Community Solar Project Interconnection

Community Solar Project System Impact Study Report

Completed for

("Applicant")
OCS045

Proposed Point of Interconnection

Circuit 5D5 out of Culver substation at 12.5 kV
(Approximately 44.487442°N, 121.249867°W)

January 8, 2021

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1.0 DESCRIPTION OF THE COMMUNITY SOLAR PROJECT

(“Applicant”) proposed interconnecting 2.875 MW of new generation to PacifiCorp’s (“Public Utility”) circuit 5D5 out of Culver substation located in Jefferson County, Oregon. The project (“Project”) will consist of twenty-three Solectria XGI 1500 125 kV inverters for a total requested nameplate output of 2.875 MW. The requested commercial operation date is October of 2021.

The Public Utility has assigned the Project “OCS045.”

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 5D5 out of Culver substation via a 12.47 kV primary meter. The proposed Point of Interconnection (“POI”) will be located at approximately 44.487442°N, 121.249867°W located in Jefferson County, Oregon. Figure 2 below is a one line diagram that illustrates the interconnection of the proposed generating facility to the Public Utility’s system.

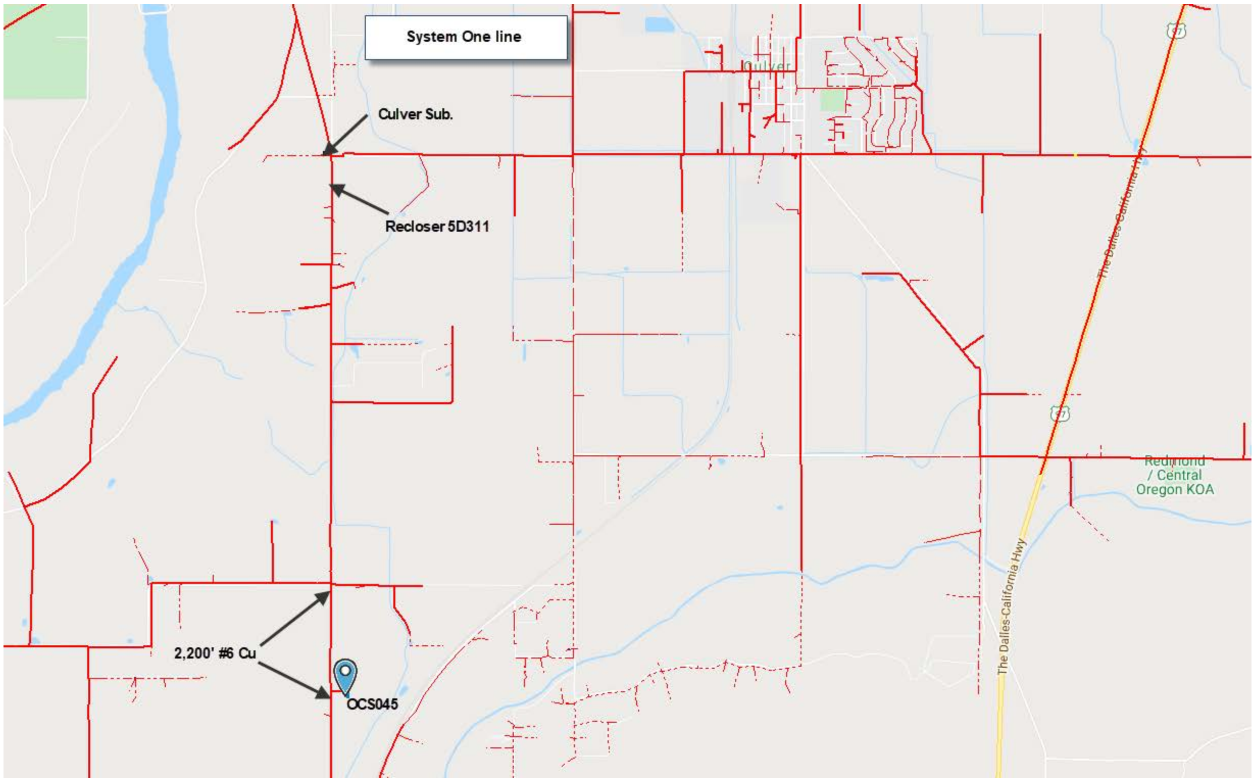

Figure 1: System Map

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.

