PACIFICORP

Community Solar Project Interconnection

Community Solar Project System Impact Study Report

Completed for

(“Applicant”)
OCS033

Proposed Point of Interconnection

Circuit 5R133 out of Glendale Substation at 12.5kV
(at approximately 42°44'41.90"N, 123°24'21.22"W)

September 16, 2020

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1.0 DESCRIPTION OF THE COMMUNITY SOLAR PROJECT

(“Applicant”) proposed interconnecting 1.0 MW of new generation to PacifiCorp’s (“Public Utility”) circuit 5R133 out of Glendale substation located in Douglas County, Oregon. The project (“Project”) will consist of eight (8) Delta M125HV 125 kW inverters for a total requested nameplate output of 1.0 MW. The requested commercial operation date is December 31, 2020.

The Public Utility has assigned the Project “OCS033.”

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 5R133 out of Glendale substation via a 12.5 kV primary meter. The proposed Point of Interconnection will be located at approximately 42°44'41.90"N, 123°24'21.22"W located in Douglas 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.

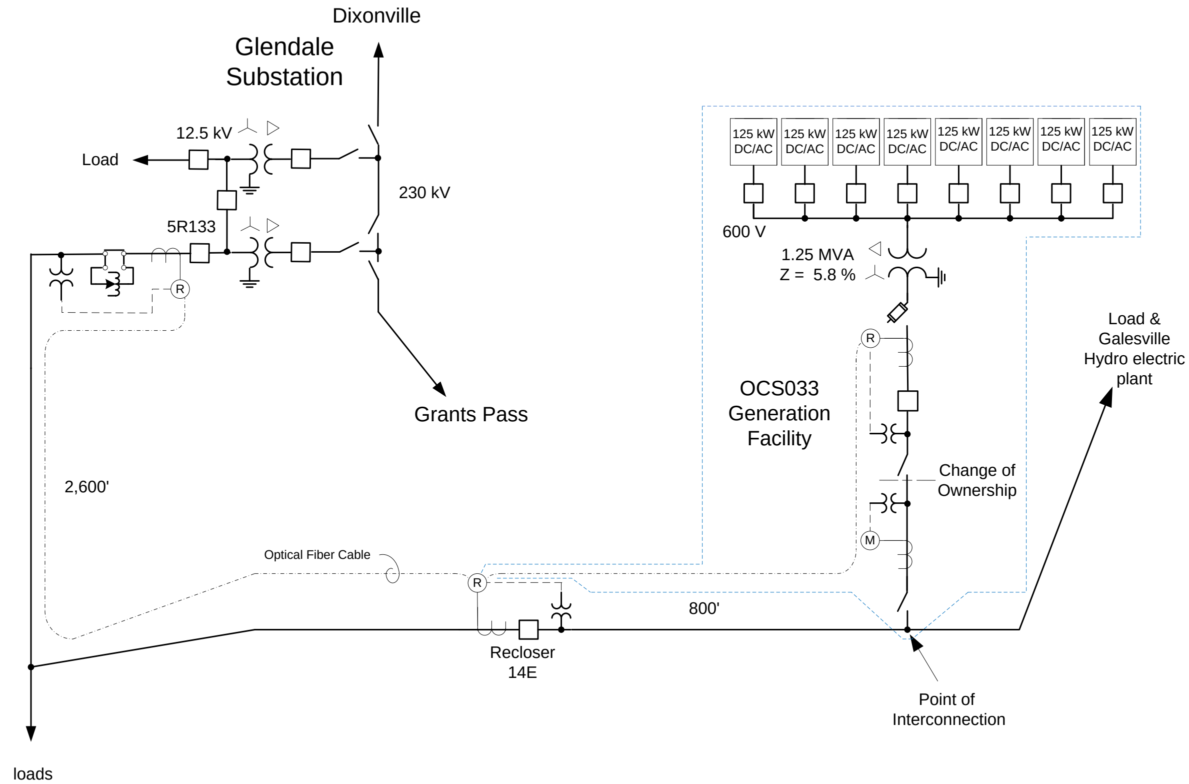

Figure 1: System One Line Diagram

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 Point of Interconnection ("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.
- The existing Galesville Hydro generating facility is required to install approximately 0.5 miles of fiber optic cable between Glendale substation and the line recloser 14E. This upgrade is required to be complete before the Applicant's generating facility can commence operations

therefore is a contingent facility. Should the Applicant wish to commence operation prior to the schedule proposed for the Galesville Hydro project, the Applicant shall be responsible for the costs of this upgrade.

