BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1610

In the Matter of PUBLIC UTILITY COMMISSION OF OREGON Investigation into Qualifying Facility Contracting and Pricing.	COMMUNITY RENEWABLE ENERGY ASSOCIATION AND RENEWABLE ENERGY COALITION'S RESPONSE TO PACIFICORP'S MOTION TO CLOSE DOCKET

I. INTRODUCTION AND SUMMARY

The Community Renewable Energy Association ("CREA") and the Renewable Energy Coalition ("Coalition" and, or jointly with CREA, the "Joint QF Parties") respectfully file this Response to PacifiCorp's Motion to Close Docket ("Motion"). For the reasons explained herein, the Public Utility Commission of Oregon ("Commission" or "OPUC") should deny the Motion.

PacifiCorp's Motion appears, at first glance, to be a victory for qualifying facilities ("QF") by backtracking PacifiCorp's efforts to impose costs on QFs in a manner not supported by the Public Utility Regulatory Policies Act ("PURPA"). However, it is not because it provides no binding resolution of the disputed issue and no assurance for individual QFs contracting with PacifiCorp as to costs it may face now or in the future. Basic fairness and sound regulatory policy dictate that the lengthy adjudicatory process that has led to this point can only end with a stipulation or binding Commission order that provides clear rules under which PacifiCorp and QFs may contract going forward.

Aside from basic fairness, there are two primary legal rules that PacifiCorp's Motion fails to overcome: (1) a party may not unilaterally escape a proceeding it initiated without any binding and adverse outcome years after the first of two trial-type proceedings on the topic; and (2) a private party may not moot a proceeding through its own voluntary cessation of its disputed conduct. Thus, PacifiCorp's assertion that this proceeding is moot is wrong and should be rejected.

The Joint QF Parties are also concerned that PacifiCorp has not explained to the Commission its actual plans for how and who should pay for third-party transmission costs in load pockets. PacifiCorp states that it proposes to prospectively discontinue allocating the third-party transmission costs at issue in this proceeding to QFs if those costs are incurred, which appears to be a victory for the QF parties. While this might initially appear to be a favorable outcome for QF developers, PacifiCorp makes no promises that it will cease assigning load pocket transmission costs to QFs by other mechanisms, such as requiring QFs to otherwise transmit their generation out of a load pocket by paying for the construction of multi-million dollar transmission lines or conditioning the QF's interconnection on an agreement with the power purchaser (i.e., PacifiCorp Energy Service Management) to obtain third-party transmission rights to deliver any excess generation to an area with sufficient load to sink the generation. Interconnection studies discussed below and attached to this Response demonstrate that PacifiCorp has already begun pursuing this alternative method of assigning third-party transmission costs to QFs. Thus, in addition to our other objections to PacifiCorp's Motion, the Joint QF Parties are concerned that PacifiCorp is seeking to achieve the same result through the interconnection process, but is not clearly communicating its actual intentions to the Commission and the parties.

II. BACKGROUND

PacifiCorp first initiated the dispute over alleged costs related to load pockets almost six years ago. PacifiCorp's actions over this time have forced numerous individual QFs into protracted negotiations and disputes that resulted in the QFs abandoning their projects, or agreeing to either pay third-party transmission costs or curtail their net output. Parties like CREA and REC were required to engage in years of protracted and costly contested case litigation before the Commission. A brief review of PacifiCorp's litigating positions during this time undercuts several of the assertions in its Motion and demonstrates the extreme hardship on the Joint QF Parties and individual QFs, if the docket is to be closed at this point without final and binding resolution of the issue that PacifiCorp itself first raised.

This case commenced as an Advice Filing by PacifiCorp, Advice No. 11-011, which was docketed in UE 235 before being moved into this docket, UM 1610, along with a complaint against PacifiCorp by Threemile Canyon Wind, which was docket UM 1546.

In its Advice No. 11-011, PacifiCorp argued that it needed Commission approval of a mechanism to assign third-party transmission costs if a QF interconnected to PacifiCorp or otherwise delivered its energy out of what PacifiCorp termed a "load pocket." *See PacifiCorp's Advice No. 11-011 Memorandum of Law*, OPUC Docket No. UE 235 (filed June 27, 2011). PacifiCorp argued that prior Commission dockets UM 1401 and AR 521 established that QFs must pay for system upgrades directly "necessitated by the interconnection of the small generator facility. . . ." *Id.* at 10 (quoting Order No. 09-196 at 5). These existing interconnection rules and policies were inadequate, according to PacifiCorp, because "third-party transmission involves the buyer of QF energy (PacifiCorp Merchant), as owner of the energy and purchaser of the third-party transmission provider" and "PacifiCorp Transmission could not solve this issue in the case of an off-system QF, which has no generator interconnection relationship with PacifiCorp Transmission." *Id.* at n. 27. Thus, PacifiCorp initially asserted that the third-party transmission problem cannot be solved through an interconnection agreement between the QF and PacifiCorp Transmission, and that Commission action was required.

PacifiCorp sought immediate relief. It asserted: "[u]nder the current Schedule 37, PacifiCorp and its customers face an impending harm" because "PacifiCorp may be forced to enter into PPAs with load pocket QFs." *Id.* at 15. PacifiCorp has also repeatedly described procuring transmission service as the only possible way to solve this alleged harm. PacifiCorp's witness, Bruce Griswold, has consistently averred under oath that: "[u]nder the BPA OATT, long-term firm point-to-point (PTP) is the *only form of transmission* that provides a dependable right to wheel output from a load pocket to PacifiCorp's larger system for the full term of a power purchase agreement." *See PacifiCorp's Advice No. 11-011 Affidavit of Bruce Griswold in Support of Memorandum of Law*, OPUC Docket No. UE 235, a ¶ 6 (filed June 27, 2011) (emph. added); *see also* UM 1610 PAC/200, Griswold/13:2-4; UM 1610 PAC/1000, Griswold/24:7-22; UM 1610 PAC/1700, Griswold/26:4-9. PacifiCorp also argued that millions of dollars in third-party transmission costs were at issue if it were required to use BPA long-term firm point-to-point transmission. *See PacifiCorp's Advice No. 11-011 Memorandum of Law*, OPUC Docket No. UE 235 at 6 (filed June 27, 2011).

From the start, CREA has opposed PacifiCorp's proposal as a narrowly focused effort to impose overstated third-party transmission costs on QFs. In CREA's first brief on this topic in UE 235, CREA directly challenged PacifiCorp's assertion that the relevant third-party transmission options are limited to third-party long-term firm point-to-point transmission. Instead, CREA maintained: "[e]very transmission agreement PacifiCorp uses to move its own generation and market purchases to its disparate service areas in its East and West control area is potentially relevant to this proceeding." *CREA's Response Brief*, OPUC Docket No. UE 235 at 7 (filed Nov. 17, 2011). CREA further asserted, "[w]ithout extensive discovery and factual inquiry, it would be impossible for any party other than PacifiCorp to identify the universe of potential transmission paths, agreements, and planned upgrades through which QF generation enables PacifiCorp to avoid transmission costs." *Id.*; *see id.* at 8 (arguing PacifiCorp "does not address possible use of non-firm point to point transmission where excess transmission capacity exists, or possible use of conditional firm or more flexible Network Transmission rights to reduce the expense with which PacifiCorp is concerned."). After full contested case proceedings in Phase I and Phase II of this docket, the Commission has not resolved some of these critical issues, which remain disputed today.

In the Phase I order, the Commission explained, "we acknowledge FERC's direction that a QF cannot be required to obtain transmission service to deliver its output from the point of delivery to load." Order No. 14-058 at 21-22 (citing *Pioneer Wind Park I, LLC,* 145 FERC ¶ 61,215 at P 38 (2013)). The Commission explained, however, that the FERC orders "leave open the issue of how a state Commission may account for transmission costs in relation to avoided costs, whether by lowering avoided cost rates, separately in interconnection cost assessments, through an addendum as suggested by Pacific Power, or by some other means." *Id.* at 22. The Commission ultimately concluded "that any third-party transmission costs incurred by a utility to move QF output from the point of delivery to load would be costs that are not included in the calculation of avoided cost rates in standard contracts," and "any costs imposed on a utility that are above the utility's avoided costs must be assigned to the QF in order to comport with PURPA avoided cost principles." *Id.* Critically, however, the Commission found that "Staff and the parties did not fully address how to calculate and assign the third-party transmission costs that are attributable to the QF." *Id.* That issue was thus deferred to Phase II. The Commission clarified the remaining issue in dispute:

> We anticipate asking parties to recommend how third-party transmission costs to transport QF output from receipt in a load pocket to load should be accounted for in standard contracts; for example, by lowering avoided standard avoided cost rates, separately in interconnection cost assessments, through an addendum as suggested by Pacific Power, or by some other means.

Id. at 22-23.

In Phase II, the critical issues remained unresolved. PacifiCorp proposed "to procure long-term, firm, point-to-point transmission for the entire term of the PPA and assign costs assigned to the QF through a PPA addendum." Order No. 16-174 at 28. CREA and the Coalition opposed that approach for numerous reasons and presented alternative arrangements that could have implemented the Commission's Phase I directive. *Id.* at 29-30. The Commission did not resolve the issue and instead ordered the parties to conduct workshops. *Id.* at 30.

After the parties were unable to reach agreement in workshops, the Commission opened this phase of the docket. A discovery dispute quickly arose regarding the scope of the remaining issue. *See ALJ Ruling*, OPUC Docket No. UM 1610 at 3-4 (Oct. 27, 2016). The Coalition strongly believes that, before the costs of third-party transmission can be allocated, the Commission must determine which forms of third-party transmission are available to resolve the problem. To develop this issue, the Coalition sought discovery regarding PacifiCorp's use of

BPA network transmission to serve PacifiCorp loads. PacifiCorp uses a large amount of BPA network transmission, which has no incremental cost for each new generating resource as its cost is tied to the amount of load served by the transmission, but has never provided any basis in this proceeding as to why it could not be used to address the load pocket problem. In PacifiCorp's view, the Commission had already determined that long-term firm point-to-point transmission was the only form of third-party transmission that could solve the problem. Administrative Law Judge ("ALJ") Kirkpatrick sided with the Coalition and granted a motion to compel production of material related to BPA network transmission, reasoning "the Commission has not yet legally determined that PacifiCorp must secure long-term firm transmission to move QF energy out of a load pocket." *Id.* at 3-4. The ALJ's ruling relied on the position of OPUC Staff "that it is necessary to first determine what transmission options exist to move QF power out of load pockets to answer the Commission's question about how to assign third-party transmission costs." *Id.* at 1.

The Joint QF Parties expected PacifiCorp to address its ability to use transmission options, other than long-term firm point-to-point transmission, in its opening testimony in this phase, but PacifiCorp elected not to address this key issue. *See* UM 1600 PAC/1700. Thus, the Joint QF Parties continued to inquire in discovery as to other forms of transmission. The Joint QF Parties intended to conduct depositions of PacifiCorp employees knowledgeable on PacifiCorp's use of BPA transmission in order to develop their response testimony.

Faced with these queries into its business practices and continued questioning of the method PacifiCorp has chosen to resolve the issue it initially raised, PacifiCorp now abruptly seeks to close the docket. It asks to have the Commission do so without resolving "what transmission options exist to move QF power out of load pockets", *ALJ Ruling*, OPUC Docket No. UM 1610 at 1 (Oct. 27, 2016), or ultimately whether PacifiCorp may address the issue "by lowering avoided standard avoided cost rates, separately in interconnection cost assessments, through an addendum as suggested by Pacific Power, or by some other means" as left open in Order No. 14-058 (at pp. 22-23). Instead, PacifiCorp apparently believes it is already free to assess the charges to QFs through PPA addenda, which its Motion states it has already done without any authorization from the Commission.

Notably absent from PacifiCorp's Motion is any description of PacifiCorp's actual plans are in the event that PacifiCorp again determines that third-party transmission is needed to move QF energy out of a load pocket. In addition to its use of unauthorized PPA addendums, PacifiCorp has also already undertaken action to achieve the same result as if it the Commission adopted PacifiCorp's recommendations in this case, but through the interconnection process. Specifically, PacifiCorp is already imposing interconnection requirements that force QFs to pay PacifiCorp Transmission to build a new transmission line to transmit the power out of the load pocket, or to obtain its own third-party transmission, potentially by "voluntarily" contracting with the power purchaser (i.e., PacifiCorp Energy Supply Management).

This is confirmed, for example, by the attached interconnection studies for interconnection queue numbers Q750 and Q758, which are, respectively, a 2 MW hydropower QF and a 2 MW solar QF that PacifiCorp identified as being located in two different load pockets. For each project, the attached interconnection study provides on page seven that the QF may either pay the costs to construct an 80-90 mile transmission line out of the load pocket or arrange for PacifiCorp Energy Supply Management to obtain third-party transmission to solve the problem. *See* Attachment 1 and Attachment 2.[1] In other words, if the QF does not agree to pay PacifiCorp Energy Service Management for third party transmission, then it will need to pay to build a new transmission line. Yet PacifiCorp's Motion does not discuss how it will change its conduct in interconnection processes for load pocket QFs.

To better understand PacifiCorp's actual position and in the hope that this docket could be closed with clear resolution, the Joint QF Parties offered to close this docket with a stipulated dismissal that would provide:

- PacifiCorp will prospectively discontinue allocating third-party transmission costs to QFs by any means, including but not limited to lowering avoided cost rates, separately in interconnection cost assessments, or through an addendum to a power purchase agreement as suggested in prior phases of this docket; and
- In cases where PacifiCorp Transmission finds in an interconnection study for a QF that PacifiCorp's system may be in a generation surplus in the area of the QF's point of interconnection and that third-party transmission may reduce the interconnection or third party transmission costs attributable to the QF, the QF shall not arrange or pay for any third party transmission, but PacifiCorp Energy Supply Management will utilize the lowest cost third-party transmission available, including network transmission, to integrate the QF's net output.

Critically, before this docket could be closed, PacifiCorp must be prevented from imposing or otherwise requiring any QF to pay for or obtain third-party transmission in any manner unless and until the Commission expressly authorizes the terms and conditions allowing for such assignment of costs. PacifiCorp refused the Joint QF Parties' efforts to discuss a stipulated dismissal on these grounds. It has declined to elaborate or explain its actual plans regarding cost responsibility for third-party transmission. Thus, PacifiCorp is unwilling to agree that it will not seek to unilaterally resolve the problem by yet other means, including through interconnection cost assessments.

[1] These studies, and others like them, can be found on PacifiCorp's interconnection queue on its OASIS website at the following link: http://www.oasis.oati.com/PPW/PPWdocs/pacificorplgiaq.htm.

Resolution of the cost allocation mechanism currently before the Commission is crucial to QFs. Before this docket can be closed, the Joint QF Parties believe that the Commission must approve a clear cost allocation mechanism, one that acknowledges and is in accordance with the Commission's prior determination "that a QF cannot be required to obtain transmission service to deliver its output from the point of delivery to load." Order No. 14-058 at 22 (citing *Pioneer Wind Park I, LLC,* 145 FERC ¶ 61,215 at P 38 (2013)). PacifiCorp must be prevented from imposing or otherwise requiring any QF to pay for or obtain third-party transmission in any manner, and the Commission must have a full record before it to properly authorize the terms and conditions under which the load pocket-related transmission costs that PacifiCorp initially stated were in the millions of dollars and now states that "the anticipated need for the proposal has not materialized." Motion at 1.

III. ARGUMENT

A. Sound Regulatory Policy Dictates Against Closing Contested Proceedings Without a Binding Resolution

The purpose of a contested case before the Commission is to resolve a dispute over matters within the Commission's jurisdiction to provide regulatory certainty for affected parties. Thus, the typical resolution of a contested case is a binding Commission order resolving all disputed issues or a legally binding stipulation that resolves all disputed issues. PacifiCorp's proposal to close this docket would result in no such binding outcome and no regulatory certainty.

The Commission should recognize that regulatory uncertainty inures to PacifiCorp's benefit in the context of negotiations with small QFs. Indeed, that is why the Commission adopted the standard contract in docket UM 1129. The Commission has long recognized that small QFs should be entitled to a standard contract with uniform rates, terms and conditions "to remove transaction costs associated with QF contract negotiations. . . ." Order No. 05-584 at 16. "Standard contracts are designed to eliminate negotiations and to thereby remove transaction costs." *Id.* The Commission has correctly found that small QFs are disadvantaged by market barriers, such as "asymmetric information and an unlevel playing field that obstruct the negotiation" and "can render certain QF projects uneconomic to get off the ground if the individual contract must be negotiated." *Id.* The Commission has also determined "that QFs greater in size than 10 MW face market barriers, such as asymmetric information and an unlevel playing field, that impede negotiation of a viable QF power purchase contract with electric utilities." *Id.* at 17. Furthermore, it is the policy of the State of Oregon to "create a settled and uniform institutional climate for the qualifying facilities in Oregon." ORS 758.515(3)(b). Any unresolved point potentially subject to negotiation therefore inures to PacifiCorp's favor, in direct contradiction to the Commission's goal of removing transaction costs and market barriers through settled and uniform terms and conditions available for QFs.

PacifiCorp's Motion is an unjustified attempt to avoid any binding determination that would finally settle the issue in dispute and protect the rights of individual QF parties seeking to contract with PacifiCorp. If PacifiCorp were truly committed to not assigning third-party transmission costs to QFs, as it states it might do in its Motion, it should have exercised the multiple (and ongoing) opportunities to enter into a stipulation to resolve this dispute in legally binding terms. Yet PacifiCorp has rejected multiple opportunities to enter into such a stipulation. Basic fairness and sound regulatory policy dictate that the lengthy adjudicatory process that has led to this point can only end with a stipulation or binding Commission order that provides clear rules under which PacifiCorp and QFs may contract going forward. Otherwise, individual QFs will be left to fend for themselves, thwarting the Commission's policy of providing clear PURPA contracting guidelines.

In fact, this issue will likely be back before the Commission in the form of a complaint proceeding within weeks or months if the Commission dismisses the load pocket issue without binding resolution. But a complaint proceeding is not the proper mechanism to resolve an important and wide-reaching policy problem. Notably, in QF complaint proceedings the Commission Staff does not participate as a party – limiting the efficacy of such proceedings for setting broad policy. Aside from the legal flaws in PacifiCorp's Motion discussed further below, the Commission should reject the proposal to close the docket without a binding resolution because it will undermine the clear contracting guidelines needed for PURPA QFs.

B. It Is Too Late for PacifiCorp to Voluntarily Dismiss Its Complaint Without a Stipulated Dismissal.

PacifiCorp's Motion ignores that a party may not initiate a case and then attempt to avoid the consequences of an adverse outcome by unilaterally dismissing the case without any binding order or stipulation. The Commission's procedural rules provide that the OPUC follows the Oregon Rules of Civil Procedure to the extent consistent with OPUC's administrative rules. OAR 860-001-0000. The Oregon Rules of Civil Procedure provide that a plaintiff, in this case PacifiCorp, may voluntarily dismiss an action without order of court or stipulation of the other parties only if it does so "not less than 5 days prior to the date of trial . . . ." ORCP 54A(1).

The purpose of this rule is obvious. Having forced other parties to litigate an issue, particularly through the stage of trial or other hearing on the merits, a party cannot simply walk away from the case without a binding resolution that protects the rights of the other parties.

Even when properly filed prior to trial, the "right to voluntarily dismiss an action is subject to judicially created limitations." *Vill. at Main St. Phase II, LLC v. Dep't of Revenue*, 360 Or. 738, 749, 387 P.3d 374, 380 (2016) (rejecting attempt to voluntarily dismiss case before tax court after an appeal of a pre-trial order); *see also* ORCP 54A(3) (noting "dismissed party shall be considered the prevailing party" for purposes of costs and fees in the case of voluntary dismissal prior to trial).

As noted above, there have now been two full cycles of contested case proceedings in UM 1610. The Commission has issued two final orders that have partially addressed issues relating to QF energy and load pockets. Thus, PacifiCorp has no right to voluntarily dismiss the load pocket issue it raised without a Commission-approved stipulated dismissal or other Commission order resolving the ongoing dispute in a manner that protects the rights of QFs from PacifiCorp's overreach during QF PPA negotiations. There has already been one evidentiary hearing on the load pocket dispute in Phase I, where CREA and other parties engaged in cross examination of PacifiCorp's witness and other witnesses on this topic. UM 1610 Phase I Hrg. Tr. at 3-12, 57-109 (May 23, 2013). The time for a second hearing on the topic in Phase II has passed because all parties waived rights to that hearing. Having failed to convince the Commission to adopt its proposal after the first two trial-type hearings PacifiCorp provides no lawful basis to voluntarily dismiss the proceeding without a binding order governing its conduct.

C. The Load Pocket Issue Is Not Moot

PacifiCorp argues that the load pocket issue is now "moot" because of "PacifiCorp's intention to discontinue allocating to QFs the third-party transmission costs at issue in this docket . . . ." *PacifiCorp's Motion to Close Docket* at 4; *see also id.* at 9-11. However, the issue is not moot because PacifiCorp has refused to make any binding commitment to change its conduct. The Joint QF Parties believe that PacifiCorp is already attempting to unilaterally require QFs to pay for third-party transmission costs or other related costs through the interconnection process rather than the unauthorized PPA addendum it has employed to date.

1. PacifiCorp's non-binding cessation of its conduct does not moot the issue.

PacifiCorp's filing does not meet the legal test for mootness. A case is moot when "the issues presented are no longer 'live' or the parties lack a legally cognizable interest in the outcome." *County of Los Angeles v. Davis*, 440 U.S. 625, 631, 99 S. Ct. 1379, 1383 (1979). However, a private party's voluntary cessation of a disputed practice does not moot a case. *Friends of the Earth, Inc. v. Laidlaw Envtl. Servs. (TOC), Inc.,* 528 U.S. 167, 189, 120 S. Ct. 693, 145 L. Ed. 2d 610 (2000).[2] If it did, that party would then be "free to return to his old ways." *Id*. Voluntary conduct may moot a case only if "subsequent events make it *absolutely clear* that the allegedly wrongful behavior could not reasonably be expected to recur", *id.* (emph. added), and if "interim relief or events have completely and irrevocably eradicated the effects of the alleged violation." *County of Los Angeles*, 440 U.S. at 631. For example, in an analogous circumstance, statements by accused monopolists "that it would be uneconomical for them to engage in any further joint operations . . . , standing alone, cannot suffice to satisfy the heavy burden of persuasion" to moot a case by voluntary conduct. *United States v. Concentrated Phosphate Exp. Ass'n*, 393 U.S. 199, 203, 89 S. Ct. 361, 364 (1968).

[2] In contrast, government officials can sometimes moot a case with voluntary cessation of challenged conduct because government officials are less likely than private parties to resume the challenged conduct once the case is dismissed. *See Fed'n of Adver. Indus. Representatives, Inc. v. City of Chicago*, 326 F.3d 924, 929 (7th Cir. 2003) (holding that where defendants are public officials, their acts of self-correction deserve greater stock if they appear genuine).

Oregon courts do not allow a party to moot a case through a non-binding cessation of its conduct. *See Safeway, Inc. v. Or. Pub. Emps. Union*, 152 Or. App. 349, 355, 954 P.2d 196, 199 (1998) ("A party's declaration that it *may* not engage in the challenged conduct in the future does not render moot an action for injunctive relief."). The courts have explained that the "'voluntary cessation' exception is best understood to apply in cases in which the challenged 'practice' is one that the defendant can readily cease – in an effort to moot the challenge – and then resume again." *Progressive Party v. Atkins*, 276 Or. App. 700, 709, 370 P.3d 506, 511 (2016) (citations omitted). The case is not moot where the party moving to dismiss maintains that it has the legal right to resume the challenged conduct and a future dispute is likely. *Id.*

In this case, a live controversy still exists because PacifiCorp maintains it has the legal right to continue assessing third-party transmission costs to QFs, but the mechanism for doing so has not been agreed to among the parties or presented to and approved by the Commission, and a future dispute is guaranteed to occur. Additionally, PacifiCorp cryptically stated during the prehearing conference on March 1, 2017 that it intended to simply address this issue through interconnection agreements, rather than face further discovery into its alleged load pocket problem. PacifiCorp states in its Motion that it "will notify the Commission of the changed circumstances and request guidance at that time" – thus explicitly reserving its right to impose third-party transmission costs on individual QFs to avoid the full scrutiny of Commission Staff and other parties in this proceeding. *PacifiCorp's Motion to Close Docket* at 11.

