_i + PD_i + PG_i + PI_i - PP_{oi} - PT_{oi} - PD_{oi} - PG_{oi} - PI_{oi})}$$

where:

<i>SO_i</i>	=	System Overhead Factor for jurisdiction i.
<i>PP_i</i>	=	Gross production plant for jurisdiction i.
<i>PT_i</i>	=	Gross transmission plant for jurisdiction i.
<i>PD_i</i>	=	Gross distribution plant for jurisdiction i.
<i>PG_i</i>	=	Gross general plant for jurisdiction i.
<i>PI_i</i>	=	Gross intangible plant for jurisdiction i.
<i>PP_{oi}</i>	=	Gross production plant for jurisdiction i allocated on a SO factor.
<i>PT_{oi}</i>	=	Gross transmission plant for jurisdiction i allocated on a SO factor.
<i>PD_{oi}</i>	=	Gross distribution plant for jurisdiction i allocated on a SO factor.
<i>PG_{oi}</i>	=	Gross general plant for jurisdiction i allocated on a SO factor.
<i>PI_{oi}</i>	=	Gross intangible plant for jurisdiction i allocated on a SO factor.
<i>N</i>	=	Number of jurisdictions.

The SO factor is used to allocate system overhead costs. The SO factor used during the Interim period is calculated by taking the gross plant allocated to a jurisdiction, excluding the plant amounts allocated on SO, and dividing it by the total gross plant for all jurisdictions, excluding plant amounts allocated on SO, for all jurisdictions.

Accounts using SO factor during the Interim period: Other Electric Operating Revenue (451, 454, 456), Miscellaneous Revenue (41160, 41170, 421), Administrative and General Expense (920-935), Depreciation Expense (403GP), Amortization Expense (404GP, 404IP), Deferred Income Tax Expenses (41010, 41110), Schedule M, Federal Income Tax True-Up (40910), General Plant (389-398, 1011390), Intangible Plant (303), Materials and Supplies (154), Stores Expense Undistributed (163), Prepayments (165), Misc. Regulatory Assets (182M), Misc. Deferred Debits (186M), Working Capital (141, 232), Rate Base Deduction Provisions (2281-2283), Other Deferred Credits (25399), Regulatory Liabilities (254), Accumulated Deferred Income Taxes (190, 282, 283), Accumulated Depreciation (108GP, 1081390), Accumulated Provision for Amortization (111GP, 111IP)

System Transmission Factor (“ST”) – Effective after Interim Period

$$ST_i = 75\% * SC_i + 25\% * SE_i$$

where:

<i>ST_i</i>	=	System Transmission Factor for jurisdiction i.
<i>SC_i</i>	=	System Capacity Factor for jurisdiction i.
<i>SE_i</i>	=	System Energy Factor for jurisdiction i.

The ST factor is used to allocate transmission related costs after the Interim period. It is calculated using a weighting of 75% of the SC factor and 25% of the SE factor for a jurisdiction.

Accounts using ST factor: Provision for Rate Refund (449), Operating Revenue (454), Other Electric Revenue (456), Miscellaneous Revenue (41160, 41170, 421), Transmission Expense (560-564, 566-573),

Transmission of Electricity by Others (565), Administrative & General Expense (920-935), Depreciation Expense (403TP, 403GP), Amortization Expense (404IP, 407), Deferred Income Tax Expenses (41010, 41110), Schedule M, Transmission Plant (350-359), General Plant (389-398, 1011390), Intangible Plant (302, 303), Plant Held for Future Use (105), Electric Plant Acquisition Adjustments (114-115), Material and Supplies (154), Prepayments (165), Misc. Regulatory Assets (182M), Misc. Deferred Debits (186M), Working Capital (232), Customer Advances for Construction (252), Other Deferred Credits (25399), Accumulated Deferred Income Taxes (190, 281-283), Accumulated Depreciation (108TP, 108GP), Accumulated Provision for Amortization (111TP, 111GP, 111IP)

Tax Depreciation Factor (“TAXDEPR”)

$$TAXDEPR_i = \frac{TAXDEPRA_i}{\sum_{i=1}^N TAXDEPRA_i}$$

where:

- $TAXDEPR_i$ = **Tax Depreciation Factor** for jurisdiction i.
- $TAXDEPRA_i$ = Tax depreciation allocated to jurisdiction i.
(Tax depreciation is allocated based on functional pre-merger and post-merger splits of plant using Divisional and System allocations from above. Each jurisdiction’s total allocated portion of tax depreciation is determined by its total allocated ratio of these functional pre- and post-merger splits to the total Company tax depreciation.)
- N = Number of jurisdictions.

The TAXDEPR factor allocates depreciation related tax costs.

Accounts using TAXDEPR: Deferred Income Tax Expense (41010) Schedule M, Accumulated Deferred Income Taxes (282)

Trojan Decommissioning Factor (“TROJD”)

$$TROJD_i = \frac{ACCT22842_i}{\sum_{i=1}^N ACCT22842_i}$$

where:

- $TROJD_i$ = **Trojan Decommissioning Factor** for jurisdiction i.
- $ACCT22842_i$ = Allocated adjusted balance in FERC Account 228.42 (Accumulated Provision for Decommissioning Trojan) for jurisdiction i.
- N = Number of jurisdictions.

The TROJD factor is used to allocate decommissioning related costs associated with the Trojan plant.

Accounts using TROJD: Deferred Income Tax Expenses (41010, 41110), Schedule M, FAS 143 ARO Regulatory Liability – Trojan Plant (254105), Asset Retirement Obligation – Trojan Plant (230), Accumulated Deferred Income Taxes (190, 283)

Trojan Decommissioning Fixed Factor (“TROJDF”)

Effective after Interim Period Based on actual TROJD allocation factors for the most recent four calendar years available prior to the end of the Interim Period. (The TROJD_i factor is as defined above.)

$$TROJDF_i = \frac{PY1TROJD_i + PY2TROJD_i + PY3TROJD_i + PY4TROJD_i}{4}$$

where:

- TROJDF_i = **Trojan Decommissioning– Fixed Factor** for jurisdiction i.
- Prior Year (PY) 1 TROJD_i = PY1 Trojan Decommissioning Factor for jurisdiction i.
- Prior Year (PY) 2 TROJD_i = PY2 Trojan Decommissioning Factor for jurisdiction i.
- Prior Year (PY) 3 TROJD_i = PY3 Trojan Decommissioning Factor for jurisdiction i.
- Prior Year (PY) 4 TROJD_i = PY4 Trojan Decommissioning Factor for jurisdiction i.

