Generation Interconnection

Feasibility Study Report

for

Queue Project AG1-499

HENRY HARRIS 69 KV

7.56 MW Capacity / 12.6 MW Energy

June 2021

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1 Introduction

This Feasibility Study has been prepared in accordance with the PJM Open Access Transmission Tariff, 36.2, as well as the Feasibility Study Agreement between the Interconnection Customer (IC), and PJM Interconnection, LLC (PJM), Transmission Provider (TP). The Interconnected Transmission Owner (ITO) is AEC.

2 Preface

The intent of the feasibility study is to determine a plan, with ballpark cost and construction time estimates, to connect the subject generation to the PJM network at a location specified by the Interconnection Customer. The Interconnection Customer may request the interconnection of generation as a capacity resource or as an energy-only resource. As a requirement for interconnection, the Interconnection Customer may be responsible for the cost of constructing: (1) Direct Connections, which are new facilities and/or facilities upgrades needed to connect the generator to the PJM network, and (2) Network Upgrades, which are facility additions, or upgrades to existing facilities, that are needed to maintain the reliability of the PJM system.

In some instances a generator interconnection may not be responsible for 100% of the identified network upgrade cost because other transmission network uses, e.g. another generation interconnection, may also contribute to the need for the same network reinforcement. Cost allocation rules for network upgrades can be found in PJM Manual 14A, Attachment B. 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 impact study is performed.

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.

The Feasibility 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.

3 General

The Interconnection Customer (IC), has proposed a Solar generating facility located in Gloucester County, New Jersey. The installed facilities will have a total capability of 12.6 MW with 7.56 MW of this output being recognized by PJM as Capacity. The proposed in-service date for this project is September 30, 2020. This study does not imply a TO commitment to this in-service date.

Queue Number	**AG1-499**
Project Name	HENRY HARRIS 69 KV
State	New Jersey
County	Gloucester
Transmission Owner	AEC
MFO	12.6
MWE	12.6
MWC	7.56
Fuel	Solar
Basecase Study Year	2024

Any new service customers who can feasibly be commercially operable prior to June 1st of the basecase study year are required to request interim deliverability analysis.

4 Point of Interconnection

AG1-499 will interconnect with the AEC distribution system at the Lambs Substation 69/12.47 kV transformer as follows:

- The first 10 MWs of generation will connect to the 69/12.47kV T1 transformer at the Lambs substation via a new express feeder.
- The next 2.6 MWs of generation will connect to the Lambs substation via a new express feeder and new 40MVA, 69/12.47kV distribution transformer.

5 Cost Summary

The AG1-499 project will be responsible for the following costs:

Description	**Total Cost**
Total Physical Interconnection Costs	$10,545,911
Total System Network Upgrade Costs	$0
Total Costs	$10,545,911

This cost excludes a Federal Income Tax Gross Up charges. This tax may or may not be charged based on whether this project meets the eligibility requirements of IRS Notice 88-129. If at a future date it is determined that the Federal Income Tax Gross charge is required, the Transmission Owner shall be reimbursed by the Interconnection Customer for such taxes.

Cost allocations for any System Upgrades will be provided in the System Impact Study Report.

6 Direct Connection Requirements

Criteria Limits for Distributed Energy Resource (DER) Connections to the ACE Distribution System (less than 69 kV)

1. Single Phase Limit

The largest capacity single phase generator or DER (battery) operating in parallel with the grid is 100kW. Above that size, a balanced 3 phase system is required. If 3 phase is available, balanced 3 phase shall be used.

2. Voltage Limits

DERs are permitted to cause up to 3% (primary) or 5% (secondary) voltage fluctuation at the Point of Interconnection and ½ the band width of any voltage regulator or ½ the net dead band of a capacitor bank. DERs in maximum output, are permitted to raise feeder voltage to the ANSI or state limit whichever is more conservative. An absorbing PF may be required to mitigate voltage rise or fluctuation impact.

3. Existing Distribution Circuit Capacity Limits

The aggregate limit of “large” generators running in parallel with a single, existing distribution circuit is:

Circuit Voltage	Aggregate Limit	Large DER Size
4 kV	1 MW	250 kW
12 – 13.8 kV	3 MW	250 kW
23 – 25 kV	6 MW	500 kW
33.26 – 34.5 kV	10 MW	1 MW

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:

Circuit Voltage	DER Limit
4 kV	1 MW
12 – 13.8 kV	10 MW
23 – 25 kV	10 MW
33.26 – 34.5 kV	20 MW

Note: Maximum Demand Loss and Annual Energy Loss both must be less than 3% for the express feeder

5. Telemetry requirements

On radial circuits that have or can incorporate Distribution Automation, telemetry is required on all systems 250kW and greater.

