Community Solar Project Interconnection

Community Solar Project System Impact Study Report

Completed for

(“Applicant”)
OCS010

Proposed Point of Interconnection

Circuit 4W8 out of Enterprise Substation at 20.8 kV
(at approximately 45.441638°N, 117.219846°W)

May 18, 2020

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1.0 DESCRIPTION OF THE COMMUNITY SOLAR PROJECT

(“Applicant”) proposed interconnecting 1.875 MW of new generation to PacifiCorp’s (“Public Utility”) circuit 4W8 out of Enterprise substation located in Wallowa County, Oregon. The project (“Project”) will consist of fifteen Sungrow SG125HV 125 kW inverters for a total requested output of 1.875 MW. The requested commercial operation date of July 1, 2021.

The Public Utility has assigned the Project “OCS010.”

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 4W8 out of Enterprise substation via a new 20.8 kV overhead primary meter. The Point of Interconnection will be located at existing pole map string 01401045.0, facility point 294006 at approximately 45.441638°N, -117.219846°W in Wallowa County, Oregon. Figure 1 below is a one line diagram that that illustrates the interconnection of the proposed generating facility to the Public Utility’s system.

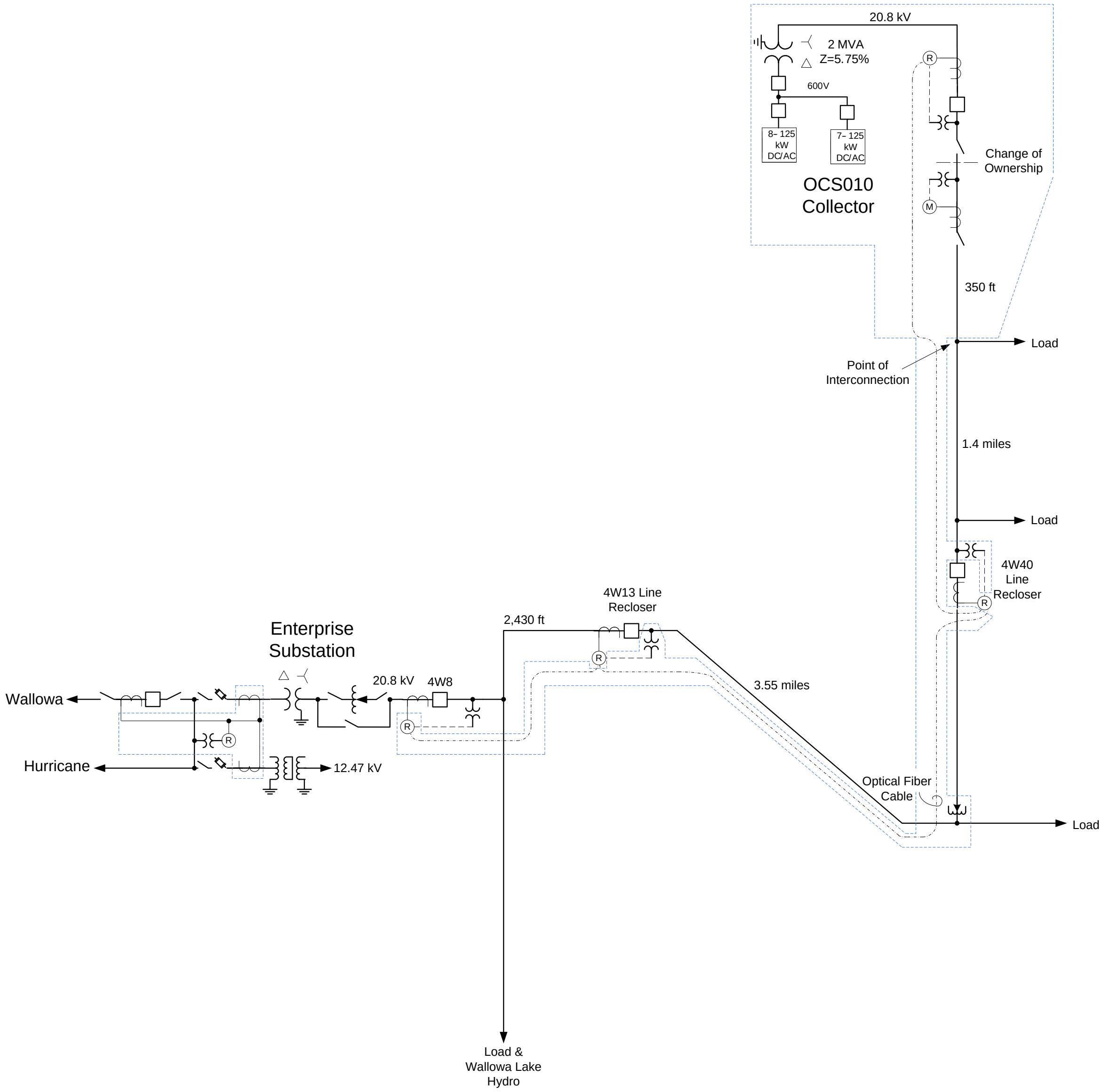

Figure 1: System One Line Diagram

5.0 Study Assumptions

- All active higher priority transmission service and/or generator interconnection and Community Solar Project requests 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.
- For study purposes there are two separate queues:
  - Generation Interconnection Queue: All relevant higher queue interconnection requests will be modeled in this study.
  - Community Solar Queue: Any relevant higher queue community solar requests will be modeled in this study.

