Community Solar Project Interconnection

Community Solar Project System Impact Study Report

Completed for

(“Applicant”)
OCS048

Proposed Point of Interconnection

Circuit 5R76 out of White City substation

February 25, 2021

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1.0 DESCRIPTION OF THE COMMUNITY SOLAR PROJECT

(“Applicant”) proposed interconnecting 1.45 MW of new generation to PacifiCorp’s (“Public Utility”) Circuit 5R76 out of White City substation located in Jackson County, Oregon. The project (“Project”) will consist of twelve (12) Chint Power Supply CPS SCH125KTL-DO/US 600125 for a total requested output of 1.45 MW (nameplate 1.5 MW). The requested commercial operation date is June 30, 2021.

The Public Utility has assigned the Project “OCS048.”

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 5R76 out of White City substation via a 12.47 kV primary meter. The proposed Point of Interconnection will be located at approximately 1100 Kirtland Road located in Jackson 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.

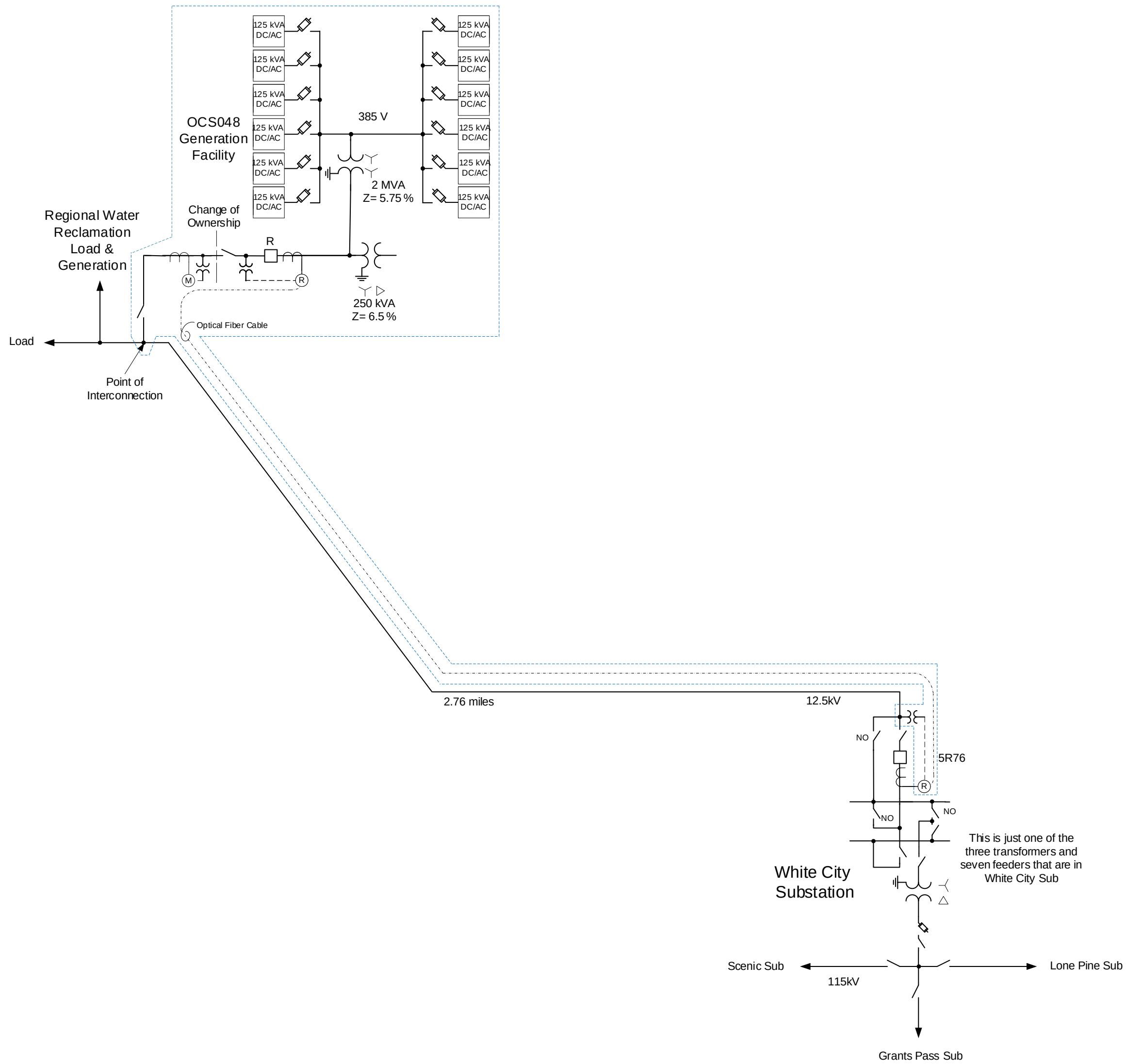

Figure 1: System One Line Diagram

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.
- All facilities will meet or exceed the minimum Western Electricity Coordinating Council ("WECC"), North American Electric Reliability Corporation ("NERC"), and Public Utility performance and design standards.
- The line extension is assumed to originate at facility point 1336002-146001.
- The generators were assumed to operate during daylight hours, 7 days per week, 12 months per year. The generation contribution at the POI was assumed to be 1450 kW at unity power factor.
- This study assumes that the Applicant will provide constant power factor control at unity power factor (100% PF).
- A White City circuit 5R76 daytime minimum load value of 2400 kW, unity power factor was assumed based on measurements. The new generation is not expected to provide reverse flow to the circuit.
- This report is based on information available at the time of the study. It is the Applicant's responsibility to check the Public Utility's web site regularly for transmission system updates (https://www.oasis.oati.com/ppw)

6.0 REQUIREMENTS

6.1 COMMUNITY SOLAR PROJECT REQUIREMENTS

The Community Solar Project and Interconnection Equipment owned by the Applicant are required to operate under constant power factor mode with a unity power factor setting unless specifically requested otherwise by the Public Utility.. The Community Solar Project is expressly forbidden from actively participating in voltage regulation of the Public Utility's system without written request or authorization from the Public Utility. The Community Solar Project 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.

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 generation facility is isolated with the Public Utility's local system until the generation disconnects. The proposed wye – wye step-up transformer will not accomplish the stabilization of the phase to neutral voltages on the 12.5 kV system. 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 wye – delta grounding transformer of adequate power size and impedance that will meet the requirement.

6.2 Transmission System Modifications

No transmission system modifications are required to accommodate the proposed Project.

