Community Solar Project Interconnection
Community Solar Project System Impact Study Report

Completed for

(“Applicant”)
OCS023

Proposed Point of Interconnection
Circuit 5L8 out of the Sprague River substation at 12 kV
(At approximately 42.455400°N, 121.4904°W)

August 5, 2020

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1.0 DESCRIPTION OF THE COMMUNITY SOLAR PROJECT

(“Applicant”) proposed interconnecting 0.6 MW of new generation to PacifiCorp’s (“Public Utility”) circuit 5L8 out of the Sprague River substation located in Klamath County, Oregon. The project (“Project”) will consist of five (5) Sungrow SG125HV 120 kW inverters for a total requested nameplate output of 0.6 MW. The requested commercial operation date is September 18, 2021.

The Public Utility has assigned the Project “OCS023.”

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 5L8 out of the Sprague River via a new primary meter. The Point of Interconnection (“POI”) will be located at approximately 42.455400°N, 121.4904°W in Klamath County, Oregon. Figures 1 and 2 below are one line diagrams that illustrate the interconnection of the proposed generating facility to the Public Utility’s system.

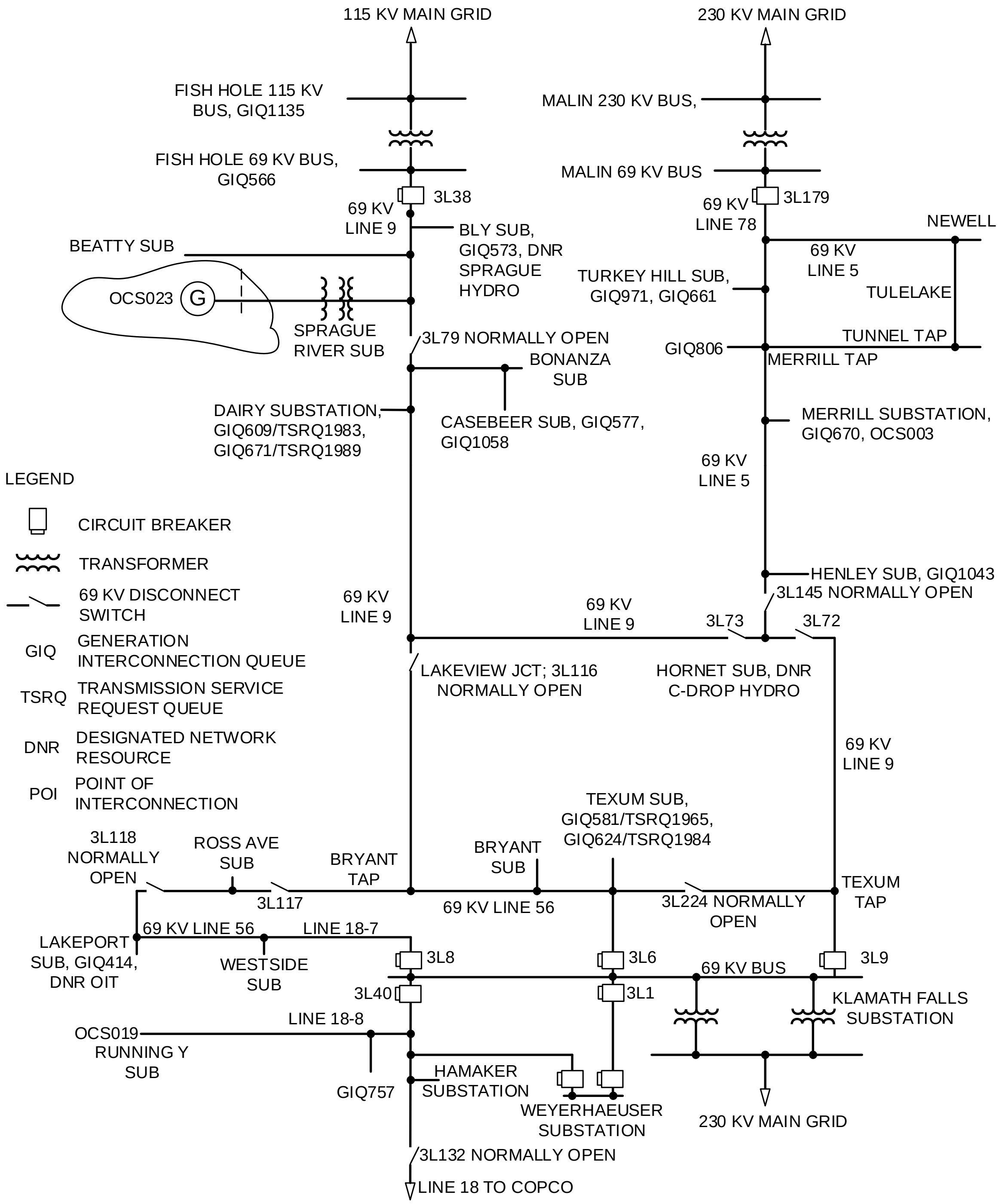

Figure 1: Transmission System One Line Diagram

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 Public Utility distribution facility point closest to the POI is 01436010.0-147660.