PacifiCorp has a demonstrated track record of acting outside the bounds of Commission orders, and leaving PacifiCorp to its own devices now will result in harm to current and prospective QFs. As PacifiCorp's Motion demonstrates, the Company has engaged in a practice of requiring a PPA "Addendum B" that purports to assign third-party transmission costs to any QF PacifiCorp unilaterally determines is in a load pocket. PacifiCorp has imposed some form of PPA addendum on at least nine QFs listed in its Motion. *See PacifiCorp's Motion to Close Docket* at 6-7 & n.10 (the nine QFs are the TMF Biofuels, Adams Solar Center, Elbe Solar Center, EBD Hydro, Monroe Hydro, and Orchard Wind Farm 1, 2, 3, and 4). But the Commission *never authorized PacifiCorp's use of such an addendum in relation to the standard contract*. In fact, as noted above, the most recent Commission determination explicitly declined to adopt PacifiCorp's use of such an addendum.[3] There is *no Commission order* authorizing use of any "Addendum B" to the standard contract that assigns third-party transmission costs to QFs eligible for standard rates. For example, the Commission's latest order authorizing PacifiCorp's standard contract forms approved contracts submitted by PacifiCorp that contained no such addendum. *See* Order No. 16-417.[4]

Additionally, as discussed above, PacifiCorp is also already using the interconnection process to assign third-party transmission costs. However, as with the a PPA addendum, the

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[3] Although PacifiCorp included such an addendum in its Advice No. 11-011, the Commission declined to adopt PacifiCorp's proposal, instead stating:

> We find, however, that Staff and the parties did not fully address how to calculate and assign the third-party transmission costs that are attributable to the QF. We defer this issue to the second phase of these proceedings. We anticipate asking parties to recommend how third-party transmission costs to transport QF output from receipt in a load pocket to load should be accounted for in standard contracts; for example, by lowering avoided standard avoided cost rates, separately in interconnection cost assessments, through an addendum as suggested by Pacific Power, or by some other means.

Order No. 14-058 at 22-23. Likewise, Order No. 16-174 did not approve PacifiCorp's proposed PPA addendum.

[4] PacifiCorp's corresponding compliance filing dated July 12, 2016 is available online at http://apps.puc.state.or.us/edockets/docket.asp?DocketID=17718. It contains no Addendum B in any standard contract form.

Commission never authorized use of the interconnection process to assign third-party transmission costs even though that was also one of the proposed methods to address the alleged problem. PacifiCorp is therefore in direct violation of Commission orders for imposing such PPA addenda and interconnection requirements on QFs. Its assertion that it will not do so again (until it changes its mind) rings hollow and provides no basis to conclude the issue is moot.

PacifiCorp in fact presents no legal authority in support of its position that the case is moot. Instead, PacifiCorp cites *In the Matter of Portland General Electric Company Report on the Feasibility of Using Stochastic Modeling in the Annual Update*, Docket No. UM 1340, Order No. 08-261 (May 19, 2008). *See PacifiCorp's Motion to Close Docket* at 5 n. 5. But that case is off point and did not address mootness. Instead, Order No. 08-261 approved an *agreement* of all parties to that case. The Commission had directed PGE to investigate the use of stochastic modeling in the annual power cost update docket. *Id.* at 1. After completing a workshop and a preliminary investigation into the issue, *all parties* to that case *agreed* that the costs of the modeling outweighed the potential benefits, and therefore Staff asked that the docket be close. *Id.* at 1-2. In contrast, PacifiCorp did not seek agreement with any other parties that would resolve the Commission's investigation here and be memorialized in a Commission order, even though the Commission clearly envisioned such an outcome when it ordered workshops after the conclusion of Phase II. Likewise, when asked by the Joint QF Parties, PacifiCorp refused to agree to a stipulated dismissal on terms that would resolve the case. *See* Attached Email.[5]

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[5] Settlement offers are generally not admissible as evidence at a hearing to prove or disprove the merits of an underlying claim, but settlement communications may be considered for the purpose of determining jurisdictional questions like the mootness argument raised by PacifiCorp. *See Zurich Am. Ins. Co. v. Watts Indus*., 417 F.3d 682, 690 (7th Cir. 2005); *see also* OAR 860-001-0350(3) (settlement offers admissible "for other purposes allowed under ORS 40.190"); ORS 40.190(b) (settlement evidence allowed for purpose other than "to prove liability for or invalidity of the claim or its amount" and noting

Accordingly, all parties here do not agree it is reasonable to close this docket and allow PacifiCorp to use its strong-arm tactics on individual QFs through interconnection agreements or some other new method of assigning alleged third-party transmission costs.

In sum, PacifiCorp's Motion fails to demonstrate the legal requirement to find the issue here moot, and it therefore must be denied.

2. PacifiCorp's factual assertions ignore the magnitude of the ongoing dispute.

PacifiCorp also suggests that because only 12 MW of QFs have necessitated cost allocation of third-party transmission the case is insignificant and thus moot. *PacifiCorp's Motion to Close Docket* at 6-7. This assertion is erroneous for several reasons.

First, even taking PacifiCorp's assertion at face value, the cost of BPA's long-term firm point-to-point transmission is significant regardless of how many QFs may be affected. PacifiCorp itself asserted when it initiated this dispute that the 8 MW of BPA long-term firm point-to-point transmission needed for the Threemile Canyon Wind QF would cost $144,096 per year. *PacifiCorp's Advice No. 11-011 Memorandum of Law*, OPUC Docket No. UE 235 at 5 (filed June 27, 2011). Additionally, PacifiCorp characterized the cost for five additional QFs comprising 44.8 MW of nameplate capacity as being approximately $810,540 per year, or an $8.16 million present value assuming payment at the 2012 BPA rates for the full term of the PPAs. *Id.* at 6. These are substantial amounts, and the risk of having them imposed upon a QF

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in commentary notes that Oregon's Rule 408 "is based on Rule 408 of the Federal Rules of Evidence"); Fed Evid R 408, Advisory Committee Note ("Since the rule excludes only when the purpose is proving the validity or invalidity of the claim or its amount, an offer for another purpose is not within the rule."). Thus, PacifiCorp's refusal to agree to a stipulated dismissal is relevant to rebut PacifiCorp's suggestion that the case is moot.

could easily destroy the economics of most QF projects – particularly given the PacifiCorp's current extremely low avoided cost rates.

PacifiCorp now characterizes these costs for third-party transmission as *de minimis* compared to its expense of responding to a deposition and 77 data requests (most of which it simply objected to without complete response). *PacifiCorp's Motion to Close Docket* at 8. This assertion is not credible. Even if the case were prosecuted in its entirety by the transmission experts retained by PacifiCorp at $600 per hour, those experts could bill over 13,000 hours of time before they imposed a cost in the ball park of the transmission costs PacifiCorp seeks to shift to the next 44.8 MW of QF projects, according to the numbers in PacifiCorp's own filing.[6] PacifiCorp routinely engages in regulatory battles over sums far smaller than the costs at issue here.

Second, PacifiCorp's assertion overlooks that its proposal affects far more QFs than just those few QFs who actually agreed to a PPA addendum that purports to allocate third-party transmission costs to the QF. For example, PacifiCorp's own Motion states that it already attempted to impose its third-party transmission cost policy on numerous QFs, and even required a PPA Addendum for nine QFs, as discussed above. The problem does not only affect the 12 MW of QFs who have actually *paid* for BPA transmission. Rather, any QF in negotiations with PacifiCorp that is faced with the mere prospect of having to pay for the third-party transmission costs is harmed through negotiation delays, risk of litigation against PacifiCorp, and costs and uncertainty about future costs that will likely cause the developer to simply abandon the development efforts. This uncertainty and litigation risk frustrates the purposes of PURPA and

[6] $8,130,000 ÷ ($600/hour) = 13,550 hours.

this Commission's policies for clear and uniform contracting guidelines. PacifiCorp provides no data or assertion regarding the number of QFs who have been presented with the prospect of the third-party transmission costs issue and later abandoned their project, and its claims that only 12 MW of QFs are affected lack any factual basis.

Moreover, PacifiCorp has previously identified its *entire* service territory in its west balancing area as consisting of "load pockets," and argued that "[a]ll qualifying facilities (QFs) are located in load pockets within PacifiCorp's service territory." UM 1610 Phase I CREA/504, Hearing Exhibit/1-3.[7] It has never disavowed this claim in any binding stipulation or order. The Commission itself accepted PacifiCorp's representation and found that "Pacific Power's entire service territory is non-contiguous, and interconnected in places by third-party transmission . . . ." Order No. 14-058 at 21. Thus, PacifiCorp's recent claim in its Motion that the problem is much less widespread is difficult to accept – particularly given PacifiCorp's aversion to entering into any sort of binding resolution of the treatment of the load pocket problem.

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[7] At the hearing in Phase I, PacifiCorp's witness, Mr. Griswold, testified as follows:

> [Counsel for CREA]. So basically there's no part of your system that's not a load pocket for QFs that are interconnecting to PacifiCorp?
>
> [Mr. Griswold]. Theoretically, yes.

UM 1610 Phase I Hrg. Tr. at 71:4-7 (May 23, 2013).

> [Counsel for CREA]. And we're talking about the entire Oregon service territory, right, potentially effected by this based on your discovery response, right?
>
> [Mr. Griswold]. That is correct.

Id. at 73:19-22.

Third, as noted above, PacifiCorp has a demonstrated a track record of acting outside the bounds of Commission orders, and leaving PacifiCorp to its own devices with any ambiguity in its PURPA obligation is highly likely to result in harm to current and prospective QFs.

If PacifiCorp truly believes that the costs in dispute are *de minimis*, PacifiCorp should enter into stipulated dismissal that brings permanent closure to the issue. Failing such a resolution, as PacifiCorp reserves the right to impose these types of costs on future QFs and the costs are material to small QFs, the issue is not moot.

D. The Commission Can Close the Docket Only After Imposing Binding Terms of Dismissal.

If the Commission is inclined to close the docket, it should do so only after entering an order that resolves the issue. The following terms should be included in any order that closes the docket to ensure that PacifiCorp cannot backtrack from its statements made to obtain such closure:

- PacifiCorp will prospectively discontinue allocating third-party transmission costs to QFs by any means, including but not limited to lowering avoided cost rates, separately in interconnection cost assessments, or through an addendum to a power purchase agreement as suggested in prior phases of this docket.
- In cases where PacifiCorp Transmission finds in an interconnection study that PacifiCorp's system is in a generation surplus in the area of the QF's point of interconnection and that third-party transmission may reduce the interconnection costs allocated to the QF, PacifiCorp Energy Supply Management will utilize the lowest cost third-party transmission available, including network transmission, to integrate the QF's output.

Given PacifiCorp's concession that its position lacks sufficient merit to continue prosecution, the Commission should provide the closure needed by simply entering an order adverse to PacifiCorp on the remaining issues in dispute.

IV. CONCLUSION

For the reasons explained herein, the Commission should deny PacifiCorp's Motion to Close Docket or, in the alternative, close the docket only after entering a binding order adverse to PacifiCorp on the remaining issues in dispute.

Respectfully submitted on March 30, 2017,

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Attachment 1

PACIFICORP TRANSMISSION

Small Generator Interconnection

Oregon Tier 4 Feasibility Study Report

Completed for

(“Interconnection Customer”)
Q0750

A Qualifying Facility

Proposed Primary Point of Interconnection

Circuit 5W202 out of Buckaroo substation

Proposed Alternate Point of Interconnection

Circuit 5W406 out of Pilot Rock

September 29, 2016

1.0 DESCRIPTION OF THE GENERATING FACILITY

("Interconnection Customer") proposed interconnecting 2 MW of new generation to PacifiCorp's ("Public Utility") circuit 5W202 out of Buckaroo substation located in Umatilla County, Oregon as the primary Point of Interconnection. Interconnection Customer has also proposed interconnecting to Public Utility's circuit 5W406 out of Pilot Rock located in Umatilla County, Oregon as an alternate Point of Interconnection. The project ("Project") will consist of 2 MW, 2222.2 kVA Chang Jiang Energy Corp. SFW2000-14/730 ver. 303F synchronous generator for a total output of 2 MW. The requested commercial operation date is December 31, 2020.

Interconnection Customer will operate this generator as a Qualifying Facility as defined by the Public Utility Regulatory Policies Act of 1978 (PURPA).

The Public Utility has assigned the Project "Q0750."

2.0 APPROVAL CRITERIA FOR TIER 4 INTERCONNECTION REVIEW

Pursuant to 860-082-0060(1), a public utility must use the Tier 4 interconnection review procedures for an application to interconnect a small generator facility that meets the following requirements:

(a) The small generator facility does not qualify for or failed to meet Tier 1, Tier 2, or Tier 3 interconnection review requirements; and
(b) The small generator facility must have a nameplate capacity of ten (10) megawatts or less.

3.0 SCOPE OF THE STUDY

Pursuant to 860-082-0060(6)(e) the Feasibility Study Report must identify any potential adverse system impacts on the public utility's transmission or distribution system or an affected system that may result from the interconnection of the Small Generating Facility. In determining possible adverse system impacts, the Public Utility must consider the aggregated nameplate capacity of all generating facilities that, on the date the feasibility study begins, are directly interconnected to the Public Utility's transmission or distribution system, have a pending completed application to interconnect with a higher queue position, or have an executed interconnection agreement with the Public Utility.

4.0 PRIMARY POINT OF INTERCONNECTION

Interconnection Customer's proposed Small Generating Facility is to be interconnected through a step up transformer owned and maintained by the Interconnection Customer. The Small Generating Facility will be interconnected with the Public Utility 12.47 kV distribution system at or near facility point ("FP") 345300. This Small Generating Facility is proposed to be connected to Public Utility's circuit 5W202, from Buckaroo substation. The Point of Interconnection ("POI") is approximately 31,100 circuit feet from Buckaroo substation. Currently, the final 8,000 circuit feet of the system to the Small Generating Facility consists of two phases and a neutral.

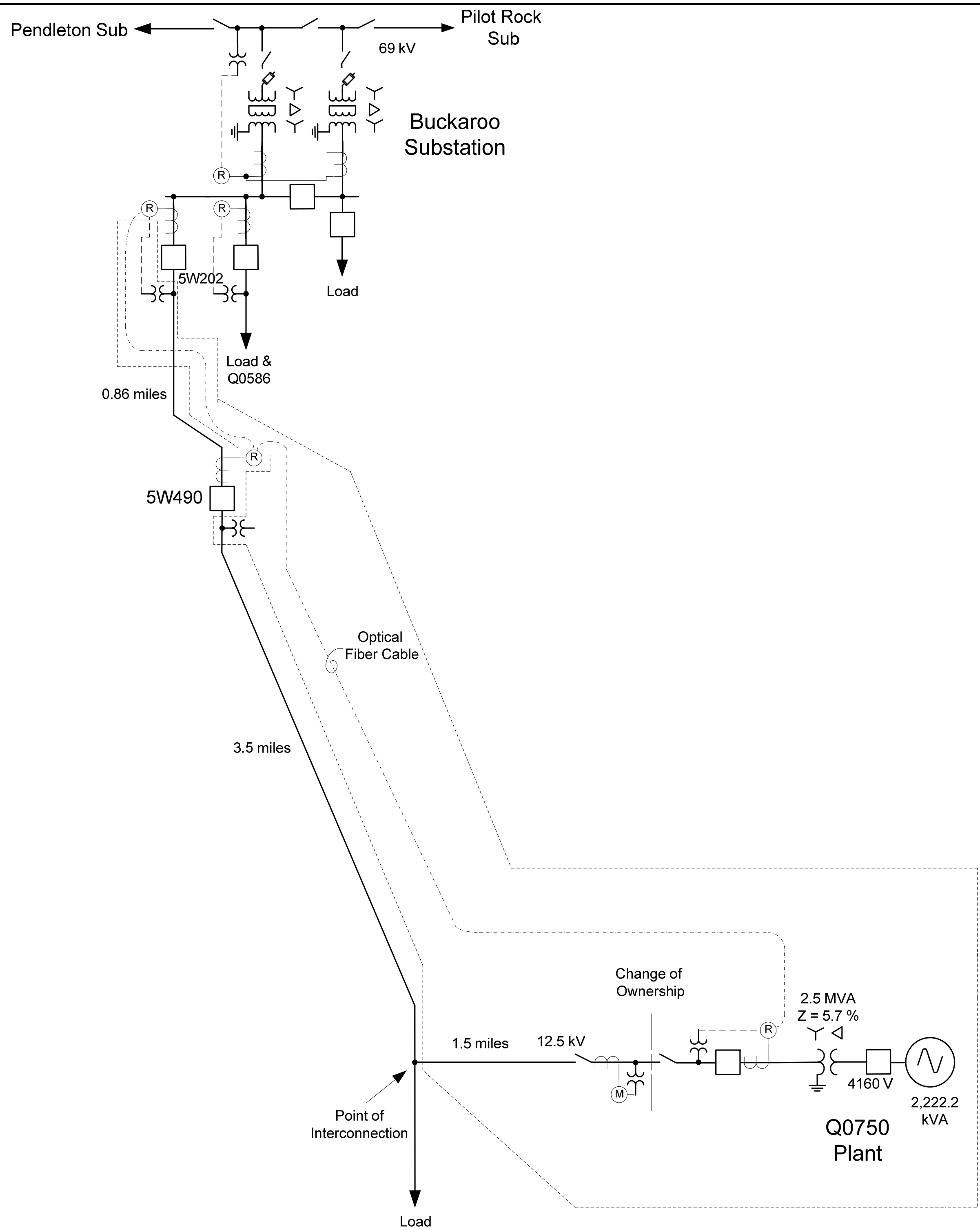

Figure 1: System One Line Diagram – Primary Point of Interconnection

4.1 ALTERNATE POINT OF INTERCONNECTION

The following alternative Point of Interconnection will be considered in this report:

The alternate POI is the same as the primary POI. The alternate POI is evaluated when served from 5W406 out of Pilot Rock substation rather than 5W202 out of Buckaroo substation.

Interconnection Customer's proposed Small Generating Facility is to be interconnected through a step up transformer owned and maintained by the Interconnection Customer. The Small Generating Facility will be interconnected with the Public Utility 12.47 kV distribution system at or near FP 345300. This Small Generating Facility is proposed to be connected to Public Utility's circuit 5W202, from Buckaroo substation. However, the alternate POI assumes the circuit in the area of the Point of Interconnection has been switched to 5W406, from Pilot Rock substation.

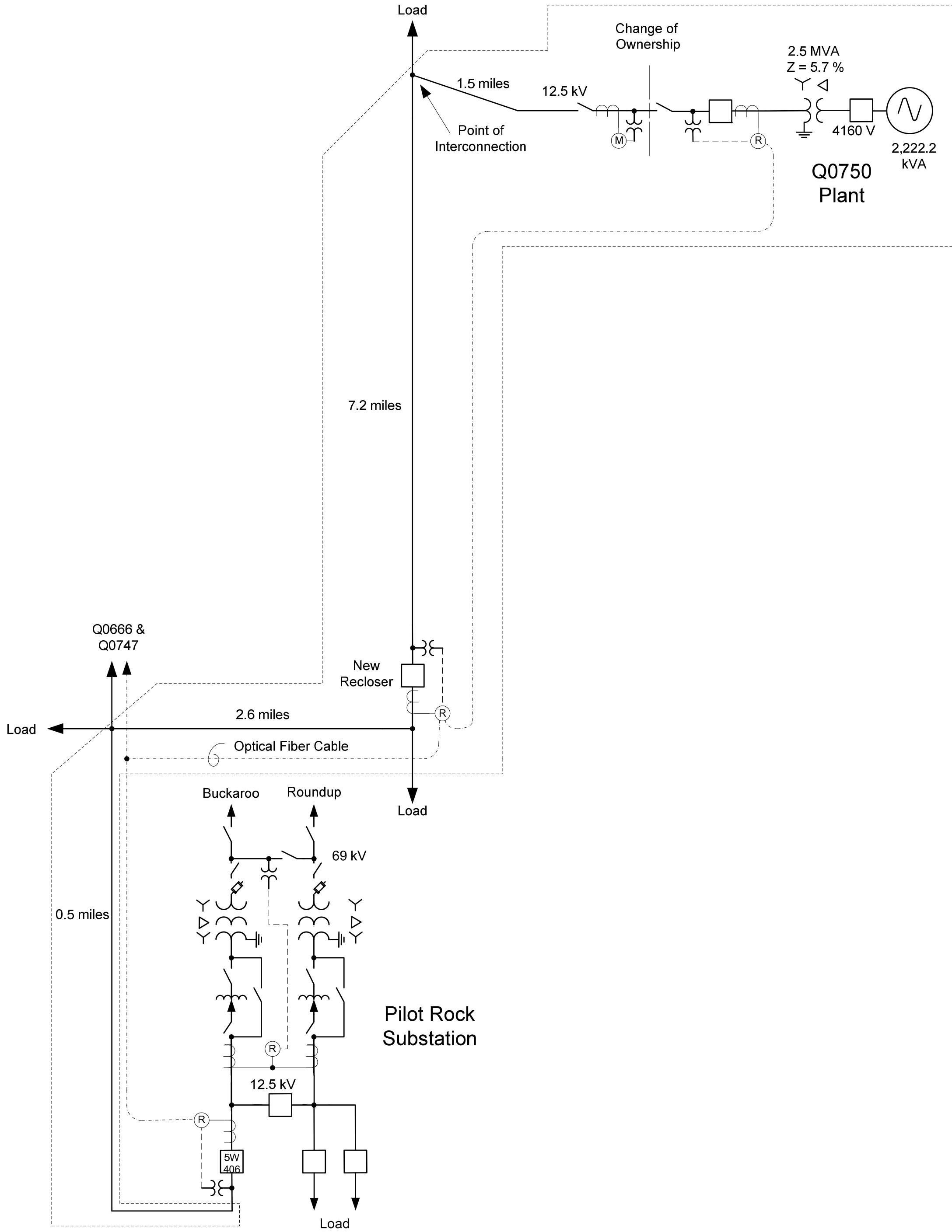

Figure 2: System One Line Diagram – Alternate Point of Interconnection

5.0 STUDY ASSUMPTIONS

- All active higher priority transmission service and/or generator interconnection requests will be considered in this study and are listed in Appendix 1. If any of these requests are withdrawn, the Public Utility reserves the right to restudy this request, as the results and conclusions contained within this study could significantly change.
- For study purposes there are two separate queues:
  - Transmission Service Queue: to the extent practical, all system upgrades that are required to accommodate active transmission service requests will be modeled in this study.
  - Generation Interconnection Queue: withal relevant higher queue interconnection requests will be modeled in this study.
- Interconnection Customer's request for interconnection service in and of itself does not convey transmission service.
- This study assumes the Project will be integrated into Public Utility's system at the agreed upon and/or proposed Point of Interconnection.
- Interconnection Customer will construct and own any facilities required between the Point of Interconnection and the Project unless specifically identified by the Public Utility.
- Generator tripping may be required for certain outages.
- All facilities will meet or exceed the minimum Western Electricity Coordinating Council ("WECC"), North American Electric Reliability Corporation ("NERC"), and Public Utility performance and design standards
- The Project was studied with one (1) 2.0 MW Chang Jiang Energy Corp SFW 2000-14/1730 with 0.9 pf as shown in Interconnection Customer provided document "160516 Q0750 Generator Data," dated August 19, 2016.
- The Project was studied with the following active higher priority queue projects on-line: Q0547, Q0586, Q0666 and Q0747.
- Reith feeder 5W202, peak demand is 9.85 MVA at 0.94 pf. The minimum load studied for the Q0750 Project is estimated at 32% of the documented peak load. The minimum load studied is 2.96 MVA at 0.999 pf.
- Historic time of use metering does not exist for the Pilot Rock substation transformers or feeders. Fifteen minute peak demand kW and kvar reads documented 8 times per year is the only load data recorded. The minimum load studied for the Q0750 Project assumed 25% of the documented peak load when modeling the distribution 12.5 kV feeder.
- Pilot Rock City feeder 5W406 peak demand load is 7.5 MVA at a 0.96 pf. The minimum load studied is 1.9 MVA at 0.96 pf.
- This report is based on information available at the time of the study. It is Interconnection Customer's responsibility to check the Public Utility's web site regularly for transmission system updates (http://www.pacificorp.com/tran.html).

6.0 REQUIREMENTS – PRIMARY POINT OF INTERCONNECTION

6.1 SMALL GENERATOR FACILITY MODIFICATIONS

The Small Generating Facility and interconnection equipment owned by Interconnection Customer are required to operate under automatic voltage control with the voltage sensed electrically at the Point of Interconnection. Small Generating Facility should have sufficient reactive capacity to enable the delivery of 100 percent of the plant output to the Point of

Interconnection at unity power factor measured at 1.0 per unit voltage under steady state conditions.

Generators capable of operating under voltage control with a voltage droop are required to do so. Studies will be required to coordinate the voltage droop setting with other facilities in the area. In general, generation and interconnection facilities should be operated so as to maintain the voltage at the Point of Interconnection between 1.01 pu to 1.04 pu. At the Public Utility's discretion, these values might be adjusted depending on the operating conditions. Within this voltage range, the Small Generating Facility should operate so as to minimize the reactive interchange between the Small Generating Facility and the Public Utility's system (delivery of power at the Point of Interconnection at approximately unity power factor). The voltage control settings of the Small Generating Facility must be coordinated with the Public Utility prior to energization (or interconnection). The reactive compensation must be designed such that the discreet switching of the reactive device (if required by Interconnection Customer) does not cause step voltage changes greater than +/-3% on the Public Utility's system.

