BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

Docket No. UM 2009

MADRAS PV1, LLC, Complainant, v. PORTLAND GENERAL ELECTRIC COMPANY, Respondent.	COMPLAINANT'S ANSWER TO PORTLAND GENERAL ELECTRIC COMPANY'S COUNTER-CLAIMS

I. INTRODUCTION

On April 22, 2019, Madras PV1, LLC ("Madras Solar") filed a complaint against Portland General Electric Company ("PGE") regarding PGE's refusal to enter into a power purchase agreement ("PPA") with Madras Solar under reasonable terms and conditions, and for PGE's delay in the process of negotiating and executing a PPA. On June 11, 2019, PGE filed its answer to the complaint. Within its answer, PGE included certain counter-claims against Madras Solar.[1] Pursuant to OAR 860-001-0400(4)(e), Madras Solar files this answer, as a response to PGE's counter-claim.

Specifically, through its counter-claim, PGE urges the Commission to include certain provisions in Madras Solar's PPA. These include:

1) Various "whereas" clauses, intended to make clear that Madras Solar will seek Network Resource Interconnection Service ("NRIS"), and that Madras Solar is required to pay for all network upgrades required to receive that service;[2]

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1 PGE's Answer at 19-35 (June 11, 2019).
2 *Id*. at 31-32.

2) Provisions stating that the fixed prices under the PPA are contingent upon Madras Solar's payment of all network upgrade costs;[3]

3) Provisions requiring that Madras Solar pay for "all costs determined by PGE" to be required for the provision of NRIS, as determined in PGE's Facilities Study, intended by PGE to affirm that Madras Solar will pursue a state-jurisdictional interconnection;[4]

4) Deadlines for executing the Facilities Study Agreement, of no later than 60 days after receipt of the System Impact Study, and executing the Interconnection Agreement no later than September 1, 2020;[5]

5) Modifications to the required Commercial Operation Date ("COD") to reflect the completion of system upgrades required by PGE, but no later than 3 years in the future;[6] and

6) Provisions requiring the sale of any test energy to PGE, and a specification of the prices at the Market Index Settlement Price[7]

Additionally, in support of its counter-claims, PGE makes multiple factual assertions in its answer. Below, Madras Solar provides a general response to the provisions PGE seeks to include within its PPA, followed by an answer to each of PGE's factual assertions in support of its counter-claim.

II. RESPONSE TO PGE'S PROPOSED PPA PROVISIONS

A. Many of PGE's Proposed Terms Are Unnecessary Given that There Are Fewer Differences in Madras Solar's and PGE's Positions than PGE Assumed When PGE Filed Its Answer and Counter Claims

PGE argues that this proceeding "presents critical issues regarding the allocation of costs associated with required network upgrades caused by a QF's siting decision, where that QF

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3 *Id.* at 32.
4 *Id.* at 33.
5 *Id.*
6 *Id.* at 34.
7 *Id*. at 34-35.

attempts to exclude those costs from both its avoided cost prices ***and*** from its interconnection process."[8] PGE asserts, specifically, that Madras Solar is attempting to avoid paying for necessary system upgrades by seeking to interconnect under a FERC-jurisdictional interconnection (where network upgrade costs, if any, would be either paid for by PGE's merchant function, if assessed under a request to designate the facility as a Network Resource, or advanced by the developer and then reimbursed in accordance with PGE's *pro forma* Open Access Transmission Tariff ("OATT"), if assessed under a FERC-jurisdictional NRIS interconnection study) and simultaneously seeking a state jurisdictional PPA (under which it is entitled to avoided cost rates that PGE states may not include the costs of those upgrades). PGE's view of Madras Solar's intent on this topic appears to be PGE's motivation for proposing many of the PPA terms it includes in its counter-claim.

PGE's characterization of Madras Solar's intent, however, is inaccurate, and its characterization of Madras Solar's actions is incomplete. Madras Solar is not seeking to avoid the costs of network upgrades. What Madras Solar is seeking to avoid are the costs of *unnecessary*, *unjustified*, and *grossly exaggerated* network upgrades. Madras Solar has committed, for purposes of the PPA, to obtaining NRIS and funding, through the interconnection process, whatever upgrades are legitimately required for NRIS.

There has been a remarkable history in this case of PGE raising interconnection-related matters to refuse to purchase Madras Solar's net output, and the case may provide a particularly salient example of the type of discriminatory behavior that FERC warned about when it said that a non-independent Transmission Provider has an inherent "incentive to find that a

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[8] *Id.* at 2 (emphasis in PGE's Answer).

disproportionate share of the costs of expansions needed to serve its own power customers is attributable to competing Interconnection Customers."[9] When Madras Solar originally approached PGE to sell its net output, PGE simply informed Madras Solar that PGE was not able to accept deliveries at Madras Solar's chosen delivery point. It took PGE approximately four months to finally agree that Madras Solar could deliver at its chosen delivery point and provide indictive pricing, an additional six months to provide a draft PPA, and yet two more months to actually begin negotiating the PPA in earnest. Although PGE ultimately reversed its position and decided that it was willing to accept Madras Solar's net output, PGE proposed charging Madras Solar $343.7 million in network upgrade costs (as identified by PGE in both the Feasibility Study and the initial System Impact Study) – costs that have since been proven to be unnecessary, unjustified, and inappropriate. Madras Solar vehemently objected, and vigorously rebutted PGE's claims that such upgrades were required, but PGE, until finally reversing its position approximately one month ago, persisted in its view that such costs were both justified and must be paid by Madras Solar in order to obtain NRIS. Thus, the fundamental disagreement between Madras Solar and PGE is not whether Madras Solar would pay for network interconnection costs, but whether PGE's $343.7 million in estimated network upgrade costs was accurate and whether FERC or the Oregon Commission would resolve any potential interconnection-related dispute.

Madras Solar pointed out that it intended to sell its test energy to a third party, and that such provisions implicate jurisdiction by FERC over the interconnection. And, under FERC

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[9] *See Standardization of Generator Interconnection Agreements and Procedures*, Federal Energy Regulatory Commission, Docket No. RM02-1-000; Order No. 2003 at Par. 696 (July 24, 2003).

precedent, Madras Solar would not bear the ultimate cost responsibility for network upgrades in any event. PGE objects to the provisions regarding sales of test energy to third parties, and Madras Solar understands PGE's objection to be based, in part, on the fact that PGE would rather have the Commission retain jurisdiction to evaluate interconnection costs than have FERC review them. PGE is correct that Madras Solar's position is that the inclusion of the test energy provisions in the PPA would provide FERC with jurisdiction over the interconnection between PGE and Madras Solar.

After Madras Solar filed its complaint in this case, PGE determined that it had, in fact, improperly conducted the System Impact Study ("SIS") that found that $343.7 million in network upgrades would be required in order to provide NRIS.[10] As PGE has explained in its testimony in support of its answer, in response to Madras Solar's requests, PGE conducted further analyses, which "prompted some questions and further examination regarding the interplay between the [Open Access Transmission Tariff ("OATT")] and [certain] grandfathered arrangements, which included working with counsel to assess PGET's interpretation of the NRIS System Impact Study methodology."[11] PGE explains that it had previously interpreted its tariff as "requir[ing] that all of the generation facilities in the local area, running at full output, be deliverable to PGE's system load in the Willamette Valley *on PGE's system* at the same time."[12] This approach was taken despite the fact that "historically, a portion of [Pelton-Round Butte's ("PRB's")] generation has been transmitted to PGE's load using grandfathered arrangements on

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[10] *See* Response Testimony of Shaun Foster and Sean Larson, PGE/200, Foster – Larson/13-14 (June 11, 2019).
[11] *Id*. 13.
[12] *Id*. at 14 (emphasis in PGE's Answer).

BPA's system."[13] PGE has now changed its position, and assumes the existence of those historical transmission arrangements in order to assess system upgrades needed to accommodate the Madras Solar project.[14] PGE then developed and prepared a revised SIS, which reduced the NRIS costs to $27 million.[15]

Although Madras Solar continues to maintain that not all of these costs are necessary, PGE's more than tenfold cost reduction changes the dynamics for the project. Madras Solar is willing to remove the provisions from its PPA that would allow it to sell test energy to a third-party, and to submit that its interconnection be considered state-jurisdictional, as it had previously asked PGE to assume for purposes of drafting the PPA.[16] Madras Solar maintains its position, of course, that it should pay for only all *reasonable, justified,* and *necessary* network upgrade costs, and that costs for certain network upgrades may be appropriately credited back to Madras Solar, to the extent they provide quantifiable system-wide benefits.

Many of PGE's proposed PPA terms, set forth in its counterclaim are therefore unnecessary. Specifically, this includes PGE's proposed terms 1, 2, and 3 as listed above. (Provision 1 being the "whereas" clauses making clear that Madras Solar will seek NRIS and be required to pay for all necessary system upgrades; provision 2 being the statements that fixed prices are contingent upon Madras Solar's payment of all network upgrade costs; and provision 3 being that Madras Solar's interconnection is subject to the Commission's jurisdiction.) In light of Madras Solar's agreement that its interconnection is state jurisdictional, and that it will pay the

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13 *Id*.
14 *Id*.
15 Attachment A, Interconnection System Impact Re-Study at 19 (July 12, 2019).
16 *See* PGE's Answer at 26.

costs of all *reasonable, justified,* and *necessary* system upgrades, subject to the Commission's policies, these provisions are not needed.

Additionally, provision 6 (setting the price for sales of test energy, and specifying that such sales will be made to PGE) should not be required. While PGE can point to no reason why Madras Solar should be required to sell *all* of its net output to PGE, because Madras Solar understands PGE's objection to this provision is motivated by its desire to ensure that the interconnection is state jurisdictional, and because Madras Solar is not opposed to this, it does not object to agreeing to sell its test energy to PGE. This agreement is conditioned upon PGE not asserting that Madras Solar's agreement to remove the test energy provisions somehow undermines Madras Solar's legally enforceable obligation to the prices and other terms and conditions in the partially executable PPAs. PGE's provision therefore is not necessary.