For Example: If the Interim Period ends December 31, 2023, then (PY) 1 = calendar year 2022, (PY) 2 = calendar year 2021, (PY) 3 = calendar year 2020, and (PY) 4 = calendar year 2019. The TROJDF factor is used to allocate decommissioning related costs associated with the Trojan plant.

Accounts using TROJDF: Deferred Income Tax Expenses (41010, 41110), Schedule M, FAS 143 ARO Regulatory Liability – Trojan Plant (254105), Asset Retirement Obligation – Trojan Plant (230), Accumulated Deferred Income Taxes (190, 283)

APPENDIX D

Nodal Pricing Model Memorandum of Understanding

EXECUTION VERSION

PacifiCorp's Nodal Pricing Model Memorandum of Understanding

Introduction

1. PacifiCorp and the undersigned parties (Parties) enter into this Memorandum of Understanding (MOU) to acknowledge their support, as described below, of PacifiCorp's investment in the development and implementation of a Nodal Pricing Model (NPM) that may be adopted for the calculation of net-power costs (NPC).

Background

2. PacifiCorp is a multi-jurisdictional electric utility that is serving customers in California, Idaho, Oregon, Utah, Washington, and Wyoming.

3. Generally, PacifiCorp has allocated costs among those states using an inter-jurisdictional cost allocation methodology.

4. PacifiCorp's current inter-jurisdictional cost allocation methodology, the 2017 PacifiCorp Inter-Jurisdictional Allocation Protocol (2017 Protocol), was adopted by the applicable regulatory commissions in Idaho, Oregon, Utah, and Wyoming in 2016, and set a process for developing a new inter-jurisdictional cost allocation methodology through a working group of stakeholders consisting of utility regulatory agencies, customers, and certain others potentially affected by inter-jurisdictional allocation procedures, known as the Multi-State Process Workgroup (MSP Workgroup).¹ Washington has used the West Control Area Inter-Jurisdictional Allocation

¹ PacifiCorp anticipates that California will adopt the 2017 Protocol in 2019.

EXECUTION VERSION

Methodology for the purposes of cost allocations since 2007. California currently uses the Revised Protocol, but a decision on adoption of the 2017 Protocol is pending before the commission.

5. Discussions among the MSP Workgroup for the potential extension of the 2017 Protocol and/or a new inter-jurisdictional cost allocation methodology are being held.

6. In late-2017, PacifiCorp presented the MSP Workgroup with a proposal to track NPC through a NPM concept designed to facilitate each state's energy policies and unique resource portfolios while still seeking to maintain the benefits of system dispatch and optimization. PacifiCorp also indicated a potential for the NPM to provide increased dispatch efficiencies.

7. PacifiCorp's NPM proposal is to use a third-party day-ahead dispatch model to determine the schedules for each of its generation resources to serve state loads on a least-cost basis, while tracking costs and benefits associated with the different resource portfolios used to serve PacifiCorp's load in each state. PacifiCorp has been in discussions with the California Independent System Operator (CAISO) to provide the day-ahead dispatch model.

8. To allow for the anticipated implementation of NPM for potential ratemaking by 2023, PacifiCorp has determined that it must now invest related capital, incur related operations and maintenance expenses, and pay related ongoing grid management charges. Attached as Exhibit A to this MOU is a description of the type of work that PacifiCorp anticipates undertaking. The Parties understand that the list is preliminary and is not intended to be a complete list.

EXECUTION VERSION

Agreement

9. As described in this MOU, the Parties affirm support for PacifiCorp's reasonable and prudent investment of related capital funds, related operations and maintenance expenses, and the related ongoing grid management charges to develop and implement an NPM. Exhibit B to this MOU is an estimate of the investments and ongoing-costs PacifiCorp anticipates it will make or incur through this effort and an explanation of the anticipated benefits, including cost-savings and compliance with state policy directives impacting resource portfolio decisions. The Parties agree that, based on the information provided by PacifiCorp, PacifiCorp's decision to invest capital funds and pay ongoing grid management charges to develop and implement an NPM is reasonable and prudent. However, the Parties do not necessarily agree that any specific investment or expenditure is reasonable or prudent and the Parties reserve all rights to audit, review, and challenge any specific investment or expenditure as unreasonable or imprudent in appropriate regulatory commission proceedings.

10. The Parties agree the associated grid management costs will be booked in Federal Energy Regulatory Commission (FERC) Account 565, which is included in PacifiCorp's NPC. NPM related costs will be allocated among the PacifiCorp states as follows²:

² References to "SG Factor" and "SE Factor" in the following table are to the System Generation Factor and the System Energy Factor, respectively, as used in the currently-applicable cost allocation protocol in each state, or any successor factors. References to "Fixed SG Factor" are to a proposed Fixed SG Factor that the Parties currently anticipate may be established as part of a future interstate cost allocation protocol.

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NPM Associated Costs	Time Period	
	January 1, 2020 Through the Effective Date of a New Interjurisdictional Cost Allocation Protocol ³	Beginning upon the Effective Date of a New Interstate Cost Allocation Protocol
CAISO Grid Management Charge	SG Factor	SE Factor
Capitalized Start-Up Costs for PacifiCorp ESM ⁴	SG Factor	Fixed SG Factor
Capitalized CAISO Implementation Fee	SG Factor	Fixed SG Factor
Ongoing Operations and Maintenance Expense	SG Factor	SE Factor

Otherwise, this MOU shall not limit the positions any Party may take regarding how nodal pricing may be used to allocate costs amongst the states before any applicable state regulatory commission.