- 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 generator is expected to operate 24 hours per day, 7 days per week, 12 months per year. The primary meter (POI) power factor studied was unity power factor 1.00 as consistent with assumptions on similar studies prior to the proposed generation facility being installed. It is assumed that the Applicant will control power factor to a value of unity 1.00.
- Load flow cases were assembled with the Glendale Substation load tap changers set at present output for case 1-3 conditions and 1.033 per unit base voltage with no compensation for cases 4-6.
- Approximated light loading during calendar year 2019-2020 on Glendale substation transformer T-3336 is .0560 MW. During light loading the new generation is expected to provide reverse power flow on the Glendale Substation transformer and load tap changer.
- Approximated light loading on circuit 5R133 from Glendale is 0.0105 MW. The new generation is expected to provide reverse power flow to circuit 5R133.
- The Applicant's facilities must be operated in a manner so as not to cause objectionable power quality issues to other Public Utility customers. Voltage fluctuations caused by the generation facility are required to meet the Public Utility's Engineering Handbook, Voltage Fluctuation and Flicker, Standard 1C.5.1 which is found at https://www.pacificpower.net/con/pqs.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 agreement. The Public Utility 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 Public Utility's Engineering Handbook standards addressing power quality, including but not limited to Voltage Level, Voltage Balance, Harmonic Distortion, and Voltage Frequency.
- 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.
- 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 case studies were assembled and studied on the 12.47 kV distribution system:
    - Winter peak, no generation.
    - Summer peak, no generation.
    - Annual light load, no generation.
    - Winter peak, full generation.
    - Summer peak, full generation.

- Annual light load, full generation.

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 automatic voltage control with the voltage sensed electrically at the POI. 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.

Studies will be required to coordinate the voltage droop setting with other facilities in the area. In general, the Community Solar Project and Interconnection Equipment should be operated so as to maintain the voltage at the POI between 1.01 pu to 1.04 pu. At the Public Utility's discretion, these values might be adjusted depending on the operating conditions. Within this voltage range, the Community Solar Project should operate so as to minimize the reactive interchange between the Community Solar Project and the Public Utility's system (delivery of power at the POI at approximately unity power factor). The voltage control settings of the Community Solar Project must be coordinated with the Public Utility prior to energization (or interconnection). The reactive compensation must be designed such that the discreet switching of the reactive device (if required by 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 proposed Applicant's facility.

6.3 DISTRIBUTION/TRANSMISSION LINE MODIFICATIONS

1. Replace the Glendale 5R133 substation load tap changer controls with controls that have functionality to ignore reverse power flow.
2. Restrict the existing regulation range of output voltage from Glendale 5R133 in the following manner: Set the base voltage to 1.033 per unit (124 volts on the 120 volt base) and no compensation.
3. Distribution scope included for a short line extension from pole 01332006.340201 to the yet to be specified point of delivery. This scope includes three new poles, one gang operated switch, on primary metering assembly, and a riser pole.

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 8 – 125 kW inverters connected to a 1.25 MVA 12.5 kV – 600 V transformer with 5.8% impedance will not push the fault duty above the interrupting rating of any of the existing fault interrupting equipment.

6.5 PROTECTION REQUIREMENTS

Between Glendale substation and the planned OCS033 generating facility there is a line recloser. The minimum daytime load on circuit 5R133 out of Glendale substation and beyond the line recloser, with the existing Galesville Hydro generating facility that is connected to this feeder, is below the maximum potential power output of the proposed OCS033 generating facility. For this reason the imbalance condition of the load and generation that the generating facility could be isolated with following the opening of either of these fault interrupting devices cannot be relied upon to cause the high speed disconnection of the generating facility for faults on the distribution system. A transfer trip circuit will need to be installed between the line recloser, Glendale substation and the OCS033 generating facility. 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 5R133 and the line recloser are both equipped with automatic reclosing. When either of the two fault interrupters open a transfer trip signal will be sent to the circuit recloser at the generating facility.

The owner of the existing Galesville Hydro generating facility is in the process of renewing its generation interconnection agreement. A requirement for the renewal is that a communication circuit for transfer trip be installed between Glendale substation and the line recloser 14E. With the completion of that communication circuit the requirement for the OCS033 project will be to extend the optical fiber cable between the line recloser 14E and the POI recloser for the OCS033 generating facility.

To ensure that the automatic reclosing of breaker 5R133 or the line recloser does not take place before the generating facility disconnects, a dead line checking control circuit will be required at both locations. The dead line 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. This type of control circuit already exists at both locations.