6. Distribution Power Transformer Limit

The aggregate of "large" DER will be limited to 50% of the substation transformer normal rating. In the case of transformers paralleled on the low side, the limit is 50% of the sum of the transformer normal ratings. This usually ensures that the LTC does not operate excessively. Note that small systems (less than the large system size for the circuits' voltage class), may continue to be interconnected when these distribution transformer limits are reached.

The absolute net reverse power limit is 40% of the transformer normal rating. This ensures that locations with transfer capability can operate safely where one transformer load automatically transfers to the remaining transformer upon outage of one transformer.

7. Express Circuit Length Limit

The maximum circuit length is limited to 5 miles for 12/13 kV, 7 miles for 25 kV, and 10 miles for 34 kV.
Note: For ACE and Pepco, no 34 kV Express Circuits will be built as that voltage level is being retired. 4 kV Express Circuits will not be built in any PHI jurisdiction.
If there is no more injection capacity or space for an additional transformer at the closest substation, the next closest substation will be considered.

8. 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. In NJ, it is the developer's responsibility to verify eligibility of this configuration for solar renewable energy certificates with New Jersey's Clean Energy Program if desired.

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

High Voltage Warning

Typically, voltage received at the meter from the utility can be up to 105% of nominal (without generation on). 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. It is recommended that transformers with no load taps should be used to adjust secondary voltage to avoid the possibility of inverter trips. Failure to account for this may result in lost energy production.

Additional Operating Requirements:

1. ACE 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.

2. It is the IC's responsibility to send the data that PJM and ACE requires directly to PJM (or in some cases to ACE directly). The IC will grant permission for PJM to send ACE the following telemetry that the IC sends to PJM: real time MW, MVAR, volts, amperes, generator/status, and interval MWH and MVARH.
3. The IC will be required to make provisions for a voice quality phone ("plain old telephone", or "POT") line within approximately 3 feet of each ACE metering position to facilitate remote interrogation and data collection.
4. 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 ACE Distribution Engineering.
5. ACE reserves the right to charge the IC operation and maintenance expenses to maintain the IC attachment facilities, including metering and telecommunications facilities, owned by ACE.

7 Transmission Owner Scope of Work

Transmission Owner scope of work required to accommodate 10 MW of generation via express feeder to Lambs T1 Substation:

1. Install approximately 500ft of overhead three phase 477AAC from Lambs Substation out to Lambs Rd.
2. Reconductor approximately 0.6 miles of existing retired 34.5 kV to make double deck distribution line along Lambs Rd to Rt. 322.
3. Reconductor approximately 0.3 miles of existing retired 34.5kV line to make double deck distribution line along Lambs Rd to Rt. 322.
4. Reconductor approximately 2.4 miles of existing three phase distribution pole line to include a second deck of three phase distribution primary along Harrisonville Rd to Bridgeton Pike.
5. Rebuild approximately 800ft existing three phase distribution pole line to include a top deck of three phase distribution primary along Bridgeton Pike to solar site.
6. Install a utility operated recloser equipped with the proper relaying and communication.
7. Install utility grade primary metering.
8. Generation telemetry and remote trip capability will be provided to the control center.
9. Connect solar express feeder to an existing 'future' feeder position on the #1-12kV bus. A new 12kV circuit breaker will be installed along with all associated relaying.
10. A detailed, time-based study may be performer during later study phases.
11. Direct transfer trip will be required. Approximately 4 miles of 48SM ADSS cable from Lambs substation to solar site was estimated for this report to provide the communication channel from Union Substation to the PV site (note: *this may require secondary zone tree trimming and railroad permit*).