- This report is based on the Preliminary One-Line (drawing E-1, Revision A) for the “” project, provided by the Customer and dated 09-23-2020
- Existing and queued generation on this line is expected to result in export to the 69 kV and 230 kV buses at Cove substation for much of the year.
- Contingency transmission configuration for the Public Utility’s system is defined as any configuration other than normal transmission configuration.
- Three case studies were assembled and studied in power flow simulation at the transmission level:
  - Case 1: Normal configuration with the 69 kV transmission sourced from Cove substation.
  - Case 2: Contingency configuration with the 69 kV transmission sourced from Redmond substation (switch 3D85 closed at Crooked River tap; switch 3D27 open at Culver substation)
  - Case 3: Contingency configuration with one 230-69 kV transformer or one 230 kV transmission line out of service at Cove
- 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 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.

Generators capable of operating under voltage control with voltage drop are required to do so. 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.

The Applicant will be required to install a transformer that will hold the phase to neutral voltages within limits when the Community Solar Project is isolated with the Distribution Provider's local system until the generation disconnects. The circuit that the project is connecting to is a four wire multi-grounded circuit with line to neutral connected load. The documentation supplied by the Applicant showed using a 200 kVA wye – delta grounding transformer with an impedance of 5.0%. Base on the Distribution Provider's calculation a transformer of that size and impedance would supply more than 25 times the transformer rating in current for a single line to ground fault on the 12.47 kV system. There is a concern that a transformer of that size and impedance would be damaged for a close in line fault. It is recommended that a 200 kVA transformer with 5.5% impedance be used.

6.2 Transmission System Modifications

The wood poles along the length of the Distribution reconductor portion (structures 11/18 – 21/18, excluding 12/18) will be replaced with 50ft Class 1 TF100 structures to accommodate the upgraded distribution conductor and new ADSS.

6.3 Distribution/Transmission Line Modifications

Public Utility will rebuild approximately 2,200 feet of existing three phase #6 copper distribution with 4/0 Al conductor. The line rebuild will start at pole 1412012.0-359961 and end at pole 359560. This makes the assumption that the primary meter tap line will be just to the north of pole 359560, based on the site plan that was provided. Remove 100T line fuses at pole 359961 as part of the line rebuild and install 100T line fuses at pole 359560. Construct a short tap line east to the generation site primary meter. Exact location has not been determined but the Public Utility assumes from the site plan this tap line will be 100 to 600 feet in length.

The 69-12.5 kV regulator at Culver substation will require settings adjustments to ensure that customers on the line remain within ANSI A and B voltage range for all loading conditions.

Under the normal configuration and the contingency configurations identified for this study, there are no identified power flow restrictions with OCS045 generation online.

