Community Solar Project Interconnection

Community Solar Project System Impact Study Report

Completed for

(“Applicant”)
OCS059

Proposed Point of Interconnection

Circuit 5L1 out of Beatty substation at 12.0 kV
(At approximately 42.441624°N, 121.246554°N)

March 5, 2021

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1.0 Description of the Community Solar Project

("Applicant") proposed interconnecting 0.625 MW of new generation to PacifiCorp's ("Public Utility") circuit 5L1 out of Beatty substation located in Klamath County, Oregon. The project ("Project") will consist of five (5) Solectria XGI 1500-125 kW inverters for a total requested output of 0.625 MW. The requested commercial operation date is March 1, 2022.

The Public Utility has assigned the Project "OCS059."

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 5L1 out of Beatty substation via a 12.0 kV primary meter. The proposed Point of Interconnection ("POI") will be located at approximately 42.441624°N, 121.246554°N located in Klamath County, Oregon. Figure 1 below is a one-line diagram that illustrates the interconnection of the proposed generating facility to the Public Utility's system.

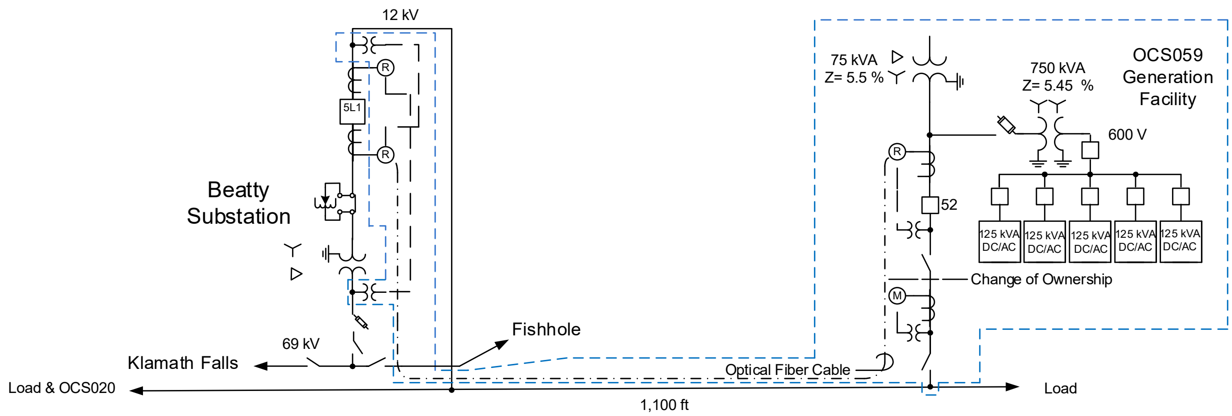

Figure 1: System One Line Diagram

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 PacifiCorp distribution facility point closest to the point of interconnection is 01436012.0-242900 approximately 1,100 feet east of Beatty Substation.
- Distribution load flows were performed at peak and light load and full and no generation with summer and winter loading conditions. The load flow model includes the proposed OCS020 165 kW generation.
- 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 Utilities system without written request or authorization from the Public Utility. The Community Solar Project shall 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. In all cases the minimum power quality requirements in PacifiCorp's Engineering Handbook section 1C shall be met and are available at https://www.pacificpower.net/about/power-quality-standards.html. Requirements specified in the System Impact Study that exceed requirements in the Engineering Handbook section 1C power quality standards shall apply.

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

6.2 Transmission System Modifications

It is possible to have reverse power flow at Beatty substation from OCS059 during light load conditions. Protection and Control equipment will need to be modified at Beatty substation to accommodate reverse power flow from the distribution system to the transmission system.

6.3 Distribution/Transmission Line Modifications

Extend #2 AAAC phase and neutral from a location at or near facility point 01436012.0-242900 to the POI. The line extension includes a pole for primary metering and a pole with a 600 amp group operated switch.

6.4 Existing Breaker Modifications – Short-Circuit

The increase in the fault duty on the system as the result of the addition of the generation facility with photovoltaic arrays fed through 5 – 125 kW inverters connected to a 750 kVA

12 kV – 600 V transformer with 5.45% impedance will not push the fault duty above the interrupting rating of any of the existing fault interrupting equipment.

6.5 Protection Requirements

The OCS059 Community Solar Project will need to disconnect in a high-speed manner for any fault on the 12 kV circuit 5L1 out of Beatty substation. The minimum daytime load on circuit 5L1 with the addition of the OCS020 project is 60 kW which is less than the potential power output of the proposed OCS059 Community Solar Project. For this reason, the imbalance condition of the load and generation that the Community Solar Project could be isolated with following the opening of 5L1 cannot be relied upon to cause the high-speed disconnection of the Community Solar Project for faults on the distribution system. A transfer trip circuit will need to be installed between Beatty Substation and the OCS059 recloser at the POI. Since most faults on overhead lines are temporary and the circuit can be restored as soon as all the sources of power to the fault have been disconnected the breaker 5L1 is equipped with automatic reclosing. When breaker 5L1 opens a transfer trip signal will be sent to the recloser at the POI for the Community Solar Project.

