Community Solar Project Interconnection

Community Solar Project System Impact Study Report

Completed for

(“Applicant”)

OCS053

Proposed Point of Interconnection

Circuit 4R13 out of Stevens Road substation at 20.8 kV

(At approximately 42.467250°N, 122.778815°W.)

February 24, 2021

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1.0 DESCRIPTION OF THE COMMUNITY SOLAR PROJECT

(“Applicant”) proposed interconnecting 2.0 MW of new generation to PacifiCorp’s (“Public Utility”) circuit 4R13 out of Stevens Road substation located in Jackson County, Oregon. The project (“Project”) will consist of sixteen (16) Solectria XGI 1500 – 125 kW inverters for a total requested nameplate output of 2.0 MW. The requested commercial operation date is December 1, 2021.

The Public Utility has assigned the Project “OCS053.”

2.0 APPROVAL CRITERIA FOR TIER 4 INTERCONNECTION REVIEW

Pursuant to the Section I(1) of the Public Utility’s CSP Interconnection Procedures, a Public Utility must use the Tier 4 review procedures for an application to interconnect a Community Solar Project that meets the following requirements:

(a) The Community Solar Project does not qualify for or failed to meet Tier 2 review requirements; and

(b) The Community Solar Project must have a nameplate capacity of three (3) megawatts or less.

3.0 SCOPE OF THE STUDY

Pursuant to Section I(6)(g) of the CPS Interconnection Procedures, the System Impact Study Report shall consist of: (1) the underlying assumptions of the study; (2) a short circuit analysis; (2) a stability analysis; (3) a power flow analysis; (4) voltage drop and flicker studies; (5) protection and set point coordination studies; (6) grounding reviews; (7) the results of the analyses; and (8) any potential impediments to providing the requested Interconnection Service, including a non-binding informational NRIS portion that addresses the additions, modifications, and upgrades to the Public Utility’s Transmission System that would be required at or beyond the point at which the Interconnection Facilities connect to the Public Utility's Transmission System to accommodate the interconnection of the CSP Project In addition, the System Impact Study shall provide a list of facilities that are required as a result of the Community Solar Project request and non-binding good faith estimates of cost responsibility and time to construct.

4.0 PROPOSED POINT OF INTERCONNECTION

The Applicant’s proposed Community Solar Project is to be interconnected to the Public Utility’s distribution circuit 4R13 out of Stevens Road substation via a 20.8 kV primary meter. The proposed Point of Interconnection (“POI”) will be located at approximately 42.467250°N, 122.778815°W located in Jackson County, Oregon. Figure 1 below is a one line diagram that illustrates the interconnection of the proposed Community Solar Project to the Public Utility’s system.