As per NERC standard VAR-001-1, the Public Utility is required to specify voltage or reactive power schedule at the Point of Interconnection. Under normal conditions, the Public Utility's system should not supply reactive power to the generation/interconnection facilities.

The Interconnection Customer's recloser must be protected with sufficient bird guarding to prevent outages to the Public Utility's other customers on the same circuit.

6.2 TRANSMISSION/DISTRIBUTION SYSTEM MODIFICATIONS

6.2.1 TRANSMISSION SYSTEM MODIFICATIONS

The Public Utility's Pendleton-Walla Walla area system as a whole is generation surplus. As a Qualifying Facility, the proposed Q0750 Project must be used to serve network load. In order to sink the generation into network load, a new 230 kV transmission line from the Pendleton area to the Yakima area system would be required. The new line would connect Roundup substation with Wine Country substation in the vicinity of Grandview, Washington. The new 230 kV line would be approximately 80 to 90 miles, depending on the line route. This new transmission line is currently required as part of the Q0747 project. However, if the Q0747 interconnection customer chooses to convert to a non-qualified facility, or drops out of the queue, the transmission line construction requirement will be required for Q0750.

In lieu of the transmission construction described above, Interconnection Customer may be able negotiate with the power purchaser to obtain third-party transmission rights to deliver any excess generation from the Pendleton-Walla Walla area system to an area with sufficient load to sink the generation. This alternative would require an agreement between Interconnection Customer and the power purchaser. Without that agreement in place, the transmission construction alternative will be required as part of the Project.

6.2.2 Distribution System Modifications

- Reconductor approximately 8,000 circuit feet of two phase primary distribution circuit from FP 345300 to FP 270302 at Birch Road and McKay Drive with three phase primary.
- Replace voltage regulators at FP 270401 along Birch Road.
- Balance load across the McKay branch of the feeder.
- Replace field recloser 5W490 with a new recloser capable of preventing reclosing on an energized line. The existing unit may possibly be modified in the field to enable this feature. If so, then a new recloser will not be required.
- Replace 65T fuses at FP 270302 with 100T fuses.

6.3 Existing Breaker Modifications – Short-Circuit

The increase in the fault duty on the system as the result of the addition of the Small Generating Facility with 1 – 2222.2 kVA generator fed through 1 – 2.5 MVA 12.47 kV – 4,160 V transformer with 5.7 % impedance will not push the fault duty above the interrupting rating of any of the existing fault interrupting equipment.

6.4 Protection Requirements

Protective relaying systems will need to be installed that will detect faults and cause the disconnection of the Small Generating Facility for 12.5 kV line faults on circuit 5W202 out of Buckaroo substation, for faults beyond the field recloser 5W490, for faults in the 69 – 12.5 kV transformers in Buckaroo substation, and for faults on the 69 kV line that Buckaroo substation is connected to. The minimum day time load on Buckaroo substation is 8.4 MW which is at or near the maximum potential power output of the proposed Small Generating Facility combined with this Project’s synchronous generator. The combination of the synchronous generator and the inverters cannot be relied upon to cause the high speed disconnection of the generation facilities for faults on the distribution or transmission for slight unbalances between load and generation after the operation of the breakers at the primary sources of fault current. Relaying will be installed that will detect the fault conditions and send transfer trip from Buckaroo substation to both the Q0586 Small Generating Facility and to this Project to cause the disconnection of the generation. The transfer trip circuit to Q0586 Small Generating Facility is part of that project’s scope of work. An optical fiber cable will be installed between Buckaroo substation, the 5W490 field recloser and the recloser for this Project. The transfer trip signal will be sent over the optical fiber cable.

For 12.5 kV circuit faults the transfer trip will be keyed by the opening of breaker 5W202 at Buckaroo substation. The 69 kV line faults will be detected by installing line relays at Buckaroo substation that will monitor the current through both of the transformers and voltages on the 69 kV system. These line relays will also detect faults in the power transformers. The line relays will key transfer trip to the Small Generating Facility. These relays will need to operate high speed to disconnect the generation before the automatic reclosing that will be taking place at the source substations to reenergize the circuit. Most faults on overhead lines are temporary in nature so that after all the sources of energy to the fault have been disconnected the circuit can be reenergized and the service to the loads restored. It will not be possible to set the new line relays to be selective as to limiting the operation for faults only on the line that Buckaroo is connected to and still clear the faults high speed. The relays will occasionally operate for faults on other 69 kV lines out of Roundup substation. This will cause the Small Generating Facility to be disconnected on occasions when the line to the Small Generating Facility does not go dead. The only way to maximize the energy production of the Small Generating Facility would be to install communication equipment for a transfer trip circuit between Roundup and Buckaroo substations. This option would increase the cost of this Project. It is assumed that Interconnection Customer prefers the less expensive option and will tolerate the occasional unnecessary interruptions. The relays for detecting the 69 kV line faults and faults in the 69 – 12.5 kV transformers are planned to be installed for the Q0586 project.

The line relay associated with the breaker 5W202 will need to be replaced with a relay that has functions that the existing relay does not have. These functions include dead line checking and the ability to communicate the transfer trip signal. In conjunction with Q0586 the control and relay panel for 5W202 will be replaced. The relay that will be installed for Q0586 will have all of the functionality needed for Q0750. The dead line checking function will require the addition of 12.5 kV VTs on the line side of the CB 5W202. The secondaries of these voltage transformers will connect to the feeder protection relay. The dead line checking will be required to delay the automatic reclosing of CB 5W202 for the cases when a failure of the protective systems leads to delayed tripping of the Small Generating Facility for a feeder fault. Reclosing for this type of situation could cause damage to the equipment and needs to be prevented.

The relay associated with the field recloser 5W490 will need to be modified. The recloser controller has all the capabilities required but needs modification to enable the functions. These functions include dead line checking, ability to communicate the transfer trip signal, and directional overcurrent functions. The fault current contribution from the Project for faults between Buckaroo substation and the recloser and for faults on the other feeders out of the substation will be in excess of the current pickup of the recloser relay. If the overcurrent elements are not made directional the recloser will trip open unnecessarily for faults on those circuits. The dead line checking function will require the addition of 12.5 kV VTs on the line side of the recloser 5W490. The secondaries of these voltage transformers will connect to the controller. The dead line checking will be required to delay the automatic reclosing of the recloser for the cases when a failure of the protective systems leads to delayed tripping of Small Generating Facility for a feeder fault. The voltage signals will also provide the quantities to make the overcurrent functions directional.

The combination of Q0586 and Q0750 power will flow toward the 69 kV at Buckaroo substation during certain times of day and certain seasons. It is planned that the controllers for the LTC's associated with those transformers will be replaced with units that react correctly with this condition as part of the Q0586 project.

The Project's circuit recloser with need to be equipped with a SEL 351R protective relay to perform the following functions:

1. Receive transfer trip from Buckaroo substation and the field recloser 5W490.

2. Detect faults on the 12.5 kV at the Small Generating Facility
3. Detect faults on the 12.5 kV line to Buckaroo substation
4. Monitor the voltage and react to under or over frequency, and / or magnitude of the voltage

All of these relaying functions are all parts of one protective relay.

6.5 Data Requirements

Due to the power size of the Project the Public Utility's Operation Centers will not require any real time data from the Small Generating Facility, so no RTU will be required.

6.6 Communication Requirements

Communication circuits will be required between Buckaroo substation and field recloser 5W490, and between field recloser 5W490 and the recloser at the Small Generating Facility for the transfer trip circuits.

7.0 Cost Estimate – Primary Point of Interconnection

The following estimate represents only scopes of work that will be performed by the Public Utility. Costs for any work being performed by Interconnection Customer are not included.

Q0750 Generating Facility *Add metering, protection & control and communications*	$ 240,000
Circuit 5W490 Distribution line work *Modify communications and relay settings*	$ 30,000
Circuit 5W202 Distribution line work *Reconductor 8,000 feet of line, replace voltage regulators, field reclosers and fuses*	$ 980,000
Fiber *Install six miles of fiber from Q0750 to Buckaroo substation*	$ 230,000
Buckaroo substation *Install voltage transformers, communications and protection & control*	$ 300,000
Total	**$1,780,000**

Note: Costs for all excavation, duct installation and easements shall be borne by Interconnection Customer and are not included in this estimate. This estimate is as accurate as possibly given the level of detailed study that has been completed to date and approximates the costs incurred by the Public Utility to interconnect this Small Generator Facility to the Public Utility's electrical distribution or transmission system. A more detailed estimate will be calculated during the System Impact Study. Interconnection Customer will be responsible for all actual costs, regardless of the estimated costs communicated to or approved by Interconnection Customer.

8.0 SCHEDULE – PRIMARY POINT OF INTERCONNECTION

It is estimated that it will take approximately 18-24 months to design, procure and construct the facilities described in this report following the execution of an interconnection agreement. The schedule will be further developed and optimized during the System Impact Study.

Please note, the time required to construct the transmission line currently assigned to higher queued project Q0747 and necessary for this Project results in a timeframe that does not support Interconnection Customer's requested commercial operation date of December 31, 2020.

9.0 REQUIREMENTS – ALTERNATE POINT OF INTERCONNECTION

9.1 SMALL GENERATOR FACILITY MODIFICATIONS

The Small Generator Facility and Interconnection Equipment owned by Interconnection Customer are required to operate under automatic voltage control with the voltage sensed electrically at the Point of Interconnection. The Small Generator Facility should have sufficient reactive capacity to enable the delivery of 100 percent of the plant output to the Point of Interconnection at unity power factor measured at 1.0 per unit voltage under steady state conditions.

Generators capable of operating under voltage control with a voltage droop are required to do so. Studies will be required to coordinate the voltage droop setting with other facilities in the area. In general, generation and interconnection facilities should be operated so as to maintain the voltage at the Point of Interconnection between 1.01 pu to 1.04 pu. At the Public Utility's discretion, these values might be adjusted depending on the operating conditions. Within this voltage range, the Small Generator Facility should operate so as to minimize the reactive interchange between the Small Generator Facility and the Public Utility's system (delivery of power at the Point of Interconnection at approximately unity power factor). The voltage control settings of the Small Generator Facility must be coordinated with the Public Utility prior to energization (or interconnection). The reactive compensation must be designed such that the discreet switching of the reactive device (if required by Interconnection Customer) does not cause step voltage changes greater than +/-3% on the Public Utility's system.

As per NERC standard VAR-001-1, the Public Utility is required to specify voltage or reactive power schedule at the Point of Interconnection. Under normal conditions, the Public Utility's system should not supply reactive power to the generation/interconnection facilities.

The Interconnection Customer's recloser must be protected with sufficient bird guarding to prevent outages to the Public Utility's other customers on the same circuit.

9.2 TRANSMISSION/DISTRIBUTION SYSTEM MODIFICATIONS

9.2.1 TRANSMISSION SYSTEM MODIFICATION

The Transmission System Modifications for the Alternate Point of Interconnection are the same as for the Primary Point of Interconnection described in section 6.2.1.

9.2.2 DISTRIBUTION SYSTEM MODIFICATIONS

- Reconductor, approximately 8,000 circuit feet of two phase primary distribution circuit from FP 345300 to FP 270302 at Birch Road and McKay Drive with three phase primary.
- Reconductor an additional 54,150 feet of three phase circuit from Birch Road and McKay Drive back to Pilot Rock substation with larger conductors (FP 270302 to FP 090505).
- Replace voltage regulators at FP 279603.
- Balance load across the northern branch of the feeder.
- Install a new field recloser on the north branch of the feeder which is set up to prevent reclosing on an energized line.
- Replace 65T fuses at FP 270302 with 100T fuses.

9.3 EXISTING BREAKER MODIFICATIONS – SHORT-CIRCUIT

The increase in the fault duty on the system as the result of the addition of the Small Generating Facility with 1 – 2222.2 kVA generator fed through 1 – 2.5 MVA 12.47 kV – 4,160 V transformer with 5.7 % impedance will not push the fault duty above the interrupting rating of any of the existing fault interrupting equipment.

9.4 PROTECTION REQUIREMENTS

Protective relaying systems will need to be installed that will detect faults and cause the disconnection of the Small Generating Facility for 12.5 kV line faults on circuit 5W406 out of Pilot Rock substation, for faults beyond the new field recloser, for faults in the 69 – 12.5 kV transformers in Pilot Rock substation, and for faults on the 69 kV line that Pilot Rock substation is connected to. The minimum day time load on Pilot Rock substation is well below the maximum potential power output of the two proposed solar facilities: Q0666 and Q0747; combined with this Project's synchronous generator. The combination of the synchronous generator and the inverters cannot be relied upon to cause the high speed disconnection of the Small Generating Facility for faults on the distribution or transmission for slight unbalances between load and generation after the operation of the breakers at the primary sources of fault current. Relaying is planned to be installed for the Q0666 and Q0747 projects in Pilot Rock substation that will detect the fault conditions. Transfer trip will be sent from Pilot Rock substation to both the Q0666 and Q0747 Small Generating Facilities. This same transfer trip signal will need to be carried to the Project to cause the disconnection of the generation. An optical fiber cable will be installed between Pilot Rock substation, the new field recloser and the recloser for the Project. The transfer trip signal will be sent over the optical fiber cable.

For 12.5 kV circuit faults the transfer trip will be keyed by the opening of breaker 5W406 at Pilot Rock substation. The 69 kV line faults will be detected by installing line relays at Pilot Rock substation that will monitor the current through both of the transformers and voltages on the 69 kV system. These line relays will also detect faults in the power transformers. The line relays will key transfer trip to the Small Generating Facility. These relays will need to operate high speed to disconnect the generation before the automatic reclosing that will be taking place at the source substations to reenergize the circuit. It will not be possible to set the new line relays to be selective as to limiting the operation for faults only on the line that Pilot Rock substation is connected to and still clear the faults high speed. The relays will occasionally operate for faults on other 69 kV lines out of Roundup substation. This will cause the Small Generating Facility to be disconnected on occasions when the line to the Small Generating Facility does not go dead. The only way to maximize the energy production of the Small Generating Facility would be to install communication equipment for a transfer trip circuit between Roundup and Pilot Rock substations. This option would increase the cost of this Project. It is assumed that Interconnection Customer prefers the less expensive option and will tolerate the occasional unnecessary interruptions.

The line relay associated with the breaker 5W406 will need to be replaced as part of the Q0666 project. This new relay will have the functions for dead line checking and the ability to communicate the transfer trip signal. The relay that will be installed for that project will have all of the functionality needed for Q0750 Project.

The relay associated with the new field recloser will have the capabilities required for the addition of the Project. These functions include dead line checking, ability to communicate the transfer trip signal, and directional overcurrent functions. The fault current contribution from the Project for faults between Pilot Rock substation and the new recloser and for faults on the other feeders out of the substation will be in excess of the current pickup of the recloser relay. If the overcurrent elements are not made directional the recloser will trip open unnecessarily for faults on these circuits. The dead line checking function will require that 12.5 kV VTs on the line side be included with the new recloser. The secondaries of these voltage transformers will connect to the controller. The dead line checking will be required to delay the automatic reclosing for the cases when a failure of the protective systems leads to delayed tripping of the Small Generating Facility for a feeder fault. The voltage signals will also provide the quantities to make the overcurrent functions directional.

This Project's power will flow toward the 69 kV at Pilot Rock substation during certain times of day and certain seasons. It is planned that the controllers for the voltage regulators will be replace with units that react correctly with this condition as part of the Q0666 project.

The Project's circuit recloser with need to be equipped with a SEL 351R protective relay to perform the following functions:

1. Receive transfer trip from Pilot Rock substation and the new field recloser.
2. Detect faults on the 12.5 kV at the Small Generating Facility
3. Detect faults on the 12.5 kV line to Pilot Rock substation
4. Monitor the voltage and react to under or over frequency, and / or magnitude of the voltage

All of these relaying functions are all parts of one protective relay.

9.5 Data Requirements

Due to the power size of the Project the Public Utility's Operation Centers will not require any real time data from the Small Generating Facility, so no RTU will be required.

9.6 Communication Requirements

Communication circuits will be required between Pilot Rock substation and the new field recloser, and between new field recloser and the recloser at the Project for the transfer trip circuits.

10.0 Cost Estimate – Alternate Point of Interconnection

The following estimate represents only scopes of work that will be performed by the Public Utility. Costs for any work being performed by Interconnection Customer are not included.

Q0750 Generating Facility *Add metering, protection & control, communications*	$ 240,000
Circuit 5W490 Distribution line work *Modify communications and relay settings*	$ 30,000
Distribution line work *Reconductor a total of 62,000 feet of line, replace voltage regulators, field reclosers and fuses*	$5,580,000
Fiber *Install 12 miles of fiber from Q0750 to Pilot Rock substation*	$ 460,000
Pilot Rock substation *Add communications*	$ 150,000
Total	**$6,460,000**

Note: Costs for all excavation, duct installation and easements shall be borne by Interconnection Customer and are not included in this estimate. This estimate is as accurate as possibly given the level of detailed study that has been completed to date and approximates the costs incurred by the Public Utility to interconnect this Small Generating Facility to the Public Utility's electrical distribution or transmission system. A more detailed estimate will be calculated during the System Impact Study. Interconnection Customer will be responsible for all actual costs, regardless of the estimated costs communicated to or approved by Interconnection Customer.

11.0 Schedule – Alternate Point of Interconnection

It is estimated that it will take approximately 24-36 months to design, procure and construct the facilities described in this report following the execution of an interconnection agreement. The schedule will be further developed and optimized during the System Impact Study.

Please note, the time required to to construct the transmission line currently assigned to higher queued project Q0747 and necessary for this Project results in a timeframe that does not support Interconnection Customer's requested commercial operation date of December 31, 2020.

12.0 PARTICIPATION BY AFFECTED SYSTEMS

Public Utility has identified the following Affected Systems: Bonneville Power Administration

Copies of this report will be shared with Affected System.

13.0 APPENDICES

Appendix 1: Higher Priority Requests
Appendix 2: Property Requirements
Appendix 3: Study Results

13.1 APPENDIX 1: HIGHER PRIORITY REQUESTS

All active higher priority transmission service and/or generator interconnection requests will be considered in this study and are identified below. If any of these requests are withdrawn, the Public Utility reserves the right to restudy this request, as the results and conclusions contained within this study could significantly change.

Transmission/Generation Interconnection Queue Requests considered:

Q0547 (18 MW) POI: Weston, line to Athena
Q0586 (6 MW) POI: Circuit 5W201 out of Buckaroo substation
Q0666 (1.98 MW) POI: Circuit 5W406 out of Pilot Rock substation
Q0747 (6 MW) POI: Circuit 5W406 out of Pilot Rock substation

13.2 Appendix 2: Property Requirements

Requirements for rights of way easements

Rights of way easements will be acquired by Interconnection Customer in the Public Utility's name for the construction, reconstruction, operation, maintenance, repair, replacement and removal of Public Utility's Interconnection Facilities that will be owned and operated by Public Utility. Interconnection Customer will acquire all necessary permits for the Project and will obtain rights of way easements for the Project on Public Utility's easement form.

Real Property Requirements for Point of Interconnection Substation

Real property for a Point of Interconnection substation will be acquired by an Interconnection Customer to accommodate Interconnection Customer's Project. The real property must be acceptable to Public Utility. Interconnection Customer will acquire fee ownership for interconnection substation unless Public Utility determines that other than fee ownership is acceptable; however, the form and instrument of such rights will be at Public Utility's sole discretion. Any land rights that Interconnection Customer is planning to retain as part of a fee property conveyance will be identified in advance to Public Utility and are subject to the Public Utility's approval.

Interconnection Customer must obtain all permits required by all relevant jurisdictions for the planned use including but not limited to conditional use permits, Certificates of Public Convenience and Necessity, California Environmental Quality Act, as well as all construction permits for the project.

Interconnection Customer will not be reimbursed through network upgrades for more than the market value of the property.

As a minimum, real property must be environmentally, physically, and operationally acceptable to Public Utility. The real property shall be a permitted or able to be permitted use in all zoning districts. Interconnection Customer shall provide Public Utility with a title report and shall transfer property without any material defects of title or other encumbrances that are not acceptable to Public Utility. Property lines shall be surveyed and show all encumbrances, encroachments, and roads.

Examples of potentially unacceptable environmental, physical, or operational conditions could include but are not limited to:

1. Environmental: known contamination of site; evidence of environmental contamination by any dangerous, hazardous or toxic materials as defined by any governmental agency; violation of building, health, safety, environmental, fire, land use, zoning or other such regulation; violation of ordinances or statutes of any governmental entities having jurisdiction over the property; underground or above ground storage tanks in area; known remediation sites on property; ongoing mitigation activities or monitoring activities; asbestos; lead-based paint, etc. A phase I environmental study is required for land being acquired in fee by the Public Utility unless waived by Public Utility.

2. Physical: inadequate site drainage; proximity to flood zone; erosion issues; wetland overlays; threatened and endangered species; archeological or culturally sensitive areas; inadequate sub-surface elements, etc. Public Utility may require Interconnection Customer to procure various studies and surveys as determined necessary by Public Utility.

Operational: inadequate access for Public Utility's equipment and vehicles; existing structures on land that require removal prior to building of substation; ongoing maintenance for landscaping or extensive landscape requirements; ongoing homeowner's or other requirements or restrictions (e.g., Covenants, Codes and Restrictions, deed restrictions, etc.) on property which are not acceptable to the Public Utility.

13.3 APPENDIX 3: STUDY RESULTS

13.3.1 TRANSMISSION SYSTEM STUDY RESULTS

Historical loads were reviewed to determine the Public Utility's minimum network load in the Pendleton area 69 kV system. The minimum network load was determined to be 19 MW. The total generation in the Pendleton area with the prior active queues (Q0547, Q0586, Q066 and Q0747) and the proposed Q0750 Project is 33.98 MW. This results in a generation surplus and net export from the Pendleton area.

Transmission level power flow study cases were evaluated for heavy summer and minimum loading conditions. For each of the cases, power flow and system voltages were evaluated with and without the proposed Q0750 Small Generating Facility to determine the impact on the transmission system during system intact (N-0) operation for the normal system configuration, outage of one transmission element (N-1), and select contingencies resulting in loss of multiple elements (i.e. breaker failure or bus fault).

System Normal (N-0) Results – Primary Point of Interconnection
With all lines in service and the Walla Walla/Pendleton system in its normal configuration, the addition of Q0750 showed no thermal or steady-state voltage deficiencies.

The Buckaroo 12.47 kV Reith Feeder 5W202 is normally served by the 69-12.47 kV, 25 MVA transformer T-9370. Transformer T-9370 also serves the Montee Feeder 5W203. The transformer summer peak load is approximately 16 MW and minimum load is approximately 4.4 MW. The addition of Q0750 will have no reverse power flow into the Public Utility's transmission system.

The minimum load in the Pendleton area is 19 MW. The prior active queues and Q0750 project has a combined total generation of 33.98 MW. The total generation exceeds the minimum load in the Pendleton area and will require a net export of up to 14.98 MW through BPA Roundup station.

Single Element Outage (N-1) Results – Primary Point of Interconnection
The Pendleton 69 kV system includes three 69 kV lines supplied from BPA Roundup substation. There are three 230-69 kV transformers at Roundup. Two transformers are operated in parallel with the 69 kV "Patawa Creek" line to Pendleton and 69 kV "Birch Creek" radial line to Pilot Rock. The remaining 230-69 kV transformer is normally operated in a loop with 69 kV "Coyote Creek" line to Buckaroo and Pendleton. Outages to one of these elements will cause severe thermal overload and voltage deficiencies.

There are no thermal deficiencies with Q0750 connected at the primary Point of Interconnection for any of the N-1 outages. Prior to Q0750, outages to the 69 kV "Coyote Creek" line from Roundup to Buckaroo or the Public Utility's 230-69 kV transformer at Roundup may result in post-transient voltage deviations exceeding 5.0% in the Pendleton area. The proposed Small Generating Facility moderately decreases the severity of these post-transient voltage deviations at this Point of Interconnection. It is not the responsibility of the proposed interconnection to correct the existing system deficiencies.

System Normal (N-0) Results – Alternate Point of Interconnection
With all lines in service and the Walla Walla/Pendleton system in its normal configuration, the addition of Q0750 showed no thermal or steady-state voltage deficiencies to the transmission system.