11. The Company shall use its best efforts to provide adequate training and documentation regarding the NPM such that Parties may understand, review, and audit NPM-derived NPC. The NPM, however, is based on CAISO FERC-jurisdictional market model to which PacifiCorp does not have and cannot provide access. For regulatory purposes, the Company will retain CAISO advisory schedules and documentation of any decision to materially deviate from those advisory schedules. The Company further agrees to provide training and facilitate access to the Company’s forecasting model for any appropriate party for regulatory purposes.

³ The Parties are currently negotiating towards a possible extension of the 2017 Inter-jurisdictional Allocation Methodology (subject to some possible changes), until a future interstate cost allocation protocol becomes effective, which the Parties currently expect may be January 1, 2023 or January 1, 2024.

⁴ PacifiCorp’s Energy Supply Management (ESM) is the business unit responsible for scheduling and dispatching PacifiCorp’s generation resources to serve retail load and buy/sell in wholesale energy and capacity markets.

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12. The Parties acknowledge that this MOU does not address any other aspect of the on-going negotiations regarding an extension of the 2017 Protocol or a new inter-jurisdictional cost allocation methodology. By executing this MOU, no Party is agreeing to any other issue not agreed to in this MOU.

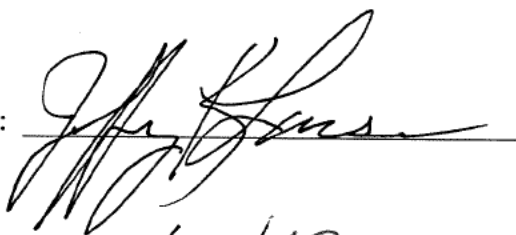
13. This MOU may be executed in counterparts and each signed counterpart constitutes an original document.

14. The obligations of any state agency that is a party to this MOU shall be interpreted in a manner consistent with its statutory authority and responsibilities, and any explanation and support provided in this MOU or in any regulatory proceeding shall be consistent with its statutory authority and responsibility.

15. This MOU is entered into by each Party on the date entered below such Party's signature.

PACIFICORP

By:




Date:

8/26/19

WIEC

Organization

By:



Date:

8/26/2019

EXECUTION VERSION

Western Resource Advocates
Organization

By: Sophie Hayes

Date: 08-26-2019

UTAH DIVISION OF PUB. UTILS.
Organization

By: [Signature]

Date: 8/26/19

Utah Association of Energy Users
Organization

By: [Signature]

Date: 8-26-19

Idaho Public Utilities Comm
Organization

By: Terri Carlock

Date: 8/26/2019

Bayer - Monsanto
Organization

By: Paul C. Budger

Date: 8/26/2019

Utah Clean Energy
Organization

By: [Signature]

Date: 8/26/2019

EXECUTION VERSION

Oregon Public Utility Commission
Organization staff

By: [Signature]

Date: 8/26/19

Powder River Basin Resource Council
Organization

By: [Signature] Shanna Anderson

Date: 8/26/19

Wyoming Office of Consumer Advocate
Organization

By: [Signature] Adam Williams

Date: 08/27/2019

Wyoming Public Service Commission Staff
Organization

By: [Signature]

Date: 8-26-2019

Alliance of Western Energy Consumers
Organization

By: [Signature]

Date: 8/27/19

Organization

By: _____

Date: _____

EXECUTION VERSION

Utah Office of Consumer Services
Organization

By: Michael Green

Date: 8-27-19

Organization

By: _____

Date: _____

Organization

By: _____

Date: _____

Organization

By: _____

Date: _____

Organization

By: _____

Date: _____


Organization

By: _____

Date: _____

EXECUTION VERSION

Oregon Citizens' Utility Board
Organization

By: 
MIKE GOETZ, General Counsel

Date: August 28, 2019

Organization

By: _____

Date: _____

Organization

By: _____

Date: _____

Organization

By: _____

Date: _____

Organization

By: _____

Date: _____

Organization

By: _____

Date: _____

EXECUTION VERSION

<u>WASHINGTON UTILITIES & TRANSPORT COMMISSION</u> Organization	<u>STAFF</u>	<u>WOLVERINE FUELS</u> Organization
By: <u>[Signature]</u>		By: <u>[Signature]</u>
Date: <u>August 24, 2019</u>		Date: <u>Sept 03, 2019</u>

Organization

By: _____

Date: _____

Organization

By: _____

Date: _____

Organization

By: _____

Date: _____

Organization

By: _____

Date: _____

EXECUTION VERSION

EXHIBIT A

Nodal Pricing Model Statement of Work

Introduction

PacifiCorp has requested the CAISO provide a design proposal for a NPM that can be used to clear energy supply and demand bids for the PacifiCorp Balancing Authority Areas (BAA)¹ one day ahead. The CAISO proposes to leverage its existing Day-Ahead Market (DAM) technology platform, the market full network model, and data interfaces available in the real-time Energy Imbalance Market (EIM) to provide the NPM solution. PacifiCorp is currently an EIM Entity participating in the EIM and has already developed systems and data interfaces with the EIM in submitting data and receiving settlement statements. Consequently, the proposed solution would require an expansion of PacifiCorp's bidding, scheduling, and settlement systems for the NPM, while gaining full access to the most advanced security constrained unit commitment tool currently used in the CAISO's DAM.

Nodal Pricing Model

Currently, the CAISO's DAM footprint is limited to the CAISO BAA (CISO). Although supply and demand schedules in the external BAAs are not optimized, they are modeled as fixed in the DAM to produce an accurate market and power flow solution. The CAISO, as the Reliability Coordinator, receives the demand forecast and generation schedules for the next day from EIM BAAs and external BAAs, as well as the Area-To-Area Net Schedule Interchange between BAAs.