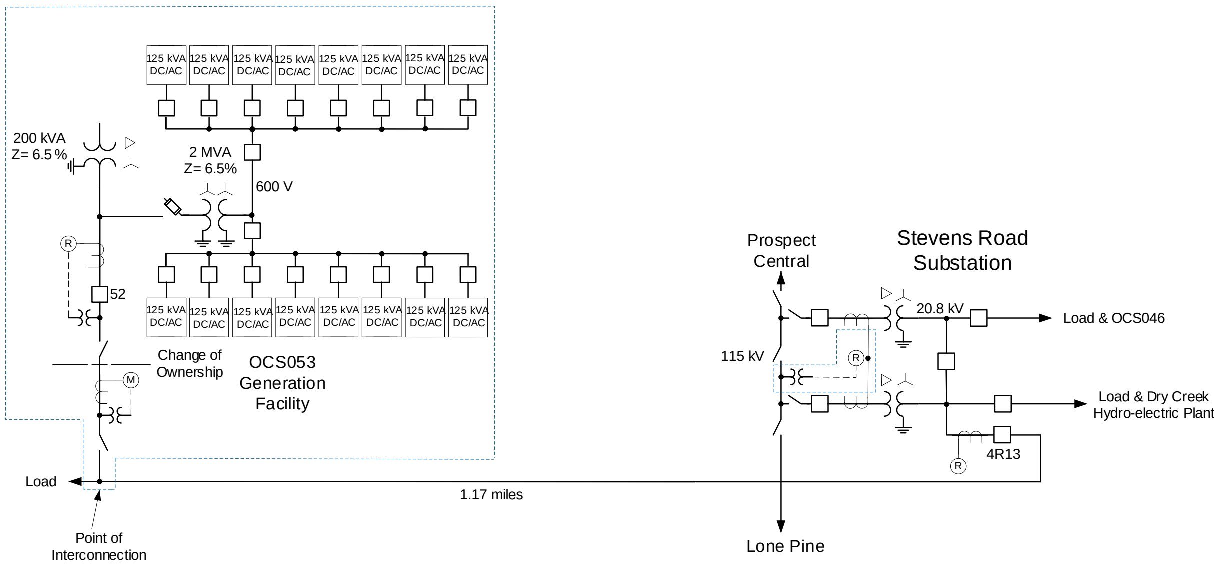

Figure 1: System One Line Diagram

5.0 Study Assumptions

- All active higher-priority requests for transmission service and/or generator interconnection service (including requests in the traditional interconnection queue and other requests in the Community Solar queue) in the local area of the requested POI will be considered in this study and are listed in Appendix 1. If any of these requests are withdrawn, the Public Utility reserves the right to restudy this request, as the results and conclusions contained within this study could significantly change.
- The Applicant's request for interconnection service in and of itself does not convey transmission service.
- This study assumes the Project will be integrated into Public Utility's system at the agreed upon and/or proposed POI.
- The Applicant will construct and own any facilities required between the POI and the Project unless specifically identified by the Public Utility.
- Line reconductor or fiber underbuild required on existing poles will be assumed to follow the most direct path on the Public Utility's system. If during detailed design the path must be modified it may result in additional cost and timing delays for the Applicant's project.
- Generator tripping may be required for certain outages.
- All facilities will meet or exceed the minimum Western Electricity Coordinating Council ("WECC"), North American Electric Reliability Corporation ("NERC"), and Public Utility performance and design standards.
- The line extension is assumed to originate at facility point 1336001-029301.
- The generators were assumed to operate during daylight hours, 7 days per week, 12 months per year. The generation contribution at the POI was assumed to be 2000 kW at unity power factor.
- This study assumes that the Applicant will provide constant power factor control at unity power factor (100% PF).

- A Stevens Road transformer T-5040 daytime minimum load value of 1793 kW, unity power factor was assumed based on measurements. The new generation is expected to provide reverse flow to the substation transformer.
- A Stevens Road circuit 4R13 daytime minimum load value of 2343 kW, unity power factor was assumed based on measurements. The new generation is not expected to provide reverse flow to the circuit.
- This report is based on information available at the time of the study. It is the Applicant's responsibility to check the Public Utility's web site regularly for transmission system updates (https://www.oasis.oati.com/ppw)

6.0 REQUIREMENTS

6.1 COMMUNITY SOLAR PROJECT REQUIREMENTS

The Community Solar Project and Interconnection Equipment owned by the Applicant are required to operate under constant power factor mode with a unity power factor setting unless specifically requested otherwise by the Public Utility. The Community Solar Project is expressly forbidden from actively participating in voltage regulation of the Public Utility's system without written request or authorization from the Public Utility. The Community Solar Project should have sufficient reactive capacity to enable the delivery of 100 percent of the plant output to the POI at unity power factor measured at 1.0 per unit voltage under steady state conditions.

Generators shall be capable of operating under Voltage-reactive power mode, Active power-reactive power mode, and Constant reactive power mode as per IEEE Std. 1547-2018. This project shall be capable of activating each of these modes one at a time. The Public Utility reserves the right to specify any mode and settings within the limits of IEEE Std 1547-2018 needed before or after the Community Solar Project enters service. The Applicant shall be responsible for implementing settings modifications and mode selections as requested by the Public Utility within an acceptable timeframe. The reactive compensation must be designed such that the discreet switching of the reactive device (if required by the Applicant) does not cause step voltage changes greater than +/-3% on the Public Utility's system.

All generators must meet applicable WECC low voltage ride-through requirements as specified in the interconnection agreement.

As per NERC standard VAR-001-1, the Public Utility is required to specify voltage or reactive power schedule at the POI. Under normal conditions, the Public Utility's system should not supply reactive power to the Community Solar Project.

6.2 TRANSMISSION SYSTEM MODIFICATIONS

No transmission system modifications are required to accommodate the Applicant's proposed facility.