- Distribution load flows were performed at peak and light load and full and no generation with summer and winter loading conditions.
- 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 power factor control with the power factor sensed electrically at the POI.

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.

The minimum power quality requirements are in PacifiCorp's Engineering Handbook section 1C and are available at https://www.pacificpower.net/about/power-quality-standards.html. Requirements 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.

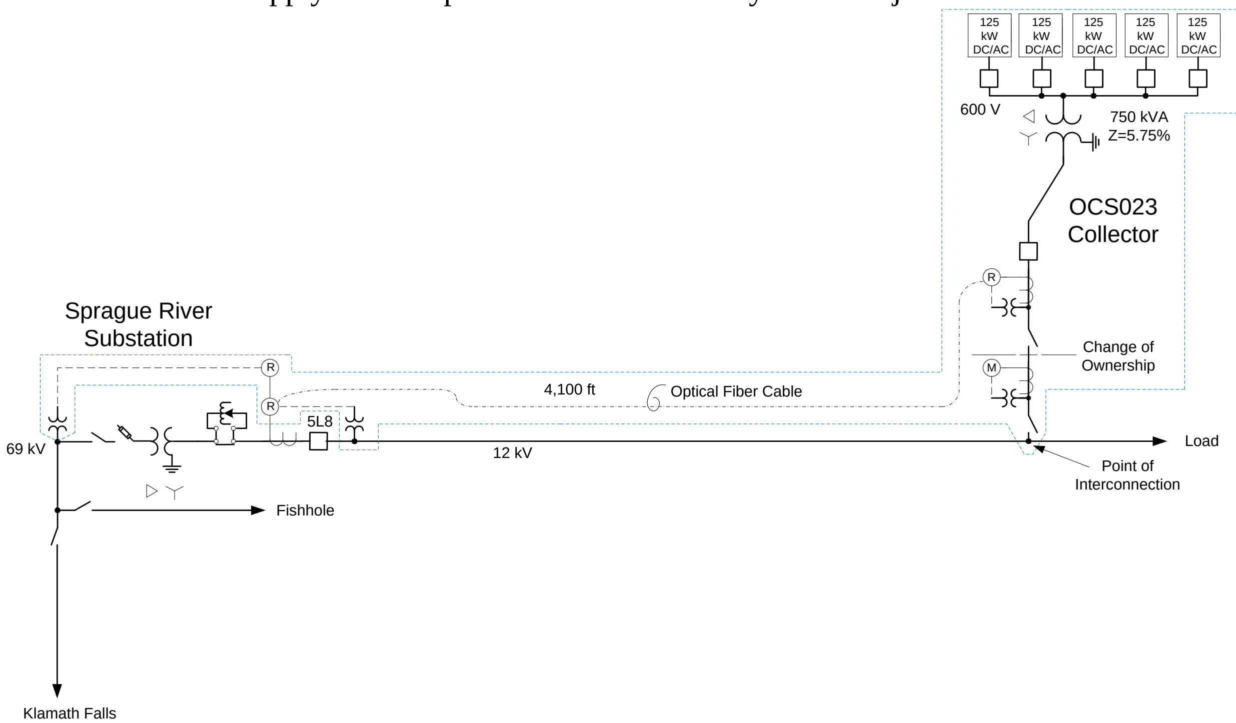

Figure 2: System One Line Diagram

6.2 Distribution/Transmission Line Modifications

Extend #2 AAAC phase and neutral conductor from Sprague River Road to the point of change of ownership. The line extension includes a pole for primary metering and a pole with a 600 amp group operated switch.

6.3 Existing Breaker Modifications – Short-Circuit

The increase in the fault duty on the system as the result of the addition of the generation facility with photovoltaic arrays fed through 5 – 125 kW inverters connected to a 750 kVA 12 kV – 600 V transformers with 5.75% impedance will not push the fault duty above the interrupting rating of any of the existing fault interrupting equipment.

