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December 15, 2020

Via Electronic Mail

Filing Center
Public Utility Commission of Oregon
P.O. Box 1088
Salem, OR 97308-1088
puc.filingcenter@state.or.us

Re: OPUC Docket No. UM 2118

Attention Filing Center:

Attached for filing in the above-captioned docket is Sunthurst Energy, LLC's Opening Testimony of Daniel Hale and Michael Beanland.

Thank you in advance for your assistance.

Sincerely,

Ken Kaufmann

Ken Kaufmann
Attorney for Sunthurst Energy, LLC

Attach.

PUBLIC UTILITY COMMISSION
OF
OREGON

SUNTHURST EXHIBIT 100

Daniel Hale
On behalf of
Sunthurst Energy, LLC

DECEMBER 15, 2020

Q. Please state your name and present occupation.

A. Daniel Hale. I am president and owner of Sunthurst Energy, LLC, an Oregon company located at: 43682 SW Brower Lane, Pendleton, OR.

Q. Tell us about yourself.

A. I am from Umatilla County and have lived in Oregon for 35 years. My Grandfather founded Pendleton Electric in 1952 where our entire family worked. My step-father was a lifetime employee with Pacific Power & Light until retirement as Regional Customer Service Manager in Walla Walla.

In 1996, I earned a Bachelor of Science degree in Construction Management from Washington State University. In 2007, I earned a Master of Arts degree in Real Estate. Between 2007 and 2009, I earned a LEED AP, Solar Training Institute, and Southern California Edison Contractor Certificates and completed 3 semesters at Southwestern Law School in Los Angeles before working full-time as a Solar Project Manager and Regional Development Manager.

Q. Tell us about Sunthurst Energy, LLC

A. In 2013, I founded Sunthurst Energy, LLC (Sunthurst). Sunthurst currently is licensed in 5 Western States. Our focus is commercial solar EPC and development. We are members of Community Coalition for Solar Access ("CCSA") and Oregon Solar Energy Industries Association ("OSEIA").

Q. Are you a licensed electrician?

A. Above a BS in Construction Management, I have an OR LRT license under Renewable Energy JATC. Previously, I held a union journeyman carpenter's card from Portland Local #247.

Q. Tell us about your participation in development of Oregon CSP program.

A. As an OSEIA member, Sunthurst joined the Community Solar Group and participated in industry stakeholder calls and input to shape the Community Solar Program (CSP) created by SB 1547. I was the only developer at the PUC's two UM1930 workshops and participated actively in both. My PRS1 Project was the first to apply in PacifiCorp's CSP queue and I have been on the ragged edge of Oregon CSP implementation from the beginning.

Q. How many Oregon CSP Projects is Sunthurst developing?

A. I currently have three solar projects seeking Oregon CSP status: Pilot Rock Solar 1 (PRS1), Pilot Rock Solar 2 (PRS2) and Tutuilla Solar Project (TSP). All three are located in PacifiCorp service territory:

	PRS1	**PRS2**	**TSP**
Nameplate (MW)	1.98	2.99	1.56
Location	Pilot Rock, OR	Pilot Rock, OR	Umatilla, OR
PacifiCorp Substation	Pilot Rock	Pilot Rock	McKay
PAC 12.5 kV Circuit	5W406	5W406	5W857
PAC Queue #	Q0666	Q1046	OCS024
Status	IA executed	IA pending	IA executed
Oregon CSP Status	Pre-certified	Pre-certified	

Q. Which are the subject of this Complaint?

A. Pilot Rock Solar 1 (Q0666) and Pilot Rock Solar 2 (Q1045).

Q. Please provide a brief background on Q0666 and Q1045:

A. In 2015, I learned of Oregon's Renewable Portfolio Standard (RPS), and the up and coming community solar efforts in the legislature. I secured a site and applied to PacifiCorp for interconnection for the Pilot Rock Solar 1 Project (PRS1) in 2015. I believe PRS1 was the first Oregon CSP in PacifiCorp's interconnection queue (Q0666). But PacifiCorp's estimated $805k cost to interconnect a 1.98 MW project remains not economically feasible.

To absorb PacifiCorp's high interconnection cost, I attempted to add capacity on the feeder with Q0747 adjacent to PRS1, with the expectation that the second interconnection at the same location would be cheaper--thereby defraying the high costs from PRS1. I designed PRS2 and submitted a 6 MW interconnection request (Q0747) for a second project adjacent to PRS1. PacifiCorp's estimated cost to interconnect Q0747 was $42,199,000. After confirming that PacifiCorp's estimate was not a joke, I withdrew my request.

In 2018, I submitted a 3 MW application for PRS2 (Q1045). Oregon's CSP looked like it was approaching implementation, and I decided to develop PRS1 and PRS2 as CSPs. I remained hopeful that the smaller PRS2 interconnection costs would be lower because it could utilize some of the same equipment installed to interconnect PRS1. PacifiCorp executed my Q1045 Study Agreement in August 2018, but unilaterally delayed completing any study for 18 months. Meanwhile, the

Oregon CSP launched in February 2019. Because PacifiCorp had not finished an interconnection study, PRS2 was not eligible for Pre-Certification. In February 2020, PacifiCorp told me that it would complete the Q1045 study in "6 to 8 months". On March 10, 2020, the Commission denied Sunthurst' petition for a waiver of the completed interconnection study requirement for CSP Pre-Certification. I then sent PacifiCorp a notice of intent to file a complaint, on March 20, 2020. On March 25, PacifiCorp sent me a completed System Impact Study (SIS) for PRS2, with an estimated cost of $1,195,000. Sunthurst' total cost to interconnect PRS1 and PRS2 was exactly $2,000,000.

Q. Why did you file your Complaint?

A. Given the price paid for output and other Project burdens under the CSP, PRS1 and PRS2 are not financeable with the interconnection costs quoted by PacifiCorp, and I doubt PacifiCorp will be successful filling its CSP capacity procurement goals. From our extensive experience, validation by credible 3rd party studies, and solar development industry contacts, we know it is feasible to interconnect small solar projects like PRS1 and PRS2 for $0.05-0.15 cents per watt-dc, which is approximately 25% of PacifiCorp's initial estimate. Through protracted negotiations the last six months, PacifiCorp has reduced its cost estimate by about 50%; however, the costs remain unreasonable.

Q. Describe what happened.

A. <u>Q0666 application.</u> When I received the System Impact Study (SIS) for Q0666, I saw that the costs were dominated by the direct transfer trip scheme

(DTT). I hired a cost consultant to determine why costs were so high. He was a long-time PacifiCorp systems engineer, now consulting to project developers. He reviewed IEEE1547 requirements as they apply to smart inverters and determined that most utilities do not require DTT for projects under 2 MW if the inverters comply with IEEE 1547. A 2016 NREL Report he provided me said only Hawaiian utilities were requiring transfer trip (a large cost) on under 5W projects. PacifiCorp would not remove the TT requirement. Nor would they allow me to install the DTT at my cost.

Q0747 application. Two priority generators in this pocket had known issues. Q547 (18MW) was only permitted for 10MW, while Q586, a 6MW, let their FAA Glare Study lapse and was having permitting challenges. Additionally, City of Pilot Rock, a small rural community, was hit hard economically with a mill closed and laid off their only policeman; they encouraged us to use more solar giving them more lease revenue. Therefore, we filed hoping for available transmission capacity if either senior queue position defaulted. However, Q586 did come online, and Q547 received three 12-month extensions and is still tying up 8MW. For my 6 MW project (Q0747), PacifiCorp estimated a cost to interconnect of $40 million dollars, including network upgrades to move generation to Grandview, Washington, some 100 miles north. Ethically, PacifiCorp should have removed Q547's 8MW and granted it to Q747, the next applicant in the queue. Q547 blocked development of remaining capacity in its Pendleton Pocket for 4 years.

Q1045 application. To avoid the cost of network upgrades, Sunthurst downsized PRS2 to 2.99 MW and submitted a new interconnection request (Q1045).

