Attachment E

SYSTEM IMPACT STUDIES

Barrelhead Solar, LLC

Wayne County, Kentucky

AG1-471 Phase I Study Report

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Up Church-Wayne County 69 kV
36.0 MW Capacity / 60.0 MW Energy

Introduction

This Phase I System Impact Study Report (PH1) has been prepared in accordance with the PJM Open Access Transmission Tariff, Part VII, Subpart D, sections 307 and 308 for New Service Requests (projects) in Transition Cycle #1. The Project Developer/Eligible Customer (developer) is Barrelhead Solar, LLC, and the Transmission Provider (TP) is PJM Interconnection, LLC (PJM). The interconnected Transmission Owner (TO) is East Kentucky Power Cooperative, Inc..

Preface

The Phase I System Impact Study is conducted on an aggregate basis within a New Services Request's Cycle, and results are provided in both (i) a single Cycle executive summary format and (ii) an individual project-level basis. The Phase I System Impact Study Results (for both the executive summary and individual reports) will be publicly available on PJM's website. Developers must obtain the results from the website.

In accordance with PJM Manual 14H, section 4.3, PJM takes the following actions during the Phase I System Impact Study:

1. PJM studies each New Service Request on a summer peak, winter peak[1] and light load RTEP base case study. The case year is dependent on the new services cycle under study. PJM will identify the base case year to be used in the study of a specific cycle on its website.
2. PJM will only perform load flow analysis during the Phase I System Impact Study.
3. In Phase I of the Cycle, PJM conducts an Affected System screen to identify any New Service Request with Affected System impacts and provides each Affected System Operator with a list of New Service Request in the Cycle with potential impacts to their respective system.
4. PJM will create both the short circuit and stability base cases to be used in the Phase II System Impact Study.
5. The Phase I System Impact Study results will be publicly available on PJM's website. Project Developers and Eligible Customers must obtain the results from the website.

The Transmission Owner takes the following actions during the Phase I System Impact Study:

1. Identify required Interconnection Facilities to accommodate the New Service Request.
2. Identify required Network Upgrades to mitigate system violations from the Phase I System Impact Study.
3. Provide planning-level preliminary estimates of Interconnection Facilities and Network Upgrades including scope, cost and elapsed time to complete the work.

Decision Point I Requirements

At the close of Phase I System Impact Study, PJM will initiate Decision Point I (DP1). During DP1, the Project Developer will have 30 days to decide whether to proceed with their project. If the Project Developer elects to proceed, they should provide the elements defined in the PJM Open Access Transmission Tariff, Part VII, Subpart D, section 309.A.1. Additional information on these elements is available in PJM Manual 14H sections 4.4, 6, and 7.

Allowable project modifications at Decision Point I are defined in PJM Open Access Transmission Tariff, Part VII, Subpart D, section 309.B. Additional information regarding allowable project modifications can be found in PJM Manual 14H, section 9.8.

General

The developer has proposed a Solar generating facility located in the East Kentucky Power Cooperative, Inc. zone — Wayne County, Kentucky. The installed facilities will have a total capability of 60.0 MW with 36.0 MW of this output being recognized by PJM as Capacity.

Project Information	
New Service Request Number	**AG1-471**
Project Name	Up Church-Wayne County 69 kV
Developer Name	Barrelhead Solar, LLC
State	Kentucky
County	Wayne
Transmission Owner	East Kentucky Power Cooperative, Inc.
MFO	60.0 MW
MWE	60.0 MW
MWC	36.0 MW
Fuel Type	Solar
Basecase Study Year	2027

Point of Interconnection

AG1-471 will interconnect on the EKPC transmission system tapping the Upchurch to Wayne County 69 kV line.

Cost Summary

The table below shows a summary of the total planning level cost estimates for this New Service Request project. These network upgrade costs are subject to change as a result of a facility study performed by the TO during the Phase II or Phase III System Impact Study.

Based on the Phase I SIS results, the AG1-471 project has the following allocation of costs for interconnection. The cost contribution towards Readiness Deposit are also shown below.

Cost Summary

Description	**Cost Allocated to AG1-471**	**Cost Subject to Readiness***
Transmission Owner Interconnection Facilities (TOIF)	$1,455,000	$0
Physical Interconnection Network Upgrades		
Stand Alone Network Upgrades	$4,360,000	$4,360,000
Network Upgrades	$16,455,000	$16,455,000
System Reliability Network Upgrades		
Steady State Thermal & Voltage (SP & LL)	$1,536,084	$1,536,084
Transient Stability	$0	$0
Short Circuit	$0	$0
Transmission Owner Analysis		
SubRegional	$0	$0
Distribution	$0	$0
Affected System Study Reinforcements	$0	$0
Total	$23,806,084	$22,351,084

* Contributes to calculation for Readiness Deposit #2 (RD2). See Readiness Deposit section of report for additional detail.

