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July 31, 2020

VIA ELECTRONIC MAIL (Kristopher.Bremer@PacifiCorp.com)

Mr. Kristopher Bremer
Director, Generation Interconnection
PacifiCorp
825 NE Multnomah, Suite 1600
Portland OR 97232

Subject: **First Amended Notice of Intent to file Complaint of Enforcement**
Q0666--Sunthurst Energy, LLC--Pilot Rock Solar 1, LLC
Q1045--Sunthurst Energy, LLC--Pilot Rock Solar 2, LLC

Dear Mr. Bremer,

By this letter, Sunthurst Energy, LLC ("Sunthurst")[1] hereby gives notice of its intent to file a Complaint with the Public Utility Commission of Oregon ("Commission") pursuant to OAR 860-082-0085 ten days from the date above, arising from PacifiCorp Corporation's ("PacifiCorp") violation of its interconnection agreement for Pilot Rock Solar 1 (Q0666); violation of its Interconnection System Impact Study Form Agreement ("System Impact Study") with Pilot Rock Solar 2, LLC (Q1045) executed August 29, 2018, and violation of various regulations in OAR Chapter 860. This letter supplements Sunthurst's Notice of Intent to file Complaint of Enforcement dated and served on PacifiCorp March 20, 2020.

Additional Provisions of Interconnection Agreements and OARs being violated.

Project Metering. PacifiCorp is requiring Sunthurst to pay for meters at (1) the high side of Pilot Rock Solar 1 (PRS1) transformer; (2) the high side of Pilot Rock Solar 2 (PRS2) transformer; and (3) the change of ownership point (COP).

This requirement (PRS1 interconnection agreement, Section 1.6) violates OAR 860-082-0070(a) because it is unreasonable to require metering at all three points at high side voltages.

Unnecessary Upgrades. The OARs and the interconnection agreements only require the interconnection customer to pay for reasonable costs that are necessary to safely interconnect the small generator. On good faith belief, PacifiCorp is requiring equipment that is unnecessary to safely interconnect PRS1 and PRS2 or, alternatively, is necessary but can be accomplished by alternative means at a lower cost. Specific instances are set forth in Sunthurst's July 23, 2020 letter to PacifiCorp attached hereto and incorporated into this Notice.

Unlawful Conditioning. PacifiCorp told Sunthurst that it must sign a writing in which it "agree[s] to pay all actual construction costs associated with our Small Generating Facility" or else withdraw PRS2 from the queue. PacifiCorp to date has not provided requested data

[1] Sunthurst owns and controls the Pilot Rock Solar 1 project and Pilot Rock Solar 2 project f/k/a Pilot Rock Solar 1.

supporting its cost estimate, nor has it provided a draft interconnection agreement for Sunthurst to review.

This requirement unreasonably requires Sunthurst to agree to unverifiable costs and in effect requires Sunthurst to agree to sign an interconnection agreement which it has never seen. It also unduly discriminates against state jurisdictional small generators. (On good faith belief, federal jurisdictional small generators do not have to sign such a promise before reviewing a draft agreement and/or the basis for the costs of interconnection).

Assignment of Network Upgrade Costs to Sunthurst. On good faith belief, PacifiCorp is charging Sunthurst for any equipment it installs in the course of interconnecting PRS1 and PRS2, including additions, modifications, and upgrades to its Transmission System. Sunthurst will argue that direct assignment of transmission system upgrades to Sunthurst unduly discriminates against PRS1 and PRS2 compared to similar FERC-jurisdictional interconnections.

Overall cost of interconnection. PacifiCorp's design standards and policies result in interconnection costs that are so much higher than costs to interconnect similar facilities at other utilities in the Western United States as to be unreasonable. See July 23 letter, page 2.

Type of relief to be requested. In its Complaint to the Commission, Sunthurst anticipates requesting immediate injunctive relief to remedy the harm alleged above.

Good faith efforts to resolve this matter. Sunthurst has continually worked in good faith with PacifiCorp attempting to secure a completed System Impact Study in a reasonable time. Sunthurst is willing to continue working on resolution.