For the NPM solution, the CAISO proposes to include in the DAM footprint the PacifiCorp BAAs, i.e. PACW and PACE, which are modeled as individual BAAs in the EIM. Using similar market features and technology optimization algorithm approaches employed in the EIM, the DAM will produce optimal unit commitment and hourly energy schedules for supply resources in PACW and PACE, subject to a power balance constraint for each of these BAAs, in addition to the power balance constraint for CISO and active transmission network constraints in CISO, PACE, and PACW. Energy transfers between PACW and PACE will be optimally scheduled, subject to applicable scheduling limits, whereas the net energy transfer to or from CISO will be fixed at zero, to prevent energy exchange between CISO and PacifiCorp that may impact the CAISO's DAM solution.

As an intended standard feature of the DAM, the CAISO will also be able to optimally schedule ancillary services to meet the corresponding requirements in PACW and PACE, by designating these BAAs as separate ancillary services regions with distinct requirements.

The ancillary services are the following:

- Regulation up and down;
- Spinning Reserve; and
- Non-Spinning Reserve

¹ PacifiCorp operates two BAAs, PacifiCorp East BAA (PACE) and PacifiCorp West BAA (PACW).

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All ancillary services have a 10-minute ramping requirement, which is shared among the upward ancillary services. Both Spinning Reserves and Non-Spinning Reserves are contingency reserves, but Non-Spinning Reserve can also be provided by offline resources that can start up within 10 minutes. The upward ancillary services procurement is cascaded so that spin can meet non-spin requirements, and regulation up can meet both spin and non-spin requirements, to minimize the overall procurement cost.

Advisory Pricing

The day-ahead settlement for the NPM is advisory, i.e. not financially binding between PacifiCorp and CAISO. Day-ahead energy and ancillary service prices for PacifiCorp resources will be published in CAISO Market Results Interface for PacifiCorp, but they will not be published in Open Access Same-time Information System (OASIS) in the public domain. Similarly, the publication of Locational Marginal Prices at PACW and PACE pricing nodes (generally referred to as PNodes) will be suppressed in OASIS.

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EXHIBIT B

PacifiCorp's Estimated Costs of the Nodal Pricing Model

CAISO Grid Management Charge or Service Fee - \$8 to 10 million per year

Capitalized PacifiCorp Start-Up Costs for Energy Supply Management and Settlement Processing - \$3 to \$5 million with 100% applicable to a future Extended Day-Ahead Market (EDAM)

Capitalized CAISO Implementation Fee – \$1 to \$2 million (based on Energy Imbalance Market, or EIM, implementation fee) one-time cost

Ongoing Operations and Maintenance Expense – \$500,000 - \$700,000 per year

Benefits of the Nodal Pricing Model

The NPM is being developed to allocate actual NPC as states move to unique generation portfolios. The NPM is intended to help preserve the system benefit of operating as a single system.

CAISO's existing technology platform is intended to reduce both schedule and budget risk to quickly implement the NPC allocation methodology that PacifiCorp is seeking to implement based on the NPM solution.

In addition to providing a method to allocate NPC, the NPM potentially offers the following benefits from using the CAISO market optimization tool:

- It provides more granular dispatch information resulting in anticipated operational cost savings.
- It allows PacifiCorp to leverage CAISO's independence as a third party market provider.
- It guarantees that the solution outcome is consistent with the CAISO EIM market solution since it is using the same exact tool and input data.
- It leverages the effort and money used to build and maintain a complex and granular Real-time network model that is used in the actual market run.
- It utilizes the same schedule data for internal and external resources informing the potential for unscheduled loop flows and is informative when performing congestion management and potentially enforcing physical flow transmission constraints.

Lastly, if the CAISO offers a Day-Ahead Market to external entities for optional participation, the NPM solution development would allow PacifiCorp to seamlessly participate in the CAISO EDAM, if and when PacifiCorp decides to join that market.

APPENDIX E

Coal-Fueled Interim Period Resource Depreciation Lives

Unit	In Service	2012 Depreciation Study Life		2018 Depreciation Study Life		Capacity (MW)	Physical Location
		OR	Other States	PP States (1)	RMP States		
A	B	C	D	E	F	G	H

Lives Addressed by Section 4.1.3.1

Cholla 4	1981	2028	2042	Apr-25	Apr-25	387	Arizona
Colstrip 3	1984	2032	2046	2027	2027	74	Montana
Colstrip 4	1986	2032	2046	2027	2027	74	Montana
Craig 1	1980	2026	2034	2025	2025	82	Colorado
Craig 2	1979	2026	2034	2026	2026	82	Colorado

Lives Addressed by Sections 4.1.3.2 and 4.1.3.3

Dave Johnston 1	1959	2023	2027	2023	2027	99	Wyoming
Dave Johnston 2	1960	2023	2027	2023	2027	106	Wyoming
Dave Johnston 3	1964	2023	2027	2023	2027	220	Wyoming
Dave Johnston 4	1972	2023	2027	2023	2027	330	Wyoming
Hunter 1	1978	2029	2042	2029	2042	418	Utah
Hunter 2	1980	2029	2042	2029	2042	269	Utah
Hunter 3	1983	2029	2042	2029	2042	471	Utah
Huntington 1	1977	2030	2036	2029	2036	459	Utah
Huntington 2	1974	2030	2036	2029	2036	450	Utah
Jim Bridger 1	1974	2025	2037	2025	2028	354	Wyoming
Jim Bridger 2	1975	2025	2037	2025	2032	359	Wyoming
Jim Bridger 3	1976	2025	2037	2025	2037	349	Wyoming
Jim Bridger 4	1979	2025	2037	2025	2037	353	Wyoming
Naughton 1	1963	2028	2029	2028	2029	156	Wyoming
Naughton 2	1968	2028	2029	2028	2029	201	Wyoming
Wyodak	1978	2026	2039	2026	2039	268	Wyoming

Lives Addressed by Section 4.1.5

Hayden 1	1965	2023	2030	2023	2030	44	Colorado
Hayden 2	1976	2023	2030	2023	2030	33	Colorado

(1) The life of coal plants for Washington is addressed in Section 4.1.4.