- The Applicant’s request for interconnection service in and of itself does not convey any other form of 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 Point of Interconnection 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.
- Time of use metering does not exist for Enterprise substation loading. The daytime minimum demand for the feeder 4W8 is estimated based on peak demand readings on the circuit.
- The minimum daytime load on 4W8 including existing generation is estimated at -430 kW and 50 KVAR, power into the substation.
- The Small Generator Facility is expected to operate during daylight hours every day 7 days per week 12 months per year.
- Contingency transmission configuration for the Public Utility’s system is defined as any configuration other than normal transmission configuration.
- Two case studies were assembled and studied in power flow simulation at the transmission level:
    - Case 1: Normal Configuration, with the Enterprise substation fed radially via the 69 kV line from Hurricane substation.
    - Case 2: Contingency Configuration with Enterprise substation fed radially via the 69 kV backup feed from OTEC via Elgin switching station (Note, this is not possible under heavy loading conditions, and was studied at Light Loading only, as a sensitivity analysis).
- 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 MODIFICATIONS

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 Point of Interconnection. The Community Solar Project should have sufficient reactive capacity to enable the delivery of 100 percent of the plant output to the Point of Interconnection at unity power factor measured at 1.0 per unit voltage under steady state conditions.

Generators capable of operating under voltage control with voltage droop 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 Point of Interconnection 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 Point of Interconnection 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 Point of interconnection. Under normal conditions, the Public Utility's system should not supply reactive power to the Community Solar Project.
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The Applicant is required to procure, install, and own a lockable gang operated switch which is able to provide a visible open as their first device after the Point of Ownership Change. The Public Utility will not operate the Applicant's switch and the Applicant will not operate the Public Utility's switch.

Certain extreme contingency configurations may warrant generation curtailment until the system returns to a normal state. This includes an outage of the Hurricane 230 – 69 kV transformer or the 230 kV source at Hurricane, resulting in loss of service and, under certain circumstances, restoration from the alternate OTEC source available at Elgin switching station.

6.2 DISTRIBUTION/TRANSMISSION LINE MODIFICATIONS

Distribution modifications made by the Public Utility are required as follows:

- The proposed Point of Interconnection is a single phase 12.0 kV line even though application documents state it is a three phase line. The Public Utility will design, procure, install, and own an additional two #2 AAC primary conductors along with any required poles and crossarms for roughly 350' to convert the Point of Interconnection to a three phase 20.8 kV system.
- From the Point of Interconnection to the point of change of ownership the Public Utility will design, procure, and install a line extension on private property consisting of at least two poles. A Public Utility owned and operated gang switch will be installed on the first pole and primary metering units will be installed on the second pole. Conductor from this primary metering pole will be installed one span to land on the Applicant's

pole, the termination of this conductor at the Applicant's pole will be the point of change of ownership. The Applicant's final pole shall be constructed to Public Utility standards. These facilities will require rights of way obtained by the applicant as required in Appendix 3.

- An existing 25 amp fuse at map string 01401045.0, facility point 324600 is predicted to be loaded to 58 amps and will be increased to a 65 amp fuse, along with this work overcurrent settings on two upstream field reclosers and the substation breaker will need to be modified to ensure system protection standards are met.
- To maintain the ability to serve ANSI range A voltages to all customers a set of three 100 amp, 27 kV voltage regulators are required to be installed near map string 01402045.0, facility point 053101 along Elk Mountain Road just north of Crow Creek Road. The controller on these voltage regulators will be required to operate in both a forward and reverse power mode.

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 15 – 125 kW inverters connected to a 2 MVA 12.5 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.

6.4 PROTECTION REQUIREMENTS

Between Enterprise substation and the planned OCS010 generating facility there are two line reclosers: 4W13 and 4W40. The minimum daytime load on circuit 4W8 out of Enterprise substation as well as beyond the line reclosers is below the maximum potential power output of the proposed OCS010 generating facility. For this reason the imbalance condition of the load and generation that the generating facility could be isolated with following the opening of any of these fault interrupting devices cannot be relied upon to cause the high speed disconnection of the generating facility for faults on the distribution system. A transfer trip circuit will need to be installed between the two line reclosers, Enterprise substation and the OCS010 generating facility. Since most faults on overhead lines are temporary and the circuit can be restored as soon as all the sources of power to the fault have been disconnected, circuit breaker 4W8 and line reclosers 4W13 and 4W40 are all equipped with automatic reclosing. When any of the three fault interrupters open, a transfer trip signal will be sent to the circuit recloser at the generating facility. An optical fiber cable will need to be installed between Enterprise substation and the circuit recloser at the generating facility. The optical fiber will be looped into the controllers of the two line reclosers. The transfer trip signals will be sent over the optical fiber cable.

