Generation Interconnection Impact Study Report

For

PJM Generation Interconnection Request Queue Position AD1-161

Stonewall – Long Mountain 69 kV

December 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 project developer 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.

The Interconnection Customer seeking to interconnect a wind or solar generation facility shall maintain meteorological data facilities as well as provide that meteorological data which is required per Schedule H to the Interconnection Service Agreement and Section 8 of Manual 14D.

General

Urban Grid Solar, LLC proposes to install PJM Project #AD1-161, a 55.0 MW (30.2 MW Capacity) solar generating facility in Appomattox County, Virginia (see Figure 2). The point of interconnection is to AEP's Stonewall – Long Mountain 69 kV line (see Figure 1).

The requested in service date is December 31, 2020.

Point of Interconnection

Point of Interconnection (Stonewall - Long Mountain 69 kV)

To accommodate the interconnection on the Stonewall – Long Mountain 69 kV circuit, a new three (3) circuit breaker 69 kV switching station physically configured in a breaker and half bus arrangement but operated as a ring-bus will be constructed (see Figure 1). Installation of associated protection and control equipment, 69 kV line risers, SCADA, and 69 kV revenue metering will also be required. AEP reserves the right to specify the final acceptable configuration considering design practices, future expansion, and compliance requirements.

Cost Summary

The AD1-161 project will be responsible for the following costs:

Description	Total Cost	
Attachment Facilities	$	200,000
Direct Connection Network Upgrades	$	3,500,000
Non Direct Connection Network Upgrades	$	1,100,000
Allocation for New System Upgrades	$	0
Contribution for Previously Identified Upgrades	$	0
Total Costs	**$**	**4,800,000**

Attachment Facilities

The total preliminary cost estimate for the Attachment work is given in the table below. These costs do not include CIAC Tax Gross-up.

Description	Total Cost
69 kV Revenue Metering	$ 200,000
Total Attachment Cost Estimate	**$** 200,000

Direct Connection Cost Estimate

The total preliminary cost estimate for the Direct Connection work is given in the table below. These costs do not include CIAC Tax Gross-up.

Description	Total Cost
Construct a new three (3) circuit breaker 69 kV switching station physically configured in a breaker and half bus arrangement but operated as a ring-bus. Installation of associated protection and control equipment, 69 kV line risers, SCADA, and 69 kV revenue metering will also be required (see Figure 1).	$ 3,500,000
Total Direct Connection Cost Estimate	**$** 3,500,000

Note: This line is built to 138 kV standards therefore the new 69 kV switching station being constructed for AD1-161 may be required to be built to 138 kV standards to allow for future energization at 138 kV. AEP does not have definite plans for 138 kV energization but we will have to look into this in more detail in the Facilities study.

Non-Direct Connection Cost Estimate

The total preliminary cost estimate for the Non-Direct Connection work is given in the table below. These costs do not include CIAC Tax Gross-up.

Description	Total Cost
Stonewall – Long Mountain 69 kV T-Line Cut In	$ 700,000
Upgrade line protection and controls at the Stonewall 69 kV substation.	Central Virginia Electric Cooperative (CVEC) will need to provide scope and estimate
Upgrade line protection and controls at the Long Mountain 69 kV substation.	$ 200,000
Upgrade line protection and controls at the B&W 69 kV substation.	$ 200,000
Total Non-Direct Facilities Cost Estimate	**$** 1,100,000

Schedule

It is anticipated that the time between receipt of executed agreements and Commercial Operation may range from 12 to 18 months if no line work is required. If line work is required, construction time would be between 24 to 36 months after signing an interconnection agreement.

Note: The time provided between anticipated normal completion of System Impact, Facilities Studies, subsequent execution of ISA and ICSA documents, and the proposed Backfeed Date is shorter than usual and may be difficult to achieve.

Interconnection Customer Requirements

It is understood that Urban Grid Solar is responsible for all costs associated with this interconnection. The cost of Urban Grid Solar's generating plant and the costs for the line connecting the generating plant to the new switching station are not included in this report; these are assumed to be Urban Grid Solar's responsibility.