APPENDIX F

Washington Inter-Jurisdictional Allocation Methodology Memorandum of Understanding

The Washington Inter-Jurisdictional Allocation Methodology Memorandum of Understanding

Introduction

PacifiCorp d/b/a Pacific Power and Light Company (PacifiCorp or Company), Staff of the Washington and Utilities and Transportation Commission (Staff), Public Counsel Unit of the Washington State Attorney General’s Office (Public Counsel) and Packaging Corporation of America (PCA), have executed this agreement (the Parties or, individually, a Party) enter into this Memorandum of Understanding (Agreement) to acknowledge their support for certain adjustments to the West Control Area Inter-Jurisdictional Allocation Methodology (WCA).

Background

PacifiCorp is a multi-jurisdictional electric utility that provides services in six states (California, Idaho, Oregon, Utah, Wyoming, and Washington). Staff is participating in PacifiCorp’s Multi-State Process (MSP), working towards the Company’s goal of developing a common cost allocation methodology amongst these six states. Currently, Washington uses the WCA for determining which costs are eligible for recovery in rates from customers in Washington.¹

As approved by the Washington Utilities and Transportation Commission (Commission), the WCA isolates the costs and revenues associated with assets located in the Company’s west “control area” or “PacifiCorp West Balancing Authority Area” (PACW), and allocates to Washington a proportionate share of the costs and revenues based primarily on Washington’s relative contribution to demand and energy requirements. The WCA includes loads, generation and transmission assets, and wholesale contracts for facilities located in California, Oregon, and Washington. It also includes transmission and generation assets located outside of California, Oregon, and Washington that are electrically located in PACW. The WCA excludes all loads and assets located within PacifiCorp’s East Balancing Authority Area (PACE).

In the context of inter-jurisdictional cost allocation, the Commission will consider a resource to be *used and useful* to Washington customers² if the resource “provides *quantifiable direct or indirect benefits to Washington [ratepayers] commensurate with its costs.*”³ To modify the WCA methodology, “any changes should be considered in the context of an overall review of that methodology.”⁴ Additionally, Parties must demonstrate that “any changes proposed more closely aligns with the allocation of costs based on causation[.]”⁵ Finally, “the party advocating for the change must make a detailed a persuasive showing demonstrating that the proposed change is appropriate.”⁶

¹ Prior to the WCA methodology being approved in Docket UE-061546, PacifiCorp proposed the Revised Protocol as its cost allocation methodology in Docket UE-050684. The Revised Protocol presented costs as an integrated six-state system. The Commission rejected the Revised Protocol because there was not sufficient evidence in the record that the methodology complied with the legal requirements in RCW 80.04.250. *See generally* UE-050684, Order 04.

² *See* RCW 80.04.250

³ Docket UE-050684, Order 04 ¶ 68.

⁴ Docket UE-130043, Order 05 ¶ 92–94.

⁵ *Id.*

⁶ *Id.*

Foundation for this Agreement

In this memorandum of understanding, the Parties agree to support certain modifications to the WCA in the Company's forthcoming rate case provided the Company can demonstrate that the modifications within this agreement provide beneficial resources to Washington customers that are *used and useful*. In particular, the Parties agree to support these modifications if PacifiCorp can demonstrate these modifications provide quantifiable direct or indirect benefits to Washington customers, and that these benefits are commensurate with their costs.⁷ The Parties agree to work collaboratively with PacifiCorp as they make this demonstration. However, as the party advocating for these changes, PacifiCorp bears the legal and factual burden to sufficiently demonstrate that these modifications better align the cost allocation methodology with the principles described above in its forthcoming general rate case.

This demonstration may include the following benefits:

- A diverse generation portfolio, including an increase in high capacity renewable generation.
- Over 170 interconnections with other BAAs and transmission operators providing access to market hubs for wholesale energy transactions (*e.g.*, Mid-C, COB, Mona, Four-Corners and Palo Verde).
- Greater Energy Imbalance Market (EIM) benefits.
- Efficiencies, such as retail load characteristics and variable resource diversity, which minimize operational costs and reduce the need to build for reserves and blackstart capability for each state.
- Washington recently enacted Senate Bill 5116, the Clean Energy Transformation Act (CETA) which, among other things, requires the elimination of coal-fired resources from PacifiCorp's electric rates by December 31, 2025. PacifiCorp's proposed modification to the WCA will facilitate a reasonable path towards PacifiCorp's compliance with CETA.⁸

Based on this understanding, the Parties agree to the following:

Agreement

- 1. Implementation.** This Agreement includes modifications to the WCA subject to approval by the Commission.

⁷ The Commission has stated that one way the Company can demonstrate this is "through historical system operation or modeling of the system showing that Eastside plant costs added to Washington rates would be offset by reductions to other cost categories (*e.g.*, power costs), such that overall costs to Washington ratepayers would be no more than without the Eastside resources." Docket UE-050684, Order 04 ¶ 69 (emphasis added).

⁸ CETA also sets a policy of 100 percent clean energy by 2045. RCW 19.405.050. Additionally, CETA establishes an interim target of 100 percent greenhouse gas (GHG) neutral by 2030, and allows utilities to meet this requirement through 80 percent non-emitting energy and an alternative compliance option, including up to 20 percent unbundled renewable energy credits. RCW 19.405.040.

- 1.1.** PacifiCorp will file a rate case that allows for rates to go into effect (after suspension) on or before January 1, 2021. This rate case will use this MOU as the basis for any proposed modifications to the WCA.
- 2. Prudence.** The proposed allocation of a particular expense or investment under this Agreement is not intended to and will not prejudice, or prevent any party from taking a position on, the prudence of those costs or the extent to which any particular cost may be reflected in rates. Nothing in this Agreement is intended to abrogate the Commission's right or obligation to: (1) determine fair, just, and reasonable rates based upon applicable laws and the record established in rate proceedings conducted by the Commission; (2) consider the impact of changes in laws, regulations, or circumstances on inter-jurisdictional allocation policies and procedures when determining fair, just, and reasonable rates; or (3) establish different allocation policies and procedures for purposes of allocating costs and revenues to different customers or customer classes.
- 3. Quantification and Analytical Support.** The Parties agree to work collaboratively and in good faith to agree on the quantification and analytical support necessary for the Company to meet its legal and factual burden.