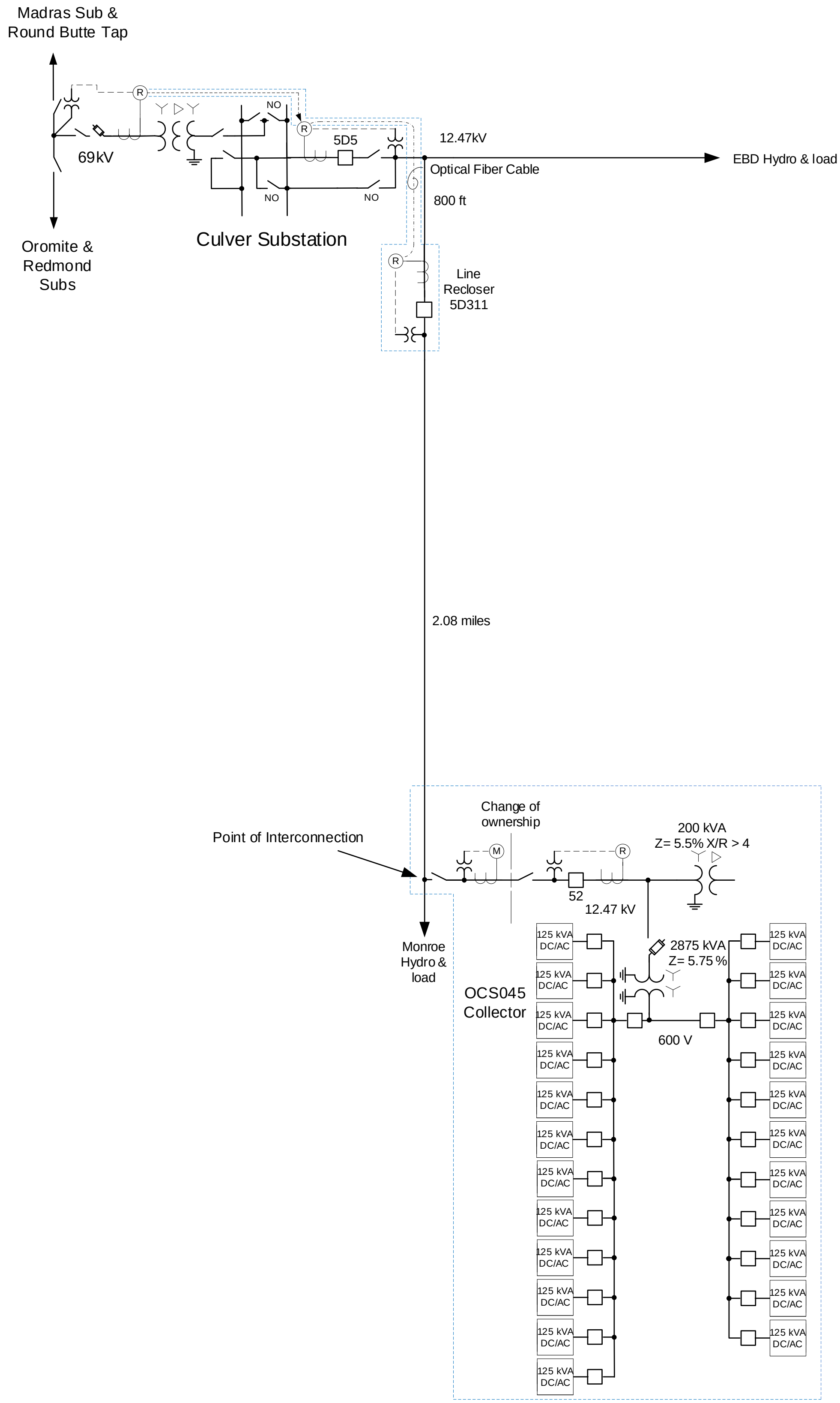

Figure 2: System One Line Diagram

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 23 – 125 kW inverters connected to 1 – 2.875 MVA 12.47 kV – 600 V transformer with 5.75 % impedance will not push the fault duty above the interrupting rating of any of the existing fault interrupting equipment.

6.5 PROTECTION REQUIREMENTS

The OCS045 Community Solar Project will need to disconnect from the network in a high-speed manner for faults on the 12.47 kV line on circuit 5D5 out of Culver substation, on the 69 kV transmission network feeding Culver substation or in the 69 – 12.47 kV transformer. There are existing generation plants on the circuit that has required the addition of relays to be installed at Culver substation to detect faults on the 69 kV transmission system or in the 69 – 12.47 kV transformer at Culver substation and send transfer trip to the generation plant. The OCS045 project will also need to receive this transfer trip signal from Culver substation.

The OCS045 Community Solar Project will be beyond a line recloser located 800 feet south of Culver substation. The Community Solar Project will need to disconnect in a high-speed manner for the operation of the line recloser. Frequently during light load and peak generation conditions with the addition of the OCS045 project approximately 2 MW of reverse power flow will occur at the line recloser. Most faults on overhead distribution lines are temporary so that once all sources of fault current have been disconnected the line recloser can automatically close restoring the service to the customers. Since the unbalance between the islanded load and generation cannot be relied upon to cause high speed disconnection of the Community Solar Project, transfer trip circuits will need to be installed between Culver substation, line recloser 5D311 and the POI recloser for the OCS045 Community Solar Project. A communication system will be required to carry the transfer trip circuits.