The typical configuration for the overcurrent devices on feeder relays and line reclosers is to have the overcurrent functions non-directional. However, with the addition of the OCS033 generating facility, for ground faults on the line between Glendale substation and the recloser, the current flowing from the generating facility will be greater than the pickup value for the ground overcurrent elements. Having the line recloser 14E trip for these faults will not be acceptable. For faults on the other feeder out of Glendale substation the current from the feeder 5R133 with the two generation facilities will be greater than the pickup value for the overcurrent elements. The overcurrent elements for line recloser 14E and 5R133 will need to be directional to prevent this type of operation.

The 12.5 kV circuit recloser planned to be installed at the collector for the OCS033 project will need to be equipped with a 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 12.5 kV equipment at the generating facility
2. Detect faults on the 12.5 kV line to Glendale substation
3. Monitor the voltage and react to under or over frequency, and /or magnitude of the voltage
4. Receive transfer trip from Glendale Substation and line recloser 14E.

6.6 DATA REQUIREMENTS (RTU)

Due to the power size of the generating facility no real time monitoring will be required by the Public Utility for the operation of the transmission network so no RTU will be required.

6.7 COMMUNICATION REQUIREMENTS

Approximately 800 feet of 48-fiber, single-mode ADSS cable will need to be installed on the distribution line between line recloser 14E and the OCS033 POI recloser for transfer trip. At recloser 14E, fibers will be spliced into the existing fiber to Glendale substation. Other fibers will be terminated in a patch panel at 14E. The fiber will be terminated in a panel at the Applicant's facility as well. The patch panels will be installed in enclosures at both sites. Fiber optic jumpers will be installed to the relays' fiber-optic transceivers at 14E and the customer's facility. At Glendale substation, fiber-optic jumpers will be installed from the existing patch panel to the relays' fiber optic transceivers.

6.8 SUBSTATION REQUIREMENTS

At the time of this study, no substation modifications are required to accommodate the proposed Applicant's facility.

6.9 METERING REQUIREMENTS

<u>Interchange Metering</u>

The metering will be located on the high side of the Applicant generator step up transformer at the POI. The metering will be installed overhead on a pole per distribution DM construction standards. 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.

<u>Station Service/Construction Power</u>

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.

OCS033 Collector Station *Install metering, transfer trip and develop relay settings*	$77,000
Glendale Substation *Develop relay settings*	$27,000
Line Recloser *Install transfer trip and develop relay settings*	$58,000
Distribution *Line extension, replace tap changer controls and develop settings*	$143,000
Communications *Install fiber*	$17,350
Total	**$322,000**

*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 12-15 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 31, 2020.

9.0 PARTICIPATION BY AFFECTED SYSTEMS

No utilities have been identified as Affected Systems.

10.0 APPENDICES

Appendix 1: Higher Priority Requests
Appendix 2: Informational Network Resource Interconnection Service Assessment
Appendix 3: Property Requirements
Appendix 4: Transmission 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)
660	10
721	55
741	40
849	100
905	50
971	2.7
1029	400
1031	80
1032	80
1033	80
1034	60
1055	4.2
1062	240
1087	50
1104	3
1120	3
1126	8
1133	80
1134	120
1135	80
1147	2.999
1158	1.8
1160	70
1192	238.5
OCS003	0.8
OCS004	0.8
OCS019	0.882
OCS020	0.594
OCS023	0.6

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.

There are currently a significant number of higher-queued requests seeking interconnection in the southern Oregon area where the CSP generator proposes to interconnect. These interconnection studies must be completed before the transmission provider can determine what upgrades and associated cost estimates may 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 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

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 three system configurations.

1. Normal transmission configuration: Glendale substation in a 230 kV loop configuration to Dixonville and Grants Pass substations.
2. Contingency transmission configuration 1: Loop open between Glendale and Dixonville with switch 1R37 open at Glendale substation. Glendale fed radial at 230 kV out of Meridian substation.
3. Contingency transmission configuration 2: Loop open between Glendale and Grants Pass with switch 1R36 open at Glendale substation. Glendale fed radial at 230 kV out of Dixonville substation.

Each Power flow analysis was conducted pre and post OCS033. The study focused on the 230 kV system from Dixonville and Gransts and distribution voltages at Glendale substation. Voltage and thermal limitation of surrounding substation buses and lines were monitored.

The results for the transmission study concluded steady state and post transient voltages are within acceptable limits. No thermal violations were identified. The proposed OCS033 project does not result in additional deficiencies to the Public Utility's transmission system.

There are no contingent facilities identified for this interconnection request.