By that time, published avoided cost prices had fallen but the new Community Solar Program looked promising. We signed the SIS Study Agreement in August 2018, but PacifiCorp breached the study agreement timelines. When I e-mailed to PacifiCorp in October seeking explanation, they said there was a “generation to load” issue. They NEVER gave an update for 12 months during which the queue was closed. This halted my ability to develop Q0666 while I waited for Q1045 study results. I asked PacifiCorp to pause engineering on Q0666 pending Q1045 results but PacifiCorp spent my $79,000 Q0666 milestone deposit anyway and halted giving me monthly invoices, which they had done up until that payment was made.

Q. After you received Q1045 SIS, what did you do?

A. I was surprised and disappointed when I found out the SIS interconnection costs were $1.195 Million. I wondered whether the fact that PRS1 and PRS2 interconnection costs totaled $2.000.00 Million was coincidence, or if PacifiCorp rounded to the nearest million.

With the help of a retired former utility electrical engineer, I investigated and found that PacifiCorp’s estimated costs were high by any measure. I read a 2018 NREL Technical Report titled *Review of Interconnection Practices and Costs in the Western United States*, which Commission Staff presented in a public meeting hosted by the authors. Figure ES-1 in that report shows a median interconnection cost in western states of about $120K/MW. PacifiCorp’s estimated costs for my two projects were $400K/MW.

I consulted a nationwide developer of utility-scale solar. I obtained data from a national solar finance company familiar with many project pro-forma financing models. A nationally-known renewable engineering firm with expertise estimating transmission costs for developers reviewed my costs. I also have personal experience managing solar for a national developer and knowing the actual costs of a comparable interconnection to PGE. Every source pointed to PacifiCorp's costs being out of line.

Q. Why do you think they were so high?

A. I think there are several reasons.

One reason is excessive scope. Two consulting engineers have confirmed to me that my interconnections do not require telemetry or the $600,000 building to shelter it that PacifiCorp initially proposed. Nor do they require annunciator panels, 48-pair fiber optic cable, or other components that would be nice to have but are not necessary. Expert Michael Bean's Opening Testimony filed on Sunthurst's behalf goes into this reason in detail.

Another reason is the age of PacifiCorp equipment. I am paying for upgrades to PacifiCorp's protection scheme and other components because PacifiCorp's substation is still using equipment installed in 1961. US DOE WEAP Replacement recommendations for distribution equipment is 30-50 years. PacifiCorp's retail customers paid for this aged equipment several times over but rather than reserve money to replace obsolete equipment, PacifiCorp charges generators who interconnect to their system to defray its programmatic replacement costs.

PacifiCorp is benefitting from this new equipment but doesn't pay for it. (For examples: feeder transformers, voltage regulators, telemetry, and annunciator.)

A third reason is the high cost of work done by PacifiCorp. Its direct cost of materials in its estimates is high even though it claims to leverage its size to buy at favorable prices. Its manpower is intensive. Approximately 10 PacifiCorp agents attend each interconnection-related teleconference I have attended. And its overhead is high. On top of the direct costs, PacifiCorp surcharges every item with its Capital Surcharge, which is currently about 8%.

All three factors are what one might expect given PacifiCorp's economic incentives: it benefits economically when it generates its own power rather than purchasing it from 3rd parties; it benefits from new interconnection facilities paid for by 3rd parties; and it is entitled to recover its actual costs, even if it overruns its estimate. It's not surprising that a utility that benefits from high interconnection costs that discourage competition, and also benefits from gold-plated interconnection facilities paid for by the competition, charges above-market rates for interconnection.

Q. Did PacifiCorp address your concerns?

A. PacifiCorp has always been courteous and patient. But progress is slow and expensive. I ask for System Impact Study results and I'm told I might get them in "6-8 months"; my lawyer writes a letter and I have the study in 5 days. I complained that a control building was not needed for my project and nothing happened. When my lawyer complained they took it out. Likewise for the annunciator panel and for telemetry, which PacifiCorp initially required but no longer requires. I don't think a regulated utility should ask for more than it is entitled to and force me to get an attorney to claw it back.

I have had a lot of decisions break against me, too. Senior queue position Q547, with 8MW of reserved, unused interconnection rights, blocked my development of additional capacity for years, although I notified PacifiCorp it was clear it would never be used. PacifiCorp's 16-month delay processing Q1045 may have deprived me from other development opportunities for the projects. I have another project, OCS024, that was originally sized at 2.45 MW based on UM2000 data reported on Jan 24, 2020. After I optioned a site for 2 MW, and after PacifiCorp confirmed the feeder number and this allowable generation size, PacifiCorp informed me that it was switching much of my feeder load to another circuit, which reduced the buildable size of my project down to 1.56 MW.

Q. What is the cost of the interconnection today?

A. In the PacifiCorp's Community Solar transmission queue, PUC Staff's report says interconnection costs for the first 24 applicants ranged between $200K/MW and $420K/MW ($0.20-0.42watt-dc). But PacifiCorp's costs for recently studied Community Solar projects OCS027-037 came in around $100K/MW ($0.10watt-dc). It appears to me that PacifiCorp's interconnection costs are dropping in its most recent community solar interconnection studies. One example is that fiber optic installation costs appear to be dropping, on a $/Linear Foot basis (as discussed in

Mr. Beanland's testimony). PacifiCorp has not revisited unit costs of fiber or other systems in my studies, however.

Q. Why aren't you satisfied with PacifiCorp's efforts to reduce costs?

A. Decreasing costs in recently published interconnection studies reinforces my belief that PacifiCorp can and should do more to further reduce the interconnection costs for PRS1 and PRS2. Mr. Beanland's testimony identifies ten specific changes that appear to be either required by, or justifiable under, existing interconnection rules.

In addition, there are changes that PacifiCorp might not be empowered to do without Commission involvement. One example is the 8% Capital Surcharge imposed on top of all project costs. To my knowledge the Commission has never examined how PacifiCorp applies the charge, let alone approved its use. I tried but was unable to verify that the 8% Capital Surcharge is included in the calculations used to calculate PacifiCorp avoided costs. On good faith, I believe they are not.

Another issue is the gross disparity between treatment of interconnection costs under FERC's SGIP rules, compared to Oregon's SGIP rules, which in my opinion unfairly allocate virtually all costs to the developer. My complaint provides a forum for the Commission to become aware of these issues and devise appropriate remedies.

My ultimate hope is to end up with interconnection costs that are financeable and to build PRS1 and PRS2, which have been my preoccupation the last 5 years.

Q. Does this conclude your testimony?

A. Yes.

CASE: UM 2118
WITNESS: MICHAEL BEANLAND, P.E.

PUBLIC UTILITY COMMISSION
OF
OREGON

SUNTHURST EXHIBIT 200

Opening Testimony

Michael Beanland, P.E.
On behalf of
Sunthurst Energy, LLC

DECEMBER 15, 2020

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I. <u>INTRODUCTION AND OVERVIEW OF TESTIMONY</u>

1. Please state your name and business address.

A. Michael David Beanland. 11616 NE 7th Cir, Vancouver, WA 98684.

2. Please describe your background and experience.

A. I received both a Bachelor of Science and a Masters of Engineering from California Polytechnic State University, San Luis Obispo, California, in electrical engineering. I am a registered professional engineer in CA, OR, WA, ID, HW, NV and NM. I have been working as an electrical engineer since 1977. From 1977-2001 I worked for electric utilities in various engineering capacities. In 2001 I moved to the consulting arena. In early 2018 I opened my own business and have been the President of Willamette Power Engineering, Inc. since then.

My work since 2001 has been both for electric utilities and for energy sector developers, including wind, battery storage, and photovoltaic. These projects have varied in size from a few MW to 100s of MW. I am the engineer of record for several small (under 10MW) photovoltaic projects.

In my capacity of performing interconnection studies and reviewing the studies performed by others, I have become familiar with the typical scope of work required for interconnections and the costs associated with that scope. In my role as a utility electrical designer, I am often called upon to develop construction cost estimates, and in that capacity I am familiar with the typical costs for equipment and construction. A summary of my qualifications is provided as **Exhibit Sunthurst/202**.