Definitions

Transmission Owner Interconnection Facilities: Facilities that are owned, controlled, operated and maintained by the Transmission Owner on the Transmission Owner's side of the Point of Change of Ownership to the Point of Interconnection, including any modifications, additions or upgrades made to such facilities and equipment, that are necessary to physically and electrically interconnect the Generating Facility with the Transmission System or interconnected distribution facilities.

Stand Alone Network Upgrades: Network Upgrades, which are not part of an Affected System, which a Project Developer may construct without affecting day-to-day operations (e.g. taking a transmission outage) of the Transmission System during their construction.

Network Upgrades: Modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider's overall Transmission System for the general benefit of all users of such Transmission System. Network Upgrades have no impact or potential impact on the Transmission System until the final tie-in is complete.

Notes

Note 1: PJM Open Access Transmission Tariff (OATT), Part VII, Subpart D, section 307.5 outlines cost allocation rules. The rules are further clarified in PJM Manual 14H, section 4.2.6. PJM shall identify the New Service Requests in the Cycle contributing to the need for the required Network Upgrades within the Cycle. All New Service Requests that contribute to the need for a Network Upgrade will receive cost allocation for that upgrade pursuant to each New Service Request's contribution to the reliability violation identified on the transmission system in accordance with PJM Manuals.

Note 2: There will be no inter-Cycle cost allocation for Interconnection Facilities or Network Upgrades identified in the System Impact Study costs identified in a Cycle; all such costs shall be allocated to New Service Requests in that Cycle.

Note 3: For Project Developers with System Reinforcements listed: If this project presents cost allocation to a System Reinforcement indicates $0, then please be aware that as changes to the interconnection process occur, such as other projects withdrawing, reducing in size, etc, the cost responsibilities can change and a cost allocation may be assigned to this project. In addition, although this project presents cost allocation to a System Reinforcement is presently $0, this project may need this system reinforcement completed to be deliverable to the PJM system. If this project desires to come into service prior to completion of the system reinforcement, the Project Developer will need to request PJM to perform an interim study to determine if they would be deliverable for all or a portion of their output for each delivery year until the system reinforcement is complete.

Readiness Deposit

Per Tariff Part VII, Subpart D, section 309 (Decision Point I) A.1.a.i and PJM Manual 14H, section 6.2, Readiness Deposit #2 (RD2) are funds committed by the Project Developer or Eligible Customer based upon the applicable contribution to Network Upgrades as defined below and not used to fund studies nor to offset Security.

During Decision Point I (DP1), the Project Developer or Eligible Customer is required to submit Readiness Deposit #2, which is calculated as 10% of cost allocation for required Phase I Network Upgrades minus Readiness Deposit #1.

Note 1: "Network Upgrades" referred to in the calculation include both (i) the Physical Interconnection Network Upgrades and (ii) the System Reliability Network Upgrades as shown in the Cost Summary table.

Note 2: Readiness Deposit #1 (RD1) = ($4,000 * Project Size (MW))

Note 3: Readiness Deposit #2 can be zero, but may not be a negative number.

Readiness Deposit #2 Due for Project AG1-471

Readiness Deposit #2 has been calculated for the project based on the Phase I System Impact Study results and is shown in the table below. This Readiness Deposit #2 must be provided at Decision Point I through either a wire transfer or letter of credit per Manual 14H, Section 6.2.

Readiness Deposit

Project ID	10% of cost allocation for Phase I Network Upgrades	Readiness Deposit #1 Received (RD1)	Readiness Deposit #2 (RD2) for AG1-471 Project due at DP1
	A	B	A - B
AG1-471	$2,235,108	$240,000	$1,995,108

Note: Failure to provide an acceptable form of Readiness Deposit #2 by the end of Decision Point I will result in withdrawal and termination of the New Service Request.

For additional detail regarding Readiness Deposit Refunds, reference PJM Manual 14H, section 6.2.1. The Readiness Deposit Letter of Credit template can be found here.

Transmission Owner Scope of Work

EKPC will construct a 69 kV switching station and a new 69 kV loop-in tap from the EKPC Wayne County-Upchurch 69 kV line to accommodate the direct connection of the PD's substation facilities to the EKPC transmission system. EKPC will also construct a 69 kV disconnect switch structure which will be the POI interface.

EKPC will also complete the required non-direct connection network upgrades at existing EKPC substations, which are system protection changes necessary at the Wayne County and Summer Shade substations to accommodate the addition of this new facility, and installation of OPGW on the existing 69 kV line sections from the new Massingale Road switching station to the Wayne County and Summer Shade substations in order to provide necessary communications infrastructure for EKPC.

The total preliminary cost estimate for the Transmission Owner scope of work (including TOIF and Physical Interconnection Network Upgrades) is given in the table below. These costs do not include CIAC Tax Gross-up.