6.4 Protection Requirements

The proposed OSC0023 project will be connected to the 12 kV circuit 5L8 out of Sprague River substation. For faults on the 12 kV circuit, the 69 – 12 kV transformer in Sprague River substation or on the 69 kV line to Fishhole substation the generating facility must disconnect in a high speed manner. Most faults on overhead circuits are temporary so that after all of the sources of power to the fault are disconnected the circuit can be re-energized. To facilitate the restoration of the circuits both 5L8 and 3L38 at Fishhole substation are setup for automatic reclosing. The 12 kV system is lightly loaded. The minimum daytime load on the 12 kV circuit out of Sprague River Substation can be less that the existing generation sources on the circuit plus the addition of the OCS023 project. Since the potential unbalance between the generation and the load that will be isolated together following the opening of breaker 5L8 cannot be relied upon to cause a high speed disconnection of the power generation facilities a transfer trip communication circuit will be needed between Sprague River substation and the OCS023 generating facility. An optical fiber cable will be installed to carry the transfer trip signal between the sites.

For 12 kV circuit faults the transfer trip will be keyed by the opening of breaker 5L8 at Sprague River substation. Currently the 69 – 12 kV transformer is protected with 69 kV fuses. The fuses were adequate since there are no significicate sources of fault current on the 12 kV before this Project. A relay will be installed as part of this Project which will be set to detect transformer faults and key transfer trip to the generating facility. 69 kV instrument voltage transformers will be installed. The relay that will be installed to detect faults in the transformer by monitoring the 12 kV current and the 69 kV voltages. This relay will also detect faults on the 69 kV line.

The 12 kV circuit relays associated with the breaker 5L8 will need to be replaced with a relay that will provide a dead-line check function. The dead line checking will be required to block the automatic reclosing of circuit breaker ("CB") 5L8 for the cases when a failure of the protective systems leads to delayed tripping of the generation facility for a feeder fault. Reclosing for this type of situation could cause damage to the equipment and needs to be prevented. A voltage instrument transformer will need to be installed on the line side of CB 5L8 to provide the signal for the relay to monitor.

At the POI for the generation facility a circuit recloser will need to be installed. A three phase set of voltage instrument transformer will need to be install on the unity side of the circuit recloser. The output of these transformers will be connected to the relay associated with the circuit recloser. This relay will need to be a SEL 651R protective relay which will be configure to perform the following functions:

1. Receive the transfer trip signals from Sprague River substation over the optical fiber cable.
2. Monitor the voltage magnitude and frequency. If the magnitude or frequency of the voltage is outside of normal range of operation the recloser will be tripped.
3. Monitor the current and the voltage to detect faults on the 12 kV distribution line.
4. Detect faults on the 12 kV system to the generating facility.

6.5 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.

6.6 Communication Requirements

An optical fiber cable will be required between Sprague River substation and the OCS023 circuit recloser at the POI to carry the transfer trip signal.

6.7 SUBSTATION REQUIREMENTS

Due to the new relaying equipment that is required to be installed for this request a new control house will need to be installed in the substation. The following major equipment has been preliminarily identified for this project and may change during actual design:

Sprague River Substation:
1 – Control House
3 – 69 kV CCVTs
1 – 12 kV VT

6.8 METERING REQUIREMENTS

Interchange Metering
The metering will be located on the high side of the Interconnection Customer 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.

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

7.0 COST ESTIMATE

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

OCS023 Collector Station *Metering and communications equipment, relay settings*	$78,000
Distribution Circuit *Line extension*	$35,000
Communications *Fiber installation*	$35,000
Sprague River Substation *Control house, relays, and instrument transformers*	$479,000
Total	**$627,000**

*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.

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 may support the Applicant's requested commercial operation date of September 18, 2021.

9.0 PARTICIPATION BY AFFECTED SYSTEMS

Public Utility has identified the following Affected Systems: None

Copies of this report will be shared with each Affected System.

10.0 APPENDICES

Appendix 1: Higher Priority Requests
Appendix 2: Informational Network Resource Interconnection Service Assessment
Appendix 3: Property Requirements
Appendix 4: 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)
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

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: DISTRIBUTION STUDY RESULTS

- The modeled power flow on Sprague River Substation breaker 5L8 and the Sprague River Substation 69 kV to 12 kV transformer bank is 156 kW reverse power flow during light load and full generation.
- No overloaded equipment or voltage issues were identified on the distribution system.