PACIFICORP

Community Solar Project Interconnection

# Community Solar Project System Impact Study Report

Completed for

**(“Applicant”)**
**OCS062**

Proposed Point of Interconnection
**Circuit 5W403 out of Pendleton substation at 12.47 kV**
**(At approximately 45°39'36.3"N, 118°46'15.8"W)**

**January 26, 2022**

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## 1.0 DESCRIPTION OF THE COMMUNITY SOLAR PROJECT

("Applicant") proposed interconnecting 2.4 MW of new generation to PacifiCorp's ("Public Utility") circuit 5W403 out of Pendleton substation located in Umatilla County, Oregon. The project ("Project") will consist of forty (40) CHINT SCA60KTL 60 kW inverters for a total requested output of 2.4 MW. The requested commercial operation date is December 31, 2021.

The Public Utility has assigned the Project "OCS062."

## 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 5W403 out of Pendleton substation via a 12.47 primary meter. The proposed Point of Interconnection ("POI") is assumed to be at facility point ("FP") 01102032.0117000 and is located at approximately 45°39'36.3"N, 118°46'15.8"W located in Umatilla 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.

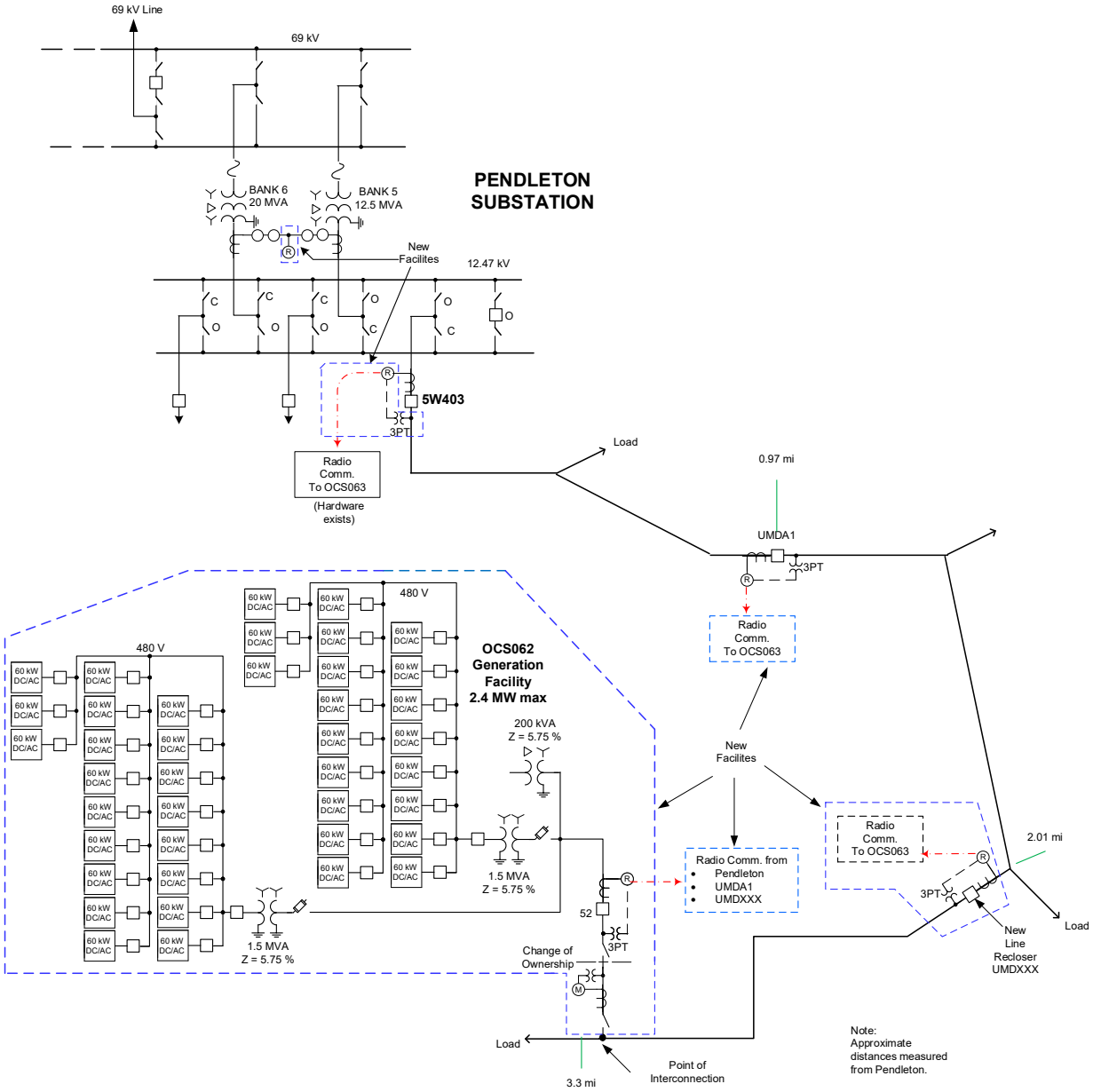


Figure 1: System One Line Diagram. Distances from Pendleton Substation are approximated.

## 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 Community Solar Project is expected to operate during daylight hours every day 7 days per week 12 months per year.
- The Community Solar Project is expected to operate in constant power factor mode with a unity power factor setting unless otherwise requested by the Public Utility. The study was conducted assuming the generation stayed within the 0.95 +/- power factor range.
- The total minimum daytime load on the 69 kV transmission system, as measured at BPA Roundup substation, is 22.9 MW with all area generation offline. At minimum daytime loading conditions on the 69 kV system, with all active and prior queued generation online, reverse power flow onto the 230 kV transmission system at BPA Roundup is likely. The addition of this project further increases the likelihood of reverse power flow conditions at BPA Roundup.
- 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 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. 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.

. Any 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.

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 Public Utility'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. Figure 1 shows the addition of a 12.47 kV 200 kVA wye – delta grounding transformer with an impedance of 5.75 %. This transformer will meet this requirement.