To insure that the automatic reclosing of circuit breaker 4W8 or line recloser 4W13 or 4W40 does not take place before the Applicant's generating facility disconnects, a dead line checking control circuit will be installed at all three locations. The dead line checking control circuit will delay the reclosing until the line is no longer energized to insure that no damage is done to any of the existing customers' equipment. Circuit breaker 4W8 is already equipped with these type of controls. Line reclosers 4W13 and 4W40 are equipped with controls that can be modified to accomplish these functions. Sets of voltage transformers ("VTs") will be added to the existing recloser installations. To accommodate both the transfer trip and the dead line checking a new relay will be installed at Enterprise substation.

During periods of the year the total minimum daytime load out of Enterprise substation is less that the potential power production of the combination of an existing hydro generator along with proposed requests OCS005, OCS006, and this OCS010. The combination of the solar generation and the synchronous generator will make it difficult to get high speed disconnection of the generation by using the effect of the unbalance between the load and the generation that are isolated together as the indication of the faulted system. For faults on the 69 kV line between Hurricane and Enterprise substations the generation facilities need to be disconnected before the reclosing takes place at Hurricane substation to have a successful reclose. For this reason the installation of relays at Enterprise substation to detect faults on the 69 kV line are required as part of the OCS010 project. The new relays at Enterprise substation will monitor the 69 kV currents and voltages to detect 69 kV faults and will trip 3W106 and transfer trip the Applicant's generating facility.

The typical configuration for the overcurrent devices on the feeder is to have the overcurrent functions non-directional. However, with the addition of the OCS010 generating facility, ground faults on the feeder between Enterprise substation and the line reclosers will result in the current flowing from the generation facility being greater than the pickup value for the ground overcurrent elements. Having the line reclosers trip for faults on the feeder toward the substation will not be acceptable. The ground relay elements for both line reclosers 4W13 and 4W40 will have the capability to set the ground overcurrent elements to be directional once the VTs are installed at each site. This will enable the line reclosers to operate correctly.

The 20.8 kV circuit recloser planned to be installed at the collector for the OCS010 project will need to be equipped with a Schweitzer Engineering Laboratories (SEL) 651R relay/controller and voltage instrument transformers mounted on the utility side of the circuit recloser. The 651R will perform the following protection functions:

1. Detect faults on the 20.8 kV equipment at the solar-electric generation facility
2. Detect faults on the 20.8 kV line to Enterprise substation
3. Monitor the voltage and react to under or over frequency, and /or magnitude of the voltage
4. Receive transfer trip from Enterprise substation and from the line reclosers 4W13 and 4W40.

6.5 Communication Requirements

Approximately 5.5 miles of 48-fiber, single mode ADSS fiber optic cable will be installed on the distribution line from Enterprise substation through Public Utility reclosers 4W13 and 4W40 and to the Applicant's recloser at the generating facility location. The fiber will be terminated in patch panels at all locations and jumpers installed to the relays' fiber optic transceivers.

6.6 SUBSTATION REQUIREMENTS

Enterprise Substation

To account for the additional generation, setting changes on regulator R-528 are required in order to maintain ANSI Range A voltages to all customers in all scenarios. New feeder and line relay protection panels will be installed. Fiber will be brought into the control house. The following equipment has been identified as being required and may change during detailed design.

3 – 69 kV, CCVT
6 – Slip-on CT (for use on the high side bushings of the existing power transformers)

6.7 METERING REQUIREMENTS

Interchange Metering

The metering will be located on the high side of the customer generator step up transformer at the Point of Delivery. 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-up 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.

OCS010 Collector Station *Communications & metering equipment, relay settings*	$72,000
Distribution *New conductor, line extension, regulator, fuse upgrade, fiber installation*	$378,000
Line Recloser 4W13 *Install optical transceivers.*	$30,000
Line Recloser 4W40 *Install optical transceivers.*	$33,000

Enterprise Substation $580,000
Protection equipment, instrument transformers

Total **$1,093,000**

*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 July 1, 2021.

9.0 PARTICIPATION BY AFFECTED SYSTEMS

Public Utility has identified the following Affected Systems: Idaho Power

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.

Generation Interconnection/Community Solar Queue Requests considered:

Q#	**Size (MW)**
650	10.000
651	10.000
652	10.000
653	10.000
1190	200.000
OCS005	0.36
OCS006	1.04
OCS009	1.625

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.

Enterprise is part of the Walla Walla transmission bubble, which currently has insufficient network load (at peak) to absorb any additional generation. Therefore, to deliver the aggregate of generation in the local system to the aggregate of load (the NRIS study scope), construction of a new 230 kV transmission line from the Enterprise area system to the Yakima area system (where the generation could be absorbed) may be required, at a minimum. The new 230 kV line would interconnect Hurricane substation with Wine Country substation in the vicinity of Grandview, Washington. The new 230 kV line would be approximately 160 to 185 miles, depending on the line route. Upgrades at both Hurricane and Wine Country substations would be required to tie in the new line. The transmission provider's high level estimate for this transmission line is $185,000,000.

10.3 APPENDIX 2: PROPERTY REQUIREMENTS

Requirements for rights of way easements
Any 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 (if required)
Real property for a point of interconnection 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.