The Generation Interconnection Agreement does not in or by itself establish a requirement for American Electric Power to provide power for consumption at the developer's facilities. A separate agreement may be reached with the local utility that provides service in the area to ensure that infrastructure is in place to meet this demand and proper metering equipment is installed. It is the responsibility of the developer to contact the local service provider to determine if a local service agreement is required.

Requirement from the PJM Open Access Transmission Tariff:

1. An Interconnection Customer entering the New Services Queue on or after October 1, 2012 with a proposed new Customer Facility that has a Maximum Facility Output equal to or greater than 100 MW shall install and maintain, at its expense, phasor measurement units (PMUs). See Section 8.5.3 of Appendix 2 to the Interconnection Service Agreement as well as section 4.3 of PJM Manual 14D for additional information.

2. The Interconnection Customer may be required to install and/or pay for metering as necessary to properly track real time output of the facility as well as installing metering which shall be used for billing purposes. See Section 8 of Appendix 2 to the Interconnection Service Agreement as well as Section 4 of PJM Manual 14D for additional information.

Revenue Metering and SCADA Requirements

PJM Requirements

The Interconnection Customer will be required to install equipment necessary to provide Revenue Metering (KWH, KVARH) and real time data (KW, KVAR) for IC's generating Resource. See PJM Manuals M-01 and M-14D, and PJM Tariff Sections 24.1 and 24.2.

AEP Requirements

The Interconnection Customer will be required to comply with all AEP Revenue Metering Requirements for Generation Interconnection Customers. The Revenue Metering Requirements may be found within the "Requirements for Connection of New Facilities or Changes to Existing Facilities Connected to the AEP Transmission System" document located at the following link:

http://www.pjm.com/~/media/planning/plan-standards/private-aep/aep-interconnection-requirements.ashx

Network Impacts

The Queue Project AD1-161 was evaluated as a 55.0 MW (Capacity 30.2 MW) injection tapping the Stonewall to Long Mountain Tap 69kV line in the AEP area. Project AD1-161 was evaluated for compliance with applicable reliability planning criteria (PJM, NERC, NERC Regional Reliability Councils, and Transmission Owners). Project AD1-161 was studied with a commercial probability of 100%. Potential network impacts were as follows:

Summer Peak Analysis - 2021

Generator Deliverability

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

None.

Light Load Analysis

Light Load Studies to be conducted during later study phases (applicable to wind, coal, nuclear, and pumped storage projects).

None.

Multiple Facility Contingency

(Double Circuit Tower Line contingencies were studied for the full energy output. The contingencies of Line with Failed Breaker and Bus Fault will be performed for the Impact Study.)

None.

Short Circuit

(Summary of impacted circuit breakers)

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.

Steady-State Voltage Requirements

(Summary of the VAR requirements based upon the results of the steady-state voltage studies)

See Attachment 3

Stability and Reactive Power Requirement for Low Voltage Ride Through

(Summary of the VAR requirements based upon the results of the dynamic studies)

See Attachment 3 – there are deficiencies that need to be addressed

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.

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.

Incremental Capacity Transfer Rights (ICTRs)

Will be determined at a later study phase

Affected System Analysis & Mitigation

LGEE Impacts:

None

MISO Impacts:

None

Duke, Progress & TVA Impacts:

None

OVEC Impacts:

None

Light Load Analysis - 2020

Light Load Studies to be conducted during later study phases (as required by PJM Manual 14B).

Light Load 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)

(Summary form of Cost allocation for transmission lines and transformers will be inserted here if any)

None

Network Impacts

The Queue Project AD1-161 was evaluated as a 55.0 MW (Capacity 30.2 MW) injection into the Stonewall – Long Mountain 69 kV line in the AEP area. Project AD1-161 was evaluated for compliance with applicable reliability planning criteria (PJM, NERC, NERC Regional Reliability Councils, and Transmission Owners). Project AD1-161 was studied with a commercial probability of 100%. Potential network impacts were as follows:

Winter Peak Analysis - 2021

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

Steady-State Voltage Requirements
(Results of the steady-state voltage studies should be inserted here)

To be determined

Short Circuit
(Summary of impacted circuit breakers)

To be determined

Affected System Analysis & Mitigation

LGEE Impacts:

LGEE Impacts to be determined during later study phases (as applicable).

MISO Impacts:

MISO Impacts to be determined during later study phases (as applicable).