B. Some of PGE's Proposed Terms Are Overly Restrictive

In its counter-claim, PGE proposes to add to Madras Solar's PPA a provision that states that Madras Solar must execute the Facilities Study Agreement no later than 60 days after receipt of the System Impact Study, and execute the Interconnection Agreement no later than September 1, 2020.[17] This would undermine and replace other provisions that Madras Solar has insisted on, which would give Madras Solar a chance to resolve interconnection disputes prior to being required to sign the interconnection agreement.[18] Because Madras Solar anticipates that it may have to continue to dispute PGE's interconnection costs, despite the fact that such costs have recently been reduced by more than an order of magnitude, it would be overly restrictive and

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[17] *Id.* at 33.
[18] Complaint at 17.

damaging to Madras Solar's rights to be required to sign an interconnection agreement within the timeline of any proceeding that may be required to resolve disputes on the subject.

PGE also asserts that the required COD should be updated to reflect the completion of network upgrades required by PGE, but no later than 3 years in the future.[19] Madras Solar appreciates that its COD should be changed in light of whatever upgrades are ultimately determined to be required to interconnect the project. However, given the likely disputes over interconnection costs, as described above, it may be too restrictive to limit the COD to within 3 years in the future. Moreover, PGE stated in the revised SIS that the NRIS "Plan of Service" (i.e., the upgrades required to provide Madras Solar with NRIS) requires 3-5 years "for design, permitting, equipment acquisition, and construction."[20] While Madras Solar believes that this timeline, like the underlying network upgrades, is exaggerated, PGE should not be allowed to insert a backdoor mechanism by which to terminate the PPA, which is what the 3-year timeline for achieving COD amounts to, as PGE could simply take in excess of 3 years to complete the required upgrades and then move to terminate the PPA. This provision should, therefore, be removed. Or, in the alternative, it should be modified to be clear that the COD should be extended in accordance with the provisions Madras Solar has proposed, which would allow a day-for-day extension of the COD to compensate for the time required to litigate complaints against PGE regarding the PPA,[21] and to account for any inability by PGE to construct the required upgrades within such 3-year period.

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[19] PGE Answer at 34.
[20] Attachment A, Interconnection System Impact Re-Study at 20.
[21] Complaint at 25.

III. ANSWER TO PGE'S FACTUAL ASSERTIONS IN SUPPORT OF COUNTER-CLAIM

Madras Solar addresses PGE's factual assertions, made in support of its counter-claim, below, in the form of an answer to each. Madras Solar denies any factual allegation not specifically admitted, and reserves its right to supplement this answer if PGE amends its counter-claim. The below does not address any allegations PGE makes in its complaint, other than those that appear under the heading of "PGE's Counterclaim," which begin with numbered paragraph 99 in PGE's Answer. Madras Solar answers each on a paragraph-by-paragraph basis.

99. Paragraph 99 simply incorporates preceding paragraphs in PGE's answer, and requires no answer. To the extent an answer is required, Madras Solar denies the preceding paragraphs.

100. Madras Solar does not have sufficient information related to the specific details of the ownership structure of the Pelton-Round Butte ("PRB") project to admit or deny the truth of all of PGE's assertions. However, Madras Solar understands and admits that the project is jointly owned by PGE and the Warm Springs Tribe.

101. Madras Solar does not have sufficient information related to the specifics of the ownership structure and associated agreements regarding the PRB project to admit or deny the truth of PGE's assertions in Paragraph 101.

102. Madras Solar admits that a portion of the PRB project output is conveyed on generation lead line to Round Butte substations, but does not have sufficient information to admit or deny that all of the output is conveyed in that method. Madras Solar does not have sufficient information to admit or deny the specifics regarding the ownership structure described by PGE.

103. Madras Solar admits that, from the Round Butte substation, a portion of PRB's output is transmitted to PGE's service territory and load on PGE's system by means of the Bethel-to-Round Butte 230 kV transmission line. Madras Solar denies that east-to-west capacity on the Bethel-to-Round Butte transmission segment is fully allocated to transmitting PRB's output to PGE's load. Madras Solar does not have sufficient information to admit or deny that this line is the sole connection between PRB and PGE's service territory over PGE's system or that the remaining portion of PRB's output that cannot be accommodated by the Bethel-to-Round Butte line flows over BPA's system, but admits its understanding is that a portion of PRB's output flows over BPA's system.

104. Paragraph 104 offers a legal conclusion, and therefore does not require that Madras Solar admit or deny it.

105. Madras Solar denies PGE's allegations in Paragraph 105, but admits that PGE's OASIS website states the following: "The points PGE at Round Butte and PGE at (System) are physically constrained from each other and have no capacity available between them from east to west due to internal system grandfathered transmission rights for Round Butte and Pelton generation as part of the PGE to PGE posted path."

106. Madras Solar admits the date Ecoplexus filed an interconnection request. The remainder of the statement sets out PGE's understanding and Madras Solar cannot admit or deny PGE's statements regarding its understanding.

107. Madras Solar admits that PGE informed Ecoplexus that the interconnection line on which Ecoplexus requested service is on a generation lead line, that the line

may be partially owned by an entity that is not FERC jurisdictional, and that there was little to no capacity to export power from the area without substantial upgrades on or about October 7, 2017, and notes that the dates of such correspondence were October 6, October 10, and October 12 of 2017. Madras Solar denies the remainder of paragraph 107.

108. Madras Solar admits the allegations in Paragraph 108.

109. Madras Solar admits the allegations in Paragraph 109.

110. Madras Solar admits that PGE's December 19, 2017 letter claimed that it could not provide pricing due to the fact that Round Butte was not a valid POD. Madras Solar denies the remainder of paragraph 110.

111. Madras Solar denies the allegations in Paragraph 111. Although Ecoplexus provided the correspondence upon the date identified by PGE, it actually stated: "Additionally, the last paragraph of your 'Request for Additional or Clarifying Information' letter states that the Facility has requested Energy Resource Interconnection Services ("ERIS"), and that 'ERIS allows the Interconnection Customer to be eligible to use the existing firm or non-firm capacity of the Transmission Provider's Transmission System, and does not convey transmission service.' Please confirm the relevance of this statement beyond simply noting that 'transmission service' will be conveyed to the Facility in the form of a Designated Network Resource ("DNR") request (or similar mechanism) submitted by PGE's Merchant function to PGE Transmission's function, subsequent to mutual execution of a PPA for the Facility."

112. Madras Solar admits the allegations in Paragraph 112.

113. Madras Solar admits that PGE stated that it was not willing to move directly to an SIS, "especially for this region of the system" and that it described that the central Oregon bulk electric system is "very complicated, somewhat limited, and involves other transmission providers who will need to be identified in the Feasibility Study Process as Affected Systems". Madras Solar admits that PGE stated that the interconnection request would need to be evaluated for NRIS if the facility was to be a QF, but whether relevant law requires NRIS for QFs is a conclusion of law, which requires no response. Madras Solar denies the remainder of paragraph 113.

114. Madras Solar admits that on January 4, 2018 it sent an email stating: "We have not decided to proceed as or not as a QF at this time." With respect to the portion of Paragraph 114 that states that PGEM was not aware of the revised study request, Madras Solar does not have the information to allow it to admit or deny the allegation. Madras Solar denies the remainder of paragraph 114.

115. Madras Solar denies admits that PGE provided a letter dated January 19, 2018. Madras Solar admits that PGE did also refer Ecoplexus to a diagram on PGE's OASIS that contained a note stating that, "The points PGE at RoundButte and PGE at (System) are physically constrained from each other and have no capacity available between them from east to west due to internal system grandfathered transmission rights for RoundButte and Pelton generation as part of the PGE to PGE posted path." Madras Solar denies that PGE indicated that it was willing to consider interconnection on the PRB generation lead line. With respect to the portion of paragraph 115 that states that PGE's communications flowed from

Ecoplexus' "seeking to interconnect in an area from which its generation could not be exported without upgrades," Madras Solar denies that the upgrades PGE has proposed as necessary are in fact necessary. Madras Solar denies the remainder of the allegations in paragraph 115.

116. Madras Solar admits that on February 8, 2018, Ecoplexus counsel sent a letter demanding PGE immediately provide indicative pricing. Madras Solar also admits that it stated that the parties did not need to resolve whether NRIS was required before providing indicative pricing. Madras Solar denies the statements regarding what Ecoplexus counsel stated PGE's cost responsibility was, but admits that Ecoplexus stated that "…the Project is an on-system QF directly interconnecting with PGE and that, as such, PGE is responsible for accepting and managing the net output of the Project, including delivering the power to load, as PGE would its other generation resources or market purchases."

117. Madras Solar admits that PGE provided indicative pricing upon the date stated. Madras Solar admits that PGE made assertions along the lines of what is alleged in paragraph 117, but notes that there are variations in the actual communications and what is stated by PGE. For example, PGE made no reference to the area being a "particularly challenging siting location."

118. With respect to the portion of the paragraph asserting that "having first claimed that the appropriate form of interconnection service did not need to be established before providing indicative pricing, Ecoplexus now claimed that such clarity was similarly not relevant to negotiating a full PPA," Madras Solar admits that on March 5, 2018, it provided a response, but that the response on that topic stated:

"…the applicability of an NRIS study – as opposed to a Network Resource Integration Service ("NITS") study – depends in part on issues that have not been resolved at this time, and need not be resolved prior to negotiating a PPA." With respect to the portion of the paragraph stating that "Ecoplexus also asked PGEM whether the indicative pricing accounted for PGE needing to redispatch other resources in order to accommodate the Madras project's output—thus seeming to assume that PGE would be responsible for backing down or redispatching existing output to facilitate the project's interconnection," Madras Solar admits that it asked for PGE to "confirm whether the indicative pricing contemplates a scenario in which PGE is redispatching and balancing its other generation and/or increasing or decreasing its market purchases in order to accommodate the output of Madras Solar." However, Madras Solar denies that it assumed that "PGE would be responsible for backing down or redispatching existing output to facilitate the project's interconnection" to the extent the paragraph is intended to communicate that Madras Solar had an expectation that it would be necessary for PGE to actually back down or redispatch existing output in order to facilitate the project's generation beyond whatever existing generation was modeled as being avoided in order to arrive at the project's avoided costs.