3. Please describe the information you reviewed in preparation of your testimony:

A. I was provided with large number (over 400) of documents and records addressing the Q0666 (Pilot Rock Solar 1 a/k/a "PRS1") and Q1045 (Pilot Rock Solar 2 a/k/a "PRS2") interconnections to PacifiCorp. These included the system impact studies, facilities studies, design drawings, cost estimates, and communications between Sunthurst and PacifiCorp. Documents I refer to in my testimony are included as exhibits.

4. On whose behalf are you appearing in this docket (UM 2118)?

A. I was approached by Sunthurst and asked to review the documents and offer my experience and expertise as to the reasonableness of the PacifiCorp interconnection requirements and estimated costs for its Pilot Rock Solar 1 (PRS1) and its Pilot Rock Solar 2 (PRS2) projects.

5. Have you previously provided testimony in any state or federal regulatory dockets or court cases?

A. In 2010, I provided testimony on behalf of PacifiCorp as it related to a generator interconnection in the Illinois Valley, Oregon area.

6. Please summarize your testimony:

A. Sunthurst's 1.98 MW Pilot Rock Solar 1 (PRS1) and its 2.99 MW Pilot Rock Solar 2 (PRS2) photovoltaic generating projects are typical of dozens of under-5MW photovoltaic projects interconnecting to distribution systems across PacifiCorp and other utility territories throughout the Pacific Northwest. These projects pose no particular technical challenges for interconnection. PacifiCorp initially estimated the cost to interconnect PRS1 and PRS2 at $805,000 and $1,195,000, for a combined cost of $2,000,000. In my experience projects like PRS1 and PRS2 can be interconnected for far less.

When challenged by Sunthurst, PacifiCorp later agreed several requirements were not essential to interconnect, including a line recloser, substation annunciator panel, a remote terminal unit (RTU, a/k/a "telemetry"), and a building to house the RTU. I agree with PacifiCorp's decision to remove the control building requirement, and to pay for the substation annunciator and telemetry package itself. However, the current $1,000,321 interconnection costs remain unjustifiably high for reasons including the following:

- substantial costs related to the annunciator panel and telemetry remain in PacifiCorp's proposed final scope of work and cost estimate, contrary to PacifiCorp's stated intent;

- PacifiCorp has included, in the relaying upgrade, the installation of line potential transformers to sense the voltage on the line ("dead-line check") as a method of reducing the possibility of restoring (reclosing) power into an energized line. A more favored practice in the region is to extend the delay on reclosing long enough that dead-line checking is not needed;
- PacifiCorp is requiring fiber optic cable from the Pilot Rock Substation to the projects as the communication path for implementing the direct transfer trip. Using spread spectrum radio is likely a substantially cheaper and fully adequate alternative;
- PacifiCorp is requiring installation of two sets of line voltage regulators. There is no supporting justification for the inclusion of the voltage regulators and begs the question of whether this is to resolve an existing problem;
- Because the Q0666 and Q1045 projects are collocated, in addition to the usual point of interconnection (POI) metering for each project, PacifiCorp is requiring a third meter to measure the total power delivered by both projects. Three meters are both excessive and not useful;
- Some of PacifiCorp's itemized costs appear unreasonably high. "Avian protection" is listed in the Q1045 cost estimate as $7,650 for what appears to be three 36-inch sections of insulating tubing installed on conductors. This is one of several line items that appear unreasonable on their face.

In addition to the unreasonable interconnection charges listed above, it may be reasonable for PacifiCorp to share the cost of certain necessary interconnection facilities that provide tangible benefits to the greater distribution system, in particular the 0.3-mile line extension and fiber optic line from PacifiCorp's existing system.

Finally, PacifiCorp requires Sunthurst to pay for project features needed to support PacifiCorp's RTU and telemetry scheme. PacifiCorp should reimburse Sunthurst for all such out-of-pocket charges.

My testimony is organized into four Parts. Part I describes my background and previews the remainder of my testimony. Part II describes the interconnection design and apportionment of installation costs, as set forth in PacifiCorp's PRS1 and PRS2 Interconnection Agreement and Interconnection Studies. In Part III, I discuss unreasonable aspects of PacifiCorp's design, estimated costs, and apportionment of estimated costs. In Part IV, I suggest changes in the design, estimated cost, and assignment of costs intended to minimize overall costs and to reasonably apportion remaining costs between PacifiCorp and Sunthurst.

II. PACIFICORP'S PROPOSED INTERCONNECTION DESIGN and COST APPORTIONMENT

1. Describe the interconnection at Pilot Rock Solar 1 and Pilot Rock Solar 2.

A. The interconnection facilities include all hardware necessary to safely interconnect the PRS1 and PRS2 solar projects to PacifiCorp's existing 12.5 kV Circuit 5W406 out of its Pilot Rock Substation, Transformer T-2144 near Pendleton. A one-line diagram of the proposed interconnection is provided in **Exhibit Sunthurst/203**. On the Project's side of the Change of Ownership Point (COP), each Pilot Rock Solar facility includes photovoltaic (PV) modules, inverters to convert the direct current produced by the solar modules to alternating current, low-voltage (480V) switchgear needed to combine the outputs from multiple inverters, a step-up transformer to raise the low-voltage produced by the inverters to the medium-voltage (12.5 kV) of the PacifiCorp distribution system, and a meter on the 12.5 kV side of the project transformer to measure the power produced by the plant.

In common to both projects is the interconnection interrupter that implements the PacifiCorp-required protection scheme including direct transfer trip. See **Sunthurst/203, Beanland/1.**

On PacifiCorp's side of the COP, the facilities include a third meter to measure combined output of PRS1 and PRS2, the 12.5 kV overhead power line, the fiber optic communication line, and at the substation, the protective relaying and communication. The PacifiCorp substation is a 69kV to 12.5 kV distribution substation with existing fused step-down transformer, voltage regulator, circuit breakers, and supporting equipment, most of which was installed in the 1960s.

Functionally, the interconnection equipment may be grouped into four categories: conductor related, system protection, metering, and telemetry. I briefly describe the facilities, by functional group, below.

CONDUCTOR RELATED DISTRIBUTION SYSTEM UPGRADES

2. What are conductor-related distribution system upgrades?

A. Conductor-related distribution system upgrades can include both the construction of new overhead or underground medium-voltage (12.5 kV to 34.5 kV) power lines or the reconstruction of existing overhead or underground medium-voltage power lines. This includes apparatus needed such as poles, cross arms, insulators, cross-arm braces, down guys, guy anchors, ground rods and wire, group-operated switches, hook-operated disconnects, etc.

3. Describe the conductor related upgrades planned for PRS interconnection.

A. For the PRS projects, the only medium-voltage distribution line work required is the overhead extension of the 12.5 kV line for a distance of about 0.3 miles (roughly five new wooden poles, plus cross arms, guys, conductor, and disconnect switches).

4. Are there any others?

A. The Q1045 system impact and facilities study reports conclude that two sets of line voltage regulators are to be installed. Line voltage regulators are intended to compensate for the normal voltage swings that occur on the electric grid as load increases which tends to drive voltage lower or as load abates which tends to drive voltage higher. The regulators automatically adjust the line voltage to deliver acceptable voltage to all customers on the distribution line after the voltage regulator. The regulators are not shown on the single line diagrams but are listed as being on tap lines from the line between the Pilot Rock Substation and the projects. They appear in the 3/27/2020 Q1045 system impact study report and the 9/4/2020 Q1045 facilities study report. The cost of the regulators appears in the 9/1/20 detailed expenditure report.

INTERCONNECTION PROTECTION REQUIREMENTS

5. What is Protection?

A. Protection equipment and systems are used in the electric power system primarily to detect and isolate electrical faults. Electrical faults are any undesired disturbance to the normal flow of electricity and thus power to the loads served. Most electrical faults in medium-voltage systems are from “shorts” where excessive electrical current flows. Shorts can be caused by vegetation, animals, lightning, or equipment failures. The intent of protective systems is to rapidly sense a fault and to rapidly isolate the faulted system or equipment from the rest of the electric system to minimize the impact of the power outage.