Modifications will be done to the existing relays at Culver Substation to key the transfer trip to the OCS045 POI recloser for detection of faults on the 69 kV system, in the 69-12.47 kV transformer, on the 12.47 kV circuit or the opening of the line recloser 5D311.

The 12.47 kV circuit recloser planned to be installed at the OCS045 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 12.47 kV equipment at the solar-electric Community Solar Project
2. Detect faults on the 12.47 kV line to Culver Substation
3. Monitor the unbalance current flowing through the grounding transformer and protect the transformer from damage due to phase unbalances on the 12.47 kV circuit
4. Monitor the voltage and react to under or over frequency, and /or magnitude of the voltage

5. Receive transfer trip from Culver Substation

6.6 DATA REQUIREMENTS (RTU)

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

At Culver Substation the alarm from the field recloser as to the health of the radio system will be monitored by the existing RTU.

6.7 COMMUNICATION REQUIREMENTS

A single-mode ADSS optical fiber cable will be installed between line recloser 5D311 and Culver substation. A SEL radio system will be installed between Culver substation and the OCS045 POI recloser. These systems will carry the transfer trip circuits between three locations. The radios, fiber transceivers, and patch panels will be mounted in cabinets at the recloser and the customer's facility.

6.8 SUBSTATION REQUIREMENTS

Install concrete capped conduits to accommodate new fiber within the substation yard.

6.9 METERING REQUIREMENTS

<u>Interchange Metering</u>

The metering will be located on the high side of the customer generator step up transformer at the POI. An overhead metering setup is assumed for this study. 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.

<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.

OCS045 Collector Station $111,000

Install metering, communications and develop relay settings

Culver Substation *Install communications and modify line relays*	$64,000
Recloser 5D311 *Install communications*	$42,000
Distribution *Line extension, line reconductor, pole replacements, replace recloser*	$307,000
Communications *Install ~900 feet of fiber*	$13,000
Total	**$537,000**

*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 appears to result in a timeframe that does not support the Applicant's requested commercial operation date of October of 2021

9.0 PARTICIPATION BY AFFECTED SYSTEMS

Public Utility has identified the following Affected Systems: Portland General Electric and Bonneville Power Administration

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

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)
TCS-43	40
TCS-44	80
TCS-45	40
TCS-46	80
TCS-51	9
TCS-52	20
TCS-53	20
TCS-54	40
OCS001	1.46
OCS002	0.9

PGE:

- 17-068; 65 MW. Requested ISD 12/31/2019.
- 19-080; 80 MW. Requested ISD 12/31/2023.
- 19-081; 53 MW. Requested ISD 12/31/2022.

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 central 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/Distribution Study Results

The following study results were observed for a power flow study of the affected system:

Assumption:

- Culver 3 MW proposed capacitor is in service on the unregulated 12.5 kV bus

Case 1: Normal Configuration

No power flow restrictions were identified.

Minimum daytime loads in the Madras area are less than the sum of all queued and in-service generation year-round. Thus, for much of the year generation at any level is likely to result in export through the 230 kV bus at Cove.

Voltages and post transient voltage steps are projected in power flow simulation to remain within permissible limits during the interruption of the OCS045 generation in the Public Utility's normal transmission configuration for all load levels.

Case 2: Contingency configuration with the 69 kV transmission sourced from Redmond substation (switch 3D85 closed at Crooked River tap; switch 3D27 open at Culver substation)

No power flow restrictions were identified.

Voltages and post transient voltage steps are projected in power flow simulation to remain within permissible limits during the interruption of the OCS045 generation in this contingency configuration for all load levels.

Case 3: Contingency configuration with one 230-69 kV transformer or one 230 kV transmission line out of service at Cove:

No power flow restrictions were identified.

Voltages and post transient voltage steps are projected in power flow simulation to remain within permissible limits during the interruption of the OCS045 generation in this contingency configuration for all load levels.