119. Paragraph 119 contains, in part, legal statements or conclusions that do not require Madras Solar to admit or deny them. Madras Solar admits that PGE's March 27 correspondence referred to Schedule 202 requirements regarding interconnection. Madras Solar denies that PGE's correspondence made reference

to whether Ecoplexus intended to sell the entirety of Madras Solar's output to PGE.

120. Madras Solar generally admits the allegations of paragraph 120, but notes that there are certain differences between the language used in the communication and PGE's characterization of it in this paragraph.

121. Madras Solar admits the allegations in paragraph 121.

122. Madras Solar admits the allegations in paragraph 122.

123. Madras Solar generally admits the allegations of paragraph 123, but notes that there are certain differences between the actual language used in the communication and PGE's characterization.

124. Madras Solar admits that on September 7, 2018, Ecoplexus provided PGET a letter that summarized the Feasibility Study results review meeting that the parties held on September 5. Among other things, the letter noted how no physical constraints on the Bethel – Round Butte 230 kV line had been identified in the Feasibility Study.

125. Madras Solar generally admits the allegations of Paragraph 125, but notes that there are certain differences between the actual language used in the communication and PGE's characterization of it in this paragraph.

126. Madras Solar admits the allegations in Paragraph 126.

127. Madras Solar admits that Ecoplexus informed PGEM of the revised capacity, "pending further design considerations, which Ecoplexus will endeavor to finalize prior to execution of the PPA." Madras Solar denies the remainder of this paragraph.

128. Madras Solar admits the allegations in Paragraph 128.

129. Madras Solar admits the allegations in Paragraph 129.

130. Madras Solar admits the allegations in Paragraph 130.

131. Madras Solar admits the allegations in Paragraph 131.

132. Madras Solar generally admits the allegations in Paragraph 132, but notes that there are differences between the actual language used in the communication and PGE's characterization in the paragraph.

133. Madras Solar admits the allegations in Paragraph 133.

134. Madras Solar admits the allegations in Paragraph 134.

135. Madras Solar generally admits the allegations in Paragraph 135, but notes that there are differences between the language used and PGE's characterization in the paragraph, including the fact that PGE did not actually discuss evidence of Ecoplexus' intent to sell a portion of the output to third parties in the written communications on that day.

136. Ecoplexus admits that PGE provided the correspondence alleged in Paragraph 136, but notes that it disagrees with PGE that any actions taken by Ecoplexus up to that point would have necessitated that it revert back to step one of the negotiation process.

137. Madras Solar generally admits the allegations in Paragraph 137, but notes that there are differences between the actual language used and PGE's characterization in the paragraph.

138. Madras Solar admits the allegations in Paragraph 138.

139. Madras Solar admits the allegations in Paragraph 139.

140. Madras Solar admits the allegations in Paragraph 140.

141. Madras Solar generally admits the allegations in Paragraph 141, but notes that there are differences between the actual language used and PGE's characterization in the paragraph.

142. Madras Solar admits the allegations in Paragraph 142.

143. Madras Solar generally admits the allegations in Paragraph 143, but notes that there are differences between the actual language used and PGE's characterization in the paragraph.

144. Madras Solar admits the allegations in Paragraph 144.

145. Madras Solar admits that Ecoplexus provided a revised PPA upon the date stated in this paragraph, and generally admits the allegations. However, Madras Solar notes that section referred to allowed Ecoplexus to delay signing of a Facilities Study Agreement until "thirty (30) days after the date upon which PGE (acting in its transmission function) issues a final System Impact Study report that is reasonably acceptable to Seller, in its sole discretion" (rather than giving it a right to refuse to sign the agreement).

146. Madras Solar generally admits the allegations in Paragraph 146, but notes that there are differences between the actual language used and PGE's characterization in the paragraph.

147. Madras Solar admits the allegations in Paragraph 147.

148. Madras Solar generally admits the allegations in Paragraph 148, but notes that there are differences between the actual language used and PGE's characterization in the paragraph.

149. Madras Solar admits the allegations in Paragraph 149.

150. Madras Solar admits the allegations in Paragraph 150.

151. Madras Solar admits that PGEM provided a revised PPA upon such date, but denies that PGEM inquired as to why Ecoplexus changed the nameplate capacity rating.

152. Madras Solar generally admits the allegations in Paragraph 152, but notes that there are differences between the actual language used and PGE's characterization in the paragraph.

153. Madras Solar admits the allegations in Paragraph 153.

154. Madras Solar admits the portion of the paragraph that "At Ecoplexus's request, PGET continues to process Ecoplexus's interconnection request for both NRIS and ERIS as a FERC-jurisdictional non-QF; PGET has offered to transition Ecoplexus's interconnection request to the QF LGIP." Madras Solar denies the allegation in the paragraph that "Ecoplexus's FERC-jurisdictional interconnection request is inconsistent with its direction to PGEM to draft a PPA that assumes that the Madras interconnection is state-jurisdictional."

155. Madras Solar denies the allegations in Paragraph 155.

156. Paragraph 156 contains statements about PGE's conclusions or positions, or provides legal argument, and thus a response is not required. To the extent a response is required, Madras Solar denies the allegations in Paragraph 156.

157. Paragraph 157 contains PGE's conclusions, position, or argument, and thus does not require a response from Madras Solar. To the extent a response is required, Madras Solar denies the allegations in Paragraph 157.

158. Madras Solar denies the allegations in Paragraph 158.

159. Paragraph 159 contains PGE's position, conclusions, or legal argument, and thus a response by Madras Solar is not required. Madras Solar admits that the size claimed for the Madras Solar project is more than 10 MW. To the extent a response to the other statements in Paragraph 159 is required, Madras Solar denies the allegations.

160. Paragraph 160 contains PGE's position, conclusions, or legal argument, and thus a response by Madras Solar is not required. To the extent a response if required, Madras Solar denies the allegations of Paragraph 160.

161. Madras Solar admits that PGE repeated its position as stated in Paragraph 161, but denies the assertions made by PGE.

162. Madras Solar denies the allegations in Paragraph 162.

163. Madras Solar denies the allegations in Paragraph 163, except that it admits that it asked PGEM to assume, for purposes of preparing a draft PPA, that it would obtain and pay for NRIS, and it admits that it later stated that its interconnection may be FERC jurisdictional.

164. Paragraph 164 contains PGE's position, conclusions, or legal argument, and thus a response by Madras Solar is not required. To the extent a response if required, Madras Solar denies the allegations in Paragraph 164.

165. Paragraph 165 contains PGE's position, conclusions, or legal argument, and thus a response by Madras Solar is not required. To the extent a response if required, Madras Solar denies the allegations of Paragraph 165.

166. Paragraph 166 contains PGE's request to the Commission, and a response is not required.

167. Paragraph 167 contains PGE's request to the Commission, and a response is not required.

168. Paragraph 168 contains PGE's request to the Commission, and a response is not required. Madras Solar denies the statements in Paragraph 168 that "Madras's avoided cost prices would vary significantly if Madras were not required to pay for system upgrades associated with NRIS, and the price paid under the contract assumes and is expressly contingent upon Madras accepting responsibility for interconnection costs and related upgrades."

169. Paragraph 169 contains PGE's request to the Commission, and a response is not required. Madras Solar denies the statements in Paragraph 169 that the request is appropriate.

170. Paragraph 170 contains PGE's request to the Commission, and a response is not required. Madras Solar denies the statements in Paragraph 170 that the request is appropriate. Paragraph 170 also contains statements regarding PGE's position, conclusions, or legal argument, and a response to those statements is not required. To the extent a response is required, Madras Solar denies those allegations.

171. Paragraph 171 contains PGE's request to the Commission, and a response is not required.

172. Paragraph 172 contains PGE's request to the Commission, and a response is not required. Paragraph 172 also contains statements regarding PGE's position,

conclusions, or legal argument, and a response to those statements is not required. To the extent a response is required, Madras Solar denies those allegations.

173. Paragraph 173 contains PGE's request to the Commission, and a response is not required.

Respectfully submitted this 12th day of August, 2019.

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Attachment A

PGE Interconnection System Impact Re-Study

Portland General Electric Company

Interconnection System Impact

Re-Study

Interconnection request:

#17-068 (65 MW Photovoltaic Project)

Issued July 12, 2019

Prepared by Transmission Planning

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Introduction

This System Impact Study[1] (SIS) examines the feasibility of connecting the proposed 65 MW photovoltaic generation and Battery Energy Storage System project to the Portland General Electric (PGE) Transmission System with a requested in-service date of December 1, 2019. The Interconnection Customer has requested a Point of Interconnection (POI) on a generation lead line for the Pelton-Round Butte Hydroelectric Facility (PRB) in Central Oregon. PRB, including the generation lead line, is jointly owned by PGE and the Confederated Tribes of the Warm Springs Reservation of Oregon (the Tribes).

The Interconnection Customer has requested generation interconnection service in conformance with the PGE Open Access Transmission Tariff (OATT). The Interconnection Customer has requested that the generation interconnection be studied for both Network Resource Interconnection Service (NRIS) and Energy Resource Interconnection Service (ERIS).

Study Scope

This SIS will evaluate the system impact to PGE's Transmission System of the Interconnection Customer's proposed interconnection at the designated POI, and identify any required Contingent Facilities, Interconnection Facilities, and Network Upgrades necessary to accommodate such request. An SIS consists of a power flow analysis, short circuit analysis, transient stability analysis, and voltage stability analysis. This SIS also includes a Total Transfer Capability (TTC) analysis to quantify the utilization of PGE Transmission System and any congestion between the designated POI and PGE load. The following objectives will to be met in this SIS:

- Documentation of the assumptions used in the analyses;
- Documentation of any system impacts (i.e. thermal overloads or voltage limit violations) observed that are adverse to the reliability of the electric system as a result of the proposed interconnection;
- Documentation of other transmission providers' transmission systems that are impacted and identification of these transmission providers as Affected Systems;
- Documentation of fault interrupting equipment with short circuit capability limits that are exceeded as a result of the proposed interconnection;
- A list of Contingent Facilities;
- A non-binding, good faith estimate of the cost for constructing Transmission Provider's Interconnection Facilities and the Network Upgrades necessary to accommodate the requested interconnection service; and,
- A non-binding, good faith estimate of the time to construct the required Transmission Provider's Interconnection Facilities and Network Upgrades, and the estimated in-service completion times of the Contingent Facilities necessary to accommodate the requested interconnection service.