6.3 DISTRIBUTION/TRANSMISSION LINE MODIFICATIONS

- The load flow model was modified from its present state to its future state by including the following construction items:
  - Issue revised load tap changer settings on Stevens Road T-5040 of:
    - Base Voltage = 122
    - R Compensation = 0
    - X Compensation = 0
  - Extend 20.8 kV facilities from the existing facility point 01336001-029301 to the POI. This line extension will require a minimum of two new Utility poles. A three-phase, gang-operated, load break disconnect switch is required on the first pole. A primary metering assembly is required on the second pole. Additional poles may be required if other Utility departments specify a control house and/or Utility protective device. Note that the Applicant's single line diagram shows an Applicant owned recloser near the utility meter. The Applicant will be responsible for obtaining all necessary permissions and easements.

6.4 EXISTING BREAKER MODIFICATIONS – SHORT-CIRCUIT

The increase in the fault duty on the system as the result of the addition of the Community Solar Project with photovoltaic arrays fed through 16 – 125 kW inverters connected to a 2 MVA 20.8 kV – 600 V transformer with 6.5% impedance will not push the fault duty above the interrupting rating of any of the existing fault interrupting equipment.

6.5 PROTECTION REQUIREMENTS

The OCS053 Community Solar Project will need to disconnect from the network in a high-speed manner for faults on the 20.8 kV line on circuit 4R13 out of Stevens Road substation. The minimum daytime load on circuit 4R13 is 2,343 kW which is above the maximum potential power output of the proposed OCS053 Community Solar Project. For this reason, the imbalance condition of the load and generation can be relied upon to cause the high-speed disconnection of the generating facilities for faults on the distribution system.

There are two 115 – 20.8 kV transformers at Stevens Road substation. The 20.8 kV bus arrangement at the substation permits the feeder circuits to be connected to either of the transformers or to both transformers in parallel. The normal configuration is to have circuits 4R13 and 4R41 connect to the same transformer. Circuit 4R17 is connected to the other transformer. Distributed generation either already in service or proposed at Stevens Road substation are the existing Dry Creek Hydro and Community Solar Projects OCS046 and OCS053. With the mix of generators and inverter sources the OCS053 project will need to be tripped high-speed for faults in either of the 115 – 20.8 kV transformers or for faults on the 115 kV transmission line to Stevens Road substation. To accomplish this, transfer trip will need to be sent from Stevens Road substation to the POI recloser for the OCS053. With both the combination of the generation source types, the potential power output of these generators and the minimum day time load connected to Steven Road substation a high-speed disconnection of the generation facilities by their own relay systems will not reliably occur during these fault conditions. The faulted transformers need to be isolated to minimize the damage to the transformer. The sources need to be disconnected from the transmission line faults to permit automatic re-energization of the line from the transmission network sources. The transformers have relay circuits to detect the transformer faults so no additional relay circuits will be needed to detect the problems. Due to the electrical isolation the transformer windings providing 115 kV line faults cannot be detected with the relays connected to instrument transformers on the 20.8 kV side. A set of line relays will need to be installed at Stevens Road Substation. These relays will be connected to current transformers on the 115 kV bushings of the transformers and 115 kV voltage instrument transformers which will need to be added as part of this project. The existing feeder circuit relay associated with 4R13 has the capability to communicate with the POI recloser relay.

The 20.8 kV circuit recloser planned to be installed at the OCS053 Project will need to equipped Schweitzer Engineering Laboratories (SEL) 651R relay/controller and voltage instrument transformers mounted on the utility side of the circuit recloser. The 651R will perform the following protection functions:

1. Detect faults on the 20.8 kV equipment at the Community Solar Project
2. Detect faults on the 20.8 kV line to Stevens Road Substation
3. Monitor the unbalance current flowing through the grounding transformer and protect the transformer from damage due to phase unbalances on the 20.8 kV circuit
4. Monitor the voltage and react to under or over frequency, and /or magnitude of the voltage
5. Receive transfer trip from Stevens Road Substation

6.6 DATA REQUIREMENTS (RTU)

Due to the power size of the project no real time data is required from this project at the Public Utility's control centers.

6.7 COMMUNICATION REQUIREMENTS

A communication system is required for transfer trip between Stevens Road Substation and the POI recloser. This will be done via an SEL-3031 radio link.

6.8 SUBSTATION REQUIREMENTS

At Stevens Road substation, three 115 kV CCVTs will be installed. A new relay panel will be installed in the control house.