### 6.2 TRANSMISSION SYSTEM MODIFICATIONS

No transmission system modifications are anticipated in order to serve this project under normal system conditions.

### 6.3 DISTRIBUTION/TRANSMISSION LINE MODIFICATIONS

Following are the distribution system upgrades required for the OCS062 project to be interconnected. Figure 2 below shows the general location of the required upgrades.

- To interconnect the Community Solar Project to the requested Pendleton substation 5W403 feeder, a gang operated switch will be required to be installed just west of the proposed POI at FP 01102032.0116001. This open switch will be the new normal open point between the Pendleton substation feeder 5W403 and the McKay substation feeder 5W856. The existing normally open 300-amp solid blade disconnects located to the east at FP 01102032.0124402 will be changed to normally closed. This normal open change will transfer two single phase services to the 5W403 feeder and will have no significant impacts to distribution feeder loadings.
- To enable the required communication assisted high speed tripping and dead line check the existing field recloser UMDA1 located at FP 01102032.0119900 will be replaced with the current Public Utility standard recloser equipped with a SEL 651R control and Low Energy Analog voltage indication integrated into the bushings.
- The Public Utility's Policy 138 requires all protective devices upstream of distribution system interconnected generators over 1.0 MW to be equipped with three pole tripping. There is a set of three 320 ampere, two shot sectionalizers that exist at FP 01102032.0124501 located along SE Goad Road south of Hwy 30 and will be upstream of the proposed POI. Replacement of these sectionalizers with a Field Recloser ("FR") is required. In this study this recloser is labeled FR UMDXXX. Protection is required to be maintained at this location as a protective device here protects over 600 homes and businesses from outages caused by faults occurring beyond this device.
- At the POI construction is required; one pole will hold the Public Utility owned and operated gang switch and on one pole primary metering units will be installed. Conductor consisting of three 4/0 AAC primary and one 4/0 AAC neutral conductors will be installed from the POI to past this primary metering pole and will continue one span to land on the first Applicant owned pole. The termination of this conductor at the Applicant's pole will be the POC. These Public Utility facilities will require an easement by the Applicant on behalf of the Public Utility.