[1] With the exception of those terms that are defined herein, capitalized terms used throughout this document have the same meanings as such terms are defined in PGE's Open Access Transmission Tariff (OATT).

This SIS considered all transmission facilities and generation facilities that, on the date the study was commenced:

- Were directly interconnected to the PGE Transmission System;
- Were interconnected to other transmission providers' transmission systems and may have an impact on the requested interconnection service;
- Have a higher queued Interconnection Request[2] to interconnection to the PGE Transmission System; and
- Have no queue position but have executed a Large Generator Interconnection Agreement (LGIA) or requested that an unexecuted LGIA be filed with FERC[3].

Additionally, this SIS considered certain generator interconnection requests on other transmission providers' transmission systems that are expected to, based on engineering judgement, impact or be impacted by the Interconnection Customer's requested generation interconnection service request.

Study Assumptions

This SIS includes the following assumptions for all system conditions and seasons:

- The Interconnection Customer's requested in-service date is December 1, 2019;
- Higher queued generation interconnection requests are included and modeled at their requested maximum generation levels. Higher queued generation interconnection requests included in this SIS are:
    - Request# 16-061 – 100 MW Battery Energy Storage System at the Bethel substation;
    - Request# 17-065 – 400 MW Photovoltaic System at the Fort Rock substation;
    - Request# 17-066 – 200 MW Battery Energy Storage System at the Rivergate substation; and,
    - Request# 17-067 – 200 MW Battery Energy Storage System at the Harborton substation.
- No generator interconnection requests on other transmission providers' transmission systems were included in this SIS[4];
- Other than the higher queued projects identified above, there are no projects in PGE's annual progress report to WECC that are schedule to be on-line prior to the Customer's requested in-service date;
- This request for interconnection service is modeled at a maximum capability of 65 MW;

[2] With respect to both generation facilities and Contingent Facilities associated with any higher quested interconnection request.
[3] As of the date of this SIS was commenced, there were no Generating Facilities that lacked a queue position but had executed an LGIA or requested that an unexecuted LGIA be filed with FERC that would impact, or be impacted by, the proposed Plan of Service resulting from the studies conducted to-date for this generation interconnection request.
[4] Previous studies have shown that the current generator interconnection requests on other transmission providers' transmission systems have little or no impact on transfers from the Round Butte substation to PGE load.

- The POI is approximately 4.9 miles north of PGE's existing Round Butte Substation on the co-owned Pelton-Round Butte 230 kV generator lead line;
- The nominal voltage at the POI is 230 kV;
- The Interconnection Customer will design, permit, build, and maintain a 230 kV generator lead line from the Interconnection Customer's generation site to the POI; and,
- There is no available capacity from east to west between Round Butte and PGE's load due to existing, historical, internal transmission rights for PRB generation. In other words, the Available Transfer Capability (ATC) of the Round Butte to PGE load path in the east to west direction is 0 MW.

Study Case Development

This SIS utilizes WECC base cases as the starting point for studying the requested generator interconnection service. WECC base cases include models for the entire Western Interconnection including facility representation of voltage levels at the sub-transmission level. WECC collects the data for the Western Interconnection through its members who provide the representation and equivalent data for elements in their systems, including: the initial conditions for the study case, up-to-date line parameters, load information, generation unit parameters, and equivalent representation consistent with the time period being studied. The WECC base cases used in this SIS were modified for use in the PGE NERC TPL-001-4 Transmission Planning Assessment (TPL) as follows:

- The TPL 2020 summer peak case is based on the WECC 2018 Heavy Summer 4 OPS case;
- The TPL 2020-2021 winter peak case is based on the WECC 2018-19 Heavy Winter 3 OPS case; and,
- The TPL 2020 spring off-peak case is based on the WECC 2021 Light Spring 1 case.

The TPL cases were further modified to include the higher queued generator interconnection requests and associated Contingent Facilities listed in the Study Assumptions section of this SIS, and higher customer loads to reflect the 1-in-5 summer and winter peak forecasted for the PGE service territory. The resulting cases are referred to in this SIS as the "Benchmark Cases".

From the Benchmark Cases, a model of the Interconnection Customer's Generating Facility and generator lead line were inserted, and the resulting cases are hereafter referred to as the "Project Cases". The differences between the Benchmark Cases and the Project Cases form the basis for comparisons of the Transmission System's performance between the pre-and post-generator interconnection topology of the system.

SIS Methodology

This SIS includes powerflow, short circuit, transient stability, and voltage stability analyses in conformance with the PGE OATT. Each of these analyses may reveal unacceptable system performance that must be mitigated to integrate the proposed interconnection to the PGE Transmission System. The Benchmark Cases and the Project Cases are analyzed to determine if Network Upgrades (taking into consideration any applicable Contingent Facilities) are necessary to ensure that the Transmission System, with the addition of the Interconnection Customer's generator, demonstrates acceptable system performance. Each analysis is performed on a version of the Project Cases that include all Contingent Facilities required by higher queued interconnection requests.

Power Flow Analysis

The NERC TPL-001-4 reliability standard requires that all transmission system elements comprising the Bulk Electric System (BES) remain within their established thermal and voltage limits following the loss of a single BES element (N-1) or the loss of two or more BES elements (N-2 or N-1-1). This SIS includes the N-1, N-2, and N-1-1 contingencies for all BES elements in the PGE Transmission System and neighboring areas. The WECC System Performance Criteria, in addition, requires that the change in bus voltage percentage not exceed 8% for N-1 contingencies.

The analysis results for each contingency are assessed for compliance with the following NERC and WECC system performance Requirements:

Pre-Contingency:

- All BES elements shall be within their normal thermal limits
- All BES elements shall be within their normal voltage limits
- All BES elements shall be within their stability limits
- The BES shall demonstrate transient and voltage stability

Post-Contingency:

- All BES elements shall be within their emergency thermal limits
- All BES elements shall be within their emergency voltage limits
- Bus Voltage Change Limits:
  - The difference between pre and post-contingency load-serving bus voltages must be less than:
    - 8% for N-1 contingencies
    - 10% for N-2 and N-1-1 contingencies[5]
- The BES shall demonstrate transient and voltage stability
- Cascading or uncontrolled separation shall not occur
- Interruption of firm service (i.e. transmission curtailment) is allowed by modeling generation redispatch for applicable contingencies when acceptable, specified by the NERC TPL-001-4 Standard:

[5] The requirement load-serving bus voltages must be less than 10% for category P2-2 through category P7; this is a PGE performance requirement and is not documented in NERC and WECC standards.

- Allowed for category P2-2 through P2-4 contingencies below 300 kV, category P4-1 through P4-5 contingencies below 300 kV, category P4-6 contingencies, category P5 contingencies below 300 kV, and category P7 contingencies

Short Circuit Analysis

Short circuit analysis is performed to identify transmission equipment with rated fault capabilities that will be exceeded by the higher fault currents that result from adding the Interconnection Customer's Generating Facility to the PGE Transmission System. Short circuit modeling information for the Northwest area is maintained through the collaborative efforts of the region's utilities.

Faults at substations in the vicinity of the POI are simulated using the Aspen OneLiner program. Increases in equipment fault duty, attributable to the proposed Generating Facility, cannot result in fault duties that exceed equipment ratings. Fault duty increases of less than 1% are not considered significant impacts to the system and thus are not required to be mitigated by the Interconnection Customer.

Transient Stability Analysis

The transmission system must demonstrate post-contingency transient stability. Post-contingency transient stability is demonstrated when generator rotor angles, and bus voltages and frequencies show positive damping within the requirements of the WECC System Performance Criterion (TPL-001-WECC-CRT-3.1). The WECC System Performance Criterion (TPL-001-WECC-CRT-3.1) establishes limits on the allowable size and duration of frequency and voltage swings during the transient period following a disturbance. The WECC System Performance Criterion (TPL-001-WECC-CRT-3.1) performance requirements are:

Rotor Angle Stability

Generators must remain in synchronism with the PGE Transmission System and the rest of the transmission system in the Northwest area through the transient period. Rotor angle oscillations must exhibit positive damping for N-1 and N-2 contingencies.

Voltage Stability

Following the clearing of a fault, load-serving bus voltages shall recover to 80% of the pre-contingency voltage within 20 seconds of the initiating event for all N-1 and N-2 events.

Following the recovery to 80% of pre-contingency voltage, a load-serving bus shall neither dip below 70% of pre-contingency voltage for more than 30 cycles nor remain below 80% of pre-contingency voltage for more than two seconds for all N-1 and N-2 events.

Following the opening of a transmission element without a fault, the voltage at a load-serving bus shall neither dip below 70% of pre-contingency voltage for more than 30 cycles nor remain below 80% of pre-contingency voltage for more than two seconds for all N-1 and N-2 events.

Frequency Stability

System frequency at any load-serving bus must not fall below 59.6 Hz for six cycles or more following an N-1 contingency, or 59.0 Hz for six cycles or more following an N-2 contingency.

Representative contingencies subject to transient stability simulations include contingencies affecting the PGE Transmission System and the neighboring transmission systems. The PowerWorld Simulator tool is used to perform transient system stability analysis.

Voltage Stability Analysis

The transmission system must demonstrate post-contingency voltage stability. Post-contingency voltage stability is demonstrated when the Reactive Margin at a bus is greater than or equal to the Reactive Power Margin Requirement (PMR).