Sincerely,

Kenneth Kaufmann

Kenneth Kaufmann
Attorney for Sunthurst Energy, LLC

Enclosure: July 23, 2020 letter to PacifiCorp

Copy:

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July 23, 2020

VIA ELECTRONIC MAIL (Matthew.Loftus@PacifiCorp.com)

Mr. Matt Loftus
Senior Transmission Counsel, PacifiCorp
825 NE Multnomah, Suite 1600
Portland, OR 97232

Subject: **Pilot Rock Solar 1, LLC (Q0666) and Pilot Rock Solar 2, LLC (Q1045)**
Questions re cost and scope of Interconnection requirements

Dear Matt:

With the acquiescence of PacifiCorp, Sunthurst Energy, LLC (Sunthurst) provides the following comments on the interconnection design for Q0666 and Q1045, including requests for cost reductions, or for design changes and cost reductions. Additional information is requested where Sunthurst requires it to complete its review.

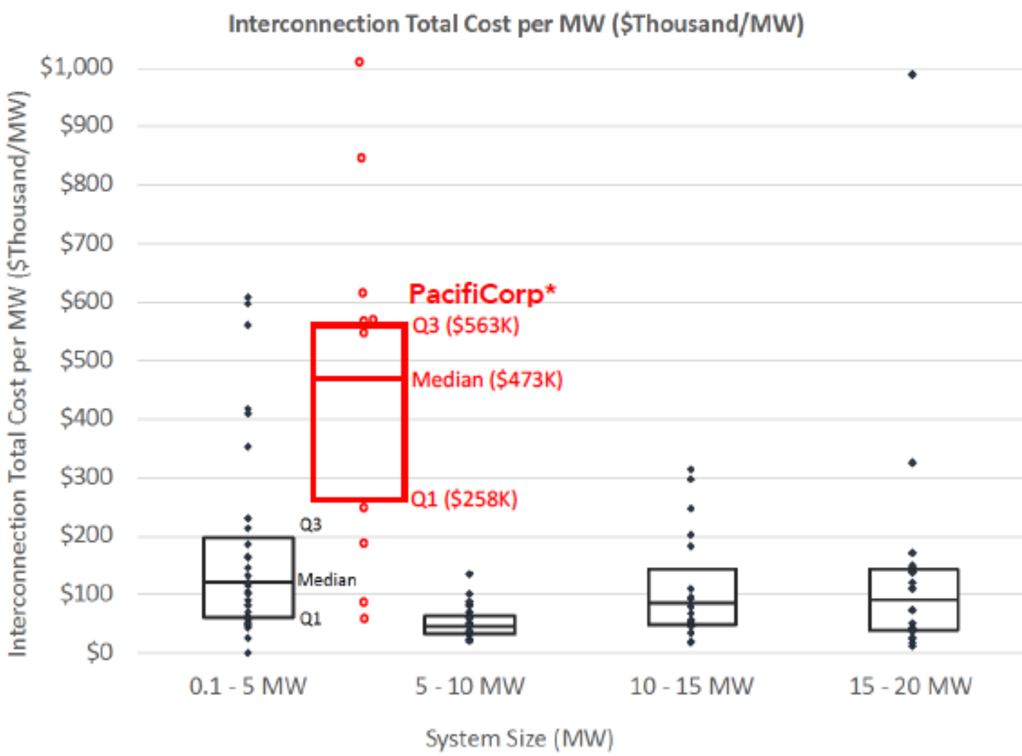
Sunthurst appreciates PacifiCorp's willingness to engage in discussions on these matters. However since PacifiCorp is obligated to impose only "reasonable" costs of equipment "necessary" to interconnect the customer, PacifiCorp has a duty to do more than just listen; it has the burden to justify the necessity of equipment and the reasonableness of its design, or else correct it. *See* OAR 860-029-0010 ("Costs of Interconnection"). The following list of opportunities to reduce the cost of Q0666 and Q1045 provides ample room for capturing savings that will facilitate a cooperative resolution. Sunthurst, in cooperation with PacifiCorp and the Commission, has invested a great deal of time and treasure to help Oregon implement its CSP program and looks forward to delivering PRS1 and PRS2 as economically and technically sound projects. Sunthurst welcomes PacifiCorp's willingness to consider reasonable cost-saving changes to facilitate success of the Oregon CSP.

Background

Sunthurst Energy, LLC (Sunthurst) is an Oregon solar PV project developer and installer. It is developing the 1.98 MW Pilot Rock Solar 1, LLC (PRS1) and the 2.99 MW Pilot Rock Solar 2, LLC (PRS2) projects located in PacifiCorp territory near Pendleton. Both projects received pre-certification under Oregon's Community Solar Program (CSP). ***PacifiCorp's estimated cost to interconnect PRS1 and PRS2 is $805,000 and $ 879,000, respectively, even though neither project requires network upgrades or transmission from a load pocket***. These costs make PRS1 and PRS2 un-financeable.