6.9 METERING REQUIREMENTS

Interchange Metering

The metering will be located on the high side of the Applicant generator step up transformer at the POI. The metering transformers will be installed overhead on a pole per distribution DM construction standards. The meter itself will be installed at the base of the pole. The Public Utility will procure, install, test, and own all revenue metering equipment. The metering will be bi-directional to measure KWH and KVARH quantities for both generation received and back feed retail load delivered. There will be no additional station service metering for supplying generation load. The metering generation and billing data will be remotely interrogated via the Public Utility's MV90 data acquisition system.

Station Service/Construction Power
The Applicant must arrange distribution voltage retail meter service for electricity consumed by the project when not generating. Temporary construction power metering shall conform to the Six State Electric Service Requirements manual. Applicant must call the PCCC Solution Center 1-800-640-2212 to arrange this service. Approval for back feed is contingent upon obtaining station service.

7.0 Cost Estimate

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

Project Administration *Project management, administrative support*	$17,000
Relay Setting Development *P&C Engineer and Relay Technician*	$27,000
Distribution *Line extension and tap changer settings*	$57,000
Metering *Metering equipment*	$18,000
Communications *Communications (radio) at POI and Steven Road Substation*	$46,000
Stevens Road Substation *Install three CCVTs and one relay panel*	$138,000
Other Costs *Capital surcharge and contingency*	$70,000
Total	**$373,000**

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

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

8.0 SCHEDULE

The Public Utility estimates it will require approximately 15-18 months to design, procure and construct the facilities described in this report following the execution of an Interconnection Agreement. The schedule will be further developed and optimized during the Facilities Study.

Please note, the time required to perform the scope of work identified in this report does not support the Applicant's requested commercial operation date of December 1, 2021.

9.0 PARTICIPATION BY AFFECTED SYSTEMS

Public Utility has identified the following Affected Systems: None

Copies of this report will be shared with each Affected System.

10.0 APPENDICES

Appendix 1: Higher Priority Requests
Appendix 2: Informational Network Resource Interconnection Service Assessment
Appendix 3: Property Requirements
Appendix 4: Transmission/Distribution Study Results

10.1 Appendix 1: Higher Priority Requests

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

Queue #	Size (MW)
721	55
741	40
849	100
905	50
971	2.7
1120	3
1126	8
1147	2.999
1160	70
OCS003	0.8
OCS004	0.8
OCS019	0.882
OCS020	0.594
OCS025	2.8
OCS034	0.978
OCS036	1.125
OCS037	1.5
OCS039	2.25
OCS040	1.64
OCS042	0.13
OCS044	0.447
OCS046	2.25
OCS047	2.25
OCS048	1.5
OCS049	2.99
OCS050	1
OCS051	1.5
OCS052	0.36

10.2 Appendix 2: Informational Network Resource Interconnection Service Assessment

The study results described above reflect an energy resource interconnection service ("ERIS") evaluation, modified in the CSP program rules to examine only generation and load conditions local to the requested CSP project's interconnection point (sometimes referred to as the "zoomed in view"). The "zoomed in view" functions to: (1) study the project's proposed interconnection without considering certain existing or higher-queued requests outside of the local area; and (2) to inform whether the CSP facility must cap its project to mitigate, although not eliminate, the risk of potential deliverability-related network upgrades to accommodate the proposed CSP generator.

By contrast, the following informational section provides a network resource interconnection service ("NRIS") evaluation performed with traditional assumptions, i.e., not modified to examine only local generation and load conditions, but rather one that assumes that all existing interconnections, higher-queued requests for interconnection service (in both the traditional and CSP queue), and generators with executed contracts beyond the local area are in-service. Depending on the severity of the conditions created when absorbing additional generation (capped or not capped) in that broader, "zoomed out" area, the local area-focused generator size cap developed in the "zoomed in" examination may not be sufficient to mitigate the need for deliverability-related network upgrades. Regardless of this report's informational NRIS results, the deliverability-related network upgrades ultimately necessary to accommodate the proposed CSP generator will depend on conditions present when the future transmission service study is performed, as well as whether network upgrade alternatives are available at that time.

