

**Generation Interconnection
Feasibility Study Report
Queue Position AB2-157**

The Interconnection Customer (IC), has proposed a 3.2 MW (1.2 MW Capacity) solar generating facility to be located in Capitol Heights, Maryland. PJM studied AB2-157 as a 3.2 MW injection into the Potomac Electric Power Company (Pepeco) system at the Ritch 69 kV substation and evaluated it for compliance with reliability criteria for summer peak conditions in 2020. The planned in-service date, as requested by the IC during the project kick-off call, is October 31, 2017.

Point of Interconnection

The Interconnection Customer requested a distribution level Point of Interconnection.

Transmission Owner Scope of Work

The Transmission Owner has provided two possible options to interconnect the AB2-157 project as follows:

Option 1 - Construct an express feeder from Substation 15 by following feeder 15139

Task	Quantity	Units	\$
Replace existing cubicle with stacked	1		500,000
Duct bank at substation	5" 4W	2105 ft.	930,986
Cable at substation -600 3-1/C	1	2105 ft.	212,892
13 kV OH 477 ACSR	1	1.2 mile	912,960
UG conduit to customer gear	5" 2W	607 ft.	199,375
UG cable to customer gear – 600 3-1/C	1	607 ft.	61,390
Recloser	1		43,133
Total			2,860,736

Option 2 – split generation between two existing feeders

1.6 MW of generation on feeder 15131

Task	Quantity	Units	\$
UG to OH rising pole @ Central Ave and Ventura Ave	1		36,000
Direct Buried UG cable to Customer - 600 3-1/C	1	1662 ft.	168,088
Recloser	1		43,133
Total			247,221

1.6 MW of generation on feeder 15131

Task	Quantity	Units	\$
UG to OH rising pole near Rollins Ave and Hanlon St.	1		36,000
Direct Buried UG cable to Customer - 600 3-1/C	1	607 ft.	61,389
Recloser	1		43,133
Total			140,522

Direct Connection Requirements

Criteria Limits for Distributed Energy Resource (DER) Connections to the ACE, DPL and Pepco Distribution Systems (less than 69kV)

1. Single Phase Limit

Any DER with a capacity that exceeds 100kW shall be a balanced 3 phase system.

2. Voltage Limits

DER’s are permitted to cause a voltage fluctuation of up to 2% at the Point of Interconnection, ½ the band width of any voltage regulator at its terminals, and ½ the net dead band of a switched capacitor bank at its connection point. When a DER is at maximum output, it shall not raise the feeder voltage above the ANSI C84.1 or state limit, whichever is more conservative.

3. Existing Distribution Circuit Capacity Limits

The aggregate limit of large (250 kW and over) generators running in parallel with a single, existing distribution circuit is 0.5 MWs on the 4kV, 3MWs on the 12 kV, 6 MWs on the 25 kV, and 10 MWs on the 34 kV.

4. Express Circuit Capacity Limits

Distributed generation installations which exceed the limit for an existing circuit require an express circuit.

The maximum generator size for express circuits shall be:

- 4 kV 0.5 MW
- 12 – 13.8 kV 10 MW
- 23 – 25 kV 10 MW
- 33.26 – 34.5 kV 15 MW

5. Distribution Power Transformer Limit

The aggregate limit of large (250 kW and over) generator injection to a single distribution transformer of 22.5 MVA nameplate or larger is 10 MW. Transformers with nameplate ratings lower than 22.5 MVA will be given lower ratings on an individual basis. If the transformer rating is significantly greater than 40 MVA it may be possible to consider a greater generation capacity.

Adding a new transformer will be considered if there is no availability on any of the existing transformers and space is available in an existing substation. Any proposed transformers would be PHI's standard distribution transformer.

6. Express Circuit Length Limit

If there is no space for an additional transformer at the closest substation, the next closest substation will be considered. The length of an express circuit is limited to 5 miles, or for the sake of the feasibility study, 3.8 straight line miles to the substation. This simplification is used because the feasibility study phase does not allow for the time and resources to examine routes in detail (including existing pole lines, easements, ROW, and environmental issues etc.)

7. When a New Substation is Required

If a distribution express circuit can't be built from an existing substation for a project, it will be necessary to construct a new distribution substation with a standard ring bus design. It will be supplied by extending existing transmission lines. It is the developer's responsibility to verify eligibility of this configuration for solar renewable energy certificates.

All limits, given above in MWs, are subject to more detailed study to ensure feasibility.