Protection sometimes includes the safe operation of the electric system including maintaining voltage and frequency for the proper operation of customers’ electronics and electrical equipment.

6. Describe the protection elements specified for PRS.

A. The existing substation feeder protection includes protective relays to detect and separate from electrical faults, but does not include systems to detect voltage or frequency abnormalities.

The new protection equipment being installed by PacifiCorp in the Pilot Rock Substation includes a modern electronic fault-detecting relay to replace the 60-year old feeder protective relays, a pair of transformer fault-detecting relays, potential transformers to detect abnormal line voltage when the feeder breaker has opened, and communication equipment.

7. What does Transfer Trip do?

A. Transfer trip is a scheme whereby the utility, upon detecting an electrical fault on its system, sends a signal to the distributed generator, tripping it off-line rapidly, to prevent the formation of an island. An “island” is a condition where the isolated generation (e.g. PRS1 and PRS2) and isolated load (e.g. load on PacifiCorp feeder 5W406) are in rough balance, enabling the isolated generation to continue operation.

An island is likely to experience abnormal voltage and frequency, which can damage customer and utility equipment if not eliminated rapidly.

8. What are the main components of the Transfer Trip scheme for the PRS projects?

A. The PRS projects' transfer trip system consists of the protective relay at the utility substation, a communication system from the substation to the project using a fiber link, and a protective device at the project to receive and implement disconnection of the photovoltaic generation.

9. Describe the transfer trip relay at PRS projects (Project TT relay).

A. The direct transfer trip (DTT) system proposed for the PRS projects includes a new substation feeder protective relay panel with an electronic relay capable of communicating with the project protection, a fiber optic communication system from the substation to the project, and a medium-voltage interrupter and protective relay at the project to receive the DTT signal and disconnect the photovoltaic system.

10. Describe the transfer trip relay at the substation (Substation TT relay)

A. The protective relay at the substation is a microprocessor-based device that is fed current and voltage signals from the medium-voltage system. It converts these voltage and current analog signals to digital form, then, using a microprocessor, performs calculations and logic to take corrective actions.

11. Describe the fiber communications link.

A. The fiber optic link is a communication system where light, either from a light-emitting diode or laser, is shined down a small glass fiber and detected by a photo-electric sensor on the receiving end. Because of the speed of light and the speeds at which the

LED can be modulated, fiber optics is well suited for high-speed communication, as are microwave transmitters and radio transmitters.

12. Tell us about the dead line checking.

A. PacifiCorp designed the substation feeder protection to detect faults, open the 5W406 circuit interrupter located at the Projects to clear the fault, then to quickly close (reclose) the circuit interrupter to restore power. The assumption is that many faults are momentary in nature and can be cleared by interrupting the fault current. Quick reclosing allows customers to be restored without requiring human intervention.

Reclosing the utility circuit interrupter at the substation into the PRS Projects can lead to equipment damage from high transient currents and voltages if the PRS Projects are online. Therefore PacifiCorp will install a “dead line” check system to monitor the voltage on the Project side of the feeder circuit interrupter at the substation and delay reclosing the circuit interrupter at the substation until no voltage is detected. The potential transformers required for the dead line check system will require the addition of a steel structure in the outdoor substation yard.

13. Are there any other components of the TT scheme at PRS?

A. Power supplies and batteries are used at both the substation and project to provide reliable power to the protective relays. Various conduits, control houses, and enclosures are needed to provide environmental and physical protection for the DTT equipment. Engineering is needed to program the protective relays and to design the entire relay and communication systems.

METERING REQUIREMENTS

14. What does metering do?

A. Metering provides information regarding the power consumed or produced by a generator. Just like the meter on a home or business that measures the energy consumed so that billing can be performed, the meter on a generator serves the same function. A bi-directional meter, such as the ones specified for PRS Projects, reads flow of power in either direction (generation or consumption).

15. What are the main components of the metering scheme for the PRS projects?

A. Each medium-voltage meter includes the medium-voltage potential and current transformers,[1] the meter socket and electronic meter, supporting structures and wires for the equipment, and the communication media needed to transmit the meter data.

16. Describe the "communication media" mentioned above.

A. Communication media includes any equipment or communication path used to promulgate a signal from one protective device to another or from the meter to the centrally-located meter-reading computer. The typical meter installed at a distributed generation site will use a cellular data modem to send and receive data over the cellular phone network, much the way a modern cell phone sends and receives data. Utilities tie their billing meter systems to the cellular network to gather data from meters.

TELEMETRY REQUIREMENTS

17. What is telemetry?

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[1] The meter is an electronic device designed for connection to low voltages (<600V). Because the medium-voltage distribution line is operating at 12,470V, potential transformers and current transformers are used to provide inputs at safe voltage and amperage to the meter.

A. Telemetry is the quasi-real time communication of situational information to a remote location.

18. What are the main components of the telemetry scheme at the PRS projects?

A. A remote terminal unit (RTU) will gather project data (MW, MVAR, etc.) and communicate it back to a central location via fiber optic communication link from the projects to the Pilot Rock substation, and radio link from the substation to PacifiCorp's existing system at Cabbage Hill substation.

19. Is Telemetry a requirement for interconnection?

A. PacifiCorp (and Bonneville Power Administration) requires telemetry for projects 3MW or larger. Neither PRS1 nor PRS2 is 3MW, but PacifiCorp has opted to require telemetry for both. After initially assigning cost responsibility to the Projects, PacifiCorp has offered to pay for telemetry.

20. Are there any other components of the telemetry scheme?

A. The RTU is housed in a small control house or outdoor enclosure that provides power and environmental protection. The control house or enclosure includes batteries and a battery charger to provide the 48VDC used by the RTU and its communication equipment. PacifiCorp initially specified a $600,000 control house but was challenged and switched to a smaller metal equipment enclosure instead.

21. Have you described all of the PRS interconnection facilities?

A. PacifiCorp additionally is requiring the installation of an annunciator panel in the substation. This panel is a box filled with lights that illuminate to provide the local operator with a quick indication of the state of the power system. It is my understanding that after initially assigning cost responsibility to the Projects, PacifiCorp has agreed to pay for the substation annunciator panel.

PacifiCorp has indicated a concern about fault current flow into the substation power transformer should the transformer suffer a failure. To detect such situation, PacifiCorp has indicated that a transformer relay system will be installed to detect abnormal fault current flow into the transformer and trip the distributed generation. This new microprocessor-based electronic relaying system will provide improved fault detection, lower maintenance costs, and improved situational awareness for PacifiCorp.

ASSIGNMENT OF COSTS

22. Is PacifiCorp requiring Sunthurst pay for all of the interconnection facilities, above?

A. According to the documents I have reviewed, Sunthurst will pay for all work performed with two exceptions: PacifiCorp will pay for the P1-111 annunciator and for the telemetry RTU:

		Cost			**"Necessary"?**
	Item	**Sunthurst**	**PacifiCorp**	**Installer**	
1	Conductor/voltage	100%		PacifiCorp	Yes
2	Protection	100%		PacifiCorp	Yes
3	Metering	100%		PacifiCorp	Yes
4	Telemetry	Fiber, land, power, cabling	RTU	PacifiCorp	No
5	P1-111 panel	Total cost less $15k	$15K	PacifiCorp	No
6	Voltage regulators			PacifiCorp	No

PacifiCorp has included in the costs to be borne by Sunthurst all of the interconnection-necessitated substation, distribution and COP costs and the engineering and project management associated with that work. In addition to interconnection-necessitated additions, PacifiCorp is installing a P1-111 panel, line voltage regulators, and a telemetry package, which are not necessary for the interconnection but will be installed as part of the interconnection facility construction. PacifiCorp offered, in an August 7 letter, to credit Sunthurst $15,000 for the P1-111 panel, which PacifiCorp has designed but not installed. It is not clear what the $15,000 is based upon, and whether it reflects the full cost of the P1-111 panel, including completed engineering, overhead, surcharge, and contingency. PacifiCorp, in its revised Q1045 Facilities Study dated September 4, 2020, removed the RTU from Sunthurst's (PRS1 and PRS2's) assigned costs. However, Sunthurst is still required to install control cabling and conduit from PRS1 and PRS2 source devices to PacifiCorp's RTU. It is still required to provide an easement for PacifiCorp to install an enclosure for its RTU, and to provide AC power to PacifiCorp's RTU enclosure.