 - 3.1.** This analysis should be substantially completed before the filing of the general rate case referenced in section 1.1 and with enough time to reasonably allow parties to review the analysis.
 - 3.2.** Before the general rate case referenced in section 1.1 is filed, if a Party determines that the Company's quantification and analytical support does not demonstrate that the Company can meet its legal and factual burden, Parties have the option to withdraw their support from this agreement.
 - 3.3.** After the general rate case referenced in section 1.1 is filed, if a Party determines that this agreement does not result in fair, just and reasonable rates for Washington customers, a party may withdraw from this agreement. The withdrawing Party must provide testimony in the general rate case explaining why this agreement does not result in fair, just and reasonable rates for Washington Customers.
 - 3.4.** In the event of a Party's withdrawal, the remaining Parties may continue to support this Agreement for approval in any proceeding before the Commission.
- 4. System Transmission.** The Parties agree that all existing system transmission⁹ costs and benefits will be allocated using the System Generation (SG) factor as specified in Attachment 1.

 - 4.1. Rate Impacts:** To mitigate the immediate overall rate impact to Washington customers in the rate case referenced in Section 1.1, Parties agree to support the framework of the following phase-in approach:

⁹ Existing transmission includes any transmission asset that is in service as of December 31, 2019.

- 4.1.1.** An incremental allocation of one-third of existing transmission costs and benefits, which are not currently allocated to Washington under the current WCA methodology, will be included in the rate case referenced in Section 1.1.
- 4.1.2.** An incremental allocation of an additional one-third of existing transmission costs and benefits, which are not currently allocated to Washington, will be included in a separate tariff rider with a rate effective date on or before January 1, 2022.
- 4.1.3.** An incremental allocation of an additional one-third of existing transmission costs and benefits, which are not currently allocated to Washington, will be included in a general rate case or through an amendment to the separate tariff rider set forth in Section 4.1.2 with a rate effective date on or before January 1, 2023.
 - 4.1.3.1.** The incremental allocation in 4.1.3 will exclude the costs and benefits of all transmission-voltage, radial lines connecting resources not otherwise included in Washington rates to PacifiCorp's interconnected, network transmission system. If PacifiCorp is required to include a portion of a transmission line in its interconnected, network transmission system for open access transmission service due to a subsequent generation or load interconnection, PacifiCorp may request to include such portion of the assets in a subsequent rate case.
- 4.1.4.** The separate tariff rider described above will remain in place until the fully allocated cost of transmission costs as described in Section 4 is included in rates through a general rate case.
- 4.2. New Transmission.** Any new transmission¹⁰ incremental to the existing transmission described and included in Section 3, will be system-allocated using the SG factor as specified in Attachment 1.
 - 4.2.1.** Similar to the methodology outlined in 4.1.3.1, Transmission which can be demonstrated to be used primarily for the transmission of power from generation assets which are not assigned to Washington under the WCA, as modified by this Agreement, will be excluded from this and any other allocation to Washington.
- 4.3. Analytical Support.** As a part of the analytical support in Section 4, the Company will quantify the differences between total depreciation and ADIT balances using a WCA Allocation of transmission and the system allocation above.

¹⁰ "New" shall constitute assets used and useful for Washington customers after December 31, 2019.

- 5. Non-Emitting Resources.** The Parties agree that all existing and new non-emitting resources will be dynamically allocated using the SG Factor specified in Attachment 1.
 - 5.1. Assignment.** If by December 31, 2023, none of the Parties to this agreement have signed a new cost allocation methodology with the Company, then the Company agrees to engage in collaborative conversations with the Parties and other interested Washington stakeholders to explore the following:
 - 5.1.1.** An Assignment method for new resources for the purposes of the WCA; and,
 - 5.1.2.** A methodology to allocate fixed shares of existing non-emitting resources.
- 6. Net Power Costs (NPC).** Forecasted NPC for ratemaking purposes will be consistent with Sections 1,4,5,6, and 7 of this agreement. Additionally, Washington customers will receive all direct and indirect benefits associated with their proportional system-allocated share of existing transmission, including Energy Imbalance Market benefits.
 - 6.1. Actual NPC.** Actual NPC for ratemaking purposes will include only the generation resources included in Washington rates and will be calculated using a spreadsheet.
 - 6.2. Qualifying Facilities.** The costs and benefits of Power Purchase Agreements for Qualifying Facilities (QF PPAs) will continue to be situs assigned to the state having jurisdiction over the QF PPA for cost responsibility, renewable energy credit assignment and resource planning.
- 7. Accelerated Depreciation.** PacifiCorp and Staff agree to support a final depreciation date of December 31, 2023, for Bridger Units 1-4, Colstrip 4 and any transmission assets associated solely with the interconnection of these units to the transmission network. This date does not represent a date of estimated closure, changes in operations, or the end of the assignment to Washington of either benefits or costs associated with these plants. Public Counsel and PCA reserve the right to make a recommendation on the depreciation for Bridger Units 1-4, Colstrip, and any transmission assets associated solely with the interconnection of these units to the transmission network in PacifiCorp's forthcoming general rate case.
 - 7.1. Capital Investments.** Washington will continue to be allocated a WCA share of ongoing capital investments expenses for these plants, excluding incremental capital investments that are made primarily for the purpose of extending the life of these plants. Incremental capital investments that are made primarily for the purpose of extending the life of these plants includes, but is not limited to, those associated with achieving compliance with environmental requirements or those necessitated by catastrophic failure.
 - 7.2. Deadline for Removal.** Consistent with RCW 19.405.030, PacifiCorp will remove from Washington rates all costs and benefits associated with Bridger units 1-4 and Colstrip unit 4 no later than December 31, 2025.