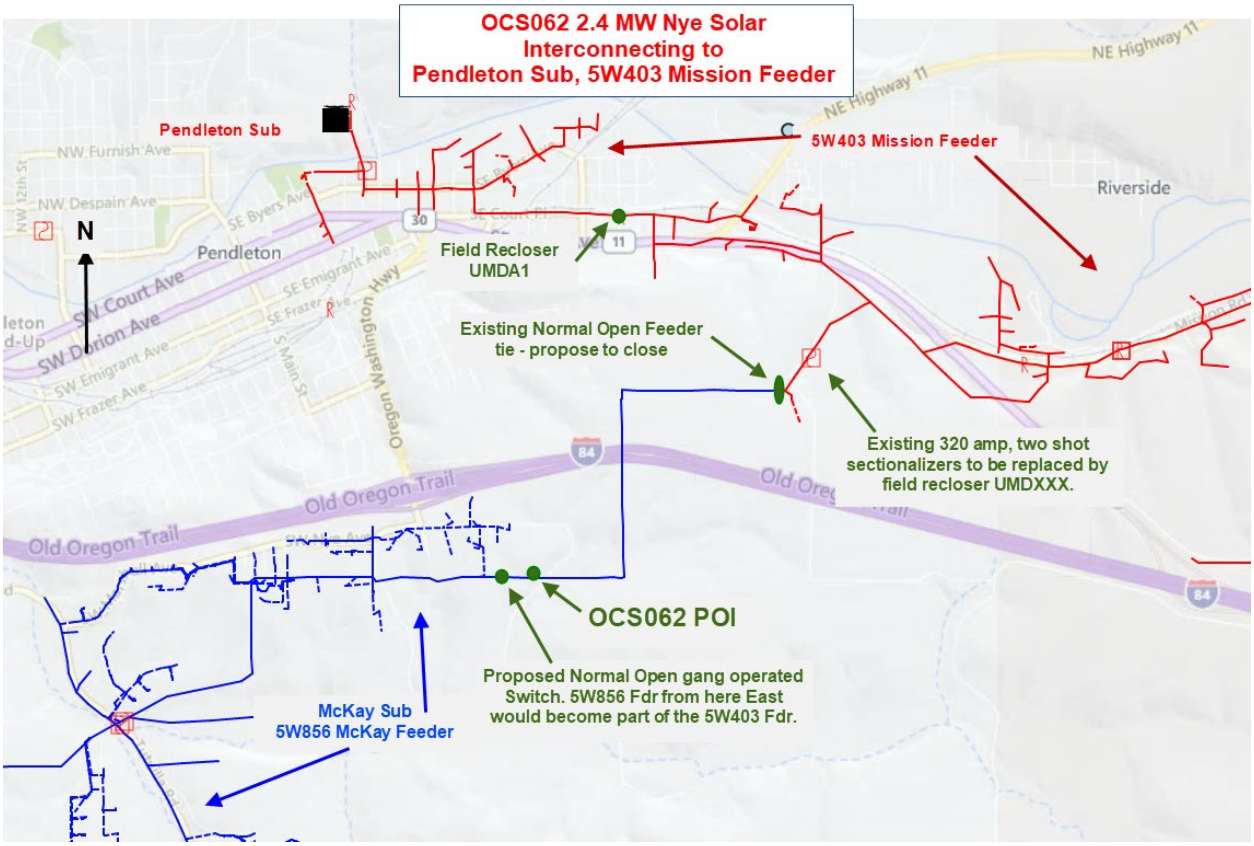


Figure 2: Feeder Map of Proposed 12.5 kV Construction

### 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 40 – 60 kW inverters connected to 2 – 1.5 MVA 12.47 kV – 480 V transformers 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 OCS062 Community Solar Project will need to disconnect in a high-speed manner for any faults on the 12.47 kV circuit 5W403 out of Pendleton substation, for faults in the 69 – 12.47 kV transformers, or on the 69 kV bus of Pendleton substation. The minimum daytime load on circuit 5W403 is less than the potential power output of the proposed OCS062 Community Solar Project. For this reason, the imbalance condition of the load cannot be isolated with just the opening of 5W403; therefore, a transfer trip circuit will be needed between Pendleton substation and the OCS062 recloser at the POI. When breaker 5W403 opens a transfer trip signal will be sent to the POI recloser to disconnect the Community Solar Project. Since most faults on overhead lines are temporary and the lines can be restored as soon as all the sources of power to the fault have been disconnected the breaker 5W403 will be equipped with automatic reclosing. The reclosing must be delayed until the Community Solar Project disconnects; this will be achieved by monitoring the