23. What is the total estimated cost to Sunthurst?

A. According to the most recent contract documents from PacifiCorp, the estimated cost of interconnecting PRS1 is $700,000 (9/2/20) and the estimated cost of interconnecting PRS2 is $300,321 (9/1/20), for a total estimated cost of $1,000,321.

24. What is the total estimated cost to PacifiCorp?

A. PacifiCorp's costs to install the P1-111 annunciator panel and the RTU are not specified in the interconnection studies. In a letter Dated August 7, 2020, PacifiCorp stated that removal of the RTU from the required facilities saved Sunthurst "approximately $525,000," and removal of the P1-111 panel saved Sunthurst about $15,000. **Sunthurst/211.**

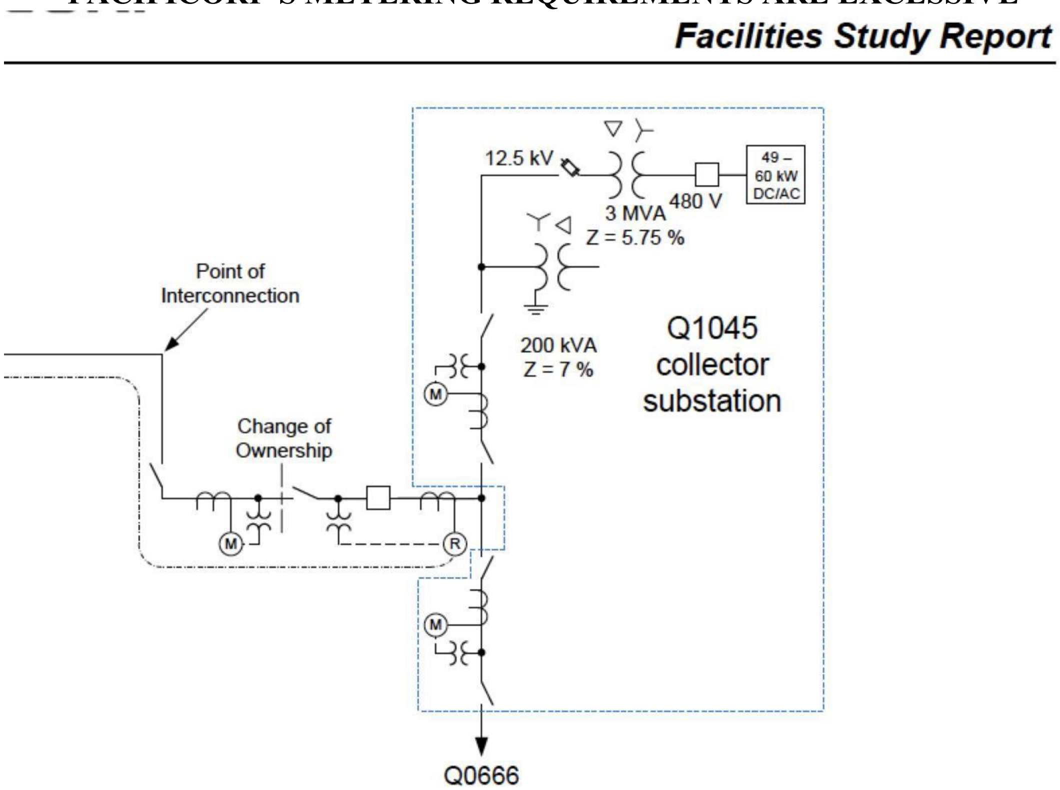
25. Who is responsible for installation?

A. Installation work performed in the Pilot Rock Substation and in the medium-voltage distribution line leading to the projects is being performed by PacifiCorp. Installation of primary metering at the project POI is being performed by PacifiCorp. Sunthurst, in addition to installing the photovoltaic generation system, is responsible for the protection equipment installed at the POI. Sunthurst also is responsible for installing control lines delivering analog data from its projects to PacifiCorp's RTU.

III. REASONABLENESS OF INTERCONNECTION DESIGN, COST, AND COST RESPONSIBILITY

This section discusses interconnection requirements that are unreasonable in scope, unreasonable in cost, and/or not reasonably allocated between Sunthurst and PacifiCorp.

PACIFICORP'S METERING REQUIREMENTS ARE EXCESSIVE



1. The one-line diagram, above, is from PacifiCorp Q1045 Facilities Study Report. Will you please describe the metering scheme PacifiCorp proposes for PRS1 and PRS2, above?

A. PacifiCorp proposes to use three medium-voltage-connected bi-directional electric metering systems. Each metering system, includes a wood power pole to support the equipment, a cluster mount to support the potential and current transformers, three medium-voltage potential transformers, three medium-voltage current transformers, a meter socket, an electronic meter, a cellular modem, and miscellaneous conduits, hardware and wire.

PacifiCorp shows one meter measuring the Pilot Rock Solar 1 power flows, one meter showing the Pilot Rock Solar 2 power flows, and a 3rd meter measuring the combined power flows from both projects.

2. Are three meters necessary to interconnect PRS1 and PRS2?

A. No. The data from any two of the meters will provide the same data as all three meters. This is known as Blondel's Theorem.

3. What is another way to meter PRS1 and PRS2 using two meters:

A. There are two feasible approaches to determine the combined power flows from PRS1 and PRS2 without using a 3rd entire metering system. Both approaches are widely used and are not novel. If we start by assuming that the meters on PRS1 and PRS2 are installed, the data can be summed digitally or electrically.

Using the digital method, the time interval data stored in each meter, when the internal clocks in the meters are roughly synchronized, can be summed to determine the total power flow. For example, if in one 5-minute interval one project is seen to have

1MW of power flow and the other is seen to have 2MW of power flow, we know that the sum of the two projects in that 5-minute interval will be 3MW.

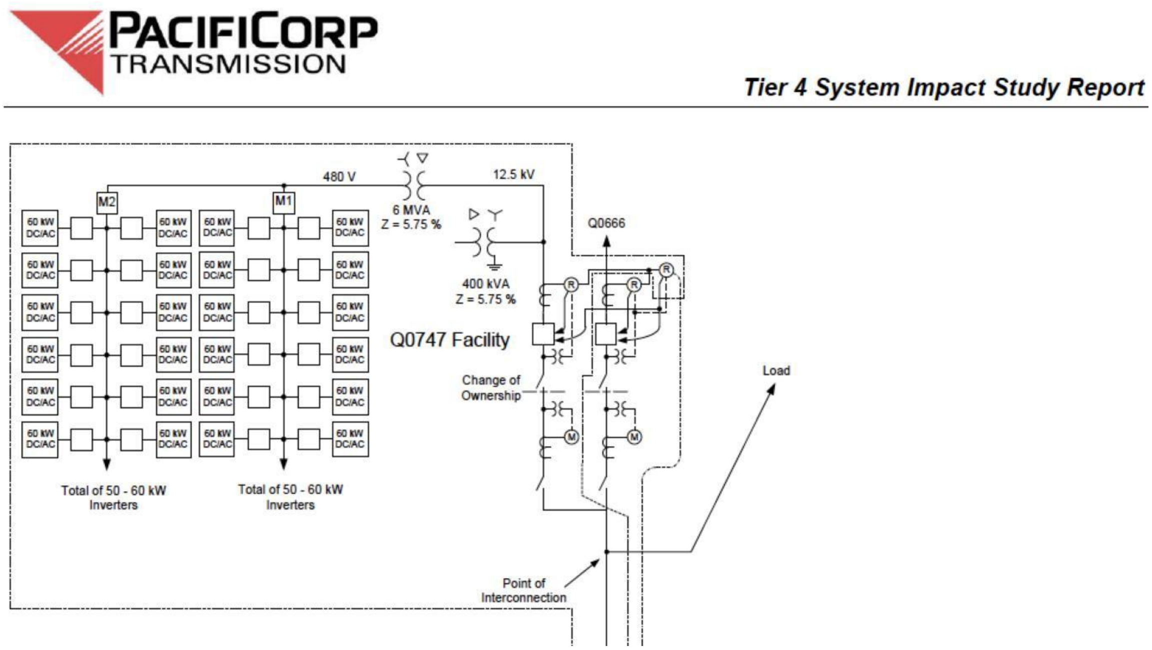
Using the electrical method, the currents flowing through the PRS1 and PRS2 meters can be placed in parallel and used as the measuring current feeding into a 3rd meter. This allows the 3rd meter to accurately measure the total power flow. For example, if 1 Amp is flowing through the PRS1 meter and 2 Amps is flowing through the PRS2 meter, then the sum of these currents can be measured in a 3rd meter to determine the total power flow.