Duke, Progress & TVA Impacts:

Duke Carolina, Progress, & TVA Impacts to be determined during later study phases (as applicable).

OVEC Impacts:

OVEC Impacts to be determined during later study phases (as applicable).

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.

1. (AEP-AEP) The 05SMITHMTN2 -05ROCKCA 138 kV line (from bus 247499 to bus 242775 ckt 1) loads from 114% to 115.03% (AC power flow) of its emergency rating (277 MVA) for the single line fault contingency outage of 'AEP_P1-2_#6215'. This project contributes approximately 3.37 MW to the thermal violation.

CONTINGENCY 'AEP_P1-2_#6215'
 OPEN BRANCH FROM BUS 242748 TO BUS 242802 CKT 1 / 242748 05PENHOK 138 242802 05SMITHMTN1 138 1
 END

Light Load Analysis - 2021

Light Load Studies to be conducted during later study phases (as required by PJM Manual 14B).

System Reinforcements

Short Circuit

(Summary form of Cost allocation for breakers will be inserted here if any)

To be determined

Stability and Reactive Power Requirement

(Results of the dynamic studies should be inserted here)

To be determined

Winter 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)
(Summary form of Cost allocation for transmission lines and transformers will be inserted here if any)

None

Figure 1: Point of Interconnection (Stonewall– Long Mountain 69 kV)