The WECC System Performance Criterion (TPL-001-WECC-CRT-3.1) requires that post-contingency PMR be demonstrated for stress levels of:

- A minimum of 105% for system normal conditions (N-0) and for N-1 contingencies; and
- A minimum of 102.5% for N-2 and N-1-1 contingencies

Representative contingencies used for the voltage stability analysis include contingencies affecting the PGE Transmission System and the neighboring transmission systems.

Both Reactive Margin and PMR are determined through the building of Q-V curves. The PowerWorld Simulator tool is used to build Q-V curves.

Total Transfer Capability Analysis

The concepts for determining transfer capability, described in NERC's 1995 *Transmission Transfer Capability* reference document, are still valid and do not change with the advent of open access transmission, or the need to determine TTCs.

The TTC analysis included the N-1 and N-2 contingencies of all BES facilities in the PGE transmission area and the neighboring areas. The analysis also included all credible and conditionally credible (as and when applicable) multiple contingencies for the study season, except for N-1-1 outages. N-1-1 outages, referred to as category P3 and P6 contingencies in the NERC TPL-001-4 standard, were excluded as the NERC standard allows for system adjustments, which can effectively mitigate issues resulting from a subsequent contingency. The TTC performance criteria are the same as the power flow and transient stability performance criteria documented above.

NRIS System Impact Study Analysis and Results

The PGE Transmission System in Central Oregon consists of PRB, the generation lead lines from PRB to the Round Butte substation, a 230 kV transmission line from the Round Butte substation to the Bethel substation in the Willamette Valley (Bethel-Round Butte 230 kV), a 230 kV transmission line from the Round Butte substation to the Redmond BPA substation (Redmond BPA-Round Butte 230 kV), a 500 kV transmission line from the Round Butte substation to the Grizzly BPA substation (Grizzly BPA-Round Butte 500 kV), and two 230 kV connections to PacifiCorp's Cove substation[6] located adjacent to the Round Butte Substation.

PGE does not have any load in Central Oregon. The Bethel-Round Butte 230 kV transmission line is the sole PGE Transmission System connection between PRB and the PGE service territory in the Willamette Valley. Currently, the output of PRB flows to PGE load via a combination of the Bethel-Round Butte 230 kV transmission line (utilizing the line's full capacity) and existing, historical transmission rights for PRB generation with the Bonneville Power Administration (BPA), all of which pre-date the OATT. There is no available capacity from east to west between Round Butte and PGE's load due to existing, historical, internal transmission rights for PRB generation. In other words, the Available Transfer Capability (ATC) of the Round Butte to PGE load path in the east to west direction is 0 MW. ATC is calculated in accordance with the NERC MOD-029-2a standard and can generally be represented as ATC = TTC - ETC, where TTC represents Total Transfer Capability and ETC represents Existing Transmission Commitments. Delivering the output of PRB to PGE load is an Existing Transmission Commitment that utilizes the full capacity of the Round Butte to PGE load path. Because the path ETC (PRB commitment) utilizes the full path TTC, the current ATC of the Round Butte to PGE load path is 0 MW. The existing TTC, and therefore the existing ETC, is determined in conformance with the NERC MOD-029-2a standard.

TTC for the Round Butte to PGE load path has not been calculated since there is currently no OASIS posted path. In order to provide generation interconnection service to PGE load, the TTC of the path must be calculated. Once the TTC of the Round Butte to PGE load path is determined, system modifications can be identified that will increase the TTC by 65 MW to facilitate the delivery of the output of the proposed interconnection.

Total Transfer Capability Analysis

NERC defines the TTC as the best engineering estimate of the total amount of electric power that can be transferred over the interface in a reliable manner in a given time-frame. TTC, expressed in terms of MW, is the measure of the ability of interconnected electric systems to reliably move or "transfer" electric power from one area to another by all of the transmission lines (or Paths) between those areas under specified system conditions. In this context, "area" refers to the configuration of generating

[6] The PacifiCorp Cove substation serves PacifiCorp's load in the Madras area. The Cove substation is a load pocket that is only connected to the Bulk Electric System by the Round Butte facilities. The Cove substation, and the associated distribution system, does not connect back to the Bulk Electric System at any other point.

stations, switching stations, substations, and connecting transmission lines that define an individual electric system control area.

This SIS addresses TTC from the perspective of the PGE Transmission System's physical characteristics and limitations. The recommended approaches and practices for calculating TTC across particular paths or interfaces is defined in NERC's May 1995 *Transmission Transfer Capability* reference document. The PGE ATC paths are shown in **Figure 1**.

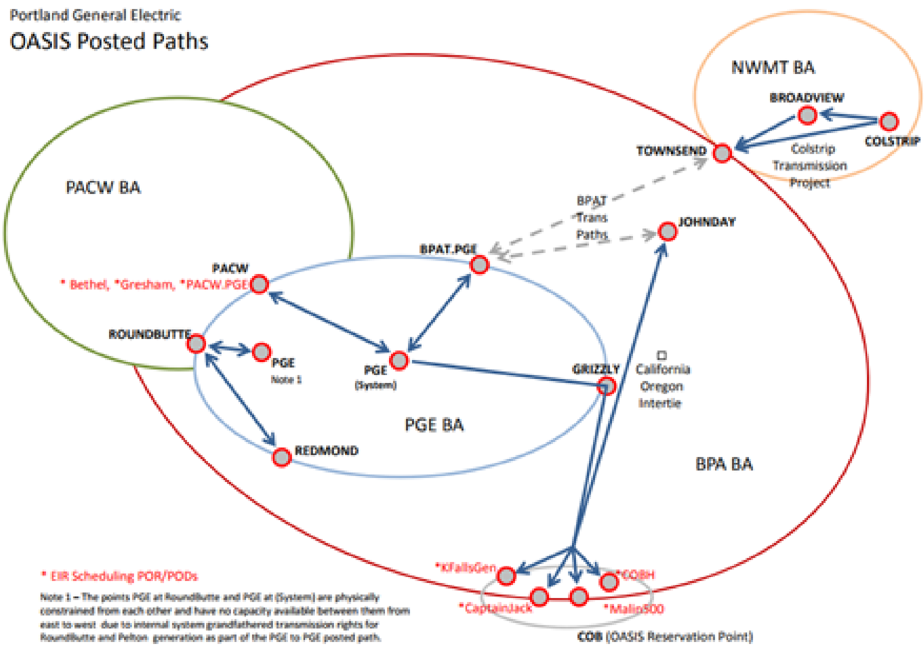

Figure 1: PGE ATC Path Diagram

Generation Dispatch

The PGE on-system generation and relevant generation in other areas were varied to achieve the maximum transfer across the Round Butte to PGE load path. The relevant external generation that was adjusted for this study includes the flowing, electrically similar generators:

- I-5 Corridor generation
- Upper Columbia generation
- Mid-Columbia generation
- Lower Columbia generation
- British Columbia generation
- California generation
- Other generation with material impacts identified using the PowerWorld Simulation software tools

Load

The PGE load levels, including PGE industrial loads but excluding station service loads, were scaled in the Benchmark Cases to 3861 MW summer peak and 3705 MW winter peak conditions. The PGE load and

PacifiCorp Portland area load were scaled together due to their geographical proximity. The PGE and PacifiCorp loads were not varied during the study. The maximum transfer across the path was achieved by varying generation and area exchange.

Remedial Action Schemes

Remedial Action Schemes (RAS) for which PGE is the Transmission Operator include the Round Butte RAS and the Grand Ronde RAS[7]. Additionally, all BPA RAS are considered during contingency analysis as defined by the applicable BPA Dispatcher Standing Orders.

Total Transfer Capability Results

A variety of generation patterns and load levels were studied in order to maximize transfers across the path. The path was studied to achieve maximum import in the direction of prevailing flow, which is from Round Butte to the PGE system. The final cases achieved maximum flow across the path of 199 MW in the summer and 260 MW in the winter. The changes in generation dispatch, path flows, and load from the starting Benchmark Cases to the stressed Benchmark Cases are summarized in the following tables:

Generation Group Name	Summer[8]		Winter[9]	
	Starting Case MW	Stressed Case MW	Starting Case MW	Stressed Case MW
I-5 Corridor Gen	4301	4128	5180	4117
Upper Columbia (Total) Gen	5429	4093	7806	7598
Mid-Columbia (Total) Gen	2588	2588	3043	3043
Lower Columbia (Total) Gen	4704	6135	4976	5082
PACW Lewis River Generation	125	30	386	326
Central Willamette Valley Generation	1145	896	1316	947
PGE On-System Generation	1524	529	2023	-85[10]

Table 1: NW Generation Dispatch Changes

[7] The Grand Ronde RAS is intended to alleviate under voltage concerns on local elements, and thus would not be triggered and has no impact to transfers on any ATC paths.
[8] The summer season is defined as starting on June 1st and ending on October 31st. However, the spring season—defined as starting April 1st and ending on May 31st—is included in the summer TTC season.
[9] The winter season is defined as starting on November 1st and ending on March 31st
[10] PGE On-System Generation includes 500 MW of Battery Energy Storage Devices. These batteries were modeled in charging mode to maximize the path transfers. Batteries in charging modes are displayed as negative generation.

Transfer Paths	Summer		Winter	
	Starting Case MW	Stressed Case MW	Starting Case MW	Stressed Case MW
BC Hydro-to-Northwest	2324	-1768	632	-2706
Montana-to-Northwest	577	741	1131	1189
Idaho-to-Northwest	-544	-244	-315	208
West of Cascades - North	3858	6651	7164	10363
West of Cascades - South	3591	5231	4245	6421
South of Allston	2112	1056	1546	222
North of John Day	4069	1188	3976	1993
California Oregon Intertie	3867	614	3741	-1096
Pacific DC Intertie (PDCI)	2800	2800	2301	2301
Midpoint-to-Summer Lake	219	-217	10	141

Table 2: Transfer Path Changes

Zone Name	Summer		Winter	
	Starting Case MW	Stressed Case MW	Starting Case MW	Stressed Case MW
PGE On System Load[11]	3861	3861	3705	3705
PAC: PTLD	446	446	480	480

Table 3: Load Changes

The loss of the Salem BPA 230/115 kV transformer sets the limitation of the Round Butte to PGE load path to 199 MW in the summer. The loss of the Ostrander BPA-Pearl BPA 500 kV transmission line sets the limitation of the Round Butte to PGE load path to 260 MW in the winter. The path was found to be thermally limited with no limiting voltage, reactive margin, or transient stability issues.