4. Is the COP meter necessary as a backup in case PRS1 or PRS2 meters fail?

A. Electric meters are well made and extremely reliable. The utility does not install redundant metering on electrical loads and meters have a service life of 30-50 years. When a rare meter failure component failure occurs, utilities have many methods available to estimate meter readings. If a single current or potential transformer fails, the resulting power flow will be only 2/3 of the actual. Where the customer has continuous performance monitoring, such as that used at typical larger distributed generators, this data can be correlated with the utility data to provide a tool for estimating data upon meter failure. If the utility has installed an RTU and telemetry to gather data in real time, this data is saved and the historical data can be used to estimate missing data. There are many options available to the utility for estimating missing data when necessary, though it is seldom necessary.

5. Are two meters unsafe?

A. No. Electrical operations crews will never rely solely on the data from an electric meter to determine if a generator is operating. PacifiCorp requires that all distributed generators be equipped with line disconnect switches that allow PacifiCorp to disconnect the DG from the distribution system. This mandatory disconnect switch is shown to the left of the Change of Ownership in the above diagram. The stated purpose for this switch is to provide PacifiCorp with a means of safely and securely disconnecting DG from the grid.



6. The one-line diagram, above, is from PacifiCorp Q0747 System Impact Study Report. Please compare the metering scheme in Q0747 to the metering scheme in Q1045:

A. Both diagrams show PRS1 and PRS2 collector systems tying into PacifiCorp's 12.5 kV distribution system at a common Point of Interconnection. (Q0666 is PRS1; Q0747 was PRS2 when PRS2 was a 6MW design). Both meter PRS1 and PRS2 separately, prior to the POI. However the Q1045 scheme has a third meter at the POI whereas the Q0747 scheme does not.

7. How do you explain this difference?

A. In the above diagram, each project has a meter and each project has a circuit interrupter. The two projects are built and operated as completely independent of each other. PacifiCorp deems two meters adequate in this early version of the project and in the later development of this project, PacifiCorp deems two meters inadequate. If these were two projects, owned and developed by different entities, connecting at the same POI, the use of the two meters is exactly what I would expect to see.

8. What is PacifiCorp Policy 138, "*Facility Connection (Interconnection) Requirements for Distribution Systems 34.5 kV and Below*"?

A. This 65-page document is the written policy established by PacifiCorp to provide for a uniform standard for the connection of distributed generation to PacifiCorp distribution systems operating at voltages of 34,500V and below. The portions discussing metering are attached as Exhibit Sunthurst/209.

9. What does PacifiCorp Policy 138 say about metering?

A. Section 4 of Policy 138 describes in general terms the metering systems PacifiCorp will require be installed for distributed generation. In general, the metering will be similar to that required for commercial retail electric service with the exception that meters must be able to measure power bi-directionally.

10. Does Policy 138 require metering at each facility and at the POI?

A. Policy 138 requires metering for each distributed generator but is mute on requiring aggregate metering for multiple projects. In my experience, PacifiCorp treats each distributed generator as an independent project based on the interconnection application.

11. What is the approximate distance from the facility metering point at PRS1 and PRS2, respectively, to the POI?

A. Based on the design information available, the distance from the PRS1 and PRS2 connections to the PacifiCorp medium-voltage supply are less than 400 feet.

12. Approximately how great are electrical losses on 400' between the COP meter and the PRS meters?

A. Making reasonable assumptions about the resistances of the conductor and load factors for PRS1 and PRS2, typical total losses between project meters and the COP meter are about 3,406W or roughly 0.07% of the plant output. Metering systems typically are accurate to about 1%. Accordingly, the losses between the project meters and the COP meter are far less than the meter's measurement error, meaning that they are undetectable with the metering system PacifiCorp plans to use.

13. Can they be estimated without a meter at the POI?

A. Conductor loss follows well known rules and can be reasonably estimated. The electrical resistance of the overhead conductors does vary slightly with temperature but reasonable assumption can be made as to the average operating temperature of the conductors. The remainder of the loss estimating is simple math based on Ohm's Law.

14. Is the three-meter requirement considered Good Utility Practice?

A. Good Utility Practice implies making a reasonable effort to provide reliable quality service at reasonable costs. Using a 3rd meter to estimate the total delivery of two distributed generator projects at one point provides little benefit to the utility. The third meter also creates an additional maintenance expense and adds another possible point of failure to the medium-voltage system. I do not consider the requirement for the 3rd meter Good Utility Practice.

15. In Data Request 3.2, Sunthurst asked PacifiCorp to describe any reason why eliminating the POI meter from the PRS1 and PRS2 metering scheme was not safe or effective. PacifiCorp replied:

[1] Without the metering equipment that PacifiCorp is requiring, the possibility exists that generation could flow onto PacifiCorp's system without PacifiCorp having the ability to monitor it which could lead to unsafe operating conditions for PacifiCorp's employees.

[2] Additionally, the "Alternative 1" metering proposal from Sunthurst Energy, LLC (Sunthurst Energy) is not effective (or acceptable) because PacifiCorp would not have a meter at the point of interconnection (POI) where the generation from both facilities is injected onto PacifiCorp's system. This is unacceptable as PacifiCorp must have a meter at the POI to ensure it knows how much energy is flowing onto its distribution system. A POI meter is standard industry practice.

[3] In addition, PRS1 and PRS2 are separate and distinct generation interconnection requests with two interconnection customers. Sunthurst Energy's proposal would create a scenario in which disputes are much more likely. First, if either meter were to fail then one or both facilities would be forced to cease operation as PacifiCorp would not have the ability to separate the generation of the two facilities. Allowing one of facilities to continue operation would potentially be discriminatory and put PacifiCorp in the position of having to defend either allowing only one facility to operate or disconnect both facilities.

[4] Second, Sunthurst Energy's metering proposal would force PacifiCorp to rely on the use of a calculation to determine meter values rather than on actual meter data. If PacifiCorp's meter interrogation system were to experience a timing error in which the timing of the reads of the two meters becomes misaligned, then Sunthurst Energy's proposal would not result in accurate data. In this scenario, the generation attributed to each project would be incorrect and lead not only to disputes between PacifiCorp, PRS1 and PRS2, but also potentially substantial accounting work to revise the data.

[5] Finally, as both PRS1 and PRS2 are proposing to participate in the Oregon Community Solar (OCS) program, the accuracy of the meter data for these facilities is even more

important. The OCS program requires generator owners to sign up subscribers for their solar generators. If there is a meter failure or a data calculation error as described above, under the OCS program not only is there a potential dispute or recalculation necessary for PRS1 and PRS2, but also potentially disputes or recalculations for dozens or even hundreds of subscribers. This scenario could lead to substantial accounting work for PacifiCorp and creates the possibility of hundreds of disputes with subscribers. Having three meters would substantially limit these potential issues.

16. What is your response to PacifiCorp's Answer, above?

A. I respond to each above-numbered paragraph with my corresponding numbered paragraph, below:

[1] No unsafe condition is created by the absence of the 3rd meter. If PacifiCorp learns of a meter failure, corrective action will be required. No utility crews will work on the electric systems without using the mandatory disconnect switches to assure that the generation is not operating.