Transmission Owner Interconnection Facilities

RTEP ID	Description	Total Cost ($USD)	Allocated Cost ($USD)
(Pending)	EKPC to install necessary equipment (a 69 kV isolation switch structure and associated switch, plus interconnection metering, fiber-optic connection and telecommunications equipment, circuit breaker and associated switches, and relay panels) at the new Massingale Road Switching Station to accept the Project Developer lead line/bus.	$1,455,000	$1,455,000

Stand-Alone Network Upgrades			
RTEP ID	**Description**	**Total Cost ($USD)**	**Allocated Cost ($USD)**
(Pending)	EKPC to construct a new 69 kV switching station (Massingale Road) to facilitate connection of the AG1-471 solar generation facility to the existing Wayne County-Upchurch 69 kV line.	$4,360,000	$4,360,000

Network Upgrades			
RTEP ID	**Description**	**Total Cost ($USD)**	**Allocated Cost ($USD)**
(Pending)	EKPC to construct transmission line facilities to loop the existing Wayne County-Upchurch 69 kV line into the new Massingale Road switching station.	$300,000	$300,000
(Pending)	EKPC to modify relays and/or settings at Wayne County Substation for the existing line to the new Massingale Road switching station.	$105,000	$105,000
(Pending)	EKPC to modify relays and/or settings at Summer Shade Substation for the existing line to the new Massingale Road switching station.	$105,000	$105,000
(Pending)	EKPC to install OPGW on the Wayne County-Massingale Road 69 kV line section (1.4 miles).	$515,000	$515,000
(Pending)	EKPC to install OPGW on the Summer Shade-Massingale Road 69 kV line section (41.7 miles).	$15,430,000	$15,430,000

Based on the scope of work for the Interconnection Facilities, it is expected to take a range of 24 to 30 month(s) after the signing of a Generator Interconnection Agreement (as this is a FERC connection) and construction kickoff call to complete the installation of the physical connection work. This assumes that there will be no environmental issues with any of the new properties associated with this project, that there will be no delays in acquiring the necessary permits for implementing the defined interconnection work, and that all system outages will be allowed when requested.

The schedule for any required Network Impact Reinforcements will be more clearly identified in the Phase II and Phase III System Impact Studies.

EKPC anticipates that it will take 24 to 30 months after the signing of the Generator Interconnection Agreement and the project kickoff call is subsequently held to complete the physical interconnection projects. This assumes no delays due to permitting or environmental issues, and that all necessary outages can be taken as needed to maintain this schedule.

Transmission Owner Analysis

No violations.

Developer Requirements

The Point of Interconnection ("POI") will be the PD side of a 69 kV disconnect switch to be installed by EKPC at the interface between the PD-owned substation facilities and EKPC's substation facilities at the new Massingale Road 69 kV substation. The exact location of this switch will be determined during project scoping, and EKPC will install, own, operate, and maintain it. The PD substation will be constructed in the vicinity of the new EKPC Massingale Road 69 kV substation. The PD will install necessary 69 kV equipment (transmission line span(s), bus conductors, jumpers, etc.) from this 69 kV disconnect switch to its substation equipment. The PD will be responsible for acquiring all rights-of-way, easements, and environmental approvals and permits for its facilities. The PD will be responsible for constructing, owning, operating, and maintaining its facilities, and EKPC will have no responsibility for any of these activities.

The PD will acquire sufficient property that is suitable for EKPC's new 69 kV switching substation and will grant ownership of this property to EKPC at no cost. Prior to taking ownership, EKPC will perform all necessary engineering and environmental reviews to ensure that the site is suitable. EKPC will have the right to request modifications to the site or to reject the site if it is not suitable for EKPC's needs.

EKPC interconnection requirements can be found here.

To the extent that these Applicable Technical Requirements and Standards may conflict with the terms and conditions of the Tariff, the Tariff shall control.

Revenue Metering and SCADA Requirements

PJM Requirements The Project Developer will be required to install equipment necessary to provide Revenue Metering (KWH, KVARH) and real time data (KW, KVAR) for PD's generating Resource. See PJM Manuals M-01 and M14D, and PJM Tariff Section 8 of Attachment O.
Meteorological Data Reporting Requirement The solar generation facility shall provide the Transmission Provider with site-specific meteorological data including:

- Temperature (degrees Fahrenheit)
- Atmospheric Pressure (hectopascals)
- Irradiance

- Forced outage data

Interconnection Transmission Owner Requirements The PD will be required to comply with all Interconnected Transmission Owner's revenue metering requirements for generation interconnection customers located at the following link: PJM - Transmission Owner Engineering & Construction Standards.

All metering needed for this interconnection project must meet the metering requirements stated in Appendix 2, section 8 of the AG1-471 GIA, and in PJM Manuals M01 and M14D. The details of applicable metering requirements are given in the in EKPC's Facility Connection Requirements Document posted on PJM website.