Summer				
Contingency Name	Limiting Element	Value	Limit	Percent
Salem BPA Transformer 230/115 kV	Chemawa BPA Transformer 230/115 kV	312.3 MVA	312.6 MVA	99.9%
Chemawa BPA-Salem BPA #1 230 kV	Chemawa BPA Transformer 230/115 kV	311.8 MVA	312.6 MVA	99.8%
Pearl BPA-Sherwood 230 kV	McLoughlin-Pearl BPA-Sherwood 230 kV	2623.8 A	2630.7 A	99.7%
Keeler BPA Transformer #2 500/230 kV	Murrayhill-St Marys 230 kV	1276.2 A	1315.4 A	97.0%

Table 4: Limiting Contingency – Summer

[11] PGE industrial loads were not scaled but are included in the PGE on-system load. PGE station service loads are not included in the listed PGE on-system load.

Winter				
Contingency Name	**Limiting Element**	**Value**	**Limit**	**Percent**
Ostrander BPA-Pearl BPA 500kV	Troutdale PACW Transformer 230/115kV	299.7 MVA	300.0 MVA	99.9%

Table 5: Limiting Contingency – Winter

PRB, as a network resource, utilizes long-term network transmission to deliver its output to PGE load. Long-term network transmission is limited to the lowest transfer capability during the requested period. Because the Round Butte to PGE load path is limited by the summer TTC of 199 MW, the long-term ETC for PRB is set to 199 MW. Long-term ETC does not vary with the season. And because seasonal ATC is equal to seasonal TTC - ETC, the summer ATC is 0 MW and the winter ATC is 61 MW.

In order to provide NRIS for the proposed interconnection, 65 MW of long-term ATC to PGE load must be created. The existing long-term ATC is 0 MW in the summer and the ETC is 199 MW. Therefore, to create 65 MW of ATC, the TTC in summer must be increased by 65 MW to a total of 264 MW. The existing long-term ATC is 61 MW in the winter and the ETC is 199 MW. Therefore, to create 65 MW of long-term ATC, the TTC in winter must be increased by 4 MW to a total of 264 MW.

The addition of the 65 MW proposed interconnection increases the flow on the Round Butte to PGE load path by only 8 MW in both the summer and winter seasons. The path flow must be increased by 57 MW in addition to the 8 MW flow contribution of the proposed interconnection to obtain the necessary TTC value of 264 MW in the summer. The flow contribution is adequate to meet the necessary TTC value for the winter.

Several options exist to increase the TTC on the Round Butte to PGE load path by the required 57 MW:

- Reconductor the Bethel-Round Butte 230 kV transmission line to reduce the line impedance and increase flow on the line;
- Install a series capacitor on the Bethel-Round Butte 230 kV transmission line to reduce the line impedance and increase flow on the line; or,
- Install a phase shifting transformer on the Bethel-Round Butte 230 kV transmission line to manage the power angle and direct flow across the line.

The cost of reconductoring the Bethel-Round Butte 230 kV transmission line is expected to be significantly more expensive than the cost to install a series capacitor or a phase shifting transformer. A reconductor, therefore, is not further examined in this SIS. Project Cases were developed for the series capacitor option and the phase shifting transformer option. Both options resulted in increases on the Round Butte to PGE load path of the required 57 MW, and both options resulted in similar system performance. The summer and winter power flow results are shown below in **Table 6**, **Table 7**, **Table 8**, and **Table 9**. With the addition of the series capacitor or the phase shifting transformer, the path was found to be thermally limited with no limiting voltage, reactive margin, or transient stability issues[12].

[12] Study results and charts are available upon request.

The addition of either a series capacitor or a phase shifting transformer to the Bethel-Round Butte 230 kV transmission line sufficiently increases the Round Butte to PGE load path TTC and thereby the ATC.

Summer – Series Capacitor				
Contingency Name	**Limiting Element**	**Value**	**Limit**	**Percent**
Pearl BPA-Sherwood 230 kV	McLoughlin-Pearl BPA-Sherwood 230 kV	2626.4 A	2630.7 A	99.8%
Salem BPA Transformer 230/115 kV	Chemawa BPA Transformer 230/115 kV	307.5 MVA	312.6 MVA	98.4%
Chemawa BPA-Salem BPA #1 230 kV	Chemawa BPA Transformer 230/115 kV	307.1 MVA	312.6 MVA	98.2%
Keeler BPA Transformer #2 500/230 kV	Murrayhill-St Marys 230 kV	1279.5 A	1315.4 A	97.3%

Table 6: Series Capacitor Option Limiting Contingency – Summer

Summer – Phase Shifting Transformer				
Contingency Name	**Limiting Element**	**Value**	**Limit**	**Percent**
Pearl BPA-Sherwood 230 kV	McLoughlin-Pearl BPA-Sherwood 230 kV	2625.4 A	2630.7 A	99.8%
Salem BPA Transformer 230/115 kV	Chemawa BPA Transformer 230/115 kV	307.4 MVA	312.6 MVA	98.3%
Chemawa BPA-Salem BPA #1 230 kV	Chemawa BPA Transformer 230/115 kV	306.6 MVA	312.6 MVA	98.2%
Keeler BPA Transformer #2 500/230 kV	Murrayhill-St Marys 230 kV	1278.9 A	1315.4 A	97.2%

Table 7: Phase Shifting Transformer Option Limiting Contingency – Summer

Winter – Series Capacitor				
Contingency Name	**Limiting Element**	**Value**	**Limit**	**Percent**
Ostrander BPA-Pearl BPA 500kV	Troutdale PACW Transformer 230/115kV	298.7 MVA	300.0 MVA	99.6%

Table 8: Series Capacitor Option Limiting Contingency – Winter

Winter – Phase Shifting Transformer				
Contingency Name	**Limiting Element**	**Value**	**Limit**	**Percent**
Ostrander BPA-Pearl BPA 500kV	Troutdale PACW Transformer 230/115kV	299.2 MVA	300.0 MVA	99.7%

Table 9: Phase Shifting Transformer Option Limiting Contingency – Winter

NRIS Preliminary Plan of Service

A Preliminary Plan of Service is developed to meet the requirements for the Interconnection Customer's NRIS request. Based on the results of the TTC analysis, a series capacitor or a phase shifting transformer is required to deliver the output of the proposed Generating Facility to the PGE load. The preliminary estimates developed for the series capacitor and phase shifting transformer options indicate that a series capacitor's total installed cost is expected to be tens of millions of dollars less expensive than the total installed cost of the phase shifting transformer. For this reason, the Preliminary Plan of Service will consider only the series capacitor option, unless further analyses indicate that the series capacitor will not provide for acceptable system performance with the Interconnection Customer's Generating Facility in service.

The Interconnection Customer's proposed step-up transformer configuration must be changed from its proposed configuration to a 230 kV (wye) / 34.5 kV (delta) to reliably protect the PGE Transmission System.

There is a known stability issue at the Round Butte substation. Following the loss of two transmission lines connected to the Round Butte substation, generation connected to Round Butte must be immediately tripped so that no more than 200 MW of generation remains on-line. Any new Generating Facility connecting to Round Butte is required to participate in the Remedial Action Scheme that protects against this instability.

The Preliminary Plan of Service for NRIS, shown in **Figure 2** below, includes the following modifications to the PGE Transmission System:

- A new POI substation designed as a 3-position 230 kV ring bus that will sectionalize the Pelton-Round Butte 230 kV generation lead line and accept the Interconnection Customer's generation lead line;
- A new series capacitor on the Bethel-Round Butte 230 kV transmission line; and,
- The addition of the Interconnection Customer's Generating Facility and the new series capacitor to the existing Round Butte Remedial Action Scheme (RAS).

The Preliminary Plan of Service for NRIS will be added to the Benchmark Cases to develop the Project Cases for NRIS. The Benchmark Cases and the Project Cases are then analyzed for power flow, short circuit, transient stability, and voltage stability to confirm that the Preliminary Plan of Service provides for acceptable system performance. It is important to note that the Bethel-Round Butte 230 kV transmission line is part of the major WECC path known as West of Cascade South (WOCS). The addition of the series capacitor to the WOCS path will require review of the path rating through the WECC Path Rating Process. The WECC Path Rating Process is separate from this SIS, not controlled by PGE, and can take up to three years.

