Generation Interconnection System Impact Study Report

For

PJM Generation Interconnection Request Queue Position AE1-015

“St. Barnabas Road 13 kV”

August 2019

Preface

The intent of the System Impact Study is to determine a plan, with approximate cost and construction time estimates, to connect the subject generation interconnection project to the PJM network at a location specified by the Interconnection Customer. As a requirement for interconnection, the Interconnection Customer may be responsible for the cost of constructing: Network Upgrades, which are facility additions, or upgrades to existing facilities, that are needed to maintain the reliability of the PJM system. All facilities required for interconnection of a generation interconnection project must be designed to meet the technical specifications (on PJM web site) for the appropriate transmission owner.

In some instances an Interconnection Customer may not be responsible for 100% of the identified network upgrade cost because other transmission network uses, e.g. another generation interconnection or merchant transmission upgrade, may also contribute to the need for the same network reinforcement. The possibility of sharing the reinforcement costs with other projects may be identified in the Feasibility Study, but the actual allocation will be deferred until the System Impact Study is performed.

The System Impact Study estimates do not include the feasibility, cost, or time required to obtain property rights and permits for construction of the required facilities. The Interconnection Customer is responsible for the right of way, real estate, and construction permit issues. For properties currently owned by Transmission Owners, the costs may be included in the study.

General

Ameresco Inc., the Interconnection Customer (IC), has proposed a 1.35 MW Energy (0.57 MW Capacity) solar generating facility to be located in Temple Hills, Maryland. PJM studied the AE1-015 project into the Potomac Electric Power Company (Pepco) system as an injection into the St. Barnabas 69 kV Substation and evaluated it for compliance with reliability criteria for summer peak conditions in 2022. AE1-015 was studied with a commercial probability of 100%. The planned in-service date, as requested by the IC, is September 30, 2019. This date may not be attainable due to required PJM studies and Transmission Owner construction schedule.

Point(s) of Interconnection

The IC requested a distribution level interconnection with capacity given on the first available feeder within reasonable vicinity of the property that will accommodate the generation. As a result, the AE1-015 project will connect to the PEPCO distribution system at the St. Barnabas 69/13 kV Substation via Feeder 15084.

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 MWs. 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.

Transmission Owner (TO) Scope of Direct Connection Work

TO work required to accommodate 1.4 MW of generation on existing feeder 15084 from Tuxedo Substation:

1. A utility operated recloser equipped with the proper relaying and communications will be required, unless further studies note otherwise.
2. Utility grade primary metering will be required.
3. Generation telemetry and remote trip capability will be provided to the control center, unless further studies note otherwise.
4. A detailed, time-based study may be performed during later study phases.
5. Protection, Planning, and other engineering departments will perform studies, design work, and prepare engineering estimates.
6. The feeder 15084 will require a three-phase tap and extension of 477 AAC with necessary equipment from St Barnabas Rd. to POI. The extension is approximately 0.1 miles long to the property line.

Ball Park Costs			
St. Barnabas Substation via 15084			
3-Phase Feeder Extension	0.1	miles	$50,000
Recloser & Metering			$60,000
SCADA Integration into EMS			$10,000
Various Departments Work			$30,000
Subtotal Cost			$150,000
Approximate Total Cost with 15% Contingency			$172,500

The estimated time to complete this work is **18-24 months** after receipt of a fully executed interconnection agreement.

Transmission Owner System Reinforcements

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

None

Multiple Facility Contingency
(Double Circuit Tower Line, Failed 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

Delivery of Energy Portion of Interconnection Request
PJM also studied the delivery of the energy portion of this interconnection request. Any problems identified below are likely to result in operational restrictions to the project under study. The developer can proceed with network upgrades to eliminate the operational restriction at their discretion by submitting a Merchant Transmission Interconnection request.

Only the most severely overloaded conditions are listed. There is no guarantee of full delivery of energy for this project by fixing only the conditions listed in this section. With a Transmission Interconnection Request, a subsequent analysis will be performed, which will study all overload conditions associated with the overloaded element(s) identified.

None

Short Circuit

No issues identified.

Stability and Reactive Power Requirement

Not required.

Light Load Analysis - 2022

No required.

High Voltage Warning

Voltage received at the meter from the utility can be 105% of nominal. Normal operating procedures dictate that voltage at the substation be raised to the higher end of an acceptable bandwidth in order to provide adequate supply to distant customers. Transformers with no load taps should be used to reduce the voltage by 2.5% to avoid the possibility of inverter trips. Failure to account for this may result in lost energy production.

Interconnection Customer Scope of Direct Connection Work

Equipment Requirements

Any transformers on the customer's side must be Wye grounded on the utility side or alternatively 3 phase potential transformers and a relay capable of detecting over/under voltage shall be installed to detect an undesirable condition on the high side of the customer's transformer.