Single-Line Diagram

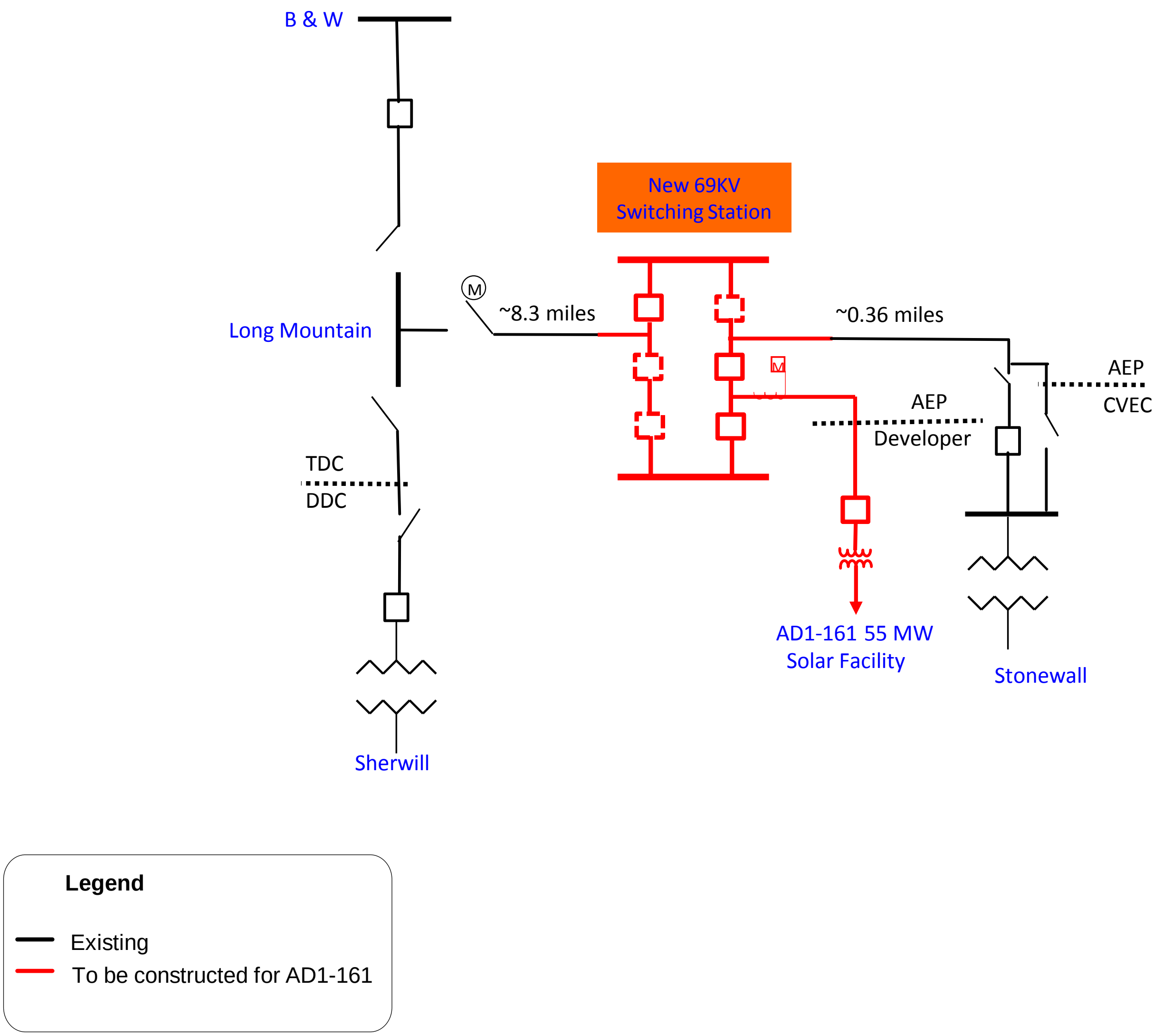

Figure 2: Point of Interconnection (Stonewall – Long Mountain 69 kV)