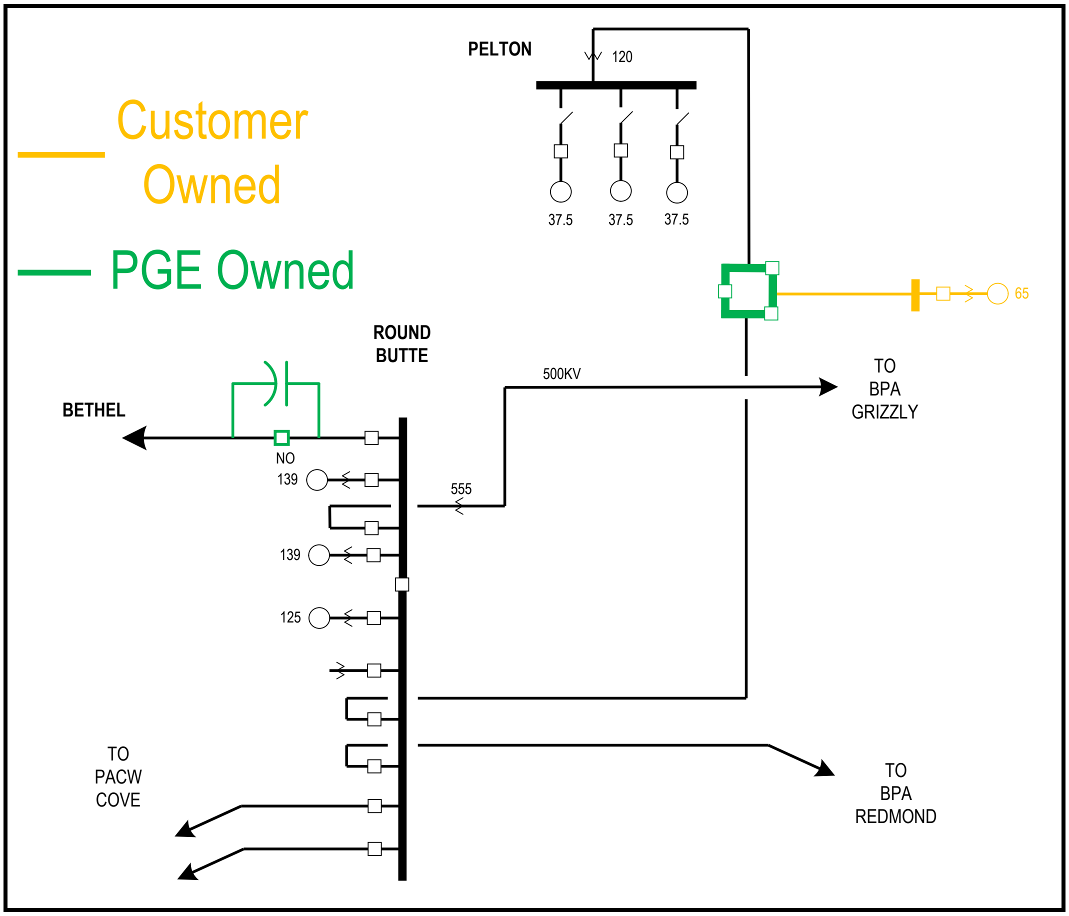

Figure 2: NRIS Preliminary Plan of Service

Power Flow Analysis

Power flow analysis was conducted on the Benchmark Cases and the Project Cases for peak summer and winter conditions, and off-peak spring conditions. The results of the power flow analysis for all seasons are nearly identical between the Benchmark Cases and the Project Cases. This is true for all categories of contingencies. Category N-1 contingencies that result in a system element loading to greater than 95% of its limit are shown below. The results of the power flow analysis for the winter season are shown below in **Table 10** and **Table 11**. The results of the N-1 analysis for summer and spring resulted in no system element loading greater than 95% of its limit and therefore are not represented in this report. The contingency results of the Benchmark Cases and the Project Cases are almost identical, resulting in no significant change attributed to the interconnection request.

Winter – Benchmark Case				
Contingency Name	**Limiting Element**	**Value**	**Limit**	**Percent**
Allston BPA-Clatsop BPA-Driscoll BPA 230kV	Allston BPA-Driscoll BPA #2 115 kV	735.8 MVA	740.0 MVA	99.4%
Allston BPA Transformer #3 230/115kV	Longview BPA Transformer 230/115 kV	401.3 MVA	420.0 MVA	95.5%

Table 10: Benchmark Case Power Flow Results - Winter

Winter – Project Case				
Contingency Name	**Limiting Element**	**Value**	**Limit**	**Percent**
Allston BPA-Clatsop BPA-Driscoll BPA 230kV	Allston BPA-Driscoll BPA #2 115 kV	735.2 MVA	740.0 MVA	99.4%
Allston BPA Transformer #3 230/115kV	Longview BPA Transformer 230/115 kV	400.8 MVA	420.0 MVA	95.8%

Table 11: Project Case Power Flow Results - Winter

Pending the results of the WECC Path Rating Process, no additional Network Upgrades have been identified as being necessary to satisfy the applicable NERC and WECC requirements as a result of the power flow analysis.

Short Circuit Analysis

Short circuit analysis was conducted on the Benchmark Cases and the Project Cases to determine the change in fault duty attributable to adding the Preliminary Plan of Service to the PGE Transmission System. This proposed interconnection has no material impact on any existing circuit breaker rating.

No additional Network Upgrades have been identified as being necessary to satisfy the applicable NERC and WECC requirements as a result of the short circuit analysis.

Transient Stability Analysis

Transient stability analysis was conducted on the Benchmark Cases and the Project Cases to determine if there is a change in system stability attributable to adding the Preliminary Plan of Service to the PGE Transmission System. Results of the transient stability analysis indicate that all generator rotor angles remain synchronized with the system, bus frequency remains above 59.6 Hz for all studied contingencies, and system voltages recover to 80% pre-contingency levels within 20 seconds.

No additional Network Upgrades have been identified as being necessary to satisfy the applicable NERC and WECC requirements as a result of the transient stability analysis.

Voltage Stability Analysis

Voltage stability analysis was conducted on the Benchmark Cases and the Project Cases to determine if there is a change in voltage stability attributable to adding the Preliminary Plan of Service to the PGE Transmission System. Results of the voltage stability analysis indicate that that positive Reactive Margin and post-contingency PMR meet the WECC System Performance Criterion (TPL-001-WECC-CRT-3.1) requirements.

No additional Network Upgrades have been identified as being necessary to satisfy the applicable NERC and WECC requirements as a result of the voltage stability analysis.

Proposed Plan of Service for NRIS

The results of the power flow analysis, short circuit analysis, transient stability analysis, and the voltage stability analysis show that the Preliminary Plan of Service for NRIS meets all NERC and WECC requirements. Because no additional Network Upgrades have been identified as being necessary, the Preliminary Plan of Service for NRIS is recommended as the Proposed Plan of Service for NRIS. A non-binding good-faith cost estimate of the Network Upgrades required for the Proposed Plan of Service for NRIS is shown below in **Table 12**, and the good-faith construction schedule is also discussed. The target accuracy of this cost estimate, in conformance with the PGE OATT, is ± 50%. The Interconnection Customer's generator lead line, located between the Generating Facility and the Point of Change of Ownership, is also not included in the estimate for the Proposed Plan of Service for NRIS since this is considered Interconnection Customer's Interconnection Facilities.

NRIS Proposed Plan of Service Cost Estimate[13]	
Network Upgrades	**Cost Estimate**
230 kV Series Capacitor at Round Butte substation, including: • Control Enclosure, Relay Racks, and Battery • Clear and grade land[14] and install fencing • 230 kV bus, structures, and disconnect switches	$10.8 M
Pelton Generator Lead Line Tap Station, including: • 230 kV three-position ring bus with circuit breakers, disconnect switches, and bus and structures • Control Enclosure, Relay Racks, and Battery • Clear and grade land[15] and install fencing • 230 kV bus, structures, and disconnect switches • Transmission Line Modification	$6.2 M
Include the POI Tap Station in the Existing Round Butte RAS, including: • Communication facilities to the POI Tap Station • Relay Racks	$10.0 M
Total	$27.0 M

Table 12: NRIS Proposed Plan of Service Cost Estimate

[13] The cost estimate for the POI substation increased in this restudy because the current estimate is more recent and more detailed. For example, the previous estimate did not include costs for land preparation, fencing, security, lighting, conduits, or engineering. This estimate also includes cost escalation to represent 2021 dollars.

[14] The costs of purchasing and permitting land adjacent to the Round Butte substation are not included in this estimate.

[15] The costs of purchasing and permitting land for the POI tap station are not included in this estimate.

The schedule required to implement the Proposed Plan of Service for NRIS requires a 3-5 year timeline for design, permitting, equipment acquisition, and construction.

There are many factors outside of the Transmission Provider’s control that could extend the time required for completing the Proposed Plan of Service outlined above. These factors include, but are not limited to: unexpected delays in the permitting process, the WECC Path Rating Process, challenges in acquiring property adjacent to the Round Butte substation, long lead times for obtaining electrical equipment, shortages of qualified workers, contractual negotiations with third parties, and inclement weather conditions. Much of the PRB generation complex, the Pelton-Round Butte 230 kV generation lead-line, and the Round Butte Substation exist within the boundaries of a federally protected natural area (Crooked River National Grassland), which could add complexity to permitting and land acquisition.

The Pelton-Round Butte 230 kV generator lead-line that the proposed POI is located on is part of the Pelton-Round Butte hydro generating facility which is not wholly owned by PGE. Consequently, the ability to interconnect to this line may be contingent upon a successful negotiation with the facility’s other owner and successful separation of the line from the hydro facility, as such line is currently identified within the scope of the Hydro License issued by FERC.

ERIS System Impact Study Results

Preliminary Plan of Service for ERIS

A Preliminary Plan of Service is developed to meet the requirements for the Interconnection Customer's ERIS request.

There is a known stability issue at the Round Butte substation. Following the loss of two transmission lines connected to the Round Butte substation, generation connected to Round Butte must be immediately tripped so that no more than 200 MW of generation remains on-line. New generation facilities connecting to Round Butte are required to participate in the Remedial Action Scheme that protects against this instability.

The Preliminary Plan of Service for ERIS, shown in **Figure 3** below, includes the following modifications to the PGE Transmission System:

- A new POI substation designed as a 3-position 230 kV ring bus that will sectionalize the Pelton-Round Butte 230 kV generation lead line and accept the Interconnection Customer's generation lead line; and
- The addition of the Interconnection Customer's Generating Facility to the existing Round Butte Remedial Action Scheme (RAS).