The metering will be installed on the side of the Point of Change in Ownership and will be owned and maintained by East Kentucky Power Cooperative ("EKPC"). Metering requirements for this facility include the installation of EKPC's standard revenue quality metering package, including potential transformers, current transformers, remote-terminal unit and associated SCADA equipment.

EKPC shall use telecommunications equipment that matches its current network and equipment requirements.

Two 48-count ADSS fibers will be installed between the EKPC substation control house and the Project Developer (PD) facility for relaying, metering, and SCADA circuit requirements. Separate paths shall be used to ensure both fibers are not damaged during a single incident. The exact details and installation plans for this fiber will be developed during project scoping.

Summer Peak Analysis

The New Service Request project was evaluated as a 60.0 MW (Capacity 36.0 MW) injection in the EKPC area. Project was evaluated for compliance with applicable reliability planning criteria (PJM, NERC, NERC Regional Reliability Councils, and Transmission Owners). Potential summer peak period network impacts were as follows:

Note: The capacity portion of New Service Requests are evaluated for single or N-1 contingencies. The full energy output of New Service Requests are evaluated for multiple facility contingencies (double circuit tower line, fault with a stuck breaker, and bus fault).

Summer Peak Analysis

Area	Facility Description	Contingency Name	Contingency Type	DC|AC	Final Cycle Loading	Rating (MVA)	Rating Type	MVA to Mitigate	MW Contribut
DAY/EKPC	7SPURLOCK-09STUART 345.0 kV Ckt 1 line	Base Case	Single	AC	117.77 %	1240.0	A	1460.36	3.17
DAY/EKPC	7SPURLOCK-09STUART 345.0 kV Ckt 1 line	DEOK_P1_ZIMMER-MELDAHL 34576_SRT-A	Single	AC	114.38 %	1532.0	B	1752.37	3.72
EKPC/LGEE	5COOPER2-5ELIHU 161.0 kV Ckt 1 line	EKPC_P1-2_LAUR-L DAM161_SRT-A	Single	AC	114.3 %	277.0	B	316.61	7.3
DAY/EKPC	7SPURLOCK-09STUART 345.0 kV Ckt 1 line	DEOK_P1_MELDAHL-SPURLOCK 4541_SRT-A	Single	AC	113.19 %	1532.0	B	1734.13	3.73
EKPC	5LAUREL DAM-5LAUREL CO 161.0 kV Ckt 1 line	P2-3-228_SRT-S	Single	AC	102.95 %	200.0	B	205.91	3.77
EKPC	5LAUREL DAM-5LAUREL CO 161.0 kV Ckt 1 line	P2-2-41_SRT-S	Single	AC	102.72 %	200.0	B	205.43	3.77
LGEE/OVEC	7TRIMBL REAC-06CLIFTY 345.0 kV Ckt 1 line	AEP_P1-2_#10136_SRT-A	Single	AC	101.62 %	1451.0	B	1474.58	4.31
LGEE/OVEC	7TRIMBL REAC-06CLIFTY 345.0 kV Ckt 1 line	AEP_P1-2_#10135_SRT-A	Single	AC	101.53 %	1451.0	B	1473.19	4.31
EKPC/LGEE	5COOPER2-5ELIHU 161.0 kV Ckt 1 line	EKPC_P4-5_LAURL S50-1024_SRT-A	Breaker	AC	137.81 %	277.0	B	381.74	12.12
DAY/EKPC	7SPURLOCK-09STUART 345.0 kV Ckt 1 line	DEOK_P2-3_1537_MELDAHL345_SRT-A	Breaker	AC	131.69 %	1532.0	B	2017.45	6.22
DAY/EKPC	7SPURLOCK-09STUART 345.0 kV Ckt 1 line	DEOK_P2-3_1535_MELDAHL345_SRT-A	Breaker	AC	131.69 %	1532.0	B	2017.42	6.22
DAY/EKPC	7SPURLOCK-09STUART 345.0 kV Ckt 1 line	DEOK_P2-3_1539_MELDAHL345_SRT-A	Breaker	AC	131.65 %	1532.0	B	2016.9	6.22
DAY/EKPC	7SPURLOCK-09STUART 345.0 kV Ckt 1 line	EKPC_P2-4_SPUR N39-152T_SRT-A	Breaker	AC	131.57 %	1532.0	B	2015.65	6.22
DAY/EKPC	7SPURLOCK-09STUART 345.0 kV Ckt 1 line	EKPC_P2-2_MELD-SPUR 345_SRT-A	Bus	AC	131.62 %	1532.0	B	2016.38	6.22
EKPC/LGEE	2SOMERSET KU-2FERGUSON SO 69.0 kV Ckt 1 line	EKPC_P7-1_COOP 161 DBL 2_SRT-A	Tower	AC	161.9 %	105.0	B	170.0	8.59
EKPC	2SOMERSET-2SOMERSET KU 69.0 kV Ckt 1 line	EKPC_P7-1_COOP 161 DBL 2_SRT-A	Tower	AC	139.27 %	115.0	B	160.16	7.55
EKPC/LGEE	5COOPER2-5ELIHU 161.0 kV Ckt 1 line	EKPC_P7-1_LAURL 161 DBL_SRT-A	Tower	AC	137.91 %	277.0	B	382.0	12.12

Summer 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 an Upgrade Request into the New Service Request process.