Published data suggest that PacifiCorp's small generator interconnection costs are exorbitant compared to such costs charged by other utilities in Oregon and the Western United States. A 2018 NREL study showed 25 interconnections throughout the Western United States between 100kW and 5MW had a median cost of about \$110k/MW.[1] **PacifiCorp's ten completed Oregon CSP facilities studies have a median cost of \$473k/MW, or more than 400% of the nation-wide average.**[2]

Figure 11 from 2018 NREL Study, Annotated with 2020 PacifiCorp CSP Data.



*PacifiCorp cost data are from 7/22/20 PacifiCorp OCSP Interconnection Queue
Figure 11. Total mitigation cost ranges in thousands of dollars, by system size (MW)

PacifiCorp's interconnection costs also are believed to be much higher than comparable interconnection costs assessed by Oregon's other IOUs, PGE and Idaho

[1] REVIEW OF INTERCONNECTION PRACTICES AND COSTS IN THE WESTERN STATES, Lori Bird, Francisco Flores, Christina Volpi, and Kristen Ardani of the National Renewable Energy Laboratory, and David Manning and Richard McAllister of the Western Interstate Energy Board (Technical Report NREL/TP-6A20-71232, April 2018) ("NREL Interconnection Cost report"), page 18. The report is available free at www.nrel.gov/publications.
[2] *See* PacifiCorp Oregon CSP interconnection queue, as of July 22, 2020, at http://www.oasis.oati.com/woa/docs/PPW/PPWdocs/pacificorpocsiaq.htm

Power.[3] If PacifiCorp's interconnection costs were in line with other utilities, the Sunthurst projects would be financeable.

Sunthurst engaged Larry Gross, P.E., VP – Power System Protection Electrical Consultants, Inc., to review PacifiCorp's design. Mr. Gross is an electrical engineer with considerable expertise in utility scale interconnections and protection and data integration schemes. Mr. Gross reviewed the Interconnection Studies prepared by PacifiCorp and attended two meetings with PacifiCorp's interconnection team to ask questions about PacifiCorp's proposed interconnection requirements. Based on the documents and the meetings, Mr. Gross provided extensive comments on PacifiCorp's proposed design, attached hereto as **Attachment A**. Although not judging the "good design practice" of PacifiCorp's proposed upgrades, Mr. Gross identified several areas where PacifiCorp's proposed interconnection facilities and distribution upgrades were either likely unnecessary, redundant, and/or provided system benefits above what PRS1 and PRS2 reasonably require from a direct technical perspective. He also noted where the documentation provided by PacifiCorp was not of sufficient detail for him to confirm the necessity of all of the requirements.

Specific interconnection design modification and supplemental data requests

1. **Metering requirements are unnecessarily expensive.**[4] The Q0666 interconnection agreement specified one metering point (two meters) at or near the Point of Interconnection (POI). After Q1045 Facilities Study, that requirement changed to require one metering point at the Pilot Rock Solar 1 (PRS1) collector substation, a second metering point at the Pilot Rock Solar 2 (PRS2) collector substation and a third metering point at the Change of Ownership Point (COP).

   Sunthurst requests that the specified meters at the PRS1 (Q0666) collector substation and the specified meters at the PRS2 (Q1045) collector substation be moved to the low side, and the specified meters at the COP be eliminated. Combined net generation from Q0666 and Q1045 facilities at the COP can be calculated using low-side meters at Q0666 and Q1045. In fact, Oregon's CSP rules require utilities to allow low-side metering for CSPs under 360 kW because of evidence that low-side metering saves tens of thousands of dollars. Order 19-392, Appdx A, p. 13. If PacifiCorp is concerned about allocating transformation losses between two projects, Sunthurst will contractually guarantee that

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[3] Because PGE does not publish studies from withdrawn projects on its OASIS, Sunthurst does not currently have data to make an exact comparison between PGE and PacifiCorp. The available PGE data show much lower interconnection costs than PacifiCorp. Sunthurst found three interconnection studies for small Oregon solar published by Idaho Power, which had a median cost of $101k/MW.

[4] Sunthurst's comments regarding metering affect aspects of both (Q0666 and Q1045) interconnections.

PacifiCorp will be kept whole from transformation losses. ***Alternatively, Sunthurst requests that metering be accomplished with one metering point at the COP and one meter at the low (480V) side of PRS2.*** Generation from PRS1 can be calculated based upon the difference between COP and PRS2 meter readings.