Inverter Requirements

The inverters 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
- Disturbance ride through for both voltage and frequency
- 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
- Ability to operate on a Volt/VAR schedule
- Ability to maintain a voltage schedule

The inverter shall operate in accordance with the IEEE 1547 series of standards that have been approved and use default settings except when specified otherwise by PEPCO. The PV owner/operator shall cooperate with PEPCO to implement these capabilities with settings acceptable to PEPCO. PEPCO reserves the right to request setting changes in the future if needed to maintain electrical system integrity. The inverters shall be capable of operating at a fixed power factor value between 0.95 lead and 0.95 lag. The value is supplied below:

1. Operate inverters at a unity power factor (“PF”) of (**1.00**)

Note: In the future, PEPCO reserves the right to issue new fixed power factor setting requirements (0.95 lead to 0.95 lag) if necessary.

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.

PEPCO will require the capability to remotely disconnect the generator from the grid by communication from its System Operations facility. Such disconnection may be facilitated by a generator breaker, a line recloser, or other method depending upon the specific circumstances and the evaluation of PEPCO.

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 PEPCO Distribution Engineering. When the trip command is sent to customer equipment rather than a utility owned recloser, the customer must have a circuit breaker capable of locking out, a lockout relay, or inverter logic that does not allow the inverters to automatically reconnect. The IC is responsible for calling PEPCO System Operations before manually reconnecting with the grid. The phone number to System Operations should be clearly displayed next to the circuit breaker or inverter controls.

As the study was performed with the generator on the transformer that it will be served from during normal conditions, the IC will not be allowed to generate when the feeder either is served by an alternate transformer or is in an alternate configuration.

Metering Requirements

The net interchange of electrical energy will be measured by the new revenue meter, owned by Company, located at the Point of Interconnection, as shown in Figure 1. This will be the official measurement of megawatt hours ("MWH") and megavar hours ("MVARH") received into and delivered by the Company's Electric System. These revenue meters will be the source for reporting generation output to PJM.

PEPCO will purchase and install all revenue quality metering instrument transformers as well as construct a metering enclosure per PEPCO specifications. PEPCO meter technicians will program and install two solid state multi-function meters (Primary & Backup) for the new metering position. The IC will be provided with one meter output, either DNP or pulse, which will be determined by PEPCO meter technicians.

The location of the metering enclosure will be determined in the construction phase. The IC will provide 120 V power to the meter cabinet.

Metering will conform to the requirements of Company's "Technical Considerations" and with PJM Manuals M-01, M-14A, M-14B and M-14D. The Company work scope will include providing, installing, operating and owning all components of the POI metering system.

Additional Operating Requirements

1. The Company will require the capability to remotely disconnect the generator from the grid by communication from its System Operations facility. This will be accomplished with a line recloser or Pepco signal to customer's generator breaker.
2. It is the Interconnection Customer's responsibility to send the data that PJM and the Company requires directly to PJM. The Interconnection Customer will grant permission for PJM to send the Company the following telemetry that the Interconnection Customer sends to PJM: real time megawatts, megavars, phase voltages, phase currents, and generator breaker status.
3. 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.
4. The Interconnection Customer will be required to submit a final Relay Coordination Study for review and approval by Company System Protection.
5. 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.
6. 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.
7. Study was performed with the generator on the transformer that it will be served from during normal conditions. Customer will not be allowed to generate when the feeder is served by an alternate transformer.

AE1-015
St. Barnabas 69/13.8 kV
Sub
1.4 MW Solar Generator

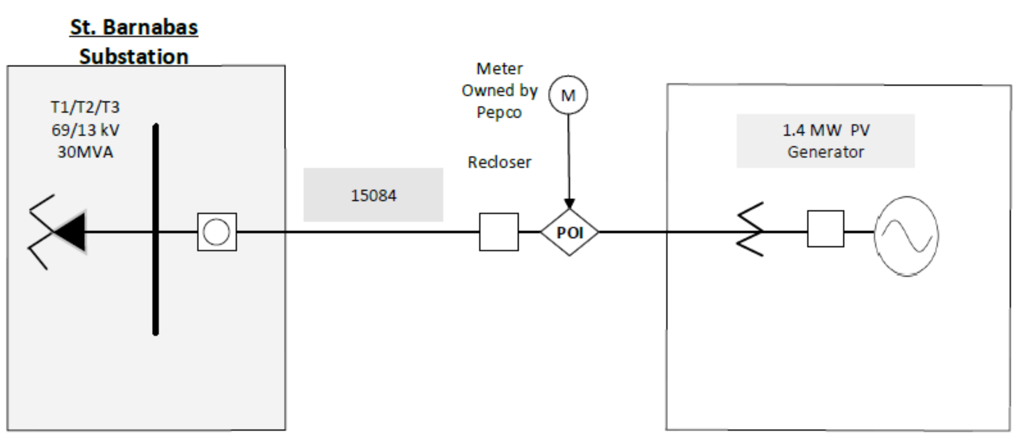

Figure 1 Single Line Interconnection Diagram

POI Point of Interconnection