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 an Upgrade Request, a subsequent analysis will be performed which shall study all overload conditions associated with the overloaded element(s) identified.

Summer Potential Congestion due to Local Energy Deliverability

Area	Facility Description	Contingency Name	Contingency Type	DC|AC	Final Cycle Loading	Rating (MVA)	Rating Type	MVA to Mitigate	MW Cor
DAY/EKPC	7SPURLOCK-09STUART 345.0 kV Ckt 1 line	Base Case	OP	AC	136.25 %	1240.0	A	1689.53	5.2
EKPC	5MARION CO-4MARION CO 161.0/138.0 kV Ckt 1 transformer	Base Case	OP	AC	119.9 %	192.0	A	230.2	3.5
EKPC	5MARION CO-4MARION CO 161.0/138.0 kV Ckt 1 transformer	EKPC_P1-2_TAYL J-KU TAYL 161_SRT-A	OP	AC	108.22 %	234.0	B	253.22	3.6
EKPC	5LAUREL DAM-5LAUREL CO 161.0 kV Ckt 1 line	P2-3-228_SRT-S	OP	AC	114.81 %	200.0	B	229.61	6.2
EKPC/LGEE	4MARION CO-4LEBANON 138.0 kV Ckt 1 line	EXT_B-138-115_SRT-S	OP	AC	110.09 %	220.0	B	242.19	3.3
LGEE/OVEC	7TRIMBL REAC-06CLIFTY 345.0 kV Ckt 1 line	AEP_P1-2_#10135_SRT-A	OP	AC	109.37 %	1451.0	B	1586.91	7.1

Winter Peak Analysis

PJM will start performing Winter Peak analysis in Transition Cycle #2.

Winter Potential Congestion due to Local Energy Deliverability

PJM will start performing Winter Peak analysis in Transition Cycle #2.

Light Load Analysis

At this time light load analysis not required for this project.

Light Load Potential Congestion due to Local Energy Deliverability

At this time light load analysis not required for this project.

Short Circuit Analysis

Short Circuit analysis is not performed as part of the Phase I System Impact Study. Short Circuit analysis will commence in the Phase II System Impact Study.

Stability Analysis

Stability analysis is not performed as part of the Phase I System Impact Study. Stability analysis will commence in the Phase II System Impact Study.

Reactive Power Analysis

Reactive Power analysis is not performed as part of the Phase I System Impact Study. Reactive Power analysis will commence in the Phase II System Impact Study.

Steady-State Voltage Analysis

Steady State Voltage analysis is not performed as part of the Phase I System Impact Study. Steady State Voltage analysis will commence in the Phase II System Impact Study.

New Service Request Dependencies

The New Service Requests below are listed in one or more dispatch for the overloads identified in this report. These projects contribute to the loading of the overloaded facilities identified in this report. The percent overload of a facility and cost allocation you may have towards a particular reinforcement could vary depending on the action of other projects. The status of each project at the time of the analysis is presented in the table. This list may change as other projects withdraw or modify their requests. This table is valid for load flow analyses only.

New Service Requests Dependencies		
Project ID	**Project Name**	**Status**
AB1-087	Sullivan 345kV #1	Suspended
AB1-088	Sullivan 345kV #2	Suspended
AC1-074	Jacksonville-Renaker 138kV I	Engineering & Procurement
AC1-089	Hillsboro-Wildcat 138kV	Partially in Service - Under Construction
AC2-075	Jacksonville-Renaker 138 kV	Under Construction
AC2-157	Sullivan 345 kV	Engineering & Procurement
AD2-048	Cynthia-Headquarters 69 kV	Engineering & Procurement
AD2-072	Van Arsdell-Mercer Industrial 69kV	Suspended
AE1-143	Marion County 161 kV	Suspended
AE1-144	Goddard-Plumville 138 kV	Active
AE2-038	Goddard-Plumsville 138 kV II	Active
AE2-071	Patton Rd-Summer Shade 69 kV	Partially in Service - Under Construction
AE2-130	Rockport 765 kV	Active
AE2-138	Avon-North Clark 345 kV	Active
AE2-210	Avon-North Clark 345 kV	Active
AE2-221	Clinton-Stuart 345 kV	Engineering & Procurement
AE2-254	Garrard County-Tommy-Gooch 69 kV	In Service
AE2-275	JK Smith-Fawkes 138 kV	Active
AE2-276	Sullivan 345kV	Active
AE2-308	Three Forks-Dale 138 kV	Active
AE2-339	Avon 138 kV	Active
AF1-038	Sewellton Jct-Webbs Crossroads 69 kV	Engineering & Procurement
AF1-050	Summer Shade - Green County 161 kV	Engineering & Procurement
AF1-083	Green County-Saloma 161 kV	Engineering & Procurement
AF1-088	Sullivan 345 kV	Active
AF1-116	Marion County 161 kV	Active
AF1-203	Patton Rd-Summer Shade 69 kV	Partially in Service - Under Construction
AF1-233	Flemingsburg – Spurlock 138kV	Active
AF1-256	Flemingsburg-Spurlock 138 kV	Active
AF2-008	Sullivan 345 kV	Active
AF2-090	Central Hardin 138 kV	Active
AF2-111	North Clark-Spurlock 345 kV	Active
AF2-260	Stephensburg-Central Hardin 69 kV	Active
AF2-306	Hope-Blevins Valley Tap 69 kV	Active
AF2-307	Hope-Blevins Valley Tap 69 kV	Active
AF2-308	Central Hardin-Stephensburg 69 kV	Active
AF2-309	Central Hardin-Stephensburg 69 kV	Active
AF2-348	North Clark-Spurlock 345 kV	Active
AF2-355	West Gerrard-J.K. Smith 345 nkV	Active
AF2-365	Munfordville KU Tap-Horse Cave Jct. 69 kV	Active
AF2-391	Central Hardin 69 kV	Active