The Pilot Rock City Feeder 5W406 is served by the 69-12.47 kV, 9.375 MVA transformer and 12.47 kV, 7.5 MVA substation voltage regulator R-816. Since historic time of use does not exist for this feeder and fifteen minute peak demand kW and kvar reads documented 8 times per year is the only load data recorded, the peak load for 5W406 is assumed to be 7.5 MVA at a 0.96 pf. The minimum load of 1.9 MVA at 0.96 pf was used for this study. Q0666 and Q0747 are also interconnecting on the same 5W406 circuit. The combined total generation on this circuit is 9.98 MW and at minimum load, an excess of up to 8 MW will be transported to the Public Utility's transmission system. A transport of 8 MW exceeds the rating for the substation voltage regulator at Pilot Rock after applying PacifiCorp Engineering Handbook limits for voltage regulators and will require a new voltage regulator.

The minimum load in the Pendleton area is 19 MW. The prior active queues and Q0750 Project has a combined total generation of 33.98 MW. The total generation exceeds the minimum load in the Pendleton area and will require a net export of up to 14.98 MW through BPA Roundup station.

Single Element Outage (N-1) Results – Primary Point of Interconnection
The Pendleton 69 kV system includes three 69 kV lines supplied from BPA Roundup substation. There are three 230-69 kV transformers at Roundup. Two transformers are operated in parallel with the 69 kV "Patawa Creek" line to Pendleton and 69 kV "Birch Creek" radial line to Pilot Rock. The remaining 230-69 kV transformer is normally operated in a loop with 69 kV "Coyote Creek" line to Buckaroo and Pendleton. Outages to one of these elements will cause severe thermal overload and voltage deficiencies.

There are no thermal deficiencies with Q0750 connected at the alternate Point of Interconnection. Prior to Q0750, outages to the 69 kV "Coyote Creek" line from Roundup to Buckaroo or the Public Utility's 230-69 kV transformer at Roundup may result in post-transient voltage deviations exceeding 5.0% in the Pendleton area. There were no significant improvements in the voltage deviation for the proposed Small Generating Facility at this Point of Interconnection. It is not the responsibility of the proposed interconnection to correct the existing system deficiencies.

	Heavy Summer 2017 – Pre-Project										Thermal
	69 kV System										
Outage	**BPA Roundup**	**Dev**	**PP&L Roundup**	**Dev**	**Buckaroo**	**Dev**	**Pendleton**	**Dev**	**Pilot Rock**	**Dev**	**Issues**
System Normal	0.969		0.988		0.964		0.959		0.941		None
Roundup Transformer 1	0.943	-2.69%	0.977	-1.16%	0.945	-1.91%	0.937	-2.30%	0.917	-2.56%	None
Roundup Transformer 2	0.943	-2.67%	0.977	-1.15%	0.945	-1.89%	0.937	-2.29%	0.917	-2.54%	None
Roundup Transformer 3	0.906	-6.47%	0.863	-12.65%	0.863	-10.43%	0.874	-8.88%	0.884	-6.00%	None
Roundup - La Grande	0.977	0.81%	0.996	0.77%	0.972	0.82%	0.967	0.83%	0.949	0.86%	None
Roundup - McNary	0.904	-6.71%	0.922	-6.71%	0.896	-7.03%	0.892	-7.05%	0.882	-6.26%	None
Roundup - Pendleton	0.991	2.31%	0.962	-2.69%	0.921	-4.43%	0.908	-5.34%	0.964	2.47%	None
Roundup - Buckaroo	0.905	-6.57%	1.021	3.35%	0.862	-10.57%	0.873	-9.00%	0.883	-6.11%	None
Roundup - Pilot Rock	0.976	0.73%	0.983	-0.53%	0.961	-0.29%	0.961	0.17%	0.951	1.13%	None
Pendleton - Athena	0.964	-0.53%	0.984	-0.39%	0.958	-0.61%	0.952	-0.75%	0.935	-0.57%	None
Pendleton - Buckaroo	0.949	-2.09%	1.003	1.49%	0.987	2.43%	0.933	-2.78%	0.921	-2.08%	None

	Heavy Summer 2017 - Primary Point of Interconnection										Thermal
	69 kV System										
Outage	**BPA Roundup**	**Dev**	**PP&L Roundup**	**Dev**	**Buckaroo**	**Dev**	**Pendleton**	**Dev**	**Pilot Rock**	**Dev**	**Issues**
System Normal	0.970		0.990		0.966		0.961		0.942		None
Roundup Transformer 1	0.945	-2.65%	0.978	-1.14%	0.948	-1.88%	0.939	-2.27%	0.918	-2.57%	None
Roundup Transformer 2	0.945	-2.63%	0.978	-1.13%	0.948	-1.86%	0.939	-2.25%	0.918	-2.55%	None
Roundup Transformer 3	0.912	-6.00%	0.872	-11.92%	0.872	-9.76%	0.881	-8.28%	0.891	-5.49%	None
Roundup - La Grande	0.978	0.82%	0.997	0.78%	0.974	0.83%	0.969	0.84%	0.951	0.88%	None

Roundup - McNary	0.909	-6.28%	0.927	-6.30%	0.902	-6.58%	0.898	-6.59%	0.888	-5.80%	None
Roundup - Pendleton	0.992	2.24%	0.965	-2.45%	0.927	-4.06%	0.914	-4.91%	0.965	2.40%	None
Roundup - Buckaroo	0.911	-6.08%	1.022	3.31%	0.871	-9.86%	0.881	-8.38%	0.890	-5.55%	None
Roundup - Pilot Rock	0.977	0.73%	0.984	-0.53%	0.963	-0.29%	0.963	0.17%	0.953	1.16%	None
Pendleton - Athena	0.965	-0.52%	0.986	-0.38%	0.960	-0.60%	0.954	-0.74%	0.937	-0.56%	None
Pendleton - Buckaroo	0.949	-2.19%	1.005	1.53%	0.990	2.51%	0.933	-2.91%	0.922	-2.20%	None
Trip Q0750	0.969	-0.14%	0.988	-0.14%	0.964	-0.21%	0.959	-0.18%	0.941	-0.15%	None

	Heavy Summer 2017 - Alternate Point of Interconnection										Thermal
	69 kV System										
Outage	**BPA Roundup**	**Dev**	**PP&L Roundup**	**Dev**	**Buckaroo**	**Dev**	**Pendleton**	**Dev**	**Pilot Rock**	**Dev**	**Issues**
System Normal	0.970		0.988		0.964		0.960		0.945		None
Roundup Transformer 1	0.945	-2.56%	0.978	-1.10%	0.947	-1.82%	0.939	-2.19%	0.923	-2.31%	None
Roundup Transformer 2	0.945	-2.54%	0.978	-1.09%	0.947	-1.80%	0.939	-2.18%	0.923	-2.30%	None
Roundup Transformer 3	0.908	-6.30%	0.866	-12.42%	0.866	-10.21%	0.876	-8.68%	0.891	-5.77%	None
Roundup - La Grande	0.977	0.81%	0.996	0.77%	0.972	0.83%	0.968	0.84%	0.953	0.86%	None
Roundup - McNary	0.907	-6.49%	0.924	-6.51%	0.898	-6.81%	0.894	-6.83%	0.889	-5.97%	None
Roundup - Pendleton	0.991	2.26%	0.962	-2.70%	0.921	-4.46%	0.908	-5.37%	0.968	2.40%	None
Roundup - Buckaroo	0.908	-6.40%	1.022	3.37%	0.864	-10.35%	0.875	-8.80%	0.890	-5.88%	None
Roundup - Pilot Rock	0.976	0.69%	0.983	-0.51%	0.961	-0.28%	0.961	0.16%	0.953	0.86%	None
Pendleton - Athena	0.965	-0.52%	0.985	-0.38%	0.958	-0.61%	0.953	-0.74%	0.940	-0.55%	None

Pendleton - Buckaroo	0.950	-2.00%	1.003	1.50%	0.987	2.43%	0.934	-2.67%	0.928	-1.87%	None
Trip Q0750	0.969	-0.05%	0.988	-0.02%	0.964	-0.03%	0.959	-0.04%	0.942	-0.38%	None

	Light Load 2017										
	69 kV System										Thermal
Outage	BPA Roundup	Dev	PP&L Roundup	Dev	Buckaroo	Dev	Pendlet on	Dev	Pilot Rock	Dev	Issues
System Normal	1.0196		1.0287		1.0197		1.0165		1.0225		None
Roundup Transformer 1	1.0122	-0.72%	1.0247	-0.39%	1.0140	-0.56%	1.0100	-0.64%	1.0165	-0.59%	None
Roundup Transformer 2	1.0123	-0.71%	1.0248	-0.38%	1.0141	-0.55%	1.0101	-0.63%	1.0165	-0.58%	None
Roundup Transformer 3	1.0038	-1.55%	0.9954	-3.24%	0.9953	-2.39%	0.9964	-1.98%	1.0096	-1.26%	None
Roundup - La Grande	1.0234	0.37%	1.0328	0.39%	1.0237	0.39%	1.0204	0.39%	1.0256	0.30%	None
Roundup - McNary	0.9971	-2.21%	1.0037	-2.43%	0.9966	-2.27%	0.9943	-2.18%	1.0041	-1.79%	None
Roundup - Pendleton	1.0324	1.26%	1.0191	-0.94%	1.0058	-1.36%	1.0006	-1.56%	1.0345	1.18%	None
Roundup - Buckaroo	1.0035	-1.58%	1.0487	1.95%	0.9948	-2.45%	0.9960	-2.02%	1.0093	-1.29%	None
Roundup - Pilot Rock	1.0206	0.10%	1.0282	-0.05%	1.0196	-0.01%	1.0168	0.04%	1.0219	-0.05%	None
Pendleton - Athena	1.0351	1.52%	1.0414	1.24%	1.0356	1.56%	1.0335	1.68%	1.0371	1.44%	None
Pendleton - Buckaroo	1.0057	-1.36%	1.0447	1.55%	1.0426	2.24%	0.9990	-1.71%	1.0111	-1.11%	None

	Light Load 2017 - Primary Point of Interconnection										Thermal Issues
	69 kV System										
Outage	BPA Roundup	Dev	PP&L Roundup	Dev	Buckaroo	Dev	Pendleton	Dev	Pilot Rock	Dev	
System Normal	1.0198		1.0290		1.0203		1.0169		1.0226		None
Roundup Transformer 1	1.0125	-0.72%	1.0249	-0.39%	1.0146	-0.56%	1.0104	-0.64%	1.0167	-0.58%	None
Roundup Transformer 2	1.0126	-0.71%	1.0250	-0.39%	1.0147	-0.56%	1.0105	-0.63%	1.0168	-0.57%	None
Roundup Transformer 3	1.0037	-1.57%	0.9963	-3.18%	0.9962	-2.37%	0.9968	-1.98%	1.0095	-1.28%	None
Roundup - La Grande	1.0236	0.37%	1.0330	0.39%	1.0243	0.39%	1.0208	0.39%	1.0258	0.31%	None
Roundup - McNary	0.9973	-2.20%	1.0041	-2.42%	0.9972	-2.27%	0.9947	-2.18%	1.0043	-1.79%	None
Roundup - Pendleton	1.0325	1.25%	1.0191	-0.97%	1.0063	-1.38%	1.0011	-1.56%	1.0346	1.17%	None
Roundup - Buckaroo	1.0034	-1.61%	1.0488	1.92%	0.9956	-2.42%	0.9963	-2.02%	1.0092	-1.31%	None
Roundup - Pilot Rock	1.0207	0.09%	1.0284	-0.06%	1.0202	-0.01%	1.0172	0.03%	1.0222	-0.04%	None
Pendleton - Athena	1.0354	1.53%	1.0418	1.25%	1.0364	1.57%	1.0341	1.69%	1.0375	1.45%	None
Pendleton - Buckaroo	1.0058	-1.37%	1.0451	1.57%	1.0436	2.28%	0.9991	-1.75%	1.0112	-1.12%	None
Trip Q0750	1.0196	-0.02%	1.0287	-0.03%	1.0197	-0.06%	1.0165	-0.04%	1.0225	-0.01%	None

	Light Load 2017 - Alternate Point of Interconnection										
	69 kV System										Thermal
Outage	**BPA Roundup**	**Dev**	**PP&L Roundup**	**Dev**	**Buckaroo**	**Dev**	**Pendleton**	**Dev**	**Pilot Rock**	**Dev**	**Issues**
System Normal	1.0251		1.0317		1.0239		1.0213		1.0371		None
Roundup Transformer 1	1.0182	-0.68%	1.0277	- 0.39%	1.0183	-0.54%	1.0151	- 0.61%	1.0301	- 0.68%	None
Roundup Transformer 2	1.0183	-0.67%	1.0277	- 0.38%	1.0184	-0.54%	1.0152	- 0.60%	1.0302	- 0.67%	None
Roundup Transformer 3	1.0059	-1.87%	0.9972	- 3.35%	0.9970	-2.62%	0.9981	- 2.27%	1.0179	- 1.85%	None
Roundup - La Grande	1.0300	0.48%	1.0365	0.47%	1.0288	0.48%	1.0262	0.48%	1.0419	0.46%	None
Roundup - McNary	0.9987	-2.57%	1.0046	- 2.63%	0.9976	-2.56%	0.9955	- 2.52%	1.0108	- 2.54%	None
Roundup - Pendleton	1.0405	1.50%	1.0199	- 1.15%	1.0064	-1.70%	1.0012	- 1.96%	1.0520	1.44%	None
Roundup - Buckaroo	1.0055	-1.91%	1.0491	1.68%	0.9965	-2.68%	0.9977	- 2.31%	1.0175	- 1.89%	None
Roundup - Pilot Rock	1.0240	-0.11%	1.0326	0.09%	1.0245	0.06%	1.0211	- 0.01%	1.0326	- 0.43%	None
Pendleton - Athena	1.0409	1.54%	1.0446	1.25%	1.0400	1.57%	1.0386	1.69%	1.0524	1.47%	None
Pendleton - Buckaroo	1.0080	-1.67%	1.0451	1.30%	1.0430	1.87%	1.0009	- 1.99%	1.0200	- 1.65%	None
Trip Q0750	1.0255	0.03%	1.0321	0.04%	1.0243	0.04%	1.0217	0.04%	1.0347	- 0.24%	None

13.3.1 DISTRIBUTION SYSTEM STUDY RESULTS

Primary POI
Description:
Reconductor, approximately 8,000 circuit feet of two phase primary distribution circuit from FP 345300 to FP 270302 at Birch Road and McKay Drive with three phase primary.
P&N:

This Project is driven by the need to provide a three phase line at the Point of Interconnection

Description:
Replace voltage regulators at FP 270401 along Birch Road.
P&N:
This Project is required to insure that reverse power flow capability is available. The existing voltage regulator may be retro fitted with this capability thus reducing the cost of this element of the project.

Description:
Balance load across the McKay branch of the feeder.
P&N:
The existing system is significantly unbalanced in the vicinity of the POI. Balancing will be required for the generation to operate successfully.

Description:
Replace field recloser 5W490 with a new recloser capable of preventing reclosing on an energized line. The existing unit may possibly be modified in the field to enable this feature. If so, then a new recloser will not be required.
P&N:
The sync check capability is needed as well as well as hot bus dead line reclosing. The existing recloser will either be replaced or modified if possible.

Description:
Replace 65T fuses at FP 270302 with 100T fuses.
P&N:
The existing 65T fuses do not have adequate capacity when the generation is producing maximum output.

<u>Alternate POI</u>

Description:
Reconductor, approximately 8,000 circuit feet of two phase primary distribution circuit from FP 345300 to FP 270302 at Birch Road and McKay Drive with three phase primary.
P&N:

This Project is driven by the need to provide a three phase line at the Point of Interconnection

Description:
Reconductor an additional 54,150 feet of three phase circuit from Birch Road and McKay Drive back to Pilot Rock substation with larger conductors (FP 270302 to FP 090505).
P&N: There is a capacity related issue on the front end of the feeder when the generation is not producing power. Also, without the replacement of this circuit the transient voltage variation resulting from the generator going off line or online significantly exceeds Public Utility's operating criteria. The calculated voltage variation is 11.7% without the reconductoring project. It is calculated at 7.5% with the reconductoring project completed.

Description:
Replace voltage regulators at FP 279603.
P&N:
This Project is required to insure that reverse power flow capability is available. The existing voltage regulator may be retro fitted with this capability thus reducing the cost of this element of the project.

Description:
Balance load across the McKay branch of the feeder.
P&N:
The existing system is significantly unbalanced in the vicinity of the POI. Balancing will be required for the generation to operate successfully.

Description:
Install a new recloser capable of preventing reclosing on an energized line.
P&N:
The sync check capability is needed as well hot bus dead line reclosing.

Description:
Replace 65T fuses at FP 270302 with 100T fuses.
P&N:
The existing 65T fuses do not have adequate capacity when the generation is producing maximum output.

Attachment 2

Small Generator Interconnection

Oregon Tier 4 Feasibility Study Report

Completed for

("Interconnection Customer")
Q0750

A Qualifying Facility

Proposed Primary Point of Interconnection
Circuit 5W202 out of Buckaroo substation

Proposed Alternate Point of Interconnection
Circuit 5W406 out of Pilot Rock

September 29, 2016

1.0 DESCRIPTION OF THE GENERATING FACILITY

(“Interconnection Customer”) proposed interconnecting 2 MW of new generation to PacifiCorp’s (“Public Utility”) circuit 5W202 out of Buckaroo substation located in Umatilla County, Oregon as the primary Point of Interconnection. Interconnection Customer has also proposed interconnecting to Public Utility’s circuit 5W406 out of Pilot Rock located in Umatilla County, Oregon as an alternate Point of Interconnection. The project (“Project”) will consist of 2 MW, 2222.2 kVA Chang Jiang Energy Corp. SFW2000-14/730 ver. 303F synchronous generator for a total output of 2 MW. The requested commercial operation date is December 31, 2020.

Interconnection Customer will operate this generator as a Qualifying Facility as defined by the Public Utility Regulatory Policies Act of 1978 (PURPA).

The Public Utility has assigned the Project “Q0750.”

2.0 APPROVAL CRITERIA FOR TIER 4 INTERCONNECTION REVIEW

Pursuant to 860-082-0060(1), a public utility must use the Tier 4 interconnection review procedures for an application to interconnect a small generator facility that meets the following requirements:

(a) The small generator facility does not qualify for or failed to meet Tier 1, Tier 2, or Tier 3 interconnection review requirements; and

(b) The small generator facility must have a nameplate capacity of ten (10) megawatts or less.

3.0 SCOPE OF THE STUDY

Pursuant to 860-082-0060(6)(e) the Feasibility Study Report must identify any potential adverse system impacts on the public utility’s transmission or distribution system or an affected system that may result from the interconnection of the Small Generating Facility. In determining possible adverse system impacts, the Public Utility must consider the aggregated nameplate capacity of all generating facilities that, on the date the feasibility study begins, are directly interconnected to the Public Utility’s transmission or distribution system, have a pending completed application to interconnect with a higher queue position, or have an executed interconnection agreement with the Public Utility.

4.0 PRIMARY POINT OF INTERCONNECTION

Interconnection Customer’s proposed Small Generating Facility is to be interconnected through a step up transformer owned and maintained by the Interconnection Customer. The Small Generating Facility will be interconnected with the Public Utility 12.47 kV distribution system at or near facility point (“FP”) 345300. This Small Generating Facility is proposed to be connected to Public Utility’s circuit 5W202, from Buckaroo substation. The Point of Interconnection (“POI”) is approximately 31,100 circuit feet from Buckaroo substation. Currently, the final 8,000 circuit feet of the system to the Small Generating Facility consists of two phases and a neutral.

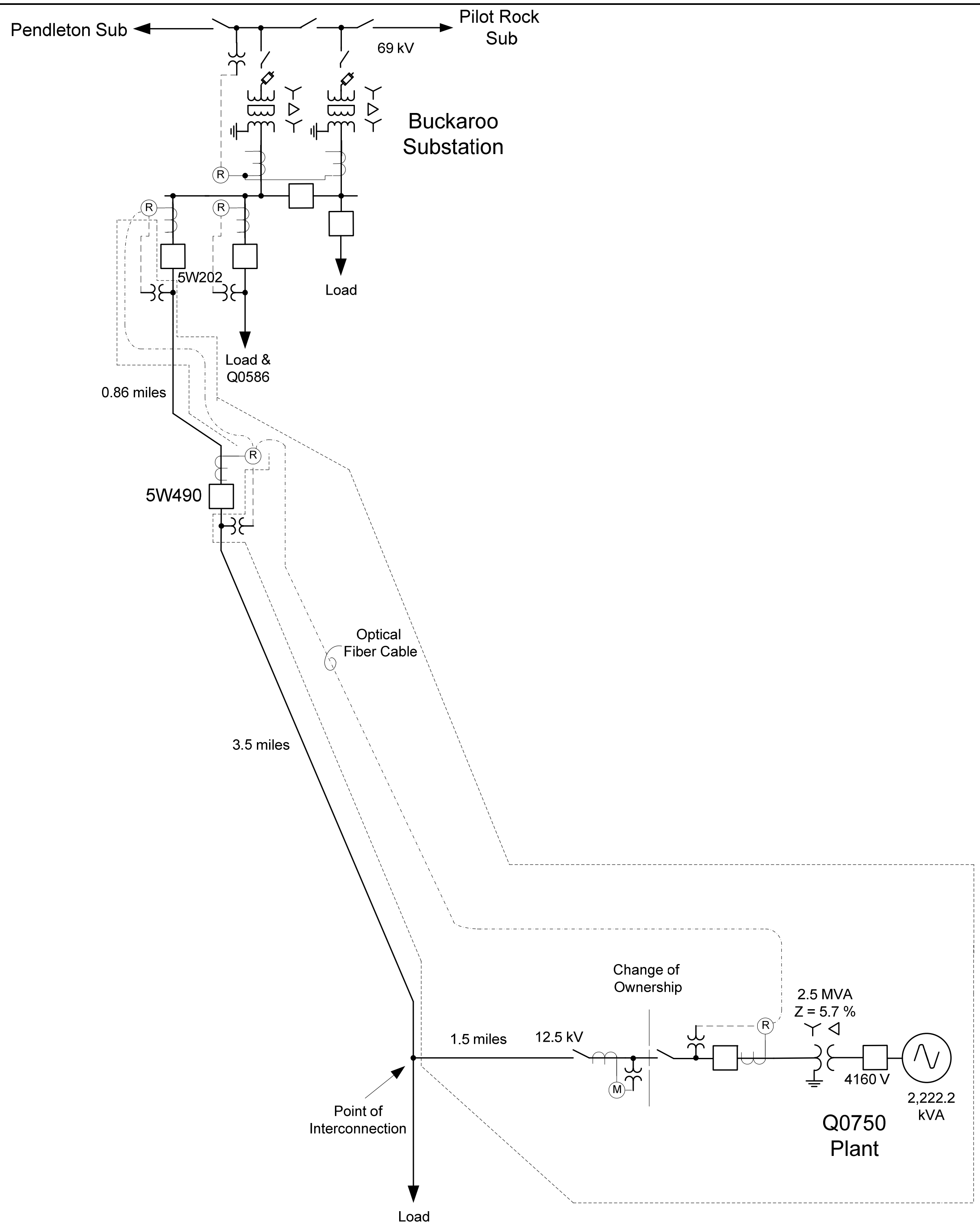

Figure 1: System One Line Diagram – Primary Point of Interconnection

4.1 ALTERNATE POINT OF INTERCONNECTION

The following alternative Point of Interconnection will be considered in this report:

The alternate POI is the same as the primary POI. The alternate POI is evaluated when served from 5W406 out of Pilot Rock substation rather than 5W202 out of Buckaroo substation.

Interconnection Customer's proposed Small Generating Facility is to be interconnected through a step up transformer owned and maintained by the Interconnection Customer. The Small Generating Facility will be interconnected with the Public Utility 12.47 kV distribution system at or near FP 345300. This Small Generating Facility is proposed to be connected to Public Utility's circuit 5W202, from Buckaroo substation. However, the alternate POI assumes the circuit in the area of the Point of Interconnection has been switched to 5W406, from Pilot Rock substation.