High Level Estimates			
Lambs T1			
Express Feeder	3	mi.	$3,000,000
Substation Feeder Terminal & Relay			$347,960
Telecommunication			$356,683
Recloser & Metering			$92,000
SCADA Integration into EMS			$11,500
Miscellaneous Engineering Costs			$69,000
Approximate Total Cost			$3,877,143

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

Transmission Owner scope of work required to accommodate 2.6 MW of generation via second express feeder to new distribution transformer at Lambs Substation:

1. Install approximately 500ft of overhead three phase 477AAC from Lambs Substation out to Lambs Rd.
2. Reconductor approximately 0.6 miles of existing retired 34.5 kV to make double deck distribution line along Lambs Rd to Rt. 322.
3. Reconductor approximately 0.3 miles of existing retired 34.5kV line to make double deck distribution line along Lambs Rd to Rt. 322.
4. Reconductor approximately 2.4 miles of existing three phase distribution pole line to include a second deck of three phase distribution primary along Harrisonville Rd to Bridgeton Pike.
5. Rebuild approximately 800ft existing three phase distribution pole line to include a top deck of three phase distribution primary along Bridgeton Pike to solar site.
6. Install a utility operated recloser equipped with the proper relaying and communication.
7. Install utility grade primary metering.
8. Generation telemetry and remote trip capability will be provided to the control center.
9. Connect second solar express feeder to a new second 69/12kV 40MVA transformer. A new #2-12kV bus will have to build for an ultimate configuration of four feeder, with only one installed for second express feeder.
10. New structure, foundations and buswork will need to be installed.
11. Three new 12kV circuit breaker will be installed, al low side transformer main breaker, a feeder breaker, and a bus tie breaker to connect the #1-12kV bus.
12. Install all associated relaying.
13. Install new 69kV bus tie breaker to separate the two transformer positions.
14. Install new disconnects, CVTs, structures, foundation, relaying.
15. A detailed, time-based study may be performer during later study phases.

16. Direct transfer trip will be required. Approximately 4 miles of 48SM ADSS cable from Lambs substation to solar site was estimated for this report to provide the communication channel from Lambs Substation to the PV site (note: *this may require secondary zone tree trimming and railroad permit*).

High Level Estimates			
New Lambs T2			
Express Feeder	3	mi.	$3,000,000
Substation Work			$3,139,585
Telecommunication			$356,683
Recloser & Metering			$92,000
SCADA Integration into EMS			$11,500
Miscellaneous Engineering Costs			$69,000
Approximate Total Cost			$6,668,768

The estimated time to complete this work is 24-36 months after receipt of a fully executed interconnection agreement.

Assumptions

1. The property is sufficient to install new 40MVA distribution transformer along with 69kV tie and distribution feeder.
2. Environment and site permitting requirements will be required.

8 Transmission Owner Analysis

None

9 Interconnection Customer Requirements

The 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.

Protective relaying and metering design and installation must comply with ACE's applicable standards. The IC is also required to provide revenue metering and real-time telemetering data to PJM in conformance with the requirements contained in PJM Manuals M-01 and M-14 and the PJM Tariff.

The IC will purchase and install all metering instrument transformers as well as construct a metering structure per ACE's specifications. The secondary wiring connections at the instrument transformers will be completed by the IC's contractors and inspected by ACE, while the secondary wiring work at the metering enclosure will be completed by ACE’s Meter technicians. The metering control cable and meter cabinets will be supplied by ACE and installed by the IC's contractors. ACE’s meter technicians will program and install two solid state multi-function meters (Primary & Backup) for the new metering position. Each meter will be equipped with load profile, telemetry, and form-c pulse outputs. The ownership of metering equipment purchased or installed by the IC shall be transferred to the Transmission Owner at Commercial Operation, unless the IC asserts its right to install, own and operate the metering system.

Power Factor Requirement

The generators used for this project shall be capable of operating at a power factor (or schedule) specified by ACE in the range of 0.95 leading to 0.95 lagging. It is the responsibility of the developer/customer to obtain equipment that can operate with these requirements while also meeting all applicable requirements of IEEE and UL standards such as, but not limited to, IEEE 1547 and UL 1741.

For this project, operate inverters at unity power factor of (1) continuously until another value is provided by ACE.

Inverter Requirements (if applicable):

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.
- 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(s) shall operate in accordance with both the IEEE 1547 and UL 1741 series of standards that have been approved and use default settings except when specified otherwise by ACE. While inverters should be capable of voltage stabilization through dynamic VAR response and capable of low voltage and system disturbance ride through, neither of these capabilities will 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 generation owner/operator shall cooperate with ACE to implement these capabilities with settings acceptable to ACE. Until such time, the inverters shall operate with a fixed power factor value between 0.95 lead and 0.95 lag as specified by ACE.