- 7.3. Resource Flexibility.** The dates articulated in this section are agreed upon by parties to facilitate the removal of coal from Washington Rates by 2025, and provide the flexibility that may allow for early compliance with CETA.
- 8. Decommissioning Cost.** Washington will continue to be allocated ongoing and expected decommissioning expenses for a WCA share of Jim Bridger Units 1-4 and Colstrip Unit 4.
- 8.1. Colstrip Engineering Study.** The Company will provide by March 30, 2020, an independent engineering study of estimated decommissioning costs for Colstrip.
- 8.2. Jim Bridger Engineering Study.** The Company will provide by January 15, 2020, an independent engineering study of estimated decommissioning costs for Jim Bridger.
- 8.3. Cost Assignment.** To facilitate the allocation of decommissioning costs, Parties agree to support a system allocation of the costs associated with an independent engineering study in 8.1 and 8.2.
- 9.** This agreement proposes modifications to the WCA, which serves as the basis for allocating costs in Washington. PacifiCorp will allocate costs based on the WCA consistent with the modifications in this Agreement for ratemaking purposes in Washington unless a different cost allocation method is approved by the Commission.
- 10.** Each Party to this Agreement represents that they are signing this Agreement in good faith and that they intend to abide by the terms of this Agreement.
- 11.** This Agreement may be executed in counterparts and each signed counterpart constitutes an original document.
- 12.** Attachment 1 contains updated allocation factors consistent with this Agreement.
- 13.** This Agreement is entered into by each Party on the date entered below such Party's signature.

The Washington Inter-Jurisdictional Allocation Methodology Memorandum of Understanding,
Page 7 of 7

PACIFICORP

By: _____

Title: _____

Date: _____

PUBLIC COUNSEL

By: _____

Title: _____

Date: _____

**STAFF OF THE WASHINGTON
UTILITIES AND TRANSPORTATION
COMMISSION**

By: _____

Title: _____

Date: _____

**PACKAGING CORPORATION OF
AMERICA**


By: _____

Title: _____

Date: _____

The Washington Inter-Jurisdictional Allocation Methodology Memorandum of Understanding,
Page 7 of 7

PACIFICORP

By: 
Title: VICE PRESIDENT, REGULATION
Date: NOVEMBER 22, 2019

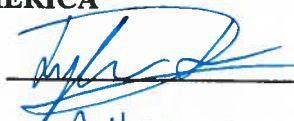
PUBLIC COUNSEL

By: _____
Title: _____
Date: _____

**STAFF OF THE WASHINGTON
UTILITIES AND TRANSPORTATION
COMMISSION**

By: _____
Title: _____
Date: _____

**PACKAGING CORPORATION OF
AMERICA**

By: 
Title: Attorney
Date: 11/22/19

The Washington Inter-Jurisdictional Allocation Methodology Memorandum of Understanding,
Page 7 of 7

PACIFICORP

**STAFF OF THE WASHINGTON
UTILITIES AND TRANSPORTATION
COMMISSION**

By: _____

By: Mark Vaccaro

Title: _____

Title: Director, Regulatory Services

Date: _____

Date: Nov. 22, 2019

PUBLIC COUNSEL

**PACKAGING CORPORATION OF
AMERICA**

By: _____

By: _____

Title: _____

Title: _____

Date: _____

Date: _____

The Washington Inter-Jurisdictional Allocation Methodology Memorandum of Understanding,
Page 7 of 7

PACIFICORP

By: _____

Title: _____

Date: _____

PUBLIC COUNSEL

By:  _____

Title: Assistant Attorney General

Date: 11/21/2019

**STAFF OF THE WASHINGTON
UTILITIES AND TRANSPORTATION
COMMISSION**

By: _____

Title: _____

Date: _____

**PACKAGING CORPORATION OF
AMERICA**

By: _____

Title: _____

Date: _____

APPENDIX G

Special Contracts

Special Contracts without Ancillary Service Contract Attributes

For allocation purposes, Special Contracts without identifiable Customer Ancillary Service attributes are viewed as one transaction.

Loads of Special Contract customers will be included in all Load-Based Dynamic Allocation Factors.

When interruptions of a Special Contract customer's service occur, the reduction in load will be reflected in the host jurisdiction's Load-Based Dynamic Allocation Factors.

Actual revenues received from Special Contract customer will be assigned to the State where the Special Contract customer is located.

See example in Table 1.

Special Contracts with Customer Ancillary Service Attributes

For allocation purposes, Special Contracts with Customer Ancillary Service attributes are viewed as two transactions. PacifiCorp sells the customer electricity at the retail service rate and then buys the electricity back during the interruption period at the Customer Ancillary Service Contract's rate.

Loads of Special Contract customers will be included in all Load-Based Dynamic Allocation Factors.

When interruptions of a Special Contract customer's service occur, the host jurisdiction's Load-Based Dynamic Allocation Factors and the retail service revenue are calculated as though the interruption did not occur.

Revenues received from Special Contract customer, before any discounts for Customer Ancillary Services attributes of the Special Contract, will be assigned to the State where the Special Contract customer is located.

Discounts from tariff prices provided for in Special Contracts that recognize the Customer Ancillary Services attributes of the Contract, and payments to retail customers for Customer Ancillary Services will be allocated among States on the same basis as System Resources.

See example in Table 2.

Buy-through of Economic Curtailment

When a buy-through option is provided with economic curtailment, the load, costs, and revenue associated with a customer buying through economic curtailment will be excluded from the calculation of State revenue requirements. The cost associated with the buy-through will be removed from the calculation of net power costs, the Special Contract customer load associated with the buy-through will be not be included in the calculation of Load-Based Dynamic Allocation Factors, and the revenue associated with the buy-through will not be included in State revenues.