line voltage with at least one new potential transformer. The overcurrent protective relay elements associated with the 5W403 circuit breaker need to be directional to avoid operation for faults in the neighbor circuits due to the feeding from OCS062. All these requirements cannot be met by the existing traditional electromechanical relays for the 5W403 circuit therefore those relays will need to be replaced with a multifunction digital relay.

The new relays for 5W403 will need three phase voltages to establish directionality. These voltages could be taken from the 12.47 kV bus if the configuration allowed for that but there are not three phases available, and the voltages are not reliable for protection because the transformers are connected to the two buses which work with the tie breaker normally open. Thus, the best solution is to use three new line potential transformers out of 5W403, which will provide the three phases for directionality and the voltage needed to implement the "dead-line checking" for the reclosing.

Pendleton substation is equipped with a 69 kV bus differential scheme. This scheme detects internal faults and trips all the 69 kV circuit breakers using a lockout relay. One of the contacts of this lock-out relay will be used to send a transfer trip to the OCS062 plant via the 5W403 relay. The two transformers that feed the 12.47 kV bus sections where 5W403 circuit are presently protected using fuses installed at the 69 kV side. These fuses are expected to melt and clear anytime there is a fault in one of the transformers or at the 12.47 kV bus. With the new OCS062 plant this protection will not suffice. A fault at the 12.47 kV bus or in low voltage side of the transformer may be able to cause the fuses to clear, but the plant will still be connected feeding the fault, as there is no interrupting device in the low voltage side of the transformer. A multifunction non-directional relay with phase and ground elements installed in current-summation configuration will detect the 12.47 kV faults and send direct transfer trip to the OCS062 plant via the 5W403 relay. This relay will have to be coordinated with all the feeder relays.

There will be two line field reclosers between Pendleton substation and the OCS062 POI recloser. Line recloser UMDA1 is at approximately 0.97 circuit miles from Pendleton substation and the other is a planned line recloser, UMDXXX, at approximately 2.01 miles from Pendleton. The Community Solar Project will need to disconnect in a high-speed manner for the operation of either of these reclosers so that the circuits can be automatically re-energized, restoring service to the customers on the circuit. The minimum daytime load on the circuit beyond either of these line reclosers will be well below the potential power output from the proposed 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 either of the line reclosers cannot be relied upon to cause the high-speed disconnection of the Community Solar Project for faults on the distribution system. Transfer trip circuits will be needed between both line reclosers and the OCS062 recloser at the POI.

To ensure that the automatic reclosing of either line recloser does not take place before the Community Solar Project disconnects, a deadline checking control circuits 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 relay/controller for UMDA1 has this capability with the addition of VTs on the load side of the line recloser. The line recloser for the UMDXXX location will be purchased with this capability.

A 12.47 kV circuit recloser will need to be installed at the POI for the OCS062 project. This circuit recloser 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 Community Solar Project
2. Detect faults on the 12.47 kV line to Pendleton 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 Pendleton substation, line recloser UMDA1, or line recloser UMDXXX.

### 6.6 Data Requirements (RTU)

Due to the power size of 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.

### 6.7 Communication Requirements

A radio system will need to be installed between Pendleton substation, line recloser UMDA1, line recloser UMDXXX, the OCS062 POI recloser, and Cabbage Hill communication site for transfer trip circuits.