[2] The added meter at the POI can be functionally provided either digitally or electrically without the costs of installing an entire 3rd metering system. The difference that a 3rd meter would possibly show is less than the metering error. In fact, the 3rd meter may "run fast" and overestimate production from the DG.S

[3] Since PRS1 and PRS2 are independent entities, standard interconnection practice requires independent metering. If either meter fails, that project could be taken off-line with no effect to the other project while repairs are being made. There is no mandate that both projects be taken out of service to repair the meter on one. In fact, the requirement for the 3rd meter has now created a worse-case scenario where the failure of the 3rd meter requires both projects to be taken out of service while repairs are made.

[4] The digital summation of data from metering points is common utility practice. Virtual net metering allows customers to digitally combine the load from several meters to be offset by the generation at different meters. Meter timing error can occur but the meters are utility-grade, meeting general commercial retail metering standards, and PacifiCorp will be regularly receiving data from the meters to allow determination of any timing error. If timing error is a problem in meters, the 3rd meter will also suffer from this same problem.

[5] Regardless of the number of virtual net meters that may be included in a community solar program, the problems of combining meters is nothing new. PacifiCorp is implying that meters fail or are inaccurate regularly and so there is a burden on PacifiCorp but there is no data supporting this hypothetical problem that would exist system-wide for every project.

OTHER FACILITIES THAT ARE UNNECESSARY

1. OAR 860-029-0010 defines "costs of interconnection" as the "reasonable costs of connection, switching, dispatching, metering, transmission, distribution, equipment necessary for system protection, safety provisions, and administrative costs incurred by an electric utility directly related to installing and maintaining the physical facilities necessary to permit purchases from a qualifying facility." Do you understand the above definition?

A. I find it to be pretty clear.

2. Do you consider the P1-111 panel a "cost of interconnection"?

A. Some technical requirements fall into the "it would be nice to have" category but not the "necessary for safe operation" category. Many substations, including Pilot Rock are not equipped with such panels. Presumably for this reason, PacifiCorp removed the P1-111 substation annunciator from Sunthurst's costs of interconnection, and I agree. If the annunciator is not a cost of interconnection, it seems to follow that all project costs arising from installing the P1-111 annunciator also are not “costs of interconnection.” A detailed cost estimate for Q0666 provided by PacifiCorp on September 4, 2020 shows $17,347 in direct costs for the P1-111 panel ($12,247 in direct material costs plus $5,100 in direct “external” costs). It therefore appears from the September 4 cost breakdown that Sunthurst is paying costs related to the P1-111 panel, despite PacifiCorp’s expressed intent to the contrary. If that is the case, I would say assigning these unnecessary interconnection costs to Sunthurst is unreasonable.

3. Based upon OAR 860-029-0010, would you consider telemetry a “cost of interconnection”?

A. Telemetry for projects under 3 MW is another feature that would be nice to have but is not necessary. Neither PacifiCorp, nor BPA, nor any applicable standard require telemetry for projects under 3 MW. If PacifiCorp required telemetry at PRS1 and PRS2 it would be treating them differently from other similarly-sized projects which have been allowed to build without telemetry. Presumably for this reason, PacifiCorp removed telemetry from Sunthurst’s costs of interconnection, and I agree.

If telemetry is not a cost of interconnection, it seems to follow that all project costs arising from installing telemetry also are not “costs of interconnection.” A detailed cost estimate for Q0666 provided by PacifiCorp on September 4, 2020 shows $3,798 for “SCADA Engineer”, which seems to be related to telemetry. Sunthurst/204. Furthermore, the Q1045 Facilities Study requires Sunthurst to provide an easement for location of the RTU facilities, the AC power supply, and all the wires and conduit necessary to supply data to the RTU from the Projects. Sunthurst may need to purchase additional equipment to provide the PacifiCorp RTU with the analog signals PacifiCorp requires. All of these costs arise from PacifiCorp's decision to install unnecessary telemetry with the interconnection facilities. Charging these costs to Sunthurst is unreasonable.

4. Based upon OAR 860-029-0010, would you consider the voltage regulators a "cost of interconnection"?

A. Voltage regulators may be necessary where the addition of new generation causes line voltages to fluctuate outside allowable limits. My own calculations indicate a voltage rise of less than 0.5% when both photovoltaic projects are operating at peak production. I have seen no supporting justification for the inclusion of the voltage regulators, which begs the question of whether they are being prescribed is to resolve an existing problem. Barring such evidence I believe that voltage regulators are not necessary and therefore not reasonably assigned to Sunthurst.

5. Based upon OAR 860-029-0010, would you consider the 0.9 mile fiber optic link to Pilot Rock substation a "cost of interconnection"?

A. PacifiCorp required Sunthurst to install fiber optic link, although a radio link likely would be cheaper. DTT system can reliably function using the slower spread-spectrum radio. Although DTT requires a communication for which fiber is well suited, any cost for fiber above the cost for radio is unnecessary.

6. Based upon OAR 860-029-0010, would you consider the dead line check system a "cost of interconnection"?

A. The dead line check system is one way to avoid reclosing a circuit interrupter into an energized line. It is not the only approach used. Another way is to slow the automatic reclose delay to provide additional time for generators and loads to disconnect. Most utilities are going away from rapid reclosing because of the problems they can cause industrial customers. With new electronic control systems, even a 0.1 second outage will require a complete shutdown and restarting of a process. Changing from a 0.35-second interval, which I understand is PacifiCorp's current setting on circuit 5W406, to a 5-second interval can achieve the same functionality at minimal risk or expense. Most utilities that use a 5-second reclosure interval do not also use the dead-line check.

Where rapid reclosing is used, large motor loads can also backfeed into the utility grid after an outage and reclosing can cause damage to the large motors. For rapid reclosing, the dead-line check is a good idea, with or without generation, to mitigate the risk of damage to large motors.

COSTS THAT APPEAR UNREASONABLY HIGH

7. Do any of the costs seem unreasonable to you?

Avian protection. In reviewing the detailed cost estimates for Q0666 and Q1045, the cost of several items seems unusually high. I mentioned already the $7,650 for "avian protection." The cost to install avian protection is not commensurate with the costs for a few feet of insulating tubing. I note that at OCS24 (a similar-size Sunthurst PV project located near Pilot Rock), PacifiCorp's estimated total cost for avian and animal enhancements is only $438.

Junction boxes. The cost of junction boxes for potential and current transformers also seems extreme. The Q0666 detailed estimate, page 4, lists four junction boxes with unit prices between $2,040 and $4,080. The J-Box normally used for yard connections to VTs and CTs is typically a mild-steel metal box about 12"x12"x6" and costs under $100.

Fiber optic cable. The $60,000 direct cost of 0.9 miles of fiber optic cable for PRS1 and PRS2 equates to nearly $10.23/linear foot (LF). This seems questionably high compared to the following recent data points obtained from Community Solar Facilities Studies (FS) and System Impact Studies (SIS) published on PacifiCorp's OASIS website:

OCS27 FS 1 mile of fiber $38,000. $7.20/ft

OCS38 SIS 1.6 miles fiber for $29k. $3.43/FT

OCS25 FS, 3.5 miles of fiber for $146k. $7.90/ft

OCS35 SIS 0.7 miles fiber for $29k. $7.85/ft

Accrued Engineering and Management costs from Non-"interconnection facilities." Further, because the engineering and project management expenses accrued include items that are no longer the responsibility of the generation projects, the engineering and costs for those items remain embedded in the costs and should be backed out. Where it is not possible to itemize specific costs, a proportional decrease in engineering and project management costs should be implemented.

Engineering hours expended on Q0666. As stated elsewhere, I will reiterate here, that accrued engineering and project management costs, both internal and external, have been incurred that are related to portions of the work that have been removed as requirements. In addition to the materials and installation time for these activities, a reasonable allocation of engineering and project management time should also be assigned to these activities and not charged to the projects.

Remaining engineering budgeted. It is likely that there is some time budgeted in 2021 for engineering and project management that are related to elements of work that are no longer considered the responsibility of the projects. The estimated labor for 2021 needs to be reexamined and re-estimated considering the reduced scope of work.