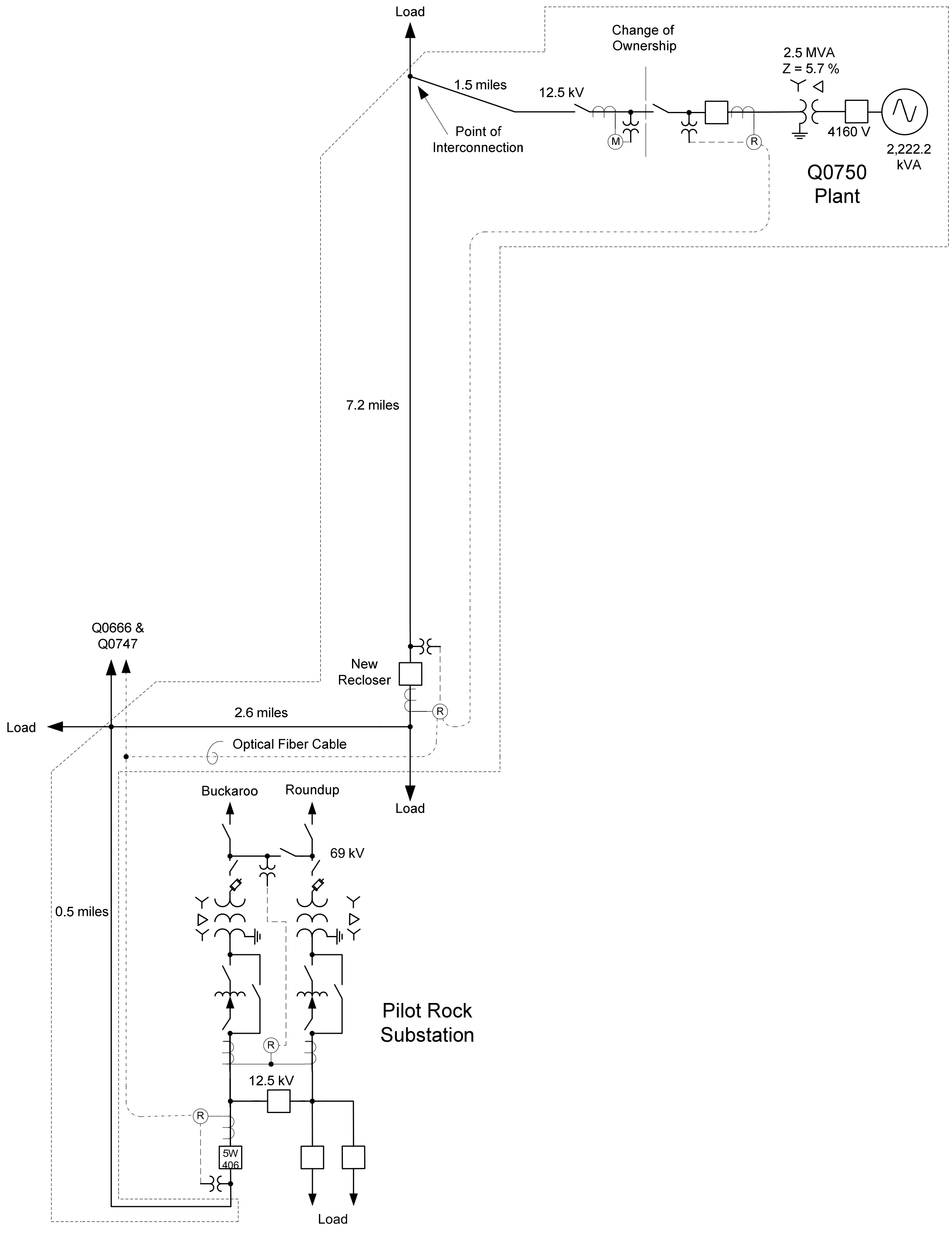

Figure 2: System One Line Diagram – Alternate Point of Interconnection

5.0 STUDY ASSUMPTIONS

- All active higher priority transmission service and/or generator interconnection requests will be considered in this study and are listed in Appendix 1. If any of these requests are withdrawn, the Public Utility reserves the right to restudy this request, as the results and conclusions contained within this study could significantly change.
- For study purposes there are two separate queues:
  - Transmission Service Queue: to the extent practical, all system upgrades that are required to accommodate active transmission service requests will be modeled in this study.
  - Generation Interconnection Queue: withal relevant higher queue interconnection requests will be modeled in this study.
- Interconnection Customer's request for interconnection service in and of itself does not convey transmission service.
- This study assumes the Project will be integrated into Public Utility's system at the agreed upon and/or proposed Point of Interconnection.
- Interconnection Customer will construct and own any facilities required between the Point of Interconnection and the Project unless specifically identified by the Public Utility.
- Generator tripping may be required for certain outages.
- All facilities will meet or exceed the minimum Western Electricity Coordinating Council ("WECC"), North American Electric Reliability Corporation ("NERC"), and Public Utility performance and design standards
- The Project was studied with one (1) 2.0 MW Chang Jiang Energy Corp SFW 2000-14/1730 with 0.9 pf as shown in Interconnection Customer provided document "160516 Q0750 Generator Data," dated August 19, 2016.
- The Project was studied with the following active higher priority queue projects on-line: Q0547, Q0586, Q0666 and Q0747.
- Reith feeder 5W202, peak demand is 9.85 MVA at 0.94 pf. The minimum load studied for the Q0750 Project is estimated at 32% of the documented peak load. The minimum load studied is 2.96 MVA at 0.999 pf.
- Historic time of use metering does not exist for the Pilot Rock substation transformers or feeders. Fifteen minute peak demand kW and kvar reads documented 8 times per year is the only load data recorded. The minimum load studied for the Q0750 Project assumed 25% of the documented peak load when modeling the distribution 12.5 kV feeder.
- Pilot Rock City feeder 5W406 peak demand load is 7.5 MVA at a 0.96 pf. The minimum load studied is 1.9 MVA at 0.96 pf.
- This report is based on information available at the time of the study. It is Interconnection Customer's responsibility to check the Public Utility's web site regularly for transmission system updates (http://www.pacificorp.com/tran.html).

6.0 REQUIREMENTS – PRIMARY POINT OF INTERCONNECTION

6.1 SMALL GENERATOR FACILITY MODIFICATIONS

The Small Generating Facility and interconnection equipment owned by Interconnection Customer are required to operate under automatic voltage control with the voltage sensed electrically at the Point of Interconnection. Small Generating Facility should have sufficient reactive capacity to enable the delivery of 100 percent of the plant output to the Point of

Interconnection at unity power factor measured at 1.0 per unit voltage under steady state conditions.

Generators capable of operating under voltage control with a voltage droop are required to do so. Studies will be required to coordinate the voltage droop setting with other facilities in the area. In general, generation and interconnection facilities should be operated so as to maintain the voltage at the Point of Interconnection between 1.01 pu to 1.04 pu. At the Public Utility's discretion, these values might be adjusted depending on the operating conditions. Within this voltage range, the Small Generating Facility should operate so as to minimize the reactive interchange between the Small Generating Facility and the Public Utility's system (delivery of power at the Point of Interconnection at approximately unity power factor). The voltage control settings of the Small Generating Facility must be coordinated with the Public Utility prior to energization (or interconnection). The reactive compensation must be designed such that the discreet switching of the reactive device (if required by Interconnection Customer) does not cause step voltage changes greater than +/-3% on the Public Utility's system.

As per NERC standard VAR-001-1, the Public Utility is required to specify voltage or reactive power schedule at the Point of Interconnection. Under normal conditions, the Public Utility's system should not supply reactive power to the generation/interconnection facilities.

The Interconnection Customer's recloser must be protected with sufficient bird guarding to prevent outages to the Public Utility's other customers on the same circuit.

6.2 TRANSMISSION/DISTRIBUTION SYSTEM MODIFICATIONS

6.2.1 TRANSMISSION SYSTEM MODIFICATIONS

The Public Utility's Pendleton-Walla Walla area system as a whole is generation surplus. As a Qualifying Facility, the proposed Q0750 Project must be used to serve network load. In order to sink the generation into network load, a new 230 kV transmission line from the Pendleton area to the Yakima area system would be required. The new line would connect Roundup substation with Wine Country substation in the vicinity of Grandview, Washington. The new 230 kV line would be approximately 80 to 90 miles, depending on the line route. This new transmission line is currently required as part of the Q0747 project. However, if the Q0747 interconnection customer chooses to convert to a non-qualified facility, or drops out of the queue, the transmission line construction requirement will be required for Q0750.

In lieu of the transmission construction described above, Interconnection Customer may be able negotiate with the power purchaser to obtain third-party transmission rights to deliver any excess generation from the Pendleton-Walla Walla area system to an area with sufficient load to sink the generation. This alternative would require an agreement between Interconnection Customer and the power purchaser. Without that agreement in place, the transmission construction alternative will be required as part of the Project.

6.2.2 Distribution System Modifications

- Reconductor approximately 8,000 circuit feet of two phase primary distribution circuit from FP 345300 to FP 270302 at Birch Road and McKay Drive with three phase primary.
- Replace voltage regulators at FP 270401 along Birch Road.
- Balance load across the McKay branch of the feeder.
- Replace field recloser 5W490 with a new recloser capable of preventing reclosing on an energized line. The existing unit may possibly be modified in the field to enable this feature. If so, then a new recloser will not be required.
- Replace 65T fuses at FP 270302 with 100T fuses.

6.3 Existing Breaker Modifications – Short-Circuit

The increase in the fault duty on the system as the result of the addition of the Small Generating Facility with 1 – 2222.2 kVA generator fed through 1 – 2.5 MVA 12.47 kV – 4,160 V transformer with 5.7 % impedance will not push the fault duty above the interrupting rating of any of the existing fault interrupting equipment.

6.4 Protection Requirements

Protective relaying systems will need to be installed that will detect faults and cause the disconnection of the Small Generating Facility for 12.5 kV line faults on circuit 5W202 out of Buckaroo substation, for faults beyond the field recloser 5W490, for faults in the 69 – 12.5 kV transformers in Buckaroo substation, and for faults on the 69 kV line that Buckaroo substation is connected to. The minimum day time load on Buckaroo substation is 8.4 MW which is at or near the maximum potential power output of the proposed Small Generating Facility combined with this Project's synchronous generator. The combination of the synchronous generator and the inverters cannot be relied upon to cause the high speed disconnection of the generation facilities for faults on the distribution or transmission for slight unbalances between load and generation after the operation of the breakers at the primary sources of fault current. Relaying will be installed that will detect the fault conditions and send transfer trip from Buckaroo substation to both the Q0586 Small Generating Facility and to this Project to cause the disconnection of the generation. The transfer trip circuit to Q0586 Small Generating Facility is part of that project's scope of work. An optical fiber cable will be installed between Buckaroo substation, the 5W490 field recloser and the recloser for this Project. The transfer trip signal will be sent over the optical fiber cable.

For 12.5 kV circuit faults the transfer trip will be keyed by the opening of breaker 5W202 at Buckaroo substation. The 69 kV line faults will be detected by installing line relays at Buckaroo substation that will monitor the current through both of the transformers and voltages on the 69 kV system. These line relays will also detect faults in the power transformers. The line relays will key transfer trip to the Small Generating Facility. These relays will need to operate high speed to disconnect the generation before the automatic reclosing that will be taking place at the source substations to reenergize the circuit. Most faults on overhead lines are temporary in nature so that after all the sources of energy to the fault have been disconnected the circuit can be reenergized and the service to the loads restored. It will not be possible to set the new line relays to be selective as to limiting the operation for faults only on the line that Buckaroo is connected to and still clear the faults high speed. The relays will occasionally operate for faults on other 69 kV lines out of Roundup substation. This will cause the Small Generating Facility to be disconnected on occasions when the line to the Small Generating Facility does not go dead. The only way to maximize the energy production of the Small Generating Facility would be to install communication equipment for a transfer trip circuit between Roundup and Buckaroo substations. This option would increase the cost of this Project. It is assumed that Interconnection Customer prefers the less expensive option and will tolerate the occasional unnecessary interruptions. The relays for detecting the 69 kV line faults and faults in the 69 – 12.5 kV transformers are planned to be installed for the Q0586 project.

The line relay associated with the breaker 5W202 will need to be replaced with a relay that has functions that the existing relay does not have. These functions include dead line checking and the ability to communicate the transfer trip signal. In conjunction with Q0586 the control and relay panel for 5W202 will be replaced. The relay that will be installed for Q0586 will have all of the functionality needed for Q0750. The dead line checking function will require the addition of 12.5 kV VTs on the line side of the CB 5W202. The secondaries of these voltage transformers will connect to the feeder protection relay. The dead line checking will be required to delay the automatic reclosing of CB 5W202 for the cases when a failure of the protective systems leads to delayed tripping of the Small Generating Facility for a feeder fault. Reclosing for this type of situation could cause damage to the equipment and needs to be prevented.

The relay associated with the field recloser 5W490 will need to be modified. The recloser controller has all the capabilities required but needs modification to enable the functions. These functions include dead line checking, ability to communicate the transfer trip signal, and directional overcurrent functions. The fault current contribution from the Project for faults between Buckaroo substation and the recloser and for faults on the other feeders out of the substation will be in excess of the current pickup of the recloser relay. If the overcurrent elements are not made directional the recloser will trip open unnecessarily for faults on those circuits. The dead line checking function will require the addition of 12.5 kV VTs on the line side of the recloser 5W490. The secondaries of these voltage transformers will connect to the controller. The dead line checking will be required to delay the automatic reclosing of the recloser for the cases when a failure of the protective systems leads to delayed tripping of Small Generating Facility for a feeder fault. The voltage signals will also provide the quantities to make the overcurrent functions directional.

The combination of Q0586 and Q0750 power will flow toward the 69 kV at Buckaroo substation during certain times of day and certain seasons. It is planned that the controllers for the LTC's associated with those transformers will be replaced with units that react correctly with this condition as part of the Q0586 project.

The Project's circuit recloser with need to be equipped with a SEL 351R protective relay to perform the following functions:

1. Receive transfer trip from Buckaroo substation and the field recloser 5W490.

2. Detect faults on the 12.5 kV at the Small Generating Facility
3. Detect faults on the 12.5 kV line to Buckaroo substation
4. Monitor the voltage and react to under or over frequency, and / or magnitude of the voltage

All of these relaying functions are all parts of one protective relay.

6.5 DATA REQUIREMENTS

Due to the power size of the Project the Public Utility's Operation Centers will not require any real time data from the Small Generating Facility, so no RTU will be required.

6.6 COMMUNICATION REQUIREMENTS

Communication circuits will be required between Buckaroo substation and field recloser 5W490, and between field recloser 5W490 and the recloser at the Small Generating Facility for the transfer trip circuits.

7.0 COST ESTIMATE – PRIMARY POINT OF INTERCONNECTION

The following estimate represents only scopes of work that will be performed by the Public Utility. Costs for any work being performed by Interconnection Customer are not included.

Q0750 Generating Facility *Add metering, protection & control and communications*	$ 240,000
Circuit 5W490 Distribution line work *Modify communications and relay settings*	$ 30,000
Circuit 5W202 Distribution line work *Reconductor 8,000 feet of line, replace voltage regulators, field reclosers and fuses*	$ 980,000
Fiber *Install six miles of fiber from Q0750 to Buckaroo substation*	$ 230,000
Buckaroo substation *Install voltage transformers, communications and protection & control*	$ 300,000
Total	**$1,780,000**

Note: Costs for all excavation, duct installation and easements shall be borne by Interconnection Customer and are not included in this estimate. This estimate is as accurate as possibly given the level of detailed study that has been completed to date and approximates the costs incurred by the Public Utility to interconnect this Small Generator Facility to the Public Utility's electrical distribution or transmission system. A more detailed estimate will be calculated during the System Impact Study. Interconnection Customer will be responsible for all actual costs, regardless of the estimated costs communicated to or approved by Interconnection Customer.

8.0 SCHEDULE – PRIMARY POINT OF INTERCONNECTION

It is estimated that it will take approximately 18-24 months to design, procure and construct the facilities described in this report following the execution of an interconnection agreement. The schedule will be further developed and optimized during the System Impact Study.

Please note, the time required to construct the transmission line currently assigned to higher queued project Q0747 and necessary for this Project results in a timeframe that does not support Interconnection Customer's requested commercial operation date of December 31, 2020.

9.0 REQUIREMENTS – ALTERNATE POINT OF INTERCONNECTION

9.1 SMALL GENERATOR FACILITY MODIFICATIONS

The Small Generator Facility and Interconnection Equipment owned by Interconnection Customer are required to operate under automatic voltage control with the voltage sensed electrically at the Point of Interconnection. The Small Generator Facility should have sufficient reactive capacity to enable the delivery of 100 percent of the plant output to the Point of Interconnection at unity power factor measured at 1.0 per unit voltage under steady state conditions.

Generators capable of operating under voltage control with a voltage droop are required to do so. Studies will be required to coordinate the voltage droop setting with other facilities in the area. In general, generation and interconnection facilities should be operated so as to maintain the voltage at the Point of Interconnection between 1.01 pu to 1.04 pu. At the Public Utility's discretion, these values might be adjusted depending on the operating conditions. Within this voltage range, the Small Generator Facility should operate so as to minimize the reactive interchange between the Small Generator Facility and the Public Utility's system (delivery of power at the Point of Interconnection at approximately unity power factor). The voltage control settings of the Small Generator Facility must be coordinated with the Public Utility prior to energization (or interconnection). The reactive compensation must be designed such that the discreet switching of the reactive device (if required by Interconnection Customer) does not cause step voltage changes greater than +/-3% on the Public Utility's system.

As per NERC standard VAR-001-1, the Public Utility is required to specify voltage or reactive power schedule at the Point of Interconnection. Under normal conditions, the Public Utility's system should not supply reactive power to the generation/interconnection facilities.

The Interconnection Customer's recloser must be protected with sufficient bird guarding to prevent outages to the Public Utility's other customers on the same circuit.

9.2 TRANSMISSION/DISTRIBUTION SYSTEM MODIFICATIONS

9.2.1 TRANSMISSION SYSTEM MODIFICATION

The Transmission System Modifications for the Alternate Point of Interconnection are the same as for the Primary Point of Interconnection described in section 6.2.1.

9.2.2 DISTRIBUTION SYSTEM MODIFICATIONS

- Reconductor, approximately 8,000 circuit feet of two phase primary distribution circuit from FP 345300 to FP 270302 at Birch Road and McKay Drive with three phase primary.
- Reconductor an additional 54,150 feet of three phase circuit from Birch Road and McKay Drive back to Pilot Rock substation with larger conductors (FP 270302 to FP 090505).
- Replace voltage regulators at FP 279603.
- Balance load across the northern branch of the feeder.
- Install a new field recloser on the north branch of the feeder which is set up to prevent reclosing on an energized line.
- Replace 65T fuses at FP 270302 with 100T fuses.

9.3 EXISTING BREAKER MODIFICATIONS – SHORT-CIRCUIT

The increase in the fault duty on the system as the result of the addition of the Small Generating Facility with 1 – 2222.2 kVA generator fed through 1 – 2.5 MVA 12.47 kV – 4,160 V transformer with 5.7 % impedance will not push the fault duty above the interrupting rating of any of the existing fault interrupting equipment.

9.4 PROTECTION REQUIREMENTS

Protective relaying systems will need to be installed that will detect faults and cause the disconnection of the Small Generating Facility for 12.5 kV line faults on circuit 5W406 out of Pilot Rock substation, for faults beyond the new field recloser, for faults in the 69 – 12.5 kV transformers in Pilot Rock substation, and for faults on the 69 kV line that Pilot Rock substation is connected to. The minimum day time load on Pilot Rock substation is well below the maximum potential power output of the two proposed solar facilities: Q0666 and Q0747; combined with this Project's synchronous generator. The combination of the synchronous generator and the inverters cannot be relied upon to cause the high speed disconnection of the Small Generating Facility for faults on the distribution or transmission for slight unbalances between load and generation after the operation of the breakers at the primary sources of fault current. Relaying is planned to be installed for the Q0666 and Q0747 projects in Pilot Rock substation that will detect the fault conditions. Transfer trip will be sent from Pilot Rock substation to both the Q0666 and Q0747 Small Generating Facilities. This same transfer trip signal will need to be carried to the Project to cause the disconnection of the generation. An optical fiber cable will be installed between Pilot Rock substation, the new field recloser and the recloser for the Project. The transfer trip signal will be sent over the optical fiber cable.

For 12.5 kV circuit faults the transfer trip will be keyed by the opening of breaker 5W406 at Pilot Rock substation. The 69 kV line faults will be detected by installing line relays at Pilot Rock substation that will monitor the current through both of the transformers and voltages on the 69 kV system. These line relays will also detect faults in the power transformers. The line relays will key transfer trip to the Small Generating Facility. These relays will need to operate high speed to disconnect the generation before the automatic reclosing that will be taking place at the source substations to reenergize the circuit. It will not be possible to set the new line relays to be selective as to limiting the operation for faults only on the line that Pilot Rock substation is connected to and still clear the faults high speed. The relays will occasionally operate for faults on other 69 kV lines out of Roundup substation. This will cause the Small Generating Facility to be disconnected on occasions when the line to the Small Generating Facility does not go dead. The only way to maximize the energy production of the Small Generating Facility would be to install communication equipment for a transfer trip circuit between Roundup and Pilot Rock substations. This option would increase the cost of this Project. It is assumed that Interconnection Customer prefers the less expensive option and will tolerate the occasional unnecessary interruptions.

The line relay associated with the breaker 5W406 will need to be replaced as part of the Q0666 project. This new relay will have the functions for dead line checking and the ability to communicate the transfer trip signal. The relay that will be installed for that project will have all of the functionality needed for Q0750 Project.

The relay associated with the new field recloser will have the capabilities required for the addition of the Project. These functions include dead line checking, ability to communicate the transfer trip signal, and directional overcurrent functions. The fault current contribution from the Project for faults between Pilot Rock substation and the new recloser and for faults on the other feeders out of the substation will be in excess of the current pickup of the recloser relay. If the overcurrent elements are not made directional the recloser will trip open unnecessarily for faults on these circuits. The dead line checking function will require that 12.5 kV VTs on the line side be included with the new recloser. The secondaries of these voltage transformers will connect to the controller. The dead line checking will be required to delay the automatic reclosing for the cases when a failure of the protective systems leads to delayed tripping of the Small Generating Facility for a feeder fault. The voltage signals will also provide the quantities to make the overcurrent functions directional.

This Project’s power will flow toward the 69 kV at Pilot Rock substation during certain times of day and certain seasons. It is planned that the controllers for the voltage regulators will be replace with units that react correctly with this condition as part of the Q0666 project.

The Project’s circuit recloser with need to be equipped with a SEL 351R protective relay to perform the following functions:

1. Receive transfer trip from Pilot Rock substation and the new field recloser.
2. Detect faults on the 12.5 kV at the Small Generating Facility
3. Detect faults on the 12.5 kV line to Pilot Rock substation
4. Monitor the voltage and react to under or over frequency, and / or magnitude of the voltage

All of these relaying functions are all parts of one protective relay.

9.5 DATA REQUIREMENTS

Due to the power size of the Project the Public Utility’s Operation Centers will not require any real time data from the Small Generating Facility, so no RTU will be required.

9.6 Communication Requirements

Communication circuits will be required between Pilot Rock substation and the new field recloser, and between new field recloser and the recloser at the Project for the transfer trip circuits.

10.0 Cost Estimate – Alternate Point of Interconnection

The following estimate represents only scopes of work that will be performed by the Public Utility. Costs for any work being performed by Interconnection Customer are not included.

Q0750 Generating Facility *Add metering, protection & control, communications*	$ 240,000
Circuit 5W490 Distribution line work *Modify communications and relay settings*	$ 30,000
Distribution line work *Reconductor a total of 62,000 feet of line, replace voltage regulators, field reclosers and fuses*	$5,580,000
Fiber *Install 12 miles of fiber from Q0750 to Pilot Rock substation*	$ 460,000
Pilot Rock substation *Add communications*	$ 150,000
Total	**$6,460,000**

Note: Costs for all excavation, duct installation and easements shall be borne by Interconnection Customer and are not included in this estimate. This estimate is as accurate as possibly given the level of detailed study that has been completed to date and approximates the costs incurred by the Public Utility to interconnect this Small Generating Facility to the Public Utility's electrical distribution or transmission system. A more detailed estimate will be calculated during the System Impact Study. Interconnection Customer will be responsible for all actual costs, regardless of the estimated costs communicated to or approved by Interconnection Customer.

11.0 Schedule – Alternate Point of Interconnection

It is estimated that it will take approximately 24-36 months to design, procure and construct the facilities described in this report following the execution of an interconnection agreement. The schedule will be further developed and optimized during the System Impact Study.

Please note, the time required to to construct the transmission line currently assigned to higher queued project Q0747 and necessary for this Project results in a timeframe that does not support Interconnection Customer's requested commercial operation date of December 31, 2020.

12.0 PARTICIPATION BY AFFECTED SYSTEMS

Public Utility has identified the following Affected Systems: Bonneville Power Administration

Copies of this report will be shared with Affected System.

13.0 APPENDICES

Appendix 1: Higher Priority Requests
Appendix 2: Property Requirements
Appendix 3: Study Results

13.1 APPENDIX 1: HIGHER PRIORITY REQUESTS

All active higher priority transmission service and/or generator interconnection requests will be considered in this study and are identified below. If any of these requests are withdrawn, the Public Utility reserves the right to restudy this request, as the results and conclusions contained within this study could significantly change.

Transmission/Generation Interconnection Queue Requests considered:

Q0547 (18 MW) POI: Weston, line to Athena
Q0586 (6 MW) POI: Circuit 5W201 out of Buckaroo substation
Q0666 (1.98 MW) POI: Circuit 5W406 out of Pilot Rock substation
Q0747 (6 MW) POI: Circuit 5W406 out of Pilot Rock substation

13.2 APPENDIX 2: PROPERTY REQUIREMENTS

Requirements for rights of way easements

Rights of way easements will be acquired by Interconnection Customer in the Public Utility's name for the construction, reconstruction, operation, maintenance, repair, replacement and removal of Public Utility's Interconnection Facilities that will be owned and operated by Public Utility. Interconnection Customer will acquire all necessary permits for the Project and will obtain rights of way easements for the Project on Public Utility's easement form.