AG1-066	Bonnyman 69 kV	Active
AG1-067	Temple Hill 69 kV	Active
AG1-070	Bon Ayr 69 kV	Active
AG1-071	Bon Ayr 69 kV	Active
AG1-306	Fawkes-Dale 138 kV	Active
AG1-320	Glendale-Stephensburg 69 kV	Active
AG1-341	Summer Shade 161 kV	Active
AG1-353	Greene County-Marion County 161 kV	Active
AG1-354	Summershade-Green County 161 kV	Active
AG1-405	Walnut Grove-Asahi 69 kV	Active
AG1-406	Walnut Grove-Asahi 69 kV	Active
AG1-456	Wildcat 138 kV	Active
AG1-488	Marion Co 161 kV	Active
AG1-522	Sullivan-Rockport 765 kV	Active
AG1-523	Sullivan-Rockport 765 kV	Active
AG1-524	Sullivan-Rockport 765 kV	Active
AG1-525	Sullivan-Rockport 765 kV	Active
AG1-526	West Garrard 345 kV	Active

Affected Systems

In Phase I of the Cycle, PJM conducts an Affected System screen to identify any New Service Request with potential Affected System impacts. PJM initiates coordination with each Affected System Operator by providing a list of New Service Requests in the Cycle with potential impacts to their respective system. If the Affected System Operator indicates an Affected System Study is required, PJM will notify the Project Developer or Eligible Customer of the need for an Affected System Study. See below if any Affected System Operator requires a study for this project:

Midcontinent Independent System Operator (MISO)	**Study Pending**
New York Independent System Operator (NYISO)	**Not required**
Tennessee Valley Authority (TVA)	**Not required**
Louisville Gas & Electric (LG&E)	**Study Pending**
Duke Energy Carolinas (DUKE)	**Not required**
Duke Energy Progress – East (CPLE)	**Not required**
Duke Energy Progress – West (CPLW)	**Not required**

System Reinforcements

Based on the Phase I analysis results, this project has potential cost responsibility for the following System Reinforcements:

AG1-471 System Reinforcements Cost Breakdown:					
TO	RTEP ID / TO ID	Title	MW Impact	Percent Allocation	Allocated Cost ($USD)
EKPC	n8368.2 / EKPC-tc1-r0012b	Rebuild the Cooper-Elihu 161 kV line section using 795 MCM ACSS conductor (4.2 miles)	12.1 MW	22.6%	$1,505,775
EKPC	n6232.1 / EKPC-tc1-r0003b	Replace the 1200A interconnection metering CTs with 2000A equipment.	7.5 MW	23.7%	$20,119
EKPC	n8368.4 / EKPC-tc1-r0012d	Upgrade the existing 795 MCM ACSR jumpers at the Cooper substation associated with the Cooper-Elihu 161 kV line using bundled 500 MCM CU or equivalent	12.1 MW	22.6%	$7,925
EKPC	n8368.3 / EKPC-tc1-r0012c	Change the Zone 3 relay setting at Elihu substation associated with the line protection to at least 392 MVA LTE rating.	12.1 MW	22.6%	$2,264
Grand Total:					**$1,536,083**

System Reinforcement					
TO	RTEP ID / TO ID	Title	Total Cost ($USD)	Allocated Cost ($USD)	Time Estimate
EKPC	n8368.2 / EKPC-tc1-r0012b	Rebuild the Cooper-Elihu 161 kV line section using 795 MCM ACSS conductor (4.2 miles)	$6,650,000	$1,505,775	24 to 30 Months