FACILITIES THAT ARE REQUIRED BUT NOT REASONABLY ASSIGNED SOLELY TO SUNTHURST

8. Does advanced fiber optic communication infrastructure provide system benefits?

A. The fiber optic cable from the substation to the project specified for the direct transfer trip (DTT) system is also being used to link the remote terminal unit installed by PacifiCorp at the project. In fact, the RTU requires the higher data speeds and bandwidth provided by the fiber; the DTT system can reliably function using the slower spread-spectrum radio. With no requirement for a data-intensive RTU at the project, the fiber optic system could be replaced by a spread-spectrum radio system at likely lower cost.

Furthermore, PacifiCorp's requirement of a 48-fiber fiber optic cable is excessive. Since only two fibers are needed to establish a bi-directional communication loop, with the DTT requiring one pair and a PacifiCorp RTU requiring a second pair, 44 of the 48 fibers are spare and unused. Because fibers are made of glass and are fragile, having spares is critical, but a 12-fiber cable is more than adequate. Although it is accepted that the incremental costs to install 48 fibers rather than 12 fibers is small, it is unlikely that 48 fibers will ever be required for any Project-related purpose and it therefore appears PacifiCorp values the extra pairs for its own future use.

9. Does the 0.3 miles of new conductor, from the Point of Interconnection (POI) to the COP, provide system benefits?

A. The 0.3 miles is an enlargement to PacifiCorp's existing distribution system. PacifiCorp will have the ability to serve new loads where it previously did not. PacifiCorp chose the location of the COP for the Projects. It could have required Sunthurst to own the 0.3 miles of line and make the COP at the closest existing PacifiCorp pole. The fact that PacifiCorp selected to put the COP at Project and not the POI shows that PacifiCorp values owning the 0.3 miles of new 12.5 kV line.

10. Are there other real, if imprecise, system benefits from the interconnection?

A. An electric grid is in fact a massively interconnected system; events hundreds of miles away will affect the power at any location. The presence of the photovoltaic generation at the medium-voltage distribution level reduces power flow on the transmission system, lowering losses, and reducing fuel used or water spilled in generating electricity.

Distributed generation may extend service life of substation transformers. When a distributed generator offsets power loads, the effect for the transformer is lower loading. For example, with 5MVA of load being served and 4MVA of generation, the transformer only sees 1MVA of power flow. The lower loading results in less heat dissipation inside the transformer and lower operating temperatures. The lower operating temperatures can add life to the transformer. The effects on life of loading are discussed in detail in ANSI/IEEE C57.92, "Guide for Loading Mineral-oil-insulated Power Transformers." Because of the dynamic nature of loads and distributed generation, there has not been a definitive analysis of the salubrious effects of distributed generation on transformer life.

The modern micro-processor protective relay required by the DTT system has many more functions than the existing analog protective relaying. A typical modern relay may have 100 or more functions of which 10-20 are typically used; the remainder are available. A modern protective relay provides detailed digital records of events that are not otherwise available. The ability to download and analyze detailed event records will provide PacifiCorp with data that can be used to improve the electric system.

The necessary facilities, including metering and protection, provide PacifiCorp with enhanced performance and situational awareness in a 60-year old substation that has not been modernized. There are benefits to PacifiCorp in that these facilities, installed at the expense of the distributed generator, will not need to be installed during any future modernization of the substation, saving PacifiCorp the costs in the future.

IV. PROPOSED MODIFICATIONS TO THE PROPOSED INTERCONNECTION AGREEMENTS.

1. What would you recommend to make the interconnection costs and allocation of costs more reasonable?

A. I have ten recommended modifications:

(1) Eliminate annunciator and telemetry related costs from Sunthurst's interconnection costs. All labor, material, and consulting costs for the P1-111 annunciator panel and telemetry included in the detailed Q1045 and Q0666 cost estimates should be paid by PacifiCorp, because those components are not necessary for PRS1 and PRS2 interconnection.

(2) Credit past and future expenditures on non-interconnection facilities. PacifiCorp should take an honest look at the sunk engineering costs that should not have been included in the final scope of work where the RTU and Annunciator are deleted from the scope.

Some proportional allocation of engineering and project management costs should be assigned to those items and paid by PacifiCorp (including overheads and PacifiCorp's blanket 8% Capital Surcharge). Similarly, PacifiCorp should state whether any of the Project Management, Engineering, and Project support (e.g. as-built drawings, de-/mobilization costs) resources in the interconnection scope of work will support PacifiCorp's work on associated non-interconnection facilities (telemetry, annunciator, etc). If yes, then the cost of any shared resources (including overheads and PacifiCorp's blanket 8% Capital Surcharge) should be equitably apportioned between Sunthurst and PacifiCorp.

(3) Credit Sunthurst its reasonable cost to accommodate PacifiCorp's telemetry. All telemetry-related costs borne by Sunthurst (described in Section III(3), above) should be reimbursed by PacifiCorp.

(4) Eliminate dead line checking. Most utilities are going away from rapid reclosing because of the problems they can cause industrial customers. Changing from a 0.35-second reclosing interval, which I understand is PacifiCorp's current setting on circuit 5W406, to a 5-second interval can achieve the same functionality at minimal risk and render the dead-line check system unnecessary.

(5) Eliminate Voltage Regulators. PacifiCorp needs to provide proof that the line voltage regulators are solving a problem created solely by the PRS1 and PRS2 generation and are not being installed to mitigate an existing condition. PacifiCorp already requires distributed generation to operate in a voltage-control mode where the distributed generator adjusts its reactive power flow to mitigate high or low voltages caused by

fluctuations in the distributed generation. Without demonstrated proof, the costs of the voltage regulators should not be assigned to the PRS1 and PRS2 projects.

(6) Eliminate 3-meters. PacifiCorp provided no rationale for the claim that digitally summing the PRS1 and PRS2 meters was unreliable, necessitating a 3rd metering system at the COP. Also, as an alternative to digitally summing metering data, it is very feasible to wire the PRS1 and PRS2 meters in a current-summing approach to feed a 3rd meter without the need to install a 3rd set of metering PT/CT and the pole and bracket required to support them. PacifiCorp should eliminate the COP meter or otherwise work with the customer to develop a cost effective and functional metering approach. Alternative approaches could include (a) metering PRS1 and PRS2 on the low voltage side, with a 3rd , mid-voltage, meter at the COP; or (b) PacifiCorp paying the costs of the 3rd meter.

(7) Revise excessive costs. At the very least, the estimated costs need to pass a reality check and not appear to be hyper-inflated. Three pieces of "avian" protection tubing that cost $7650 is unreasonable. A 12" x 12" metal box that costs $4000 is unreasonable. Fiber optic cable costs look high (on a $/LF basis) compared to similar small interconnections. PacifiCorp should justify those costs, revise them to be reasonable, or else remove them.

(8) Share cost of 0.3 mile line extension. Sharing the cost recognizes that PacifiCorp derives benefit from this addition to its distribution system. It lowers the cost of serving new customers in the vicinity. At the very least, if PacifiCorp ever in the future uses this line, paid for by the Projects, for other purposes, then PacifiCorp should be required to

compensate the Projects for that use. This type of shared cost and reimbursement for use is widely used in the utility industry.

(9) Share the cost of fiber communication. For communication, PacifiCorp and Sunthurst should split the cost of a 12-fiber cable. One fiber pair will serve the DTT; one fiber pair will serve the PacifiCorp's RTU, and the remaining fibers can be available for spares. PacifiCorp can pay the incremental cost difference if it desires 48-count fiber. If PacifiCorp objects, then Sunthurst could pay for a spread-spectrum radio system that provides the required DTT functionality at lower cost and PacifiCorp can pay fiber optics related costs, including engineering.

(10) Let Sunthurst self-perform construction. Because the regulations allow PacifiCorp to charge actual costs to the interconnecting customer, there is no incentive to PacifiCorp to be frugal or develop a more cost-effective design. PacifiCorp's high rates and overheads, including an 8% surcharge on all job costs, practically ensure that its construction costs will be well above market rates. On other interconnection projects I am familiar with, PacifiCorp allows the Project to supply and install equipment for PacifiCorp use.

2. Does this conclude your testimony?

A. Yes.