Real Property Requirements for Point of Interconnection Substation

Real property for a Point of Interconnection substation will be acquired by an Interconnection Customer to accommodate Interconnection Customer's Project. The real property must be acceptable to Public Utility. Interconnection Customer will acquire fee ownership for interconnection substation unless Public Utility determines that other than fee ownership is acceptable; however, the form and instrument of such rights will be at Public Utility's sole discretion. Any land rights that Interconnection Customer is planning to retain as part of a fee property conveyance will be identified in advance to Public Utility and are subject to the Public Utility's approval.

Interconnection Customer must obtain all permits required by all relevant jurisdictions for the planned use including but not limited to conditional use permits, Certificates of Public Convenience and Necessity, California Environmental Quality Act, as well as all construction permits for the project.

Interconnection Customer will not be reimbursed through network upgrades for more than the market value of the property.

As a minimum, real property must be environmentally, physically, and operationally acceptable to Public Utility. The real property shall be a permitted or able to be permitted use in all zoning districts. Interconnection Customer shall provide Public Utility with a title report and shall transfer property without any material defects of title or other encumbrances that are not acceptable to Public Utility. Property lines shall be surveyed and show all encumbrances, encroachments, and roads.

Examples of potentially unacceptable environmental, physical, or operational conditions could include but are not limited to:

1. Environmental: known contamination of site; evidence of environmental contamination by any dangerous, hazardous or toxic materials as defined by any governmental agency; violation of building, health, safety, environmental, fire, land use, zoning or other such regulation; violation of ordinances or statutes of any governmental entities having jurisdiction over the property; underground or above ground storage tanks in area; known remediation sites on property; ongoing mitigation activities or monitoring activities; asbestos; lead-based paint, etc. A phase I environmental study is required for land being acquired in fee by the Public Utility unless waived by Public Utility.

2. Physical: inadequate site drainage; proximity to flood zone; erosion issues; wetland overlays; threatened and endangered species; archeological or culturally sensitive areas; inadequate sub-surface elements, etc. Public Utility may require Interconnection Customer to procure various studies and surveys as determined necessary by Public Utility.

Operational: inadequate access for Public Utility's equipment and vehicles; existing structures on land that require removal prior to building of substation; ongoing maintenance for landscaping or extensive landscape requirements; ongoing homeowner's or other requirements or restrictions (e.g., Covenants, Codes and Restrictions, deed restrictions, etc.) on property which are not acceptable to the Public Utility.

13.3 APPENDIX 3: STUDY RESULTS

13.3.1 TRANSMISSION SYSTEM STUDY RESULTS

Historical loads were reviewed to determine the Public Utility's minimum network load in the Pendleton area 69 kV system. The minimum network load was determined to be 19 MW. The total generation in the Pendleton area with the prior active queues (Q0547, Q0586, Q066 and Q0747) and the proposed Q0750 Project is 33.98 MW. This results in a generation surplus and net export from the Pendleton area.

Transmission level power flow study cases were evaluated for heavy summer and minimum loading conditions. For each of the cases, power flow and system voltages were evaluated with and without the proposed Q0750 Small Generating Facility to determine the impact on the transmission system during system intact (N-0) operation for the normal system configuration, outage of one transmission element (N-1), and select contingencies resulting in loss of multiple elements (i.e. breaker failure or bus fault).

System Normal (N-0) Results – Primary Point of Interconnection
With all lines in service and the Walla Walla/Pendleton system in its normal configuration, the addition of Q0750 showed no thermal or steady-state voltage deficiencies.

The Buckaroo 12.47 kV Reith Feeder 5W202 is normally served by the 69-12.47 kV, 25 MVA transformer T-9370. Transformer T-9370 also serves the Montee Feeder 5W203. The transformer summer peak load is approximately 16 MW and minimum load is approximately 4.4 MW. The addition of Q0750 will have no reverse power flow into the Public Utility's transmission system.

The minimum load in the Pendleton area is 19 MW. The prior active queues and Q0750 project has a combined total generation of 33.98 MW. The total generation exceeds the minimum load in the Pendleton area and will require a net export of up to 14.98 MW through BPA Roundup station.

Single Element Outage (N-1) Results – Primary Point of Interconnection
The Pendleton 69 kV system includes three 69 kV lines supplied from BPA Roundup substation. There are three 230-69 kV transformers at Roundup. Two transformers are operated in parallel with the 69 kV "Patawa Creek" line to Pendleton and 69 kV "Birch Creek" radial line to Pilot Rock. The remaining 230-69 kV transformer is normally operated in a loop with 69 kV "Coyote Creek" line to Buckaroo and Pendleton. Outages to one of these elements will cause severe thermal overload and voltage deficiencies.

There are no thermal deficiencies with Q0750 connected at the primary Point of Interconnection for any of the N-1 outages. Prior to Q0750, outages to the 69 kV "Coyote Creek" line from Roundup to Buckaroo or the Public Utility's 230-69 kV transformer at Roundup may result in post-transient voltage deviations exceeding 5.0% in the Pendleton area. The proposed Small Generating Facility moderately decreases the severity of these post-transient voltage deviations at this Point of Interconnection. It is not the responsibility of the proposed interconnection to correct the existing system deficiencies.

System Normal (N-0) Results – Alternate Point of Interconnection
With all lines in service and the Walla Walla/Pendleton system in its normal configuration, the addition of Q0750 showed no thermal or steady-state voltage deficiencies to the transmission system.

The Pilot Rock City Feeder 5W406 is served by the 69-12.47 kV, 9.375 MVA transformer and 12.47 kV, 7.5 MVA substation voltage regulator R-816. Since historic time of use does not exist for this feeder and fifteen minute peak demand kW and kvar reads documented 8 times per year is the only load data recorded, the peak load for 5W406 is assumed to be 7.5 MVA at a 0.96 pf. The minimum load of 1.9 MVA at 0.96 pf was used for this study. Q0666 and Q0747 are also interconnecting on the same 5W406 circuit. The combined total generation on this circuit is 9.98 MW and at minimum load, an excess of up to 8 MW will be transported to the Public Utility's transmission system. A transport of 8 MW exceeds the rating for the substation voltage regulator at Pilot Rock after applying PacifiCorp Engineering Handbook limits for voltage regulators and will require a new voltage regulator.

The minimum load in the Pendleton area is 19 MW. The prior active queues and Q0750 Project has a combined total generation of 33.98 MW. The total generation exceeds the minimum load in the Pendleton area and will require a net export of up to 14.98 MW through BPA Roundup station.

Single Element Outage (N-1) Results – Primary Point of Interconnection
The Pendleton 69 kV system includes three 69 kV lines supplied from BPA Roundup substation. There are three 230-69 kV transformers at Roundup. Two transformers are operated in parallel with the 69 kV "Patawa Creek" line to Pendleton and 69 kV "Birch Creek" radial line to Pilot Rock. The remaining 230-69 kV transformer is normally operated in a loop with 69 kV "Coyote Creek" line to Buckaroo and Pendleton. Outages to one of these elements will cause severe thermal overload and voltage deficiencies.

There are no thermal deficiencies with Q0750 connected at the alternate Point of Interconnection. Prior to Q0750, outages to the 69 kV "Coyote Creek" line from Roundup to Buckaroo or the Public Utility's 230-69 kV transformer at Roundup may result in post-transient voltage deviations exceeding 5.0% in the Pendleton area. There were no significant improvements in the voltage deviation for the proposed Small Generating Facility at this Point of Interconnection. It is not the responsibility of the proposed interconnection to correct the existing system deficiencies.

	Heavy Summer 2017 – Pre-Project 69 kV System										Thermal
Outage	**BPA Roundup**	**Dev**	**PP&L Roundup**	**Dev**	**Buckaroo**	**Dev**	**Pendleton**	**Dev**	**Pilot Rock**	**Dev**	**Issues**
System Normal	0.969		0.988		0.964		0.959		0.941		None
Roundup Transformer 1	0.943	-2.69%	0.977	-1.16%	0.945	-1.91%	0.937	-2.30%	0.917	-2.56%	None
Roundup Transformer 2	0.943	-2.67%	0.977	-1.15%	0.945	-1.89%	0.937	-2.29%	0.917	-2.54%	None
Roundup Transformer 3	0.906	-6.47%	0.863	-12.65%	0.863	-10.43%	0.874	-8.88%	0.884	-6.00%	None
Roundup - La Grande	0.977	0.81%	0.996	0.77%	0.972	0.82%	0.967	0.83%	0.949	0.86%	None
Roundup - McNary	0.904	-6.71%	0.922	-6.71%	0.896	-7.03%	0.892	-7.05%	0.882	-6.26%	None
Roundup - Pendleton	0.991	2.31%	0.962	-2.69%	0.921	-4.43%	0.908	-5.34%	0.964	2.47%	None
Roundup - Buckaroo	0.905	-6.57%	1.021	3.35%	0.862	-10.57%	0.873	-9.00%	0.883	-6.11%	None
Roundup - Pilot Rock	0.976	0.73%	0.983	-0.53%	0.961	-0.29%	0.961	0.17%	0.951	1.13%	None
Pendleton - Athena	0.964	-0.53%	0.984	-0.39%	0.958	-0.61%	0.952	-0.75%	0.935	-0.57%	None
Pendleton - Buckaroo	0.949	-2.09%	1.003	1.49%	0.987	2.43%	0.933	-2.78%	0.921	-2.08%	None

	Heavy Summer 2017 - Primary Point of Interconnection 69 kV System										Thermal
Outage	**BPA Roundup**	**Dev**	**PP&L Roundup**	**Dev**	**Buckaroo**	**Dev**	**Pendleton**	**Dev**	**Pilot Rock**	**Dev**	**Issues**
System Normal	0.970		0.990		0.966		0.961		0.942		None
Roundup Transformer 1	0.945	-2.65%	0.978	-1.14%	0.948	-1.88%	0.939	-2.27%	0.918	-2.57%	None
Roundup Transformer 2	0.945	-2.63%	0.978	-1.13%	0.948	-1.86%	0.939	-2.25%	0.918	-2.55%	None
Roundup Transformer 3	0.912	-6.00%	0.872	-11.92%	0.872	-9.76%	0.881	-8.28%	0.891	-5.49%	None
Roundup - La Grande	0.978	0.82%	0.997	0.78%	0.974	0.83%	0.969	0.84%	0.951	0.88%	None

Roundup - McNary	0.909	-6.28%	0.927	-6.30%	0.902	-6.58%	0.898	-6.59%	0.888	-5.80%	None
Roundup - Pendleton	0.992	2.24%	0.965	-2.45%	0.927	-4.06%	0.914	-4.91%	0.965	2.40%	None
Roundup - Buckaroo	0.911	-6.08%	1.022	3.31%	0.871	-9.86%	0.881	-8.38%	0.890	-5.55%	None
Roundup - Pilot Rock	0.977	0.73%	0.984	-0.53%	0.963	-0.29%	0.963	0.17%	0.953	1.16%	None
Pendleton - Athena	0.965	-0.52%	0.986	-0.38%	0.960	-0.60%	0.954	-0.74%	0.937	-0.56%	None
Pendleton - Buckaroo	0.949	-2.19%	1.005	1.53%	0.990	2.51%	0.933	-2.91%	0.922	-2.20%	None
Trip Q0750	0.969	-0.14%	0.988	-0.14%	0.964	-0.21%	0.959	-0.18%	0.941	-0.15%	None

	Heavy Summer 2017 - Alternate Point of Interconnection										
	69 kV System										**Thermal**
Outage	**BPA Roundup**	**Dev**	**PP&L Roundup**	**Dev**	**Buckaroo**	**Dev**	**Pendleton**	**Dev**	**Pilot Rock**	**Dev**	**Issues**
System Normal	0.970		0.988		0.964		0.960		0.945		None
Roundup Transformer 1	0.945	-2.56%	0.978	-1.10%	0.947	-1.82%	0.939	-2.19%	0.923	-2.31%	None
Roundup Transformer 2	0.945	-2.54%	0.978	-1.09%	0.947	-1.80%	0.939	-2.18%	0.923	-2.30%	None
Roundup Transformer 3	0.908	-6.30%	0.866	-12.42%	0.866	-10.21%	0.876	-8.68%	0.891	-5.77%	None
Roundup - La Grande	0.977	0.81%	0.996	0.77%	0.972	0.83%	0.968	0.84%	0.953	0.86%	None
Roundup - McNary	0.907	-6.49%	0.924	-6.51%	0.898	-6.81%	0.894	-6.83%	0.889	-5.97%	None
Roundup - Pendleton	0.991	2.26%	0.962	-2.70%	0.921	-4.46%	0.908	-5.37%	0.968	2.40%	None
Roundup - Buckaroo	0.908	-6.40%	1.022	3.37%	0.864	-10.35%	0.875	-8.80%	0.890	-5.88%	None
Roundup - Pilot Rock	0.976	0.69%	0.983	-0.51%	0.961	-0.28%	0.961	0.16%	0.953	0.86%	None
Pendleton - Athena	0.965	-0.52%	0.985	-0.38%	0.958	-0.61%	0.953	-0.74%	0.940	-0.55%	None

Pendleton - Buckaroo	0.950	-2.00%	1.003	1.50%	0.987	2.43%	0.934	-2.67%	0.928	-1.87%	None
Trip Q0750	0.969	-0.05%	0.988	-0.02%	0.964	-0.03%	0.959	-0.04%	0.942	-0.38%	None

	Light Load 2017										
	69 kV System										Thermal
Outage	**BPA Roundup**	**Dev**	**PP&L Roundup**	**Dev**	**Buckaroo**	**Dev**	**Pendleton**	**Dev**	**Pilot Rock**	**Dev**	**Issues**
System Normal	1.0196		1.0287		1.0197		1.0165		1.0225		None
Roundup Transformer 1	1.0122	-0.72%	1.0247	-0.39%	1.0140	-0.56%	1.0100	-0.64%	1.0165	-0.59%	None
Roundup Transformer 2	1.0123	-0.71%	1.0248	-0.38%	1.0141	-0.55%	1.0101	-0.63%	1.0165	-0.58%	None
Roundup Transformer 3	1.0038	-1.55%	0.9954	-3.24%	0.9953	-2.39%	0.9964	-1.98%	1.0096	-1.26%	None
Roundup - La Grande	1.0234	0.37%	1.0328	0.39%	1.0237	0.39%	1.0204	0.39%	1.0256	0.30%	None
Roundup - McNary	0.9971	-2.21%	1.0037	-2.43%	0.9966	-2.27%	0.9943	-2.18%	1.0041	-1.79%	None
Roundup - Pendleton	1.0324	1.26%	1.0191	-0.94%	1.0058	-1.36%	1.0006	-1.56%	1.0345	1.18%	None
Roundup - Buckaroo	1.0035	-1.58%	1.0487	1.95%	0.9948	-2.45%	0.9960	-2.02%	1.0093	-1.29%	None
Roundup - Pilot Rock	1.0206	0.10%	1.0282	-0.05%	1.0196	-0.01%	1.0168	0.04%	1.0219	-0.05%	None
Pendleton - Athena	1.0351	1.52%	1.0414	1.24%	1.0356	1.56%	1.0335	1.68%	1.0371	1.44%	None
Pendleton - Buckaroo	1.0057	-1.36%	1.0447	1.55%	1.0426	2.24%	0.9990	-1.71%	1.0111	-1.11%	None

	Light Load 2017 - Primary Point of Interconnection										
	69 kV System										Thermal
Outage	BPA Roundup	Dev	PP&L Roundup	Dev	Buckaroo	Dev	Pendleton	Dev	Pilot Rock	Dev	Issues
System Normal	1.0198		1.0290		1.0203		1.0169		1.0226		None
Roundup Transformer 1	1.0125	-0.72%	1.0249	-0.39%	1.0146	-0.56%	1.0104	-0.64%	1.0167	-0.58%	None
Roundup Transformer 2	1.0126	-0.71%	1.0250	-0.39%	1.0147	-0.56%	1.0105	-0.63%	1.0168	-0.57%	None
Roundup Transformer 3	1.0037	-1.57%	0.9963	-3.18%	0.9962	-2.37%	0.9968	-1.98%	1.0095	-1.28%	None
Roundup - La Grande	1.0236	0.37%	1.0330	0.39%	1.0243	0.39%	1.0208	0.39%	1.0258	0.31%	None
Roundup - McNary	0.9973	-2.20%	1.0041	-2.42%	0.9972	-2.27%	0.9947	-2.18%	1.0043	-1.79%	None
Roundup - Pendleton	1.0325	1.25%	1.0191	-0.97%	1.0063	-1.38%	1.0011	-1.56%	1.0346	1.17%	None
Roundup - Buckaroo	1.0034	-1.61%	1.0488	1.92%	0.9956	-2.42%	0.9963	-2.02%	1.0092	-1.31%	None
Roundup - Pilot Rock	1.0207	0.09%	1.0284	-0.06%	1.0202	-0.01%	1.0172	0.03%	1.0222	-0.04%	None
Pendleton - Athena	1.0354	1.53%	1.0418	1.25%	1.0364	1.57%	1.0341	1.69%	1.0375	1.45%	None
Pendleton - Buckaroo	1.0058	-1.37%	1.0451	1.57%	1.0436	2.28%	0.9991	-1.75%	1.0112	-1.12%	None
Trip Q0750	1.0196	-0.02%	1.0287	-0.03%	1.0197	-0.06%	1.0165	-0.04%	1.0225	-0.01%	None

	Light Load 2017 - Alternate Point of Interconnection										
	69 kV System										Thermal
Outage	BPA Roundup	Dev	PP&L Roundup	Dev	Buckaroo	Dev	Pendleton	Dev	Pilot Rock	Dev	Issues
System Normal	1.0251		1.0317		1.0239		1.0213		1.0371		None
Roundup Transformer 1	1.0182	-0.68%	1.0277	-0.39%	1.0183	-0.54%	1.0151	-0.61%	1.0301	-0.68%	None
Roundup Transformer 2	1.0183	-0.67%	1.0277	-0.38%	1.0184	-0.54%	1.0152	-0.60%	1.0302	-0.67%	None
Roundup Transformer 3	1.0059	-1.87%	0.9972	-3.35%	0.9970	-2.62%	0.9981	-2.27%	1.0179	-1.85%	None
Roundup - La Grande	1.0300	0.48%	1.0365	0.47%	1.0288	0.48%	1.0262	0.48%	1.0419	0.46%	None
Roundup - McNary	0.9987	-2.57%	1.0046	-2.63%	0.9976	-2.56%	0.9955	-2.52%	1.0108	-2.54%	None
Roundup - Pendleton	1.0405	1.50%	1.0199	-1.15%	1.0064	-1.70%	1.0012	-1.96%	1.0520	1.44%	None
Roundup - Buckaroo	1.0055	-1.91%	1.0491	1.68%	0.9965	-2.68%	0.9977	-2.31%	1.0175	-1.89%	None
Roundup - Pilot Rock	1.0240	-0.11%	1.0326	0.09%	1.0245	0.06%	1.0211	-0.01%	1.0326	-0.43%	None
Pendleton - Athena	1.0409	1.54%	1.0446	1.25%	1.0400	1.57%	1.0386	1.69%	1.0524	1.47%	None
Pendleton - Buckaroo	1.0080	-1.67%	1.0451	1.30%	1.0430	1.87%	1.0009	-1.99%	1.0200	-1.65%	None
Trip Q0750	1.0255	0.03%	1.0321	0.04%	1.0243	0.04%	1.0217	0.04%	1.0347	-0.24%	None

13.3.1 Distribution System Study Results

<u>Primary POI</u>
Description:
Reconductor, approximately 8,000 circuit feet of two phase primary distribution circuit from FP 345300 to FP 270302 at Birch Road and McKay Drive with three phase primary.
P&N:

This Project is driven by the need to provide a three phase line at the Point of Interconnection

Description:
Replace voltage regulators at FP 270401 along Birch Road.
P&N:
This Project is required to insure that reverse power flow capability is available. The existing voltage regulator may be retro fitted with this capability thus reducing the cost of this element of the project.

Description:
Balance load across the McKay branch of the feeder.
P&N:
The existing system is significantly unbalanced in the vicinity of the POI. Balancing will be required for the generation to operate successfully.

Description:
Replace field recloser 5W490 with a new recloser capable of preventing reclosing on an energized line. The existing unit may possibly be modified in the field to enable this feature. If so, then a new recloser will not be required.
P&N:
The sync check capability is needed as well as well as hot bus dead line reclosing. The existing recloser will either be replaced or modified if possible.

Description:
Replace 65T fuses at FP 270302 with 100T fuses.
P&N:
The existing 65T fuses do not have adequate capacity when the generation is producing maximum output.

<u>Alternate POI</u>

Description:
Reconductor, approximately 8,000 circuit feet of two phase primary distribution circuit from FP 345300 to FP 270302 at Birch Road and McKay Drive with three phase primary.
P&N:

This Project is driven by the need to provide a three phase line at the Point of Interconnection

Description:
Reconductor an additional 54,150 feet of three phase circuit from Birch Road and McKay Drive back to Pilot Rock substation with larger conductors (FP 270302 to FP 090505).
P&N: There is a capacity related issue on the front end of the feeder when the generation is not producing power. Also, without the replacement of this circuit the transient voltage variation resulting from the generator going off line or online significantly exceeds Public Utility's operating criteria. The calculated voltage variation is 11.7% without the reconductoring project. It is calculated at 7.5% with the reconductoring project completed.

Description:
Replace voltage regulators at FP 279603.
P&N:
This Project is required to insure that reverse power flow capability is available. The existing voltage regulator may be retro fitted with this capability thus reducing the cost of this element of the project.

Description:
Balance load across the McKay branch of the feeder.
P&N:
The existing system is significantly unbalanced in the vicinity of the POI. Balancing will be required for the generation to operate successfully.

Description:
Install a new recloser capable of preventing reclosing on an energized line.
P&N:
The sync check capability is needed as well hot bus dead line reclosing.

Description:
Replace 65T fuses at FP 270302 with 100T fuses.
P&N:
The existing 65T fuses do not have adequate capacity when the generation is producing maximum output.

Attachment 2

Small Generator Interconnection

Oregon Tier 4 System Impact Study Report

Completed for

(“Interconnection Customer”)
Q0758

A Qualifying Facility

Proposed Point of Interconnection

Circuit 5L7 out of Bonanza substation

August 25, 2016

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1.0 Description of the Generating Facility

(“Interconnection Customer”) proposed interconnecting 2 MW of new generation to PacifiCorp’s (“Public Utility”) circuit 5L7 out of Bonanza substation at approximately 42°13'18.14"N, 121°27'27.91"W located in Klamath County, Oregon. The project (“Project”) will consist of two (2) 1 MW Power Electronics HEC-USPlus FS1001CU inverters for a total output of 2 MW. The requested commercial operation date is June 30, 2018.

Interconnection Customer will operate this generator as a Qualifying Facility as defined by the Public Utility Regulatory Policies Act of 1978 (PURPA).

The Public Utility has assigned the Project “Q0758.”

2.0 Approval Criteria for Tier 4 Interconnection Review

Pursuant to 860-082-0060(1), a public utility must use the Tier 4 interconnection review procedures for an application to interconnect a small generator facility that meets the following requirements:

(a) The small generator facility does not qualify for or failed to meet Tier 1, Tier 2, or Tier 3 interconnection review requirements; and
(b) The small generator facility must have a nameplate capacity of ten (10) megawatts or less.

3.0 Scope of the Study

Pursuant to 860-082-0060(7)(g) the System Impact Study Report shall consist of a short circuit analysis, a stability analysis, a power flow analysis, voltage drop and flicker studies, protection and set point coordination studies, and grounding reviews, as necessary. The System Impact Study shall state the assumptions upon which it is based, state the results of the analyses, and provide the requirement or potential impediments to providing the requested interconnection service, including a preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the interconnection. The System Impact Study shall provide a list of facilities that are required as a result of the Interconnection Request and non-binding good faith estimates of cost responsibility and time to construct.

A stability study is not required due to the relatively small size of the generation facility.

4.0 Independent Study Evaluation

Pursuant to 860-082-0060(7)(h), the application has not provided an independent system impact study that is to be addressed and evaluated along with the results from the Public Utility’s own evaluation of the interconnection of the proposed Small Generator Facility.

5.0 Proposed Point of Interconnection

The Interconnection Customer’s proposed Small Generator Facility is to be interconnected to 12.0 kV circuit 5L7 out of Bonanza substation at approximately 42°13'18.14"N, 121°27'27.91"W located in Klamath County, Oregon.