To ensure that the automatic reclosing of breaker 5L1 does not take place before the Community Solar Project has disconnected, a deadline checking control circuit will be installed. The deadline checking control circuit will delay the reclosing until the line is no longer energized to ensure that no damage is done to any of the existing customers' equipment. The enabling of this type of controls will require the addition of a voltage instrument transformer (VT) on the line side of breaker 5L1. The existing feeder relay and control system will need to be replaced with a relay that can accommodate both the transfer trip and the deadline checking circuit. A similar control circuit has already been installed at Fishhole substation on breaker 3L38 in conjunction with earlier generation interconnection projects. Fishhole substation is the normal source of power for Beatty substation.

Beatty substation has only one 12 kV circuit so by having a Community Solar Project on that circuit which has the potential to carry the load on the circuit creates two other protective relay issues that must be dealt with. The Community Solar Project must disconnect from the circuit for faults on the 69 kV transmission line that Beatty substation is connected to and for faults in the 69 – 12 kV transformer in the substation. The 69 kV line faults cannot be detected by monitoring the voltages on the 12 kV system due to the isolation the transformer at Beatty substation provides. Line relays will need to be installed at Beatty substation which will monitor the 69 kV bus voltage and the 12 kV current through the transformer. This requires the addition of a three-phase set of 69 kV voltage instrument transformers at Beatty substation. With these relays the 69 kV line faults will be detected and will key the transfer trip to the solar facility.

Faults in the 69 – 12 kV transformer at Beatty substation are presently detected and cleared with 69 kV fuses. These are adequate since the size of the sources on the 12 kV side have been less than the minimum load so the generation will not remain connected after the fuses blow. The relay that is proposed to detect faults on the 69 kV system will also be capable of detecting the reversed current flow into the transformer for a fault in the transformer and will initiate transfer trip to the Community Solar Project for such an event.

The 12 kV circuit recloser planned to be installed at the OCS059 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 12 kV equipment at the Community Solar Project
2. Detect faults on the 12 kV line to Beatty Substation
3. Monitor the unbalance current flowing through the grounding transformer and protect the transformer from damage due to phase unbalances on the 12 kV circuit
4. Monitor the voltage and react to under or over frequency, and /or magnitude of the voltage
5. Receive transfer trip from Beatty Substation

6.6 DATA REQUIREMENTS (RTU)

Due to the power size of the solar-electric generation facility no real time monitoring will be required by the Transmission Provider for the operation of the transmission network so no RTU will be required.

6.7 COMMUNICATION REQUIREMENTS

Approximately 1,100 feet of 48-fiber, single-mode, ADSS cable will be installed along the distribution line between Beatty substation and the OCS059 POI recloser for transfer trip circuit. It will be terminated in patch panels in cabinets at both ends.

6.8 SUBSTATION REQUIREMENTS

At Beatty substation, the substation will be expanded to accommodate a new control house to house the additional relay and communications panels. A set of three 69 kV voltage transformers and junction box will be required and installed on a new structure. An additional 12.5kV voltage transformer (VT) will also be required and will be installed on an existing structure on the line side of breaker 5L1.

6.9 METERING REQUIREMENTS

Interchange Metering

The metering will be located on the high side of the customer generator step up transformer at the Point of Interconnection. 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 Interconnection Customer 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 and administrative support*	$23,000
Relay Setting Development *P&C Engineer and Relay Technician*	$7,000
Distribution *Line extension*	$30,000
Metering *Metering equipment*	$26,000
Communications *Communications at POI, install fiber.*	$31,000
Beatty Substation *Expand substation, install control house, VTs, line relays and communications*	$672,000
Other Costs *Capital surcharge and contingency*	$197,000
Total	**$986,000**

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

Please note, the time required to perform the scope of work identified in this report does not support the Applicant's requested commercial operation date of March 1, 2022.

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.

Transmission/Generation Interconnection/Community Solar Queue Requests considered:

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
OCS053	2.0
OCS054	1.0
OCS055	2.0

OCS058	2.875

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, 0.625 MW of additional generation can be absorbed. As a result, the transmission provider 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 transmission provider'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 point of interconnection 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

Transmission:

Three base cases were developed to represent heavy summer, heavy winter and light spring load conditions. A Power flow analysis was performed on each case for two system configurations.

1. Normal transmission configuration: Beatty substation fed radial out Fish Hole at 69 kV with normally open switch 3L79 at Bonanza Tap.
2. Contingency transmission configuration: 69kV line section between Beatty and Bly out of service. Beatty transferred to alternate feed out of Klamath Falls using switch 3L79 at Bonanza Tap.

Each Power flow analysis was conducted pre and post OCS059. The study focused on the 69 kV system in the Klamath Falls to Bly area and distribution voltages at Beatty substation. Voltage and thermal limitation of surrounding substation buses and lines were monitored.

The results for the transmission study concluded that steady state and post transient voltages are within acceptable limits. No thermal violations were identified. The proposed OCS059 project does not result in additional deficiencies to the Transmission Provider's transmission system. Although no voltage or thermal violation were found, the addition of OCS059 can cause reverse power flow on transformer T-3136 and associate regulators. Protection settings and regulator controls will need to be updated to accommodate reverse power flow.

Distribution:

- The modeled power flow on Beatty Substation breaker 5L1 and Beatty Substation transformer T-3136 is 569 kW reverse power flow during light load flow and full generation.