Considering existing generation and higher-queued requests to interconnect in the Southern Oregon/Northern California area where the CSP generator proposes to interconnect, 0.36 MW of additional generation can be absorbed. As a result, the Public Utility determines that no additional network upgrades would be required for the aggregate of generation in the local area to be delivered to the aggregate of load on the Public Utility's transmission system (the NRIS study scope).

10.3 APPENDIX 3: PROPERTY REQUIREMENTS

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

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

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

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

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

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

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

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

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

10.4 APPENDIX 4: TRANSMISSION/DISTRIBUTION STUDY RESULTS

The Applicant's facilities must be operated in a manner so as not to cause objectionable power quality issues to other Distribution Provider customers. Voltage fluctuations caused by the Community Solar Project are required to meet the Distribution Provider's Engineering Handbook, Voltage Fluctuation and Flicker, Standard 1C.5.1 which is found at https://www.pacificpower.net/about/power-quality-standards.html Table 1 of Standard 1C.5.1 indicates that for this project the medium voltage planning levels for voltage fluctuation under any condition is a Pst < 0.9 and a Plt < 0.7. It is the Applicant's responsibility to design and construct a system capable of meeting these levels. Specific system information will be provided on request to the Applicant for design purposes. During operation if measured voltage fluctuation levels exceed the limits specified in Standard 1C.5.1 the Applicant is required to cease generation until the condition is mitigated. The requirement for the Applicant's system to meet Standard 1C.5.1 will be incorporated in the interconnection contract. The Distribution Provider may, at its' discretion, disconnect the Applicant's facilities until mitigations to meet these standards are made. The Applicant must also comply with all of the Distribution Provider's Engineering Handbook standards addressing power quality, including but not limited to Voltage Level, Voltage Balance, Harmonic Distortion, and Voltage Frequency.

The calculated voltage fluctuation from full generation to no generation in the light load case was 0.3%.

For calculation of the forecasted voltage fluctuation, it was assumed that the power flow from the Applicant would change from full generation to no generation during a one minute interval.

Six cases were assembled and studied at the 20.8 kV distribution voltage level.

- Daytime minimum load, no generation.
- Daytime minimum load, full generation.
- Summer peak, no generation.
- Summer peak, full generation.
- Winter peak, no generation.
- Winter peak, full generation.

The following substation load tap changer output voltages were assumed in the respective cases. The values are based on new LTC settings:

- Daytime minimum load case: 1.017 per unit.
- Summer peak case: 1.017 per unit.
- Winter peak case: 1.017 per unit.

Three base cases were developed and studied in power flow simulation at the transmission level covering summer peak load, winter peak load and daytime minimum load conditions. Analysis was performed on each case evaluating two transmission system configurations prior to and with the requested OCS053 generation:

- Normal transmission configuration: 115 kV Line 19 closed between Lone Pine and Prospect Central substations; 115 kV Line 12 open between Prospect Central and Tiller substations; 69 kV Line 6 open between Prospect Central and Dodge Bridge substations; Stevens Road substation supplied from Lone Pine 115 kV source via 115 kV Line 19.
- Contingency transmission configuration: Same as normal transmission configuration except 115 kV Line 19 is open between Lone Pine and Stevens Road substations; 115 kV Line 12 path closed between Prospect Central and Dixonville/Nickel Mountain substations; Stevens Road substation supplied from Dixonville/Nickel Mountain 115 kV sources via 115 kV Line 12.

Contingency transmission configuration for the Public Utility's system is defined as any configuration other than normal transmission configuration.

A power flow simulation of adding the OCS053 Community Solar Project (operating at 2.0 MW maximum) to the Public Utility's substation and transmission system predicted the following:

- 115 kV Line 19 rated 113 MVA will be loaded to 110 MVA on approximately 10.7 miles of the path between Lone Pine and Stevens Road substations after the addition of OCS053 during daytime minimum loading conditions in normal transmission configuration.
- 115 kV Line 12 rated 74 MVA would be overloaded by existing generation and the addition of OCS053 would further overload the line to 116 MVA on the 41 mile path between Prospect Central and Days Creek substations in contingency transmission configuration. Existing generation would be curtailed in this outage configuration.
- The steady state voltages and post-transient voltage deviation on Public Utility's system are predicted in power flow simulation to remain within acceptable limits in normal transmission configuration and contingency transmission configuration.
- Power flow can be accepted from OCS053 in normal transmission configuration.
- Power flow may not be accepted from OCS053 in contingency transmission configuration.