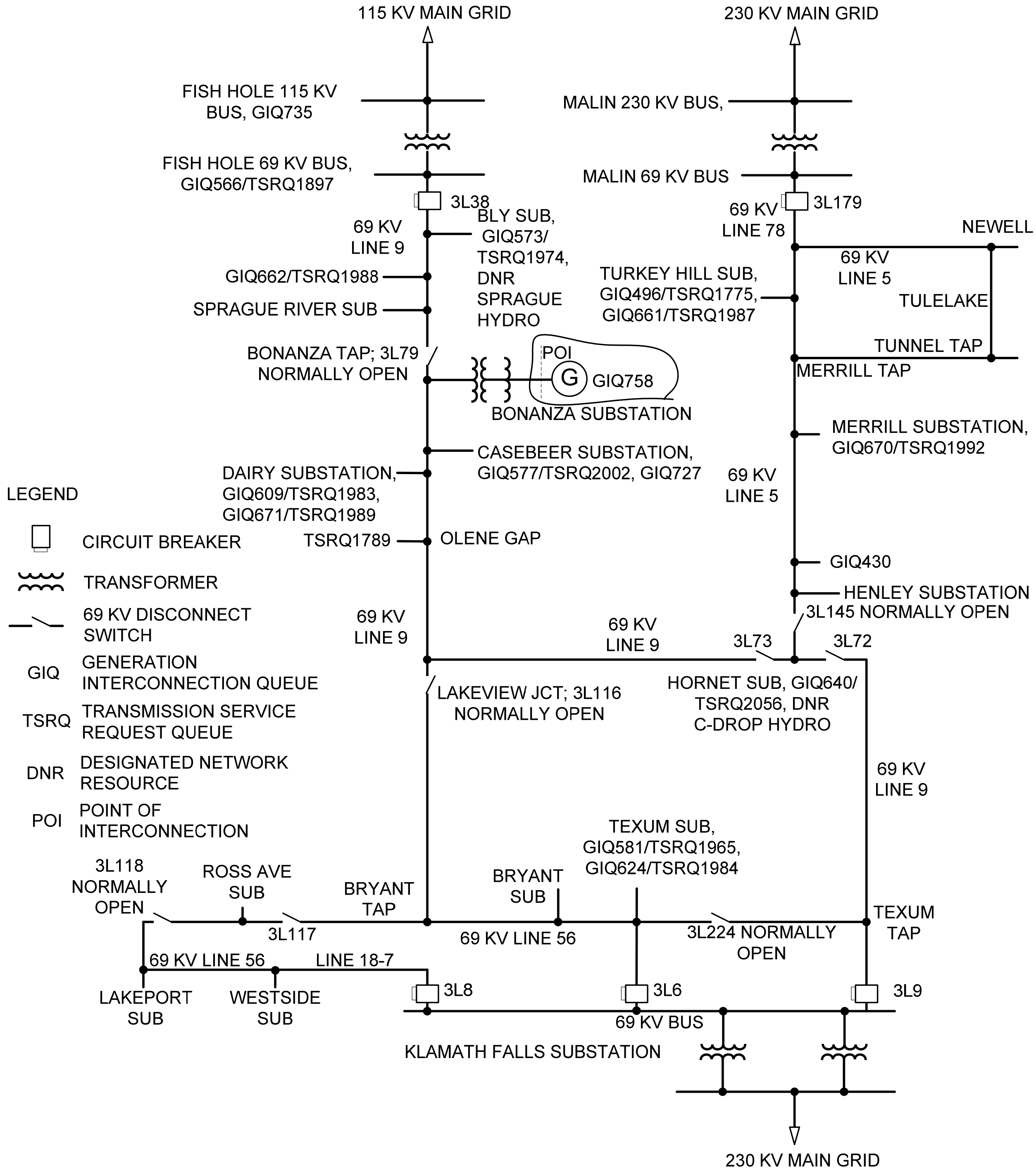

Figure 1: Transmission System One Line Diagram

5.1 STUDY ASSUMPTIONS

- All active higher priority transmission service and/or generator interconnection requests will be considered in this study and are listed in Appendix 1. If any of these requests are withdrawn, the Public Utility reserves the right to restudy this request, as the results and conclusions contained within this study could significantly change.
- For study purposes there are two separate queues:
  - Transmission Service Queue: to the extent practical, all System Upgrades that are required to accommodate active transmission service requests will be modeled in this study.
  - Generation Interconnection Queue: All relevant higher queue interconnection requests will be modeled in this study.
- The Interconnection Customer's request for interconnection service in and of itself does not convey transmission service.
- This study assumes the Project will be integrated into Public Utility's system at the agreed upon and/or proposed Point of Interconnection ("POI").
- The Interconnection Customer will construct and own any facilities required between the POI and the Project unless specifically identified by the Public Utility.
- Generator tripping may be required for certain outages.
- All facilities will meet or exceed the minimum Western Electricity Coordinating Council ("WECC"), North American Electric Reliability Corporation ("NERC"), and Public Utility performance and design standards.
- The POI used for this study is PacifiCorp's facility point 01439011.0-064802 on the 12.0 kV feeder 5L7 out of Bonanza substation.
- Distribution load flows were performed at peak and light load and full and no generation with summer and winter loading conditions. Voltage regulation at the Bonanza substation regulator was modeled at Base Voltage = 121.5 v, R = 7 v and X = 3 v based on a VT ratio of 100:1 and a CT ratio of 400:0.2. The load flows with generation include existing net metering projects and 400 kW of queued net metering projects.
- Four case studies were assembled and studied in power flow simulation at the transmission level:
  1. Normal transmission system configuration no. 1 for the Public Utility's Bonanza substation is defined as receiving supply via radial 69 kV Line 9 (K5) from the energized 69 kV and 230 kV system at Klamath Falls substation; Line 9 (K5) open from Bonanza Tap to Sprague River substation; Line 56-2 (K7B) open from Lakeview Junction to Bryant Tap; Line 5 (K4) open from Hornet substation to Henley Tap; Line K5A open between Texum substation and Texum Tap.
  2. Contingency transmission configuration for the Public Utility's system is defined as any configuration other than normal transmission configuration.
  3. Contingency transmission configuration no. 2 is defined as the same as the normal transmission system configuration except that 69 kV Line 9 (K5) between Bonanza Tap and Dairy substation is out of service; Fishhole substation supplies Casebeer, Bonanza, Sprague River, Beatty and Bly substations via radial 69 kV Line 9 (K5); Fishhole substation is supplied from energized 115 kV Line 61 (K2)

which is supplied at Chiloquin substation and Alturas substation from the energized 230 kV transmission system.

4. Contingency transmission configuration no. 3 is defined as the same as the normal transmission system configuration except that 69 kV Line 9 (K5) between Klamath Falls and Hornet substation is out of service; Malin substation supplies Bonanza substation via 69 kV Line 78 (K9), Line 5 (K4) and Line 9 (K5), also supplying Casebeer, Dairy, Hornet, Henley, Merrill, Turkey Hill, Tulelake and Newell substations; Line 5 (K4) is open between Newell and Clear Lake substations; Line 40 (K10) is open between Tunnel substation and Tunnel Tap.
5. Contingency transmission configuration no. 4 is defined as the same as the normal transmission system configuration except that 69 kV Line 9 (K5) between Lakeview Junction and Hornet substation is out of service; Klamath Falls substation circuit breaker 3L6 supplies Bonanza substation via 69 kV Line 56 (K7), Line 56-2 (K7B) and Line 9 (K5), also supplying Casebeer, Dairy, Ross Avenue, Bryant and Texum substations; Line 56 (K7) is open between Lakeport and Ross Avenue substations; Line K5A is open between Texum and Texum Tap.

- Summer peak load is defined as the highest load demand that occurs on the Public Utility's power system during the summer season.
- Winter peak load is defined as the highest load demand that occurs on the Public Utility's power system during the winter season.
- Light load is defined as the minimum load demand that occurs on the Public Utility's power system at any time during the year.
- Steady state voltage is defined as the voltage after all voltage regulating devices, both electronic and mechanical, have reached a quiescent state for the power flow and voltage conditions at a specific time.
- Post transient voltage is defined as the voltage measured after high speed switching transients and the effects of generator exciter controls have settled out and before any mechanically operated load tap changing and voltage regulating devices have started to adjust to new system conditions.
- Post transient voltage step is defined as the difference between the voltage before an event and the post transient voltage after the event. PacifiCorp policy limits the post transient voltage step to a maximum of 6.0 percent for infrequent switching events single such as the separation of a generation facility from the transmission system. Any post transient voltage step occurring on the transmission system is imposed directly on customers in the region.
- Reactive margin is a volt-ampere measure of power system voltage stability that may be reduced in magnitude by the connection of load or generation operating at constant power factor. Greater magnitude negative reactive margin indicates greater voltage stability. Zero and positive magnitude reactive margin indicate impending voltage collapse. The measurement of reactive margin is made in a power flow simulation model.
- Daylight minimum load measured in the Public Utility's southern Oregon region in 2015 was approximately 450 MW.
- Designated Network Resource generation within the southern Oregon region at the time of this study was approximately 542 MW.

- Active higher priority generation interconnection applicants requesting Network Resource status within the southern Oregon region at the time of this study totaled 1198 MW.
- This report is based on information available at the time of the study. It is the Interconnection Customer's responsibility to check the Public Utility's web site regularly for transmission system updates (http://www.pacificorp.com/tran.html)

6.0 REQUIREMENTS

6.1 DISTRIBUTION STUDY RESULTS

- The calculated load flow on Bonanza breaker 5L7, regulator R-1129 and transformer bank T-3123,4,5 during light load conditions and full generation is 2.1 MW reverse power flow.
- The calculated load flow on the distribution line recloser at FP 01439011.0-096400 during light load conditions and full generation is 2.2 MW reverse power flow.
- Distribution primary voltage spread between light load with full generation and peak load with no generation is 4.3% at the Q0758 point of interconnection. The voltage spread is within the 5.0% limit.
- The non-steady state voltage change from full generation to no generation at the POIis 5.01% and is within the 6.0% limit.

6.2 SMALL GENERATOR FACILITY MODIFICATIONS

The Small Generator Facility and Interconnection Equipment owned by the Interconnection Customer are required to operate under automatic power factor control with the power factor sensed electrically at the Point of Interconnection. The required power factor is 1.0 per unit at the Point of Interconnection.

In general, the Small Generating Facility and Interconnection Equipment should be operated so as to maintain the voltage at the POI between 1.01 pu to 1.04 pu. At the Public Utility's discretion, these values might be adjusted depending on the operating conditions.

As per NERC standard VAR-001-1, the Public Utility is required to specify voltage or reactive power schedule at the Point of interconnection. Under normal conditions, the Public Utility's system should not supply reactive power to the Small Generating Facility.

The minimum power quality requirements are in PacifiCorp's Engineering Handbook section 1C and are available at http://www.pacificpower.net/con/pqs.html. Requirements in the System Impact Study that exceed requirements in the Engineering Handbook section 1C power quality standards shall apply.

6.3 DISTRIBUTION/TRANSMISSION SYSTEM MODIFICATIONS

- Extend #2 AAAC phase and neutral conductors from facility point 01439011.0-064802 to the change of ownership. Include a pole with a group operated switch and a pole with primary metering.
- Change the regulator control settings for regulator R-1192 at Bonanza substation to base voltage = 121.5 volts, R = 7 volts and X = 3 volts based on a VT ratio of 100:1 and a CT ratio of 400:0.2. Modify regulator controller R-1192 if necessary to accommodate reverse power flow.
- Addition of dead-line check at Bonanza substation breaker 5L7 and at line recloser 01439011.0-096400 is included with the 400 kW queued net metering generation projects.
- Increase the thermal rating of approximately 11.4 miles of 69 kV Line 9 (K5) between Klamath Falls substation and the Q1789 point of receipt near Olene Gap, Oregon, to a summer rating of 80 MVA or greater to permit flow from Q0758 and higher priority queue applicants. To provide this rating increase the line will be reconductored from the existing 397.5 ACSR conductor to 795 ACSR. Preliminarily, six structures will have to be replaced with new tangent structures out of the approximate 100 existing structures on this line.
- Assuming that the transmission upgrades identified for the higher queued projects are complete, required transmission modifications are limited to those listed above. The current requirements for the higher queued projects include the construction of new transmission from the Public Utility's southern Oregon load area to the Willamette and Portland load areas. The estimate for the transmission construction is approximately $230,000,000 and is anticipated to take a minimum of 6 years to construct.
- If the designation of the higher priority projects are changed to Energy Resource or are removed, the Q0729 Project will need to be restudied to determine the reliability impacts that would result from the requirement that 100% of the Project output be delivered to network load. If the Q0729 Interconnection Customer desires an in-service date prior to the higher queue priority projects then the transmission modifications required for those projects will be assigned to this Project.
- A possible alternative to modifications of the Public Utility's transmission system would be procurement by the Interconnection Customer of third party transmission service to export the Project output. This option must be agreed upon by the Interconnection Customer and its power purchaser as the Public Utility has no authority to require this arrangement. If the Interconnection Customer and power purchaser do not agree on this option or fail to notify the Public Utility that they've agreed to this option any transmission modifications identified as necessary to deliver the generation to available network load will be required.

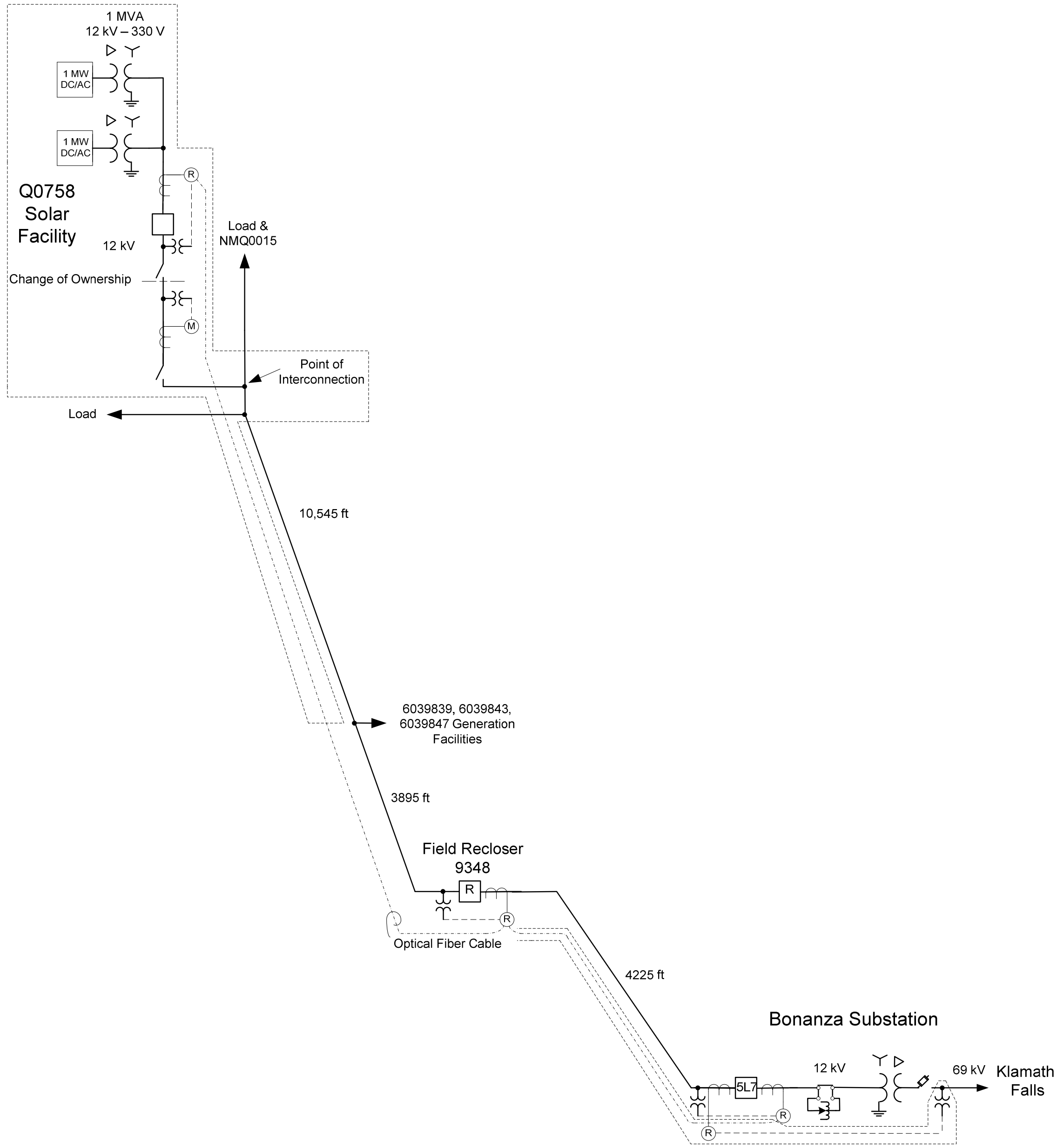

Figure 2: System One Line Diagram

6.4 EXISTING BREAKER MODIFICATIONS – SHORT-CIRCUIT

The increase in the fault duty on the system as the result of the addition of the Generating Facility with photovoltaic arrays fed through 2 – 1 MW inverters connected to 2 – 1 MVA 12 kV – 330 V transformers with 5% impedance along with the earlier solar electric generation projects on this 12 kV circuit will not push the fault duty above the interrupting rating of any of the existing fault interrupting equipment.

6.5 PROTECTION REQUIREMENTS

Protective relaying systems will need to be installed that will detect faults and cause the disconnection of the generation facility for 12 kV line faults on circuit 5L7 out of Bonanza substation, faults in the 69 – 12 kV transformer in Bonanza substation, faults on the 69 kV line from Bonanza substation to Klamath Falls substation and faults on the 12 kV circuit beyond field recloser 9348. The minimum day time load on Bonanza substation is less than the maximum potential power output of the proposed Small Generating Facility in addition to the other solar electric generation facilities that are in-service or are in the process to be connected to the 12 kV circuit out of Bonanza substation. For this reason the unbalance condition of the load and generation cannot be relied upon to cause the high speed disconnection of the generation facility for faults on the distribution and transmission system. The relay on field recloser 9348 will be modified and a transfer trip circuit installed between the recloser and a group of solar electric generation projects 3895 feet north of the field recloser 9348 in conjunction with an earlier project.

An optical fiber to carry a transfer trip signal will need to be installed from the end of that earlier fiber to the Q0758 project recloser. With this optical fiber a transfer trip signal will be sent to trip the Project recloser for the opening of the field recloser 9348. This will permit the continued use of a high speed automatic recloser following the tripping of field recloser 9348. This field recloser will be equipped with voltage instrument transformers (VTs) on the line side of the recloser to delay the reclosing operation if for some reason the solar facility is not disconnected in a timely manner. The addition of the VTs and the modification of the recloser's controls is part of the earlier project.

The relay on 5L7 is equipped to communicate over an optical fiber cable. An optical fiber cable will be installed between Bonanza substation and field recloser 9348. With this cable and the cable from the recloser to the Q0758 Project recloser a transfer trip signal will be sent from Bonanza substation to the Project for the opening of 5L7. The relaying for 5L7 has been modified for one of the earlier solar electric generation projects to delay the automatic reclosing if the solar projects do not disconnect after the opening 5L7 in a timely manner.

Line relays will be installed at Bonanza substation that will monitor the 69 kV bus voltage and the 12 kV current through the transformer. With these relays the 69 kV line faults will be detected and the transfer trip will be keyed. These relays will need to operate high speed to disconnect the generation before the automatic reclosing that will be taking place at Klamath Falls substation to restore the circuit. It will not be possible to set the line relays to be selective as to limiting the operation for faults only on the line that Bonanza substation is connected to and still clear the faults high speed. The relays will occasionally operate for faults on other 69 kV lines out of Klamath Falls substation. This will cause the Small Generating Facility to be disconnected on occasions when the line to the Small Generating Facility does not go dead. The only way to maximize the energy production of the Interconnection Customer's Small Generating Facility would be to install communication facilities to receive transfer trip from Klamath Falls substation to Bonanza substation. This option would increase the cost of this Project. It is assumed that the Interconnection Customer would prefer the less costly option and will tolerate the occasional unnecessary interruptions. For 69 – 12 kV transformer faults are presently detected and cleared with 69 kV fuses. The fuses are adequate since there were minimal sources on the 12 kV side. With the addition of this generation facility the relays that are planned for detecting 69 kV faults will also detect transformer faults and send transfer trip to the generation project.

The voltage regulator R-1129's controller in Bonanza substation will need to be replaced with a unit that can sense reverse power flow and modify the controller's operating mode.

At the POI a protective relay will need to be installed. A SEL 351R protective relay will perform the following functions:

1. Detect faults on the 12 kV at the generation facility
2. Monitor the voltage and react to under or over frequency, and / or magnitude of the voltage
3. Receive transfer trip from Bonanza substation.
4. Receive transfer trip from field recloser 9348
5. Detect faults on the 12 kV line to Bonanza substation

All of these relaying functions will be performed by a single SEL 351R relay.

All of the protective relaying that has been noted in this report is for the protection and safe, reliable operation of the distribution and transmission facilities. Additional relaying is needed for detecting problems in the Small Generating Facility. The relaying for the Small Generating Facility is the responsibility of the Interconnection Customer.

6.6 Data Requirements (RTU)

Due to the small power size of the Small Generating Facility no real time data from the plant will be needed by the Public Utility so no RTU will be required.

6.7 Communication Requirements

6.7.1 *Line Protection*

The Public Utility will install a 48-fiber, single-mode, ADSS fiber optic cable between the Q0758 project recloser and the cable at the tap for the 6039839, 6039843, and 6039847 generation facilities. The cable will terminate in patch panels that will be mounted in NEMA cabinets. The same type of cable will have been installed between the tap to the generation facilities and field recloser 9348 in conjunction with an earlier project. The Public Utility will also install this cable from the field recloser to Bonanza substation, where it will be terminated in a patch panel. Jumpers will be installed between the patch panels and the relays at the end points, and to the other patch panels at the tap point.

6.7.2 *Data Delivery to the Control Centers*

The Interconnect Customer will order a T1 lease from Bonanza substation to Klamath substation. The Public Utility will provide a Ground Potential Rise report to the Interconnect Customer for the Klamath substation termination. The Public Utility will install a channel bank, DSX panel, DC-DC converters, router, and a fuse panel in Bonanza substation to carry SCADA, voice, and data circuits back to control centers via Klamath substation. At Klamath substation, these circuits will be cross-connected to channels to control centers over existing communication systems.

6.8 Substation Requirements

Bonanza substation – Install 69kV VT's between power fuses and transformers. Install new control house to support line panel, annunciator, and SCADA/communications panel.

6.9 Metering Requirements

Interchange Metering

The Public Utility will procure, install, test, and own all revenue metering equipment. Standalone revenue metering will be located on the high side of generator step up transformer. The revenue metering instrument transformers will be installed overhead on a pole. The meter instrument transformer mounting shall conform to the Public Utility's DM construction standards.

The metering will be bi-directional to measure KWH and KVARH quantities. The metering programming is for both generation received to the Public Utility and delivered retail load to the Interconnection Customer per tariff when not generating. The metering generation and billing data will be remotely interrogated via the Public Utility's MV90 data acquisition system.

The meter shall be mounted on the pole below the instrument transformers within a meter socket enclosure. Metering mounting will conform to the Public Utilities Standards including, the Six State Electric Service Requirements. Generation Meter requirements and instrument-rated metering are the same as commercial installations.

Station Service/Construction Power

The Project is within the Public Utility's service territory. Prior to back feed Interconnection Customer must arrange distribution voltage retail meter service for electricity consumed by the Project including temporary construction power. The Interconnection Customer must call the PCCC Solution Center 1-800-640-2212 to arrange this service. Approval for back feed is contingent upon obtaining station service.

7.0 COST ESTIMATE

The following estimate represents only scopes of work that will be performed by the Public Utility. Costs for any work being performed by the Interconnection Customer are not included.

Q0758 Collector substation *Add metering, communications, protection & control*	$ 497,000
***Distribution line work** *Line extension to Q0758 site and relocate underbuild onto new structures*	$ 106,000
Field recloser 9348 *Modify transfer trip controls*	$ 171,000
Bonanza substation *Add VTs and control house*	$1,365,000
Line 9 *Pole replacement and line reconductor*	$2,312,000
Control Centers *Modify communications*	$ 29,000
Total	**$4,480,000**

*Any distribution line modifications identified in this report will require a field visit analysis in order to obtain a more thorough understanding of the specific requirements. The estimate provided above for this work could change substantially based on the results of this analysis. Until this field analysis is performed the Public Utility must develop the Project schedule using conservative assumptions. The Interconnection Customer may request that the Public Utility perform this field analysis, at the Interconnection Customer's expense, prior to the execution of an Interconnection Agreement in order to obtain more cost and schedule certainty.