Table 1
Interruptible Contract Without Ancillary Service Contract Attributes
Effect on Revenue Requirement

	<u>Factor</u>	<u>Total system</u>	<u>Jurisdiction 1</u>	<u>Jurisdiction 2</u>	<u>Jurisdiction 3</u>
1 Loads					
2 Jurisdictional Loads - No Interruptible Service					
3		72,000	24,000	36,000	12,000
4		42,000,000	14,000,000	21,000,000	7,000,000
5					
6 Jurisdictional Loads - With Interruptible Service - Reflecting Actual Interruptions					
7		71,700	24,000	35,700	12,000
8		41,962,500	14,000,000	20,962,500	7,000,000
9					
10 Special Contract Customer Revenue and Load - Non Interruptible Service					
11		\$ 20,000,000		\$ 20,000,000	
12		900	-	900	-
13		500,000	-	500,000	-
14					
15 Special Contract Customer Revenue and Load - With Interruptible Service (75 MW X 500 Hours of Interruption)					
16		\$ 16,000,000		\$ 16,000,000	
17					
18		\$ 16,000,000		\$ 16,000,000	
19		600	-	600	-
20		462,500	-	462,500	-
21					
22		\$4,000,000			
23					
24 Allocation Factors					
25 No Interruptible Service					
26	SE1	100.00%	33.33%	50.00%	16.67%
27	SC1	100.00%	33.33%	50.00%	16.67%
28	SG1	100.00%	33.33%	50.00%	16.67%
29					
30 With Interruptible Service (Reflecting Actual Physical Interruptions)					
31	SE2	100.00%	33.36%	49.96%	16.68%
32	SC2	100.00%	33.47%	49.79%	16.74%
33	SG2	100.00%	33.45%	49.83%	16.72%
34					
35					
No Interruptible Service					
36					
37					
38 Cost of Service					
39	SE1	\$ 500,000,000	\$ 166,666,667	\$ 250,000,000	\$ 83,333,333
40	SG1	\$ 1,000,000,000	\$ 333,333,333	\$ 500,000,000	\$ 166,666,667
41		\$ 1,500,000,000	\$ 500,000,000	\$ 750,000,000	\$ 250,000,000
42					
43 Revenues					
44	Situs	\$ 20,000,000		\$ 20,000,000	
45	Situs	\$ 1,480,000,000	\$ 500,000,000	\$ 730,000,000	\$ 250,000,000
46					
47					
With Interruptible Service					
48					
49					
50 Cost of Service					
51	SE2	\$ 498,000,000	\$ 166,148,347	\$ 248,777,480	\$ 83,074,173
52	SG2	\$ 998,000,000	\$ 334,058,577	\$ 496,912,134	\$ 167,029,289
53		\$ 1,496,000,000	\$ 500,206,924	\$ 745,689,614	\$ 250,103,462
54					
55 Revenues					
56	Situs	\$ 16,000,000		\$ 16,000,000	
57	Situs	\$ 1,480,000,000	\$ 500,206,924	\$ 729,689,614	\$ 250,103,462

Table 2
Interruptible Contract With Ancillary Service Contract Attributes
Effect on Revenue Requirement

	<u>Factor</u>	<u>Total system</u>	<u>Jurisdiction 1</u>	<u>Jurisdiction 2</u>	<u>Jurisdiction 3</u>
1 Loads					
2 Jurisdictional Loads - No Interruptible Service					
3		72,000	24,000	36,000	12,000
4		42,000,000	14,000,000	21,000,000	7,000,000
5					
6 Jurisdictional Loads - With Interruptible Service - Reflecting Actual Interruptions					
7		71,700	24,000	35,700	12,000
8		41,962,500	14,000,000	20,962,500	7,000,000
9					
10 Special Contract Customer Revenue and Load - Non Interruptible Service					
11		\$ 20,000,000		\$ 20,000,000	
12		900	-	900	-
13		500,000	-	500,000	-
14					
15 Special Contract Customer Revenue and Load - With Interruptible Service (75 MW X 500 Hours of Interruption)					
16		\$ 20,000,000		\$ 20,000,000	
17				\$ (4,000,000)	
18		\$ 16,000,000		\$ 16,000,000	
19		600	-	600	-
20		462,500	-	462,500	-
21					
22		\$4,000,000			
23					
24 Allocation Factors					
25 No Interruptible Service					
26	SE1	100.00%	33.33%	50.00%	16.67%
27	SC1	100.00%	33.33%	50.00%	16.67%
28	SG1	100.00%	33.33%	50.00%	16.67%
29					
30 With Interruptible Service (Reflecting Actual Physical Interruptions)					
31	SE2	100.00%	33.36%	49.96%	16.68%
32	SC2	100.00%	33.47%	49.79%	16.74%
33	SG2	100.00%	33.45%	49.83%	16.72%
34					
35					
36 No Interruptible Service					
37					
38 Cost of Service					
39	SE1	\$ 500,000,000	\$ 166,666,667	\$ 250,000,000	\$ 83,333,333
40	SG1	\$ 1,000,000,000	\$ 333,333,333	\$ 500,000,000	\$ 166,666,667
41		\$ 1,500,000,000	\$ 500,000,000	\$ 750,000,000	\$ 250,000,000
42					
43 Revenues					
44	Situs	\$ 20,000,000		\$ 20,000,000	
45	Situs	\$ 1,480,000,000	\$ 500,000,000	\$ 730,000,000	\$ 250,000,000
46					
47					
48 With Interruptible Service & Ancillary Service Contract					
49					
50 Cost of Service					
51	SE1	\$ 498,000,000	\$ 166,000,000	\$ 249,000,000	\$ 83,000,000
52	SG1	\$ 998,000,000	\$ 332,666,667	\$ 499,000,000	\$ 166,333,333
53	SG1	\$ 2,000,000	\$ 666,667	\$ 1,000,000	\$ 333,333
54	SE1	\$ 2,000,000	\$ 666,667	\$ 1,000,000	\$ 333,333
55		\$ 1,500,000,000	\$ 500,000,000	\$ 750,000,000	\$ 250,000,000
56					
57 Revenues					
58	Situs	\$ 20,000,000		\$ 20,000,000	
59	Situs	\$ 1,480,000,000	\$ 500,000,000	\$ 730,000,000	\$ 250,000,000