Security Requirements

It is the responsibility of the owner to secure the generator or inverter from any unauthorized access (including physical and remote access) which could alter settings or adversely affect its ability to operate as required. Security measures should include utilizing secure password settings and/or physical locks on cabinet doors.

10 Revenue Metering and SCADA Requirements

10.1 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 Section 8 of Attachment O.

10.2 Interconnected Transmission Owner Requirements

The IC will be required to comply with all Interconnected Transmission Owner's revenue metering requirements for generation interconnection customers located at the following link:

http://www.pjm.com/planning/design-engineering/to-tech-standards/

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

ACE Meter Department will construct a 12 kV three phase primary metering cluster mount with installed metering devices equipped with load profile, telemetry, and I/O's, including DNP outputs. An ACE contractor or overhead line crew will put the cluster mount assembly into service, and Meter Department technicians will complete the secondary wiring and related meter work at the base of the metering pole. A meter technician will assist the contractor or ACE overhead line crew in energizing this equipment. The meter technician will also program and install two solid state multi-function meters (Primary & Backup) for the new metering position.

ACE will supply a wireless modem for MV90 interrogation. In the event that a wireless modem is unable to reliably communicate, the Interconnection Customer will be required to make provisions for a POTS (Plain Old Telephone Service) line or equivalent technology approved by ACE within approximately three feet of the ACE metering position to facilitate remote interrogation and data collection.

The Interconnection Customer will provide 120V power to the meter cabinet from an uninterruptable power source.

Metering will conform to the requirements of Company's metering standards 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.

11 Summer Peak - Load Flow Analysis

The Queue Project AG1-499 was evaluated as a 12.6 MW (Capacity 7.6 MW) injection at the LAMBS 12.9 kV substation. Project AG1-499 was evaluated for compliance with applicable reliability planning criteria (PJM, NERC, NERC Regional Reliability Councils, and Transmission Owners). Project AG1-499 was studied with a commercial probability of 53.0 %. Potential network impacts were as follows:

11.1 Generation Deliverability

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

None

11.2 Multiple Facility Contingency

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

None

11.3 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

11.4 Potential Congestion due to Local Energy Deliverability

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.

Note: Only the most severely overloaded conditions are listed below. 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 shall study all overload conditions associated with the overloaded element(s) identified.

ID	FROM BUS#	FROM BUS	kV	FROM BUS AREA	TO BUS#	TO BUS	kV	TO BUS AREA	CKT ID	CONT NAME	Type	Rating MVA	PRE PROJECT LOADING %	POST PROJECT LOADING %	AC|DC	MW IMPACT
169786939	940000	AE1-240 TAP	69.0	AE	228226	SHRMAN#2	69.0	AE	1	Base Case	operation	82.0	132.07	132.55	DC	0.87

11.5 System Reinforcements - Summer Peak Load Flow - Primary POI

ID	Idx	Facility	Upgrade Description	Cost
			TOTAL COST	$0

11.6 Flow Gate Details

The following indices contain additional information about each facility presented in the body of the report. For each index, a description of the flowgate and its contingency was included for convenience. The intent of the indices is to provide more details on which projects/generators have contributions to the flowgate in question. All New Service Queue Requests, through the end of the Queue under study, that are contributors to a flowgate will be listed in the indices. Please note that there may be contributors that are subsequently queued after the queue under study that are not listed in the indices. Although this information is not used "as is" for cost allocation purposes, it can be used to gage the impact of other projects/generators. It should be noted the project/generator MW contributions presented in the body of the report are Full MW Impact contributions which are also noted in the indices column named "Full MW Impact", whereas the loading percentages reported in the body of the report, take into consideration the PJM Generator Deliverability Test rules such as commercial probability of each project as well as the ramping impact of "Adder" contributions. The MW Impact found and used in the analysis is shown in the indices column named "Gendeliv MW Impact".

None

11.7 Queue Dependencies

The Queue Projects below are listed in one or more indices for the overloads identified in your report. These projects contribute to the loading of the overloaded facilities identified in your report. The percent overload of a facility and cost allocation you may have towards a particular reinforcement could vary depending on the action of these earlier projects. The status of each project at the time of the analysis is presented in the table. This list may change as earlier projects withdraw or modify their requests.

None

11.8 Contingency Descriptions

None

12 Short Circuit Analysis

The following Breakers are overdutied:

None

12.1 System Reinforcements - Short Circuit

None

13 Affected Systems

None