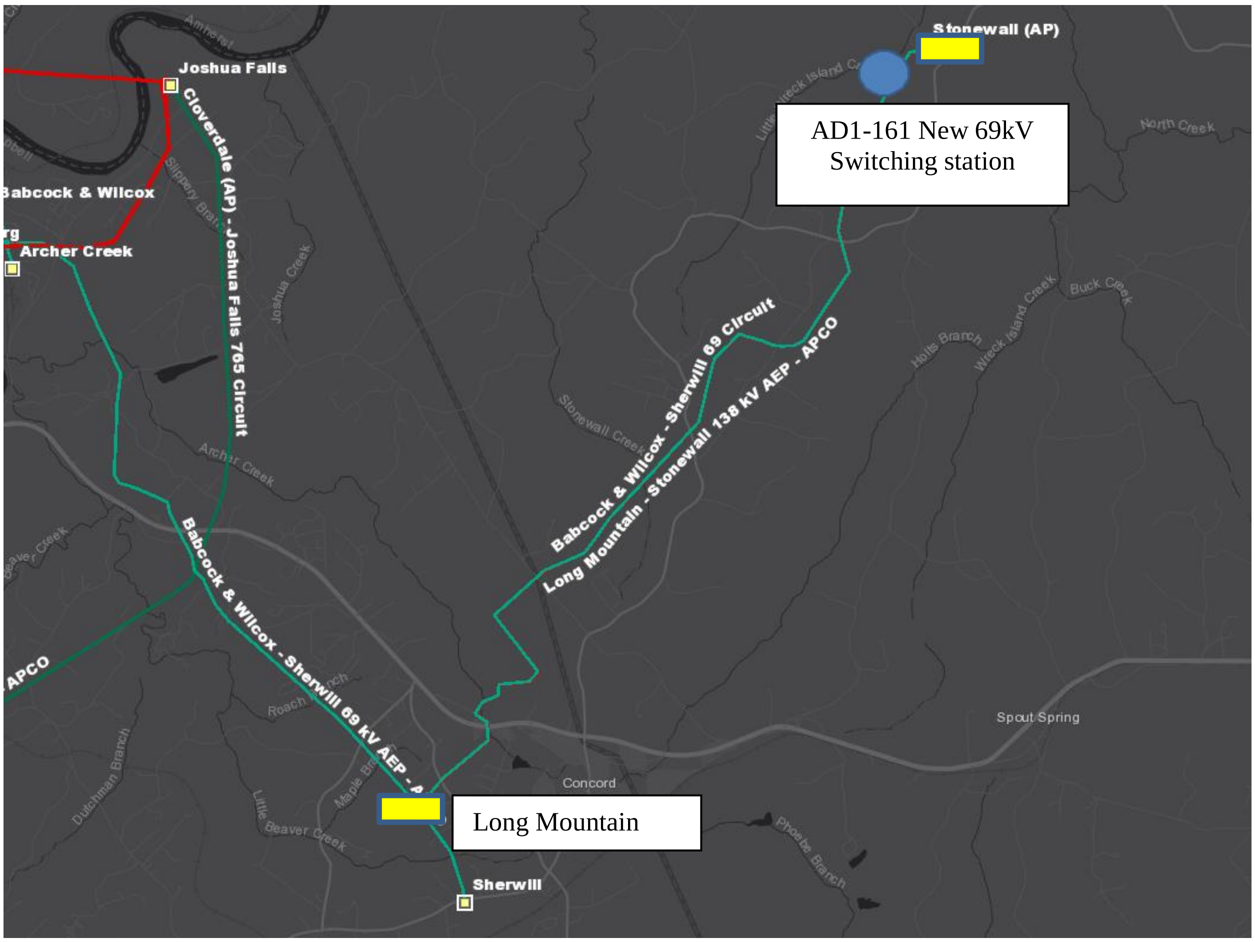

Figure 3: Dynamic Simulation Analysis

Executive Summary

Generator Interconnection Request AD1-161 is for a 55.0 MW Maximum Facility Output (MFO) solar generating facility. AD1-161 consists of 22 x TMEIC PVH-L2700GR inverters rated at 2.56 MW each. The Point of Interconnection (POI) is at a tap of South Stonewall – Long Mountain Tap (Stonewall Tap) 69 kV circuit in the American Electric Power (AEP) transmission system, Appomattox County, Virginia.

This report describes a dynamic simulation analysis of AD1-161 as part of the overall system impact study.

The load flow scenario for the analysis was based on the RTEP 2021 peak load case, modified to include applicable queue projects. AD1-161 has been dispatched online at maximum power output, with 1.0 p.u. voltage at the generator bus.

AD1-161 was tested for compliance with NERC, PJM, Transmission Owner and other applicable criteria. Steady-state condition and 33 contingencies were studied, each with a 20 seconds simulation time period. Studied faults included:

a) Steady-state operation (20 second);

b) Three-phase faults with normal clearing time;

c) Single-phase faults with stuck breaker;

d) Single-phase faults placed at 80% of the line with delayed (Zone 2) clearing at line end remote from the fault due to primary communications/relay failure;

No relevant bus, multi-circuit tower failure, or high-speed reclosing (HSR) contingencies were identified for this study.

Prior contingencies provided by PJM are listed for Facility Study Phase.

For all simulations, the queue project under study along with the rest of the PJM system were required to maintain synchronism and with all states returning to an acceptable new condition following the disturbance.

For all of the fault contingencies tested on the 2021 peak load case:

a) AD1-161 was able to ride through the faults (except for faults where protective action trips a generator(s)),

b) Post-contingency oscillations were positively damped with a damping margin of at least 3%.

c) Following fault clearing, all bus voltages recovered to a minimum of 0.7 per unit after 2.5 seconds (except where protective action isolates that bus).

d) No transmission element tripped, other than those either directly connected or designed to trip as a consequence of that fault.

The reactive power capability of AD1-161 meets the 0.95 lagging and leading PF requirement at the high side of the main transformer.

Oscillatory response for the reactive power and terminal voltage observed for AD1-161 during fault application in contingencies P1.01 ~ P1.07 and P1.16.

For the majority of contingencies, slow reactive power recovery was observed for Smith Mountain Unit 2. These contingencies were run out to 30 seconds and it was found that the system stabilizes at the end of the simulation.

Following protection settings were updated to resolve fictitious frequency tripping issue and undervoltage tripping due to long-lasting faults:

- Fictitious frequency issue around the POI caused tripping of the AD1-161 for contingencies P1.04 to P1.07 and P1.14 to P1.16. Therefore, the instantaneous frequency relays MINS 93524409 (f > 61.8 Hz) and MINS 93524411 (f < 57.8 Hz) were disabled.
- To prevent tripping of the unit at 60 cycles, the pickup time for MINS 93524405 was increased from 1.000 seconds to 1.009 seconds.
- To prevent tripping of the unit at 72 cycles, the pickup time for MINS 93524406 was increased from 1.200 seconds to 1.600 seconds. The Developer confirmed that the change in settings was acceptable.

After the instantaneous frequency protection elements were disabled and voltage protection pick up time were adjusted there were no critical issues and the dynamic recovery of queue project and nearby units was acceptable.

No mitigations were found to be required.