Sunthurst's consulting electrical engineer concluded that the above metering schemes are technically sound and using the two lower voltage metering points is frequently used at the transmission level.[5] The requested alternatives to the proposed design would slash the combined cost of metering PRS1 and PRS2 without affecting safety, accuracy, or reliability.

2. **<u>PC-611 Panel installation may not be necessary</u>**. Based on information provided by PacifiCorp, Sunthurst's professional consulting engineer identified that the functionality required by PacifiCorp as a result of PRS1 and PRS2 interconnections does not appear to require the added PC-611 panel. Specifically, transfer trip can be performed using an SEL-2505 relay bolted inside the existing panel, and the reclosing could be delayed with other means using the SEL-2505 contacts.[7] ***Sunthurst requests PacifiCorp explain why PC-611 is required. If the justification includes updating old equipment that otherwise is scheduled for programmatic replacement, then Sunthurst asks PacifiCorp to contribute the difference between the cost of the PC-611 panel and the cost of the alternative proposed by Sunthurst's engineer, or else eliminate the PC-611 panel***.

3. **<u>Cost of new Fiber Optic install should be shared</u>.** The $70,000 fiber optic installation specified by PacifiCorp is a more expensive means of communication for the required transfer trip protection than point-to-point radio. PacifiCorp's choice of a 48-fiber cable provides much more fiber than PRS1 and PRS2 need and may show PacifiCorp's anticipation of using spare fibers for non-customer related uses. Sunthurst does not object if PacifiCorp prefers the expandability and excess capacity built into its choice of 48-fiber cable communications, however the excess cost of fiber compared to a functionally adequate radio communication link should be born by PacifiCorp. ***Sunthurst requests that PacifiCorp pay the difference between the cost of the fiber optic system specified by PacifiCorp and the cost of direct radio communication to Pilot Rock substation suitable for PRS1 and PRS2***.

4. **<u>Voltage Measurement at the feeder relay is not necessary</u>**. Sunthurst's consulting engineer reviewed PacifiCorp's design and believes based on the information available to him that the three line side voltage transformers (VTs) specified by PacifiCorp are not required for reclose voltage sensing as that

[5] See July 20 email from Larry Gross, attached, page 2, ¶2.
[7] See July 20 email from Larry Gross, attached, page 4, ¶2.

function may be performed using the transfer trip scheme communication channel.[9] Nor are the specified voltage transformers necessary for directionality determination necessary to protect PacifiCorp's equipment from Pilot Rock generation in the event of a bus, transformer or transmission line fault, because PRS1 and PRS2's inverters' will only contribute fault current of about 107% of nameplate after about 4 ms and islanding protection after the main distribution transformer fuse clears will disconnect the generation. This appears to make PacifiCorp's proposed voltage directionality based protection unnecessary.[10] ***Sunthurst requests that PacifiCorp remove the three high-side VTs after confirming that these optional protection practices and warranted performance of Sunthurst's inverters provide adequate protection.***

5. **P1-111 Annunciator Panel at Pilot Rock substation is not necessary.** Sunthurst's consulting engineer concluded based on the available information that the P1-111 panel specified in the Q0666 interconnection agreement is an unnecessary upgrade of existing functionality at Pilot Rock substation, which does not currently have annunciation. The existing relays have targets to indicate tripping and the SEL-2505 relay proposed by Sunthurst, above, has status lights that would make the annunciator redundant.[11] ***Sunthurst requests that the panel be deleted or reimbursed by PacifiCorp as a network upgrade or a distribution system upgrade not necessitated by PRS1 and PRS2.***

6. **PC-510 Transformer Metering Panels at Pilot Rock substation are unnecessary.** Sunthurst's consulting engineer noted that PacifiCorp's intended uses for the two PC-510 panels add additional benefit to the protection system that go beyond current protection philosophies for fault clearing. The generation equipment (recloser control or inverters) will provide adequate fault clearing when configured properly, rendering the PC-510 panels unnecessary upgrades.[12] ***Sunthurst requests that PacifiCorp remove the PC-510 panels.*** Sunthurst also notes that a single panel using an SEL-787 would provide better protection at lower cost than two PC-510 panels.[13]

[9] See July 20 email from Larry Gross, attached, page3, ¶ 1(a).
[10] See July 20 email from Larry Gross, attached, pages 3-4, ¶¶1(b)-(c).
[11] See July 20 email from Larry Gross, attached, page 5, ¶3.
[12] See July 20 email from Larry Gross, attached, page 5, ¶4.
[13] See July 20 email from Larry Gross, attached, page 5, ¶4.