Contributor

Description: Rebuild the Cooper-Elihu 161 kV line section using 795 MCM ACSS conductor (4.2 miles)

Flowgates Addressed by this Reinforcement	
Facility	Contingency
5ELIHU-5COOPER2 161.0 kV Ckt 1 line	(Any)

New Ratings			
Facility	Rating Set	Rating Type	Rating Value
5ELIHU-5COOPER2 161.0 kV Ckt 1 line	(All)	A	308.0 MVA
5ELIHU-5COOPER2 161.0 kV Ckt 1 line	(All)	B	373.0 MVA
5ELIHU-5COOPER2 161.0 kV Ckt 1 line	(All)	C	373.0 MVA

Cost Allocation			
Project	MW Impact	Percent Allocation	Allocated Cost ($USD)
AG1-353	12.9 MW	24.1%	$1,602,642
AG1-354	17.8 MW	33.2%	$2,210,168
AG1-471	12.1 MW	22.6%	$1,505,775
AG1-488	10.7 MW	20.0%	$1,331,416

System Reinforcement					
TO	RTEP ID / TO ID	Title	Total Cost ($USD)	Allocated Cost ($USD)	Time Estimate
EKPC	n6232.1 / EKPC-tc1-r0003b	Replace the 1200A interconnection metering CTs with 2000A equipment.	$85,000	$20,119	Sep 25 2024

Contributor

Description: Replace the 1200A interconnection metering CTs with 1600A equipment.

Flowgates Addressed by this Reinforcement	
Facility	Contingency
2SOMERSET-2SOMERSET KU 69.0 kV Ckt 1 line	(Any)

New Ratings			
Facility	Rating Set	Rating Type	Rating Value
2SOMERSET-2SOMERSET KU 69.0 kV Ckt 1 line	(All)	A	169.0 MVA
2SOMERSET-2SOMERSET KU 69.0 kV Ckt 1 line	(All)	B	229.0 MVA
2SOMERSET-2SOMERSET KU 69.0 kV Ckt 1 line	(All)	C	258.0 MVA

Cost Allocation			
Project	MW Impact	Percent Allocation	Allocated Cost ($USD)
AG1-353	7.7 MW	24.3%	$20,641
AG1-354	9.9 MW	31.1%	$26,451
AG1-471	7.5 MW	23.7%	$20,119
AG1-488	6.7 MW	20.9%	$17,789

System Reinforcement					
TO	RTEP ID / TO ID	Title	Total Cost ($USD)	Allocated Cost ($USD)	Time Estimate
EKPC	n8368.4 / EKPC-tc1-r0012d	Upgrade the existing 795 MCM ACSR jumpers at the Cooper substation associated with the Cooper-Elihu 161 kV line using bundled 500 MCM CU or equivalent	$35,000	$7,925	9 to 12 Months

Contributor

Description: Upgrade the existing 795 MCM ACSR jumpers at the Cooper substation associated with the Cooper-Elihu 161 kV line using bundled 500 MCM CU or equivalent

Flowgates Addressed by this Reinforcement	
Facility	Contingency
5ELIHU-5COOPER2 161.0 kV Ckt 1 line	(Any)

New Ratings			
Facility	Rating Set	Rating Type	Rating Value
5ELIHU-5COOPER2 161.0 kV Ckt 1 line	SUM	A	308.0 MVA
5ELIHU-5COOPER2 161.0 kV Ckt 1 line	SUM	B	383.0 MVA
5ELIHU-5COOPER2 161.0 kV Ckt 1 line	SUM	C	390.0 MVA

Cost Allocation			
Project	MW Impact	Percent Allocation	Allocated Cost ($USD)
AG1-353	12.9 MW	24.1%	$8,435
AG1-354	17.8 MW	33.2%	$11,632
AG1-471	12.1 MW	22.6%	$7,925
AG1-488	10.7 MW	20.0%	$7,007

System Reinforcement					
TO	RTEP ID / TO ID	Title	Total Cost ($USD)	Allocated Cost ($USD)	Time Estimate
EKPC	n8368.3 / EKPC-tc1-r0012c	Change the Zone 3 relay setting at Elihu substation associated with the line protection to at least 392 MVA LTE rating.	$10,000	$2,264	6 Months

Contributor

Description: Change the Zone 3 relay setting at Elihu substation associated with the line protection to at least 437 MVA LTE rating.