Note: Costs for any excavation, duct installation and easements shall be borne by the Interconnection Customer and are not included in this estimate. This estimate is as accurate as possibly given the level of detailed study that has been completed to date and approximates the costs incurred by Public Utility to interconnect this Small Generator Facility to Public Utility's electrical distribution or transmission system. A more detailed estimate will be calculated during the Facilities Study. The Interconnection Customer will be responsible for all actual costs, regardless of the estimated costs communicated to or approved by the Interconnection Customer.

8.0 SCHEDULE

The Public Utility estimates it will require approximately 18-24 months to design, procure and construct the facilities described in this report following the execution of an Interconnection Agreement. The schedule will be further developed and optimized during the Facilities Study.

Please note, due to the transmission modifications assigned to previously queued projects which is required to ensure 100% delivery of the Interconnection Customer's Project output to network load results in a timeframe that does not support the Interconnection Customer's requested commercial operation date of June 30, 2018.

9.0 PARTICIPATION BY AFFECTED SYSTEMS

No Affected Systems were identified in relation to this Interconnection Request.

10.0 APPENDICES

Appendix 1: Higher Priority Requests
Appendix 2: Property Requirements
Appendix 3: Study Results

10.1 APPENDIX 1: HIGHER PRIORITY REQUESTS

All active higher priority transmission service and/or generator interconnection requests will be considered in this study and are identified below. If any of these requests are withdrawn, the Public Utility reserves the right to restudy this request, as the results and conclusions contained within this study could significantly change.

GIQ: Generation Interconnection Queue.
TSRQ: Transmission Service Request Queue.

Transmission/Generation Interconnection Queue Requests considered:

Designated Network Resource North Fork Sprague, 1.18 MW, Bly substation

Designated Network Resource C Drop Hydro, 1.1 MW, Hornet substation

TSRQ1789 (AREF 79058467), 50 MW, POR 69 kV Line 9(K5) near Olene Gap, Oregon

GIQ0430, 12 MW, 69 kV Line 5 near Merrill, Oregon

GIQ0496, 2 MW, Turkey Hill substation
TSRQ1775 (AREF 78784599), 2 MW, POR Turkey Hill substation

GIQ0573, 5 MW, Bly substation
TSRQ1974 (AREF 81074553), 5 MW, POR Bly substation

GIQ0566, 8.5 MW, Fishhole substation
TSRQ1897 (AREF 80103182), 8.5 MW, POR Fishhole substation

GIQ0577, 4.8MW, Bonanza substation
TSRQ2002 (AREF 81460501), 4.8 MW, POR Bonanza substation

GIQ0581, 0.83 MW, Texum substation
TSRQ1965 (AREF 80959436), 0.83 MW, POR Texum substation

GIQ0609, 8 MW, Dairy substation
TSRQ1983 (AREF 81235956), 8 MW, POR Dairy substation

GIQ0624, 2.9 MW, Texum substation
TSRQ1984 (AREF 81235960), 2.9 MW, POR Texum substation

GIQ0640, 10 MW, Hornet substation
TSRQ2056 (AREF 82206368), 10 MW, POR Hornet substation

GIQ0661, 10 MW, Turkey Hill substation
TSRQ1987 (AREF 81288790), 10 MW, POR Turkey Hill substation

GIQ0662, 10 MW, 69 kV Line 9 (K5) near Bly, Oregon
TSRQ1988 (AREF 81288866), 10 MW, POR 69 kV Line 9 (K5) near Bly, Oregon

GIQ0670, 8 MW, Merrill substation
TSRQ1992 (AREF 81316143), 8 MW, POR Merrill substation

GIQ0671, 10 MW, Dairy substation
TSRQ1989 (AREF 81315991), 10 MW, POR Dairy substation

GIQ0727, 2 MW, Casebeer substation

GIQ0735, 53.4 MW, Fishhole substation 115 kV bus

10.2 APPENDIX 2: PROPERTY REQUIREMENTS

Requirements for rights of way easements

Rights of way easements will be acquired by the Interconnection Customer in the Public Utility's name for the construction, reconstruction, operation, maintenance, repair, replacement and removal of Public Utility's Interconnection Facilities that will be owned and operated by PacifiCorp. Interconnection Customer will acquire all necessary permits for the project and will obtain rights of way easements for the project on Public Utility's easement form.

Real Property Requirements for Point of Interconnection Substation

Real property for a point of interconnection substation will be acquired by an Interconnection Customer to accommodate the Interconnection Customer's project. The real property must be acceptable to Public Utility. Interconnection Customer will acquire fee ownership for interconnection substation unless Public Utility determines that other than fee ownership is acceptable; however, the form and instrument of such rights will be at Public Utility's sole discretion. Any land rights that Interconnection Customer is planning to retain as part of a fee property conveyance will be identified in advance to Public Utility and are subject to the Public Utility's approval.

The Interconnection Customer must obtain all permits required by all relevant jurisdictions for the planned use including but not limited to conditional use permits, Certificates of Public Convenience and Necessity, California Environmental Quality Act, as well as all construction permits for the project.

Interconnection Customer will not be reimbursed through network upgrades for more than the market value of the property.

As a minimum, real property must be environmentally, physically, and operationally acceptable to Public Utility. The real property shall be a permitted or permittable use in all zoning districts. The Interconnection Customer shall provide Public Utility with a title report and shall transfer property without any material defects of title or other encumbrances that are not acceptable to Public Utility. Property lines shall be surveyed and show all encumbrances, encroachments, and roads.

Examples of potentially unacceptable environmental, physical, or operational conditions could include but are not limited to:

- Environmental: known contamination of site; evidence of environmental contamination by any dangerous, hazardous or toxic materials as defined by any governmental agency; violation of building, health, safety, environmental, fire, land use, zoning or other such regulation; violation of ordinances or statutes of any governmental entities having jurisdiction over the property; underground or above ground storage tanks in area; known remediation sites on property; ongoing mitigation activities or monitoring activities; asbestos; lead-based paint, etc. A phase I environmental study is required for land being acquired in fee by the Public Utility unless waived by Public Utility.

- Physical: inadequate site drainage; proximity to flood zone; erosion issues; wetland overlays; threatened and endangered species; archeological or culturally sensitive areas; inadequate sub-surface elements, etc. Public Utility may require Interconnection Customer to procure various studies and surveys as determined necessary by Public Utility.

- Operational: inadequate access for Public Utility's equipment and vehicles; existing structures on land that require removal prior to building of substation; ongoing maintenance for landscaping or extensive landscape requirements; ongoing homeowner's or other requirements or restrictions (e.g., Covenants, Codes and Restrictions, deed restrictions, etc.) on property which are not acceptable to the Public Utility.

10.3 APPENDIX 3: STUDY RESULTS

10.3.1 SUMMARY

An evaluation of the impact of adding the Q0758 generation facility to the Public Utility's substation and transmission system using power flow simulation suggested the following:

- When operating in normal transmission configuration no. 1 at light load, the Public Utility's 69 kV Line 9 (K5) existing conductor between Klamath Falls substation and the TSRQ1789 POR at Olene Gap would be overloaded by higher priority generation and transmission requests, and would be further overloaded by the addition of Q0758. Increasing approximately 11.4 miles of Line 9 (K5) conductor rating to 80 MVA or greater would resolve the overloading issue.
- When operating in contingency transmission configuration no. 3 at light load, the transmission line conductors would be overloaded between Malin substation and the TSRQ1789 POR at Olene Gap by higher priority generation and transmission requests, and would be further overloaded by the addition of Q0758.
- When operating in contingency transmission configuration no. 4 at summer peak load, the transmission line conductors would be overloaded between Bryant Tap and Lakeview Junction by higher priority generation and transmission requests, and would be further overloaded by the addition of Q0758.
- When operating in contingency transmission configuration no. 4 at light load, the transmission line conductors would be overloaded between Klamath Falls substation and the TSRQ1789 POR at Olene Gap by higher priority generation and transmission requests, and would be further overloaded by the addition of Q0758.
- When operating in normal transmission configuration no. 1, the voltages and post transient voltage steps at Public Utility's Bonanza substation and the transmission system after the addition of Q0758 are predicted to be acceptable.
- When operating in contingency transmission configuration no. 2 at summer peak load, the voltage stability is excessively low.
- When operating in contingency transmission configuration no. 3 at summer peak load, the voltage stability is excessively low.
- When operating in contingency transmission configuration no. 4 at summer peak load, the voltage stability is low and minimum transmission voltage cannot be maintained.
- Generation may not be accepted from Q0758 when the Public Utility's system is operating in contingency transmission configuration no. 2 due to severe low voltage conditions that may occur under certain seasonal loading conditions each year.
- Generation may not be accepted from Q0758 when the Public Utility's system is operating in contingency transmission configuration no. 3 and 4 due to transmission line overloading due to heavy seasonal loading and generation by prior queue applicants.

10.3.2 NORMAL TRANSMISSION CONFIGURATION NO. 1

In normal transmission configuration no. 1, fully defined in Study Assumptions, Klamath Falls substation supplies 69 kV to the radial transmission system serving Bonanza, Casebeer, Dairy and Hornet substations as well as the proposed Q0758 point of interconnection on the distribution system supplied from Bonanza substation. In power flow simulation, Q0758 was then separated from the transmission system.

Transmission Line Loading

Transmission flows in normal transmission configuration no. 1 are predicted in power flow simulation to be overloaded by higher priority generation and transmission requests and further overloaded after the addition of Q0758. The conductor thermal capacity of approximately 11.4 miles of 69 kV Line 9 (K5) must be increased to 80 MVA to be capable of carrying power from Q0758 and the higher priority generation and transmission service requests.

Table 10.3.2.a. Transmission line flows during normal transmission configuration no. 1 (Klamath Falls supply; Bonanza Tap-Sprague River open; Hornet-Henley Tap open; Texum-Texum Tap open).

Season	**Location**	**Q0758 Generation, MW**	**Line Flow, MVA**	**Line Rating, MVA**
Summer Peak Load	Line 9 Klamath Falls-Hornet	0	44.8	60
Summer Peak Load	Line 9 Klamath Falls-Hornet	2.0	46.2	60
Winter Peak Load	Line 9 Klamath Falls-Hornet	0	54.6	90
Winter Peak Load	Line 9 Klamath Falls-Hornet	2.0	56.5	90
Light Load	Line 9 Klamath Falls-Hornet	0	**77.0**	60
Light Load	Line 9 Klamath Falls-Hornet	2.0	**78.8**	60

Table 10.3.2.b. Transmission line flows during normal transmission configuration no. 1 (Klamath Falls supply; Bonanza Tap-Sprague River open; Hornet-Henley Tap open; Texum-Texum Tap open).

Season	**Location**	**Q0758 Generation, MW**	**Line Flow, MVA**	**Line Rating, MVA**
Summer Peak Load	Line 9 Hornet-Olene Gap	0	50.4	60
Summer Peak Load	Line 9 Hornet-Olene Gap	2.0	52.0	60
Winter Peak Load	Line 9 Hornet-Olene Gap	0	67.0	90
Winter Peak Load	Line 9 Hornet-Olene Gap	2.0	68.9	90
Light Load	Line 9 Hornet-Olene Gap	0	**69.9**	60
Light Load	Line 9 Hornet-Olene Gap	2.0	**71.7**	60

Transmission System Voltages

An evaluation of the effects of generation on 12 kV distribution feeder 5L7 indicated that the voltage effects of Q0758 separation from the power system could be minimized by operation of the Q0758 inverters at a constant power factor of 1.00.

When operating at a constant power factor of 1.00, the voltage and post transient voltage steps are projected in power flow simulation to remain within permissible limits at Bonanza substation and on the transmission system during separation of the Q0758 generation facility in the Public Utility's normal transmission configuration no. 1.

Table 10.3.2.c Power system voltages when Q0758 trips during normal transmission configuration no. 1 (Klamath Falls supply; Bonanza Tap-Sprague River open; Hornet-Henley Tap open; Texum-Texum Tap open).

Season	Location	Q0758, MW	Q0758, MVAr	Steady State Voltage, per unit	Post Transient Voltage After Q0758 Separation, per unit	Post Transient Voltage Step, percent
Summer Peak Load	Bonanza Sub 12 kV bus	2.0	0	1.048	1.040	0.8%
Winter Peak Load	Bonanza Sub 12 kV bus	2.0	0	1.016	1.011	0.5%
Light Load	Bonanza Sub 12 kV bus	2.0	0	1.015	1.015	0%

Table 10.3.2.d shows acceptable reactive margin.

Table 10.3.2.d. Power system voltage stability measured by reactive margin during normal transmission configuration no. 1 (Klamath Falls supply; Bonanza Tap-Sprague River open; Hornet-Henley Tap open; Texum-Texum Tap open).

Season	Location	Q0758 Generation, MW	Q0758 Generation, MVAR	Voltage Stability; Magnitude of Reactive Margin, MVAR
Summer Peak Load	Bonanza Sub, 69 kV	0	0	-77.0
Summer Peak Load	Bonanza Sub, 69 kV	2.0	0	-78.4
Light Load	Bonanza Sub, 69 kV	0	0	-85.9
Light Load	Bonanza Sub, 69 kV	2.0	0	-86.3

10.3.3 CONTINGENCY TRANSMISSION CONFIGURATION NO. 2

In contingency transmission configuration no. 2, fully defined in Study Assumptions, the radial 69 kV transmission path is closed from Fishhole substation to Bonanza substation. The configuration represents one of the available alternative transmission supply paths to Bonanza substation but is only available during periods when loading is below the annual peak loading level. In power flow simulation, Q0758 was then separated from the transmission system.

Transmission Line Loading

Transmission flows in contingency transmission configuration no. 2 could not be evaluated because severe voltage conditions prevent the supply of Bonanza and Bonanza substations from Fishhole substation under peak loading conditions.

Transmission System Voltages

Power flow simulation indicated that at summer peak load at Bonanza and Casebeer substations cannot be supplied with adequate transmission voltage by the line from Fishhole substation in contingency transmission configuration no. 2. The configuration can be used only during limited periods of lighter loading in order to maintain service to load during scheduled maintenance activity on the normal transmission supply path. Generation cannot be accepted from Q0758 when the system is in contingency transmission configuration no. 2.

Table 10.3.3.a Power system voltages when Q0758 trips during contingency transmission configuration no. 2 (Fishhole supply; Bonanza Tap-Dairy open).

Season	Location	Q0758, MW	Q0758, MVAr	Steady State Voltage, per unit
Summer Peak Load	Bonanza Sub 69 kV bus	0	0	**0.803**

Table 10.3.3.b shows reactive margin measure of voltage stability at the Bonanza substation 69 kV bus, more negative reactive margin magnitude indicating greater voltage stability. The reactive margin predicted at summer peak load when operating in contingency transmission configuration no. 2 indicates poor voltage stability compared with the reactive margin predicted in normal transmission configuration Table 10.3.2.d.

Table 10.3.3.b. Power system voltage stability measured by reactive margin during contingency transmission configuration no. 2 (Fishhole supply; Bonanza Tap-Dairy open).

Season	Location	Q0758 Generation, MW	Q0758 Generation, MVAR	Voltage Stability; Magnitude of Reactive Margin, MVAR
Summer Peak Load	Bonanza Sub, 69 kV	0	0	-4.5

10.3.4 CONTINGENCY TRANSMISSION CONFIGURATION NO. 3

In contingency transmission configuration no. 3, fully defined in Study Assumptions, the radial 69 kV transmission path is closed from 69 kV source bus at Malin substation to Bonanza substation. The configuration represents one of the available alternative transmission supply paths to Bonanza substation but is only available during periods when loading is below the annual peak loading level. In power flow simulation, Q0758 was then separated from the transmission system.

Transmission Line Loading

Transmission conductors in contingency transmission configuration no. 3 are predicted in power flow simulation to be overloaded by higher priority generation and transmission requests and further overloaded after the addition of Q0758. The conductor thermal capacity of approximately 35.8 miles of 69 kV line is too low to carry the predicted flow at light load, but increasing the conductor thermal rating is not the sole solution because voltage instability at summer peak load is also an issue.

Table 10.3.4.a. Transmission line flows during contingency transmission configuration no. 3 (Malin supply; Klamath Falls-Hornet open; Bryant Tap-Lakeview Jct open; Bonanza Tap-Sprague River open).

Season	Location	Q0758 Generation, MW	Line Flow, MVA	Line Rating, MVA
Light Load	Line 9 Olene Gap-Hornet	0	**67.3**	60
Light Load	Line 9 Olene Gap-Hornet	2.0	**69.1**	60
Light Load	Line 5 Hornet-Henley Tap	0	**74.2**	60
Light Load	Line 5 Hornet-Henley Tap	2.0	**76.0**	60
Light Load	Line 9 Henley Tap-Q0430 Tap	0	**72.8**	60
Light Load	Line 9 Henley Tap-Q0430 Tap	2.0	**74.6**	60
Light Load	Line 9 Q0430 Tap-Merrill	0	**80.6**	60
Light Load	Line 9 Q0430 Tap-Merrill	2.0	**82.3**	60
Light Load	Line 9 Merrill-Turkey Hill	0	**85.0**	60
Light Load	Line 9 Merrill-Turkey Hill	2.0	**86.7**	60
Light Load	Line 9 Turkey Hill-Malin Tap	0	**93.2**	60
Light Load	Line 9 Turkey Hill-Malin Tap	2.0	**94.8**	60
Light Load	Line 9 Malin Tap-Malin	0	**90.2**	73
Light Load	Line 9 Malin Tap-Malin	2.0	**92.3**	73

Transmission System Voltages

Power flow simulation indicates that summer peak load at Bonanza and Casebeer substations cannot be supplied adequate transmission voltage by the line from Malin substation in contingency transmission configuration no. 3. The configuration can be used during periods of lesser load. Generation cannot be accepted from Q0758 when the system is in contingency transmission configuration no. 3.

Table 10.3.4.b Power system voltages when Q0758 trips during contingency transmission configuration no. 3 (Malin supply; Klamath Falls-Hornet open; Bryant Tap-Lakeview Jct open; Bonanza Tap-Sprague River open).

Season	Location	Q0758, MW	Q0758, MVAr	Steady State Voltage, per unit
Summer Peak Load	Bonanza Sub 69 kV bus	0	0	**0.845***

* All higher priority generation interconnection applicants not in service in power flow simulation; existing loads remain connected.

Table 10.3.4.c shows reactive margin measures of voltage stability at the Bonanza substation 69 kV bus. The reactive margin predicted at summer peak load when operating in contingency transmission configuration no. 3 indicates poor voltage stability compared with the reactive margin predicted in normal transmission configuration Table 10.3.2.d.

Table 10.3.4.c. Power system voltage stability measured by reactive margin during contingency transmission configuration no. 3 (Malin supply; Klamath Falls-Hornet open; Bryant Tap-Lakeview Jct open; Bonanza Tap-Sprague River open).

Season	Location	Q0758 Generation, MW	Q0758 Generation, MVAR	Voltage Stability; Magnitude of Reactive Margin, MVAR
Summer Peak Load	Bonanza Sub, 69 kV	0	0	**-6.3***

* All higher priority generation interconnection applicants not in service in power flow simulation; existing loads remain connected.

10.3.5 Contingency Transmission Configuration No. 4

In contingency transmission configuration no. 4, fully defined in Study Assumptions, the radial 69 kV transmission path is closed from circuit breaker 3L6 at Klamath Falls substation to Bonanza substation via Texum, Bryant, and Dairy substations. The configuration represents one of the available alternative transmission supply paths to Bonanza substation. In power flow simulation, Q0758 was then separated from the transmission system.

Transmission Line Loading

Contingency transmission configuration no. 4 can be used only when loading is somewhat below summer peak load level in order to avoid overloading 69 kV Line 56 (K7) from Klamath Falls to Bryant substation.

Table 10.3.5.a. Transmission line flows during contingency transmission configuration no. 4 (Klamath Falls-Texum-Bryant-Dairy-Bonanza substation path closed).

Season	Location	Q0758 generation, MW	Line Flow, MVA	Line Rating, MVA
Summer Peak Load	Line 56 Bryant Tap-Lakeview Jct	0	**49.2**	37
Summer Peak Load	Line 56 Bryant Tap-Lakeview Jct	2.0	**51.4**	37
Summer Peak Load	Line 56 Klamath Falls-Texum	0	**86.0***	60
Summer Peak Load	Line 56 Texum-Bryant	0	**67.7***	40
Light Load	Line 56 Klamath Falls-Texum	0	**67.0**	60
Light Load	Line 56 Klamath Falls-Texum	2.0	**68.7**	60
Light Load	Line 56 Texum-Bryant	0	**65.8**	40
Light Load	Line 56 Texum-Bryant	2.0	**67.3**	40
Light Load	Line 56-2 Bryant Tap-Lakeview Jct	0	**71.6**	37
Light Load	Line 56-2 Bryant Tap-Lakeview Jct	2.0	**73.2**	37
Light Load	Line 9 Lakeview Jct-Olene Gap	0	**72.1**	60
Light Load	Line 9 Lakeview Jct-Olene Gap	2.0	**73.9**	60

* All higher priority generation interconnection applicants not in service in power flow simulation; existing loads remain connected.

Generation cannot be accepted from Q0758 when the Public Utility's system is operating in contingency transmission configuration no. 4. The configuration can be used only for supplying load when loading is below the summer peak load level.

Transmission System Voltages

It is not possible to maintain adequate voltage at Bonanza substation in contingency transmission configuration no. 4 during summer peak loading, as indicated in Table 10.3.5.b.

Table 10.3.5.b. Power system voltages when Q0758 trips during contingency transmission configuration no. 4 (Klamath Falls-Texum-Bryant-Dairy-Bonanza substation path closed).

Season	Location	Q0758, MW	Q0758, MVAr	Steady State Voltage, per unit
Summer Peak Load	Bonanza Sub 69 kV bus	0	0	**0.883***

* All higher priority generation and transmission service requests on Lines 9 and 56 not generating.

Attachment 3

From: **Apperson, Erin** Erin.Apperson@pacificorp.com
Subject: RE: UM 1610 PacifiCorp's Dismissal Proposal
Date: March 24, 2017 at 3:47 PM
To: Greg Adams Greg@richardsonadams.com, Kamman, Sarah Sarah.Kamman@pacificorp.com, Kruse, Karen karen.kruse@troutmansanders.com
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EA

Greg,

PacifiCorp appreciates REC and CREA's efforts to set forth a proposed stipulated dismissal for consideration. We cannot accept, however, because the terms of the proposed stipulation reach beyond the scope of the issues in this phase of UM 1610.

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From: Greg Adams [mailto:Greg@richardsonadams.com]
Sent: Tuesday, March 21, 2017 4:02 PM
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Cc: dockets@oregoncub.org; dockets@oseia.org; Oregon Dockets <OregonDockets@PacifiCorp.com>; dockets@renewablenw.org; Greg Adams <Greg@richardsonadams.com>; da@thenescogroup.com; brittany.andrus@state.or.us; stephanie.andrus@state.or.us; Apperson, Erin <Erin.Apperson@pacificorp.com>; james@utilityadvocates.org; diane.broad@state.or.us; dbrown@obsidianrenewables.com; Dalley, Bryce <Bryce.Dalley@pacificorp.com>; dina@renewablenw.org; bill@oneenergyrenewables.com; afoukal@coronalgroup.com; mike@oregoncub.org; tgregory@obsidianrenewables.com;

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Subject: [INTERNET] UM 1610 PacifiCorp's Dismissal Proposal

Sarah, Erin, and Karen,

After reviewing PacifiCorp's motion to close the docket, CREA and REC propose that to avoid future disputes the active parties memorialize the outcome of this long-running issue into a stipulated dismissal that could be approved by the OPUC on the following terms:

In OPUC Order No. 14-058 (at pp. 22-23), the OPUC directed the parties to address the question of "how third-party transmission costs to transport QF output from receipt in a load pocket to load should be accounted for in standard contracts; for example, by lowering avoided standard avoided cost rates, separately in interconnection cost assessments, through an addendum as suggested by Pacific Power, or by some other means."

The active parties stipulate to dismiss further investigation of the issue by resolving it as follows:

- PacifiCorp will prospectively discontinue allocating third-party transmission costs to QFs by any means, including but not limited to lowering avoided cost rates, separately in interconnection cost assessments, or through an addendum to a power purchase agreement as suggested in prior phases of this docket; and
- In cases where PacifiCorp Transmission finds in an interconnection study for a QF that PacifiCorp's system may be in a generation surplus in the area of the QF's point of interconnection and that third-party transmission may reduce the interconnection or third party transmission costs attributable to the QF, the QF shall not arrange or pay for any third party transmission, but PacifiCorp Energy Supply Management will utilize the lowest cost third-party transmission available, including network transmission, to integrate the QF's net output.

Please let us know if this agreeable this week as PacifiCorp's agreement to enter into a stipulated dismissal to memorialize the outcome of the remaining issues informs the position stipulated dismissal to memorialize the outcome of the remaining issues informs the position CREA and REC will take in response to PacifiCorp's motion to close the docket.

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