7. **<u>Telemetry is unnecessary</u>.** PacifiCorp is requiring telemetry as part of the Q1045 interconnection, although neither Q0666 nor Q1045 exceeds the 3MW threshold for telemetry enshrined in Oregon's OAR. Sunthurst understands based on the data provided that telemetry adds at least $180,000 to the cost of the Q1045 interconnection. A portion of the telemetry equipment will be installed, if at all, on PacifiCorp's transmission system, meaning those components are network upgrades. ***Sunthurst requests that PacifiCorp eliminate telemetry from the interconnection requirement.***

8. **<u>Justification for regulator controller replacement not provided</u>.** ***Sunthurst requests copies of PacifiCorp's analysis used to determine that a controls upgrade is required in this specific application.***

9. **<u>Itemized cost estimate for installations</u>.** ***To complete its review, Sunthurst requires the work papers or summaries behind its high level cost estimates. Such documentation should, at a minimum, identify all components over $5,000 as well as contingency and overhead costs.***

10. **<u>Drawings requested</u>**. ***To complete its review, Sunthurst requires copies of the Station One line Diagrams (meter and relay), AC Schematics (Three Line Diagrams), DC Schematics, and any removal drawings.***

11. **<u>Historical Final Costs of Interconnection</u>.** Information provided by PacifiCorp show a $169,000 contingency included in the Q1045 cost estimate. ***Sunthurst requests that PacifiCorp provide data characterizing what fraction of budgeted contingency it typically consumes on similar interconnections.*** This data would help Sunthurst and its lenders better anticipate the final cost of interconnecting to PacifiCorp.

Summation

The changes above, taken together, suggest strongly that safe, reliable interconnection of Q1045 and Q0666 comprised of only necessary interconnection facilities and distribution upgrades can be achieved at costs in line with the median costs published in the 2018 NREL study. Given the availability of technically sound alternatives at much lower installation cost, Sunthurst believes PacifiCorp's current interconnection scheme proposed for PRS1 and PRS2, is unreasonable.

Neither IEEE 1547, federal, nor Oregon law appear to proscribe the specific alternative interconnection solutions proposed by Sunthurst, meaning that PacifiCorp has discretion to grant Sunthurst's request for functionally equivalent, less costly, measures. However, if PacifiCorp desired, Sunthurst (and, presumably, Commission staff and the CSP Program Administrator) would cooperate in seeking express approval from the Commission in this instance in order to serve the Commission's goal of delivering CSPs to PacifiCorp customers. A previous PacifiCorp request for waiver of interconnection requirements to facilitate cost-effective customer-owned solar received enthusiastic approval of staff and the Commission.[14]

In Docket No. UM 1930 (the docket that implemented the Oregon CSP), Staff recently expressed concern that "additional opportunities to enable efficient integration of small generators are not being considered collaboratively". **The Commission, in adopting staff's recommendations, instructed staff to *"work with parties to continue to explore avenues for CSP generators and utilities to collaboratively consider additional one-off interconnection enhancements*.**"[15] Sunthurst respectfully requests that PacifiCorp adhere to the Commission's instructions, and collaborate to facilitate interconnection of Q0666 and Q1045.

Thank you for your time and consideration.

Kenneth Kaufmann
Attorney for Sunthurst Energy, LLC

Attachment A-- **July 20 email from Consulting Engineer Larry Gross to Sunthurst**

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[14] *In re SOLWATT, LLC and KENT and LAURA MADISON, Request for Waiver of the Primary Voltage Interconnection Requirements under OAR 860-084-0130 (2) of the Solar Photovoltaic Pilot Program.* 2012 Ore. PUC LEXIS 98, *5-8 (March 27, 2012) Order No. 12-107; UM 1538.

[15] Order No. 19-392, Appdx A at 13-14, 2019 ORE. PUC LEXIS 486, *29-30 (November 8, 2019).

July 20 email from Consulting Engineer Larry Gross to Sunthurst

Daniel,

Sunthurst has asked Electrical Consultants, Inc. to review the technical interconnection requirements identified by the utility for the Q0666 project. The following summary of findings is based on the review of the Tier 4 Facilities Study Report dated November 18, 2015 and revised November 23, 2015, and additional project data provided by Sunthurst. In addition, information gathered during a telephone conversation with utility technical representatives, and my experience with renewable generation, protection, metering, SCADA, and communication systems was used as a technical basis. Due to schedule and limited design details at this time, this review is subject to change if further data is provided.