6.3 Distribution/Transmission Line Modifications

- The load flow model was modified from its present state to its future state by including the following construction items:
  - Extend 12.47 kV facilities from the existing facility point 01336002-146001 to the POI. This line extension was scoped as underground cable, with 140T fuses on the riser pole. 900 feet of 3-phase, 4/0 AL cable shall be installed to a new padmounted primary metering cabinet. The Applicant will be responsible for the installation of the conduit system for the underground cable from the pole to the metering cabinet according to the Public Utility's specifications. The Applicant will be responsible for the procurement and installation of the box pad base for the primary metering cabinet according to the Public Utility's specifications. The Public Utility will install cable terminations on the utility side of the primary metering cabinet, and the Applicant will install cable terminations on the Applicant side of the primary metering cabinet. The Applicant will be responsible for obtaining all necessary permissions and easements.

6.4 Existing Breaker Modifications – Short-Circuit

The increase in the fault duty on the system as the result of the addition of the Community Solar Project with photovoltaic arrays fed through 12 – 125 kW inverters connected to 1 – 2 MVA 12.5 kV – 385 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 OCS048 Community Solar Project will need to disconnect in a high-speed manner for any fault on the 12.5 kV circuit 5R76 out of White City substation. The minimum daytime load on circuit 5R76 with the existing generation at the Regional Water Reclamation plant does not provide adequate margin above the potential power output of the proposed OCS048 Community Solar Project to rely on the imbalance condition of the load and generation that the generation facilities could be isolated with following the opening of 5R76 to result in high-speed disconnection of the generating facility for faults on the distribution system. A transfer trip circuit will need to be installed between White City substation and the OCS048 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 5R76 is equipped with automatic reclosing. When breaker 5R76 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 5R76 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 5R76. 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.

The 12.5 kV circuit recloser planned to be installed at the OCS048 Project will need to equipped Schweitzer Engineering Laboratories (SEL) 651R relay/controller and voltage instrument transformers mounted on the Public 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 Community Solar Project
2. Detect faults on the 12.5 kV line to White City substation
3. Monitor the voltage and react to under or over frequency, and /or magnitude of the voltage
4. Monitor the unbalance current flowing from the grounding transformer to prevent damage to the transformer due to phase unbalance conditions on the 12.5 kV line.
5. Receive transfer trip from White City substation

6.6 DATA REQUIREMENTS (RTU)

Due to the power size of the proposed generation 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

An optical fiber cable will need to be installed along the distribution line between the circuit recloser at the POI and White City substation for transfer trip.