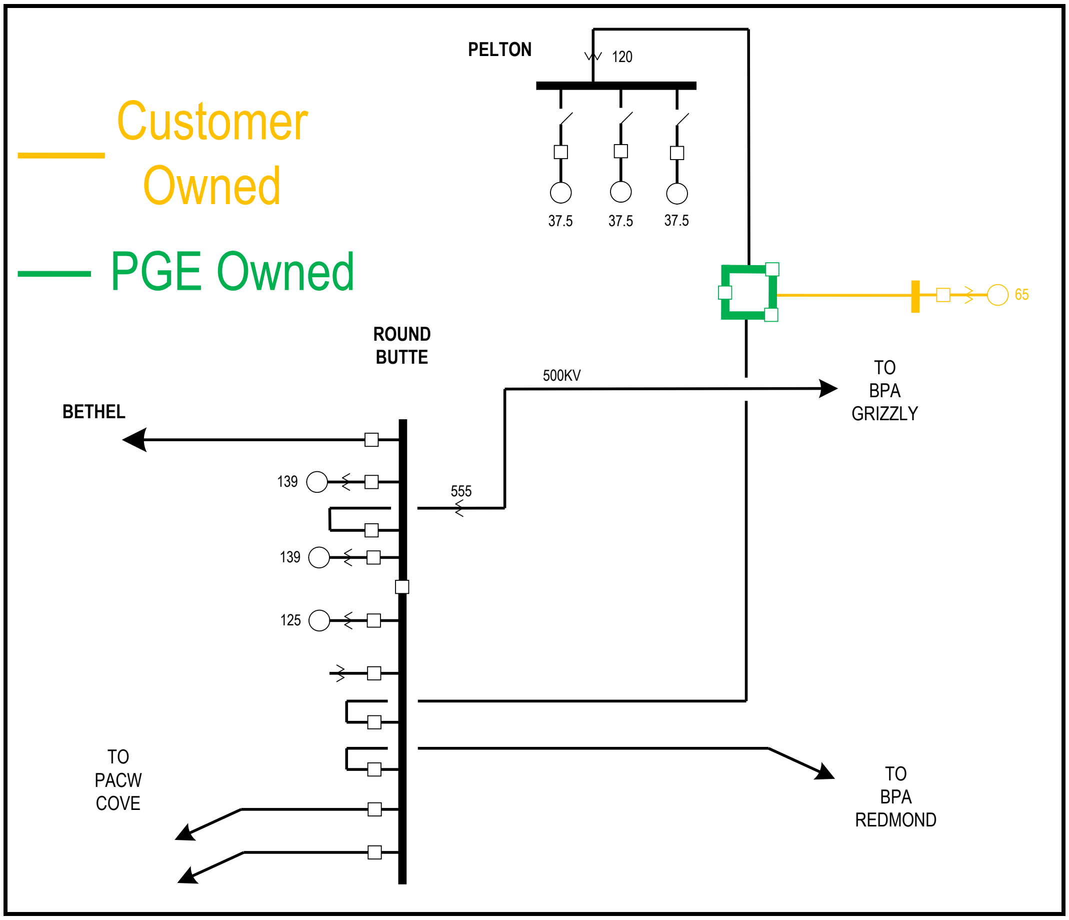

Figure 3: ERIS Preliminary Plan of Service

The Preliminary Plan of Service for ERIS will be added to the Benchmark Cases to develop the Project Cases for ERIS. The Benchmark Cases and the Project Cases are then analyzed for powerflow, short circuit, transient stability, and voltage stability to confirm that the Preliminary Plan of Service provides for acceptable system performance.

Power Flow Analysis

Power flow analysis was conducted on the Benchmark Cases and the Project Cases for peak summer and winter conditions, and off-peak spring conditions. The results of the power flow analysis for all seasons are nearly identical between the Benchmark Cases and the Project Cases. This is true for all categories of contingencies. Category N-1 contingencies that result in a system element loading to greater than 95% of its limit are shown below. The results of the power flow analysis for the winter season are shown below in **Table 13** and **Table 14**. The results of the N-1 analysis for summer and spring resulted in no system element loading greater than 95% of its limit and are therefore not represented in this report. The contingency results of the Benchmark Cases and the Project Cases are almost identical, resulting in no significant change attributed to the interconnection request.

Winter – Benchmark Case				
Contingency Name	**Limiting Element**	**Value**	**Limit**	**Percent**
Allston BPA-Clatsop BPA-Driscoll BPA 230kV	Allston BPA-Driscoll BPA #2 115 kV	735.8 MVA	740.0 MVA	99.4%
Allston BPA Transformer #3 230/115kV	Longview BPA Transformer 230/115 kV	401.3 MVA	420.0 MVA	95.5%

Table 13: Benchmark Case Power Flow Results - Winter

Winter – Project Case				
Contingency Name	**Limiting Element**	**Value**	**Limit**	**Percent**
Allston BPA-Clatsop BPA-Driscoll BPA 230kV	Allston BPA-Driscoll BPA #2 115 kV	735.5 MVA	740.0 MVA	99.4%
Allston BPA Transformer #3 230/115kV	Longview BPA Transformer 230/115 kV	400.8 MVA	420.0 MVA	95.4%

Table 14: Project Case Power Flow Results - Winter

No additional Network Upgrades have been identified as necessary to satisfy the applicable NERC and WECC requirements as a result of the power flow analysis.

Short Circuit Analysis

Short circuit analysis was conducted on the Benchmark Cases and the Project Cases to determine the change in fault duty attributable to adding the Preliminary Plan of Service to the PGE Transmission System. This proposed interconnection has no material impact on any existing circuit breaker rating.

No additional Network Upgrades have been identified as necessary to satisfy the applicable NERC and WECC requirements as a result of the short circuit analysis.

Transient Stability Analysis

Transient stability analysis was conducted on the Benchmark Cases and the Project Cases to determine if there is a change in system stability attributable to adding the Preliminary Plan of Service to the PGE Transmission System. Results of the transient stability analysis indicate that all generator rotor angles remain synchronized with the system, bus frequency remains above 59.6 Hz for all studied contingencies, and system voltages recover to 80% pre-contingency levels within 20 seconds.

No additional Network Upgrades have been identified as necessary to satisfy the applicable NERC and WECC requirements as a result of the transient stability analysis.

Voltage Stability Analysis

Voltage stability analysis was conducted on the Benchmark Cases and the Project Cases to determine if there is a change in voltage stability attributable to adding the Preliminary Plan of Service to the PGE Transmission System. Results of the voltage stability analysis indicate that Positive Reactive Margin and post-contingency PMR meet the WECC System Performance Criterion (TPL-001-WECC-CRT-3.1) requirements.

No additional Network Upgrades have been identified as necessary to satisfy the applicable NERC and WECC requirements as a result of the voltage stability analysis.

Proposed Plan of Service for ERIS

The results of the power flow analysis, short circuit analysis, transient stability analysis, and the voltage stability analysis show that the Preliminary Plan of Service for ERIS meets all NERC and WECC requirements. As no additional Network Upgrades have been identified as necessary, the Preliminary Plan of Service for ERIS is recommended as the Proposed Plan of Service for ERIS. A non-binding good-faith cost estimate of the Network Upgrades required for the Proposed Plan of Service for ERIS is shown below in **Table 15**, and the good-faith construction schedule is also discussed. The Interconnection Customer's generator lead line, located between the Generating Facility and the Point of Change of Ownership, is not included in the estimate for the Proposed Plan of Service for ERIS since this is considered Interconnection Customer's Interconnection Facilities. The target accuracy of this cost estimate, in conformance with the PGE OATT, is ± 50%.

ERIS Proposed Plan of Service Cost Estimate[16]	
Network Upgrades	**Cost Estimate**
Pelton Generator Lead Line Tap Station, including: • 230 kV three-position ring bus with circuit breakers, disconnect switches, and bus and structures • Control Enclosure, Relay Racks, and Battery • Clear and grade land[17] and install fencing • 230 kV bus, structures, and disconnect switches • Transmission Line Modification	$6.2 M
Include the POI Tap Station in the Existing Round Butte RAS, including: • Communication facilities to the POI Tap Station • Relay Racks	$10.0 M
Total	$16.2 M

Table 15: ERIS Proposed Plan of Service Cost Estimate

The Network Upgrades required to implement the Proposed Plan of Service for ERIS requires a 2-5 year timeline for design, permitting, equipment acquisition, and construction.

There are many factors outside of the Transmission Provider's control that could extend the time required for completing the ERIS Proposed Plan of Service outlined above. These factors include, but are not limited to: unexpected delays in the permitting process, challenges in acquiring property adjacent to the Round Butte substation, shortages of qualified workers, and inclement weather conditions.

The Pelton-Round Butte 230 kV generator lead-line that the proposed POI is located on is part of the Pelton-Round Butte hydro generating facility which is not wholly owned by PGE. Consequently, the ability to interconnect to this line may be contingent upon a successful negotiation with the facility's other owner and successful separation of the line from the hydro facility, as such line is currently identified within the scope of the Hydro License issued by FERC.

[16] The cost estimate for the POI substation increased in this restudy because the current estimate is more recent and more detailed. For example, the previous estimate did not include costs for land preparation, fencing, security, lighting, conduits, or engineering. This estimate also includes cost escalation to represent 2021 dollars.
[17] The costs of purchasing and permitting land for the POI tap station are not included in this estimate.

Conclusion

This SIS concludes that the Interconnection Customer's request for interconnection service can be met by proceeding with either the NRIS or the ERIS Proposed Plan of Service, but the Interconnection Customer's requested in-service date cannot be met. The in-service date, based on the Proposed Plan of Service for either ERIS and NRIS, is expected to be between 2021 and 2024, as discussed above.

The study results demonstrate that the Proposed Plan of Service for both NRIS and ERIS satisfy the requirements for power flow, short circuit, transient stability, and voltage stability analysis. Since the WOCS path is a major WECC path, a rerating study will be needed as outlined in WECC's document: "Project Coordination, Path Rating and Progress Report Processes". Beyond the rerating of the WOCS path, the Proposed Plan of Service is adequate for either the requested NRIS or ERIS.

The cost of the NRIS Proposed Plan of Service is approximately $27 M and will take approximately 3-5 years to complete, while the cost of the ERIS Proposed Plan of Service is approximately $16.2 M and will take approximately 2-5 years to complete.

No Contingent Facilities were identified in this SIS.

PGE cannot guarantee that future analysis (i.e. Transmission Service or Operational Studies) will not identify additional problems or system constraints that require mitigation or reduce operation. Neither ERIS nor NRIS conveys or implies any type of transmission service. If there is a material change in any aspect of the Generating Facility that is the subject of this study/report, a SIS restudy may be required.