SEL-3031 spread-spectrum radios and existing communication facilities will be used to communicate between the POI recloser, recloser UMDXXX, recloser UMDA1, and Pendleton substation. SEL-3031 links will be established from the POI recloser to the Public Utility's Cabbage Hill communications site and from recloser UMDXXX to Cabbage Hill. An SEL-3031 link will be established from recloser UMDA1 to Pendleton substation. At the UMDXXX recloser, an approximately 90' wood pole will be installed and equipment cabinet. At the POI recloser, an approximately 50' wood pole will be installed, and at recloser UMDA1 an approximately 30' wood pole will be installed. At Cabbage Hill, the antennas will be mounted on the existing tower. Communications from Recloser UMDA1 and Pendleton substation will be routed to Cabbage Hill over existing communication systems between Pendleton and Cabbage Hill.

### 6.8 Substation Requirements

**Pendleton Substation**

Three, 12.5 kV voltage transformers will be installed on the line side of breaker 5W403. Relay panels will be installed in the existing control house.

### 6.9 METERING REQUIREMENTS

Interchange Metering

The metering will be located on the high side of the customer 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 on the pole near the ground. 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**<br>*Project management and administrative support* | $21,000 |
| **Relay Setting Development**<br>*P&C Engineer and Relay Technician* | $30,000 |
| **Distribution**<br>*Line extension, gang Switch, install recloser replacing sectionalizers and replace existing recloser* | $128,000 |
| **Metering**<br>*Metering equipment* | $26,000 |
| **Communications**<br>*Communications at reclosers, POI, Cabbage Hill Communications Site and Pendleton Substation* | $179,000 |
| **Pendleton Substation**<br>*Install VTs and protection panels* | $190,000 |
| **Other Costs**<br>*Capital surcharge* | $46,000 |

| | |
|---|---|
| **Total** | **$620,000** |

*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 31, 2021.

## 9.0 PARTICIPATION BY AFFECTED SYSTEMS

Public Utility has identified the following Affected Systems: 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
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:

Q0547 (18 MW)
Q0666 (1.98 MW)
Q1045 (3 MW)
OCS024 (1.56 MW)

## 10.2 APPENDIX 2: INFORMATIONAL NETWORK RESOURCE INTERCONNECTION SERVICE ASSESSMENT

The following is the Public Utility's assessment of the requirements that would be assigned to this interconnection request were it to be for network resource interconnection service. This assessment is for informational purposes only as part of the Oregon Community Solar program and is not required for the Applicant's interconnection request.

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 Pendleton area where the CSP generator proposes to interconnect, 2.4 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 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 Pendleton Sub 5W403 Mission feeder will have a portion of its' load transferred to the newly constructed McKay Sub 5W857 Wildhorse feeder. SCADA metering exists for the 5W403 Mission feeder, a CYME system study was performed which resulted in the following Net Minimum Daytime Loads (Net MDL):
  - Pendleton Sub Bank #5 T-3241 = 2.35 MW
  - 5W403 – Mission feeder Net MDL = 2.35 MW
  - Field Recloser UMDA1 Net MDL = 1.97 MW
  - Proposed Field Recloser UMDXXX = 0.06 MW.

- This 2.4 MW OCS062 project will result in total generation (existing and proposed) as a percent of potential MDL being:
  - Pendleton Sub Bank #5 T-3241 – 102% of the transformer's potential MDL (includes 638 kW of existing generation).
  - CB 5W403 – 102% of the feeders potential MDL (includes 638 kW of existing generation).
  - Field Recloser UMDA1 - 118% of the recloser potential MDL (includes 493 kW of existing generation).
  - Proposed Field Recloser UMDXXX – 1610% of the reclosers potential MDL (includes 95 kW of existing generation).

- The total minimum daytime load on Pendleton substation is adequate to absorb the OCS062 generation. This project is unlikely to back-feed the 69 kV transmission system.

- The total minimum daytime load on the 69 kV transmission system, as measured at BPA Roundup substation, is 22.9 MW with all area generation offline. At minimum daytime loading conditions on the 69 kV system, with all active and prior queued generation online, reverse power flow onto the 230 kV transmission system at BPA Roundup is likely. The addition of this project further increases the likelihood of reverse power flow conditions at BPA Roundup.

- To meet IEEE 1547 voltage fluctuation requirements an instantaneous generator output change from 100% to 0% must not produce more than a 3% change in voltage in any operating scenario. Studies show no scenario where more than a 3% voltage change will occur for an immediate generation output change from 100% to 0%.