Additional Operating Requirements

1. The Interconnection Customer will be required to make provisions for a voice quality phone line within approximately 3 feet of each Company metering position to facilitate remote interrogation and data collection.
2. A mutually acceptable means of interrupting and disconnecting the generator with a visible break, able to be tagged and locked out, shall be worked out with Company Distribution Engineering.
3. Company reserves the right to charge the Interconnection Customer operation and maintenance expenses to maintain the Interconnection Customer attachment facilities, including metering and telecommunications facilities, owned by Company.

Interconnection Customer Scope of Work

The Interconnection Customer (IC) is responsible for all design and construction related to activities on their side of the Point of Interconnection. Site preparation, including grading and an access road, as necessary, is assumed to be by the IC. Route selection, line design, and right-of-way acquisition of the direct connect facilities is not included in this report, and is the responsibility of the IC.

The Interconnection Customer will be required to install metering and telemetry equipment to provide revenue metering and real-time telemetry data to PJM. The requirements for this equipment are listed in Appendix 2, Section 8 of Attachment O to the PJM Tariff, as well as PJM Manuals 01 and 14D. Protective relaying and metering design and installation must comply with PHI's Applicable Standards.

The Interconnection Customer will purchase and install all metering instrument transformers as well as construct a metering structure per PHI's specifications. The secondary wiring connections at the instrument transformers will be completed by the Interconnection Customer's contractors and inspected by PHI, while the secondary wiring work at the metering enclosure will be completed by PHI's meter technicians. The metering control cable and meter cabinets will be supplied by PHI and

installed by the Interconnection Customer's contractors. PHI's meter technicians will program and install two solid state multi function meters (Primary & Backup) for the new metering position.

The Interconnection Customer must submit a single line showing a relay with inputs from a 3 phase voltage sensing device. The 3 phase voltage sensing must be done on the utility side of the customer's transformer. The relay should be capable of detecting and tripping for over/under voltage. Alternatively, the customer can replace the delta-Wye transformer with a transformer that is Wye grounded on the utility side.

The Interconnection Customer must install a disconnect switch in a mutually agreeable location with TO that contains appropriate naming placards.

Inverter Requirements and Capabilities

The inverter at the DG location shall have the following capabilities:

- Voltage flicker reduction through dynamic VAR or fixed PF response
- Ramp rate control
- SCADA communications
- Curtailment or other mitigation ability if high voltage were to occur
- Low voltage and system disturbance ride through
- Ability to receive and respond to a transfer trip signal
- Ability to adjust PF or VARs based on utility signal
- Ability to Adjust Real Power Output based on utility signal

The inverter shall operate in accordance with the IEEE 1547 series of standards that have been approved. While inverters should be capable of voltage stabilization thru dynamic VAR response and capable of low voltage and system disturbance ride through, neither of these capabilities shall be implemented until such time that the IEEE 1547 series of standards are revised and approved to include standards for these capabilities. At such time as these revised standards become available, the PV owner/operator shall cooperate with the Company (the 'Company' referring to ACE, DPL, or PEPCO) to implement these capabilities with settings acceptable to the Company. It is the responsibility of the owner to secure the inverter from any unauthorized access (including physical and remote access) which could alter settings or adversely affect the inverter's ability to operate as required. Security measures should include utilizing secure password settings and/or physical locks on cabinet doors.

Summer Peak Analysis - 2019

Transmission Network Impacts

Potential transmission network impacts are as follows:

Generator Deliverability

(Single or N-1 contingencies for the Capacity portion only of the interconnection)

None

Multiple Facility Contingency

(Double Circuit Tower Line, Fault with a Stuck Breaker, and Bus Fault contingencies for the full energy output)

None

Contribution to Previously Identified Overloads

(This project contributes to the following contingency overloads, i.e. "Network Impacts", identified for earlier generation or transmission interconnection projects in the PJM Queue)

None

Summer Peak Load Flow Analysis Reinforcements

New System Reinforcements

(Upgrades required to mitigate reliability criteria violations, i.e. Network Impacts, initially caused by the addition of this project generation)

None

Contribution to Previously Identified System Reinforcements

(Overloads initially caused by prior Queue positions with additional contribution to overloading by this project. This project may have a % allocation cost responsibility which will be calculated and reported for the Impact Study)

None

Steady-State Voltage Requirements

(Results of the steady-state voltage studies should be inserted here)

None

Short Circuit

No issues identified.

Stability and Reactive Power Requirement

Not required.

Light Load Analysis - 2020

Not required.

Facilities Study Estimate

(If a Facilities Study is required, provide the estimated duration and cost estimate to perform Facilities Study)

6 months; \$15,000 if required