The following is a description of the utility requirements and the likely technical basis of the requirements. There is mention of typical practice, but this review is not intended to identify with any certainty the legal basis of the requirements or what the utility policies state. Utilities base their facility studies on the technical requirements that are expected, and the complete design and detailed analysis may not have been thoroughly completed if the proposed equipment is flexible enough to handle several scenarios. Another item worth noting is the consistency of designs between projects. If there is customization of a scheme it may reduce hardware costs, but increase engineering costs and maintenance costs for the utility. The utility has very specific pre-designed panels that are a “one size fits all” which reduces the time and cost to design and construct but often adds costs to the panel due to additional hardware and panel building.

Some of these solutions highlight how this interconnection could be done with minimal cost, but not necessarily how it should be done. The utility can still proceed with the upgrades based on them being good practice. What you would have to explore is if all those costs should be allocated to the project. For example, if this was a modern distribution station, the only upgrades you may have to do are the fiber and the regulator controls. Everything else would be already in place.

Generating Facility Modifications ($203,000)

1. **An SEL-351 type relay is required.** Sunthurst plans to use an SEL-351R or SEL-651R in conjunction with a recloser (pole mounted fault interrupting device). Either is acceptable with the SEL-651R being a more modern option with added features. This device will detect faults on the 12.47 kV system between the recloser and the step up transformers. The utility will determine the settings with input from the customer if additional protection or coordination requirements are desired. The programming will be provided by the utility. The programming will include voltage and frequency islanding protection. **There are no suggested methods for reducing or reallocating costs unless the engineering cost for the settings development is itemized for review and determined to be higher than expected. The only item provided by the utility is relay programming, no hardware.**
2. **The utility requires and will provide metering (two meters) and measurement devices** at or near the change of ownership. This is required to adequately measure the project production at the change of ownership. Two meters monitor the same data for redundancy. There is a question that was posed by Sunthurst regarding a single

metering location instead of three when both Q0666 and Q1045 are connected. The technical solution proposed by Sunthurst to have a single metering location with a split allocation reported by Sunthurst is a technically sound solution and is often done at the transmission level. The utility will provide access for Sunthurst to read the metering data via communication port or pulsed contacts. **There are no suggested methods for reducing or reallocating costs of the single project metering. Only a single meter is required but the second meter is for redundancy in the case of failure the site would not require being shut down or production being under-reported. The Sunthurst proposal for metering the two co-located projects would reduce install costs but will add some additional regular reporting for Sunthurst.**

3. **Communication equipment will be required to remotely interrogate the meter using MV90.** This is a common requirement for interconnections and allows the utility to automatically read the interconnection meter using an industry standard protocol that integrates with the overall utility metering system. Communication paths are usually via telephone (cellular or basic dial up) or Ethernet connectivity on a utility Ethernet network. The utility indicated they were going to use the Utility Ethernet Network via the required fiber (see fiber discussion below). **As a standalone system upgrade, the least expensive would be to use a cellular modem. It is unclear who would pay for any ongoing cellular fees, but the data volume is minimal and is often included in a utility plan for little to no additional charge. Due to other system upgrades, the lower cost adder may be to use the fiber and utility network. See other line items.**
4. **SEL-2829 optical transceiver.** This is required for the transfer trip scheme, and **is the least expensive way to communicate between two SEL relays that are not co-located. If the SEL-2505 alternative is used (see discussions below), then this device is not needed at the utility substation end.**
5. **A metering panel is required.** This will hold the two meters and test switches to allow for online testing. It is unclear if this metering panel is intended and priced to be installed in a building or not. There is no mention in the facility report that any voltage for powering the meters is required like Q1045. It is expected that these will be powered by the equipment installed by the utility. **There may be a cost savings if this was priced as a full indoor panel as opposed to a pole mounted NEMA box that only contains the two meters and test switches. The specific pricing is unclear.**
6. **Communication Fiber associated equipment.** The utility will install fiber hung on the poles under the distribution line for the entire length of the distribution line from Pilot Rock substation to the generating facility. The fiber is a 48-count fiber, single mode, ADSS. A fiber patch panel and other communication equipment will be installed. It is unclear what other communication equipment is required, but with the large fiber count, homeruns could be made to every device not requiring any additional network switches. **There would be savings in installing a smaller count fiber if all of the fiber was not going to be dedicated to these projects. If the 48 ct fiber is specified for future capacity beyond the tap location, then the cost is not directly attributable to the technical requirements of this project. Higher count fibers are often specified because the majority of the cost is the installation so the additional fiber is best installed at the initial install.**