6.8 Substation Requirements

At White City substation, a 12.5kV voltage transformer (VT) will be installed on an existing structure on the line side of breaker 5R76 and a junction box.

6.9 Metering Requirements

Interchange Metering

The Public Utility metering shall be installed at the point of delivery adjacent to the Applicant's transformer and disconnect devices. The metering instrument transformers will be installed inside a primary metering enclosure, with the meter socket located on the enclosure. The Public Utility will procure, install, test, and own all revenue metering equipment. Standalone revenue metering will be located on the high side of the Applicant's generator step up transformer. The metering will be bi-directional to measure KWH and KVARH quantities for both generation received and 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. The present output rating of the generation project is below the requirement for SCADA.

Station Service/Construction Power

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

7.0 Cost Estimate

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

Project Administration *Project management, administrative support*	$17,000
Protection & Control *P&C Engineer and Relay Technician*	$15,000
Metering *Metering equipment*	$26,000
Distribution *Underground Line Extension, Conductor, Fuses, Riser Pole*	$100,000
Communications *Install 2.8 miles of fiber and communications equipment*	$135,000

Substation *Installation of instrument transformer*	$77,000
Other Costs *Capital surcharge and contingency*	$85,000
Total Project Cost	**$455,000**

*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 12-14 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 June 30, 2021.

9.0 PARTICIPATION BY AFFECTED SYSTEMS

Public Utility has identified the following Affected Systems: None

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

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, 2.25 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 Interconnection Customer's facilities must be operated in a manner so as not to cause objectionable power quality issues to other Distribution Provider customers. Voltage fluctuations caused by the generation facility are required to meet the Distribution Provider's Engineering Handbook, Voltage Fluctuation and Flicker, Standard 1C.5.1 which is found at https://www.pacificpower.net/about/power-quality-standards.html Table 1 of Standard 1C.5.1 indicates that for this project the medium voltage planning levels for voltage fluctuation under any condition is a $P_{st} < 0.9$ and a $P_{lt} < 0.7$. It is the Interconnection Customer's responsibility to design and construct a system capable of meeting these levels. Specific system information will be provided on request to the Interconnection Customer for design purposes. During operation if measured voltage fluctuation levels exceed the limits specified in Standard 1C.5.1 the Interconnection Customer is required to cease generation until the condition is mitigated. The requirement for the Interconnection Customer's system to meet Standard 1C.5.1 will be incorporated in the interconnection contract. The Distribution Provider may, at its' discretion, disconnect the Interconnection Customer's facilities until mitigations to meet these standards are made. The Interconnection Customer must also comply with all of the Distribution Provider's Engineering Handbook standards addressing power quality, including but not limited to Voltage Level, Voltage Balance, Harmonic Distortion, and Voltage Frequency.
- For calculation of the forecasted voltage fluctuation, it was assumed that the power flow from the Interconnection Customer would change from full generation to no generation during a one minute interval.
- Six cases were assembled and studied at the 12.47 kV distribution voltage level.
  - Daytime minimum load, no generation.
  - Daytime minimum load, full generation.
  - Summer peak, no generation.
  - Summer peak, full generation.
  - Winter peak, no generation.
  - Winter peak, full generation.
- The following substation load tap changer output voltages were assumed in the respective cases. The values are based on new LTC settings:
  - Daytime minimum load case: 1.013 per unit.
  - Summer peak case: 1.038 per unit.
  - Winter peak case: 1.033 per unit.

  Three base cases were developed and studied in power flow simulation at the transmission level covering summer peak load, winter peak load and daytime minimum load conditions. Analysis was performed on each case evaluating three transmission system configurations prior to and with the requested OCS048 generation:

    - Normal transmission configuration: White City substation supplied by looped 115 kV transmission system served from Lone Pine 230-115 kV substation and Whetstone 230-115 kV substation via Line 40.

  - Contingency transmission configuration 1: Lone Pine-Vilas Road segment of 115 kV Line 40 is out of service. White City substation supplied from Whetstone 230-115 kV source via Line 40.
  - Contingency transmission configuration 2: Whetstone-White City segment of 115 kV Line 40 is out of service. White City substation supplied from Lone Pine 230-115 kV source via Line 40.
- The calculated voltage fluctuation from full generation to no generation in the light load case was 0.7%.

The results of the transmission study show that the proposed OCS048 project does not result in negative impacts to the Public Utility's transmission system. Power flow simulation indicates that steady state and post transient voltages are projected to remain within acceptable limits and loading on transmission facilities is projected to remain within facility ratings.

There are no contingent facilities identified for this interconnection request at the transmission level.