Distribution Line Requirements ($55,000)

1. **Line Extension.** The utility will install 0.3 miles of new distribution line to extend a tap connection from the existing distribution line to the change of ownership. **There are no suggested methods for reducing or reallocating costs.**
2. **Gang operated switch and primary metering units.** The gang-operated switch is required for an isolation point operated by the utility. The metering units are what measure the system values for metering. **There are no suggested methods for reducing or reallocating costs.**
3. **Replace the tap-changing controller to address reverse power.** When there is power flow from the distribution system to the transmission system, the calculated voltage drop between the substation and the end-of-the-circuit customer is not accurate. A different controller can adjust its control requirements when power is flowing in the reverse direction. **There is the possibility that a controls upgrade is not required depending on the load flow details, which we do not have. If additional generation is added to the circuits, then the reverse power requirement may become more important. This may include Q1045.**

Fiber ($70,000)

1. **Fiber.** The fiber is required for the transfer trip. It is not required for the metering for Q0666, but it is preferred to use for the metering if the fiber is already required for other reasons. **There is likely a slight reduction in hardware and installation costs if point-to-point radios were used for the transfer trip scheme. This solution is not as reliable but is used by many utilities. The installed cost is likely less than installed fiber. This solution requires line of site visibility and a licensed frequency is recommended. Also, as mentioned above there is some savings in using a fiber with a smaller count of strands.**

Pilot Rock Substation ($477,000)

1. **Three Line Side VTs.** These voltage transformers are required for providing the feeder and transformer relays directional sensing and verification that the generator has disconnected prior to reclosing the breaker after a fault.
   a. For reclosing the line side voltage measurement provides indication that the generator is disconnected before it recloses. This is a typical utility practice. If it is not, the relay delays its reclosing. **The voltage sensing for reclosing is not required since the transfer trip scheme is in place. The scheme can provide positive feedback that the recloser is open via mechanical auxiliary contact as well as that the voltage is reduced to an acceptable level via measurement by the recloser. The processing delay will be about 2-4 ms. If the communication system is out of service, the recloser can either go to lockout or a reasonable time delay (5 seconds) could be used.**
   b. The feeder directional sensing is usually needed to determine the difference between a forward and reverse fault. For forward faults the utility source feeds the fault through the feeder breaker. For bus, transformer, transmission, or adjacent feeder faults, the generator feeds the fault through the feeder breaker. If the difference in current flow between the two directions is not a large enough difference, then the protection pickup value cannot be set high enough. The existing setting pickup value is about 600 Amps instantaneous. This is an unusually low value for an instantaneous setting, but the utility indicated they are using a fuse saving scheme, which typically has a fast initial

trip for the first fault trip before reclosing. This value is believed to be above the fault contribution of the inverters after about 4 ms, which is identified to be 107%. This would need to be confirmed by the inverter manufacturer including during voltage ride through time periods. It should also be noted that it is expected that the generation transformers are larger than the existing customer load transformers currently on the distribution line. This means that inrush currents could exceed the 600 Amp fault level and the utility may want to reconsider the fuse saving scheme. This can also be addressed by using harmonic blocking at the recloser, which in turn could block the relaying at the substation. Although these upgrades are good protection design practice, **based on these expectations, a voltage measurement at the feeder relay is not required for this interconnection.**

c. The other requirement for the VTs is to provide directionality for the transformer relay. For transformer or transmission faults, the generator feeds the fault into or through the transformer. The utility wants to minimize damage to the transformer for any fault. The directional relay would allow a low set overcurrent element to trip for any current flowing from the distribution circuit into or through the transformer. This may not be an effective means to detect faults because the fault current generated by the generation is only slightly above its normal full generation output, so trying to detect fault current versus normal generation flowing into the transformer may not be practical. In addition, the full fault contribution from the generation is believed to be below the withstand capabilities (normal load capacity) of the transformer, so no additional damage could develop other than at the fault location. The damage at the fault location is determined by the time delay of the fault clearing. The amount of current that the generation may produce is expected to be well below the existing fuse protection of the transformer, so any additional requirements to better protect the transformer from fault duration at the point of the fault would not be represented by the existing protection philosophy on the transformer. Due to the difficulty of determining a reverse fault versus a forward fault at the transformer, a neutral CT could be added and directionality could be provided or a differential relay with REF would provide high-speed protection for removing generation, but none of these schemes improve the time delay of the fuse clearing which is the existing protection. Although these upgrades are good protection design practice, **based on these expectations, a voltage measurement is not needed for this interconnection for the reverse transformer protection.**

2. **PC-611 Panel.** This is believed to be the feeder protection panel. The feeder relays are old electromechanical relays. Most utilities in the US have upgraded their distribution feeder relays to an advance microprocessor relay already or have a plan in place to do so without regard to interconnections, however, many require upgrading when an interconnection is on a distribution circuit with an old relay. This often provides flexibility to perform directionality (see above), better monitoring, and flexibility for transfer tripping and special logic schemes that possibly are required. The concern in this case is that the fault currents and existing system does not appear to require the upgrade. There may be specific studies that show advanced relaying is required but it is not clear why. The current levels and voltage requirements were addressed above. The transfer tripping could be performed using the SEL-2505 bolted inside the existing panel,

a lower cost solution, and the reclosing could be delayed with other means when necessary using contacts from the SEL-2505. Although the feeder upgrade is good protection design practice, **based on these expectations, a new, advanced relay does not appear to be technically required for this interconnection.**

3. **PI-111 annunciator panel.** It is not clear why this panel is required for this interconnection since the existing station does not have any annunciation. The existing relays have targets to indicate tripping and an SEL-2505 has lights to indicate input and output contact statuses including data digital alarm points from the Generator up to 8 indications. This device could be upgraded to an SEL-2506, which would then have front panel indication. **Based on these expectations, the annunciator panel does not appear to be technically required.**
4. **PC-510 Transformer Metering Panel (qty 2).** This panel was confirmed by the utility to not be for metering, although the relay can provide metering and is often used for that by the utility. This panel would include the SEL-751 relay for detecting transformer faults and tripping the generator. As Identified above, this relay may be good protection practice, but it adds additional benefit to the protection system that is beyond what are the current protection philosophies for fault clearing times. The recloser or inverters will clear for a fault themselves in a reasonable amount of time given the current flow value for a transformer fault once the fuse clears. Although adding the transformer metering panels is good protection and station upgrade practice, **based on these expectations, an advanced transformer relay is not required for this interconnection.** It should also be noted that a single panel that uses an SEL-787 could monitor both transformer low sides for REF protection. This would not be a typical panel design for the utility, would provide much faster protection, but is still not required for this interconnection.
5. **Fiber channel and associated equipment.** The fiber is required for the transfer trip. This equipment could be limited to a patch panel only if no relays were upgraded or installed as described above. The device that would interface with the existing relays for transfer trip and block reclosing would be the SEL-2505, which has a built-in fiber port. **No other communication equipment appears to be needed. By keeping the relay system design simplified, the fiber design could be as well. The number of fibers as mentioned above is another possible cost reduction item.**

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CERTIFICATE OF SERVICE

In accordance with ORCP 9, I hereby certify that on July 31, 2020, I caused to be served a full and exact copy of the foregoing **First Amended Notice of Intent to file Complaint of Enforcement** via:

- ☐ First Class Mail with postage prepaid, deposited in the US mail at Lake Oswego, Oregon
- ☐ hand delivery
- ☐ facsimile transmission
- ☐ overnight delivery
- ☒ e-mail
- ☒ OPUC EFILING SYSTEM, if registered at the party's e-mail address as recorded on the date of service in the eFiling system, pursuant to UTCR 21.100 addressed to the following parties at the address(es) listed below:

Mr. Kristopher Bremer Director, Generation Interconnection PacifiCorp 825 NE Multnomah, Suite 1600 Portland OR 97232 **Kristopher.Bremer@PacifiCorp.com** (electronic mail)	Filing Center Public Utility Commission of Oregon PO Box 1088 Salem, OR 97308-1088 **PUC.FilingCenter@state.or.us** (electronic mail)
Matthew Loftus Senior Transmission Counsel PacifiCorp 825 NE Multnomah St, Suite 1600 Portland, OR 97232 **Matthew.Loftus@PacifiCorp.com** (electronic mail)	

Dated: July 31, 2020
s/ Kenneth E Kaufmann
Kenneth E Kaufmann
Attorney for Sunthurst Energy, LLC
OSB# 982672