Flowgates Addressed by this Reinforcement	
Facility	**Contingency**
5ELIHU-5COOPER2 161.0 kV Ckt 1 line	(Any)

New Ratings			
Facility	**Rating Set**	**Rating Type**	**Rating Value**
5ELIHU-5COOPER2 161.0 kV Ckt 1 line	SUM	A	308.0 MVA
5ELIHU-5COOPER2 161.0 kV Ckt 1 line	SUM	B	381.0 MVA
5ELIHU-5COOPER2 161.0 kV Ckt 1 line	SUM	C	390.0 MVA

Cost Allocation			
Project	**MW Impact**	**Percent Allocation**	**Allocated Cost ($USD)**
AG1-353	12.9 MW	24.1%	$2,410
AG1-354	17.8 MW	33.2%	$3,324
AG1-471	12.1 MW	22.6%	$2,264
AG1-488	10.7 MW	20.0%	$2,002

System Reinforcement					
TO	**RTEP ID / TO ID**	**Title**	**Total Cost ($USD)**	**Allocated Cost ($USD)**	**Time Estimate**
LGEE	(Pending) / LGEE_TC1_13411	Build new 345kV substation in Clark CO, IN by tapping the existing Trimble-Speed & Trimble-Ghent 345kV line near Miles Rd. Build new 345kV line between new 345kV station and OVEC Clifty Creek 345kV.	$90,000,000	$0	36 to 48 Months

Potential Aggregate Contributor

Note: Based on PJM cost allocation criteria, AG1-471 currently does not receive cost allocation towards this upgrade. As changes to the PJM process occur (such as other projects withdrawing from the cycle or reducing in size) AG1-471 could receive cost allocation. Although AG1-471 may not presently have cost responsibility for this upgrade, AG1-471 is a potential Aggregate Pool Contributor.

Description: Trimble-Clifty 345 kV line is a tie line between LG&E and OVEC. The line is owned by LG&E. The potential upgrade on the Trimble-Clifty 345 kV line, if determined to be a constraint by LG&E, is to build new 345kV station in Clark Co, IN by tapping Trimble-Speed & Trimble-Ghent 345kV lines. Build new 345kV line from new station to OVEC Clift Creek (~15 miles). **LG&E will determine if there are any LG&E system impacts, including on Trimble- Clifty line. Final LG&E Impacts and necessary LG&E system upgrade(s) will be determined once the LG&E affected system study is completed by LG&E. OVEC: no upgrades required

Flowgates Addressed by this Reinforcement	
Facility	**Contingency**
06CLIFTY-7TRIMBL REAC 345.0 kV Ckt 1 line	(Any)

New Ratings			
Facility	**Rating Set**	**Rating Type**	**Rating Value**
06CLIFTY-7TRIMBL REAC 345.0 kV Ckt 1 line	(All)	B	0.0 MVA

System Reinforcement					
TO	**RTEP ID / TO ID**	**Title**	**Total Cost ($USD)**	**Allocated Cost ($USD)**	**Time Estimate**
OVEC	(Pending) / OVEC_TC1_15103	No overload on OVEC facilities. Facility is owned by LGEE.	$0	$0	TBD

Note: This reinforcement is fictitious and will not be cost allocated to projects. It is listed for information purposes only.

Description: No overload on OVEC facilities. Other affected facility is owned by LGEE. The need for any upgrades on LGEE equipment will be determined by their Affected System Study.

Flowgates Addressed by this Reinforcement	
Facility	**Contingency**
06CLIFTY-7TRIMBL REAC 345.0 kV Ckt 1 line	(Any)

System Reinforcement

TO	RTEP ID / TO ID	Title	Total Cost ($USD)	Allocated Cost ($USD)	Time Estimate
EKPC	n5780.4 / EKPC-tc1-r0020d	Replace the 3000A wave trap at Spurlock Station associated with the Spurlock-Stuart 345 kV line with 3600A equipment.	$195,000	$0	15 to 18 Months

Potential Aggregate Contributor

Note: Based on PJM cost allocation criteria, AG1-471 currently does not receive cost allocation towards this upgrade. As changes to the PJM process occur (such as other projects withdrawing from the cycle or reducing in size) AG1-471 could receive cost allocation. Although AG1-471 may not presently have cost responsibility for this upgrade, AG1-471 is a potential Aggregate Pool Contributor.

Description: Replace the 3000A wave trap at Spurlock Station associated with the Spurlock-Stuart 345 kV line with 3600A equipment.

Flowgates Addressed by this Reinforcement

Facility	Contingency
09STUART-7SPURLOCK 345.0 kV Ckt 1 line	(Any)

New Ratings

Facility	Rating Set	Rating Type	Rating Value
09STUART-7SPURLOCK 345.0 kV Ckt 1 line	(All)	A	1868.0 MVA
09STUART-7SPURLOCK 345.0 kV Ckt 1 line	(All)	B	2080.0 MVA
09STUART-7SPURLOCK 345.0 kV Ckt 1 line	(All)	C	2112.0 MVA

System Reinforcement

TO	RTEP ID / TO ID	Title	Total Cost ($USD)	Allocated Cost ($USD)	Time Estimate
EKPC	(Pending) / EKPC-tc1-r0020c	Increase the maximum operating temperature of the 954 MCM ACSS transmission line conductor (3.8 miles) in the Spurlock-Stuart 345 kV line to 392 degrees F.	$10,115,000	$0	24 to 30 Months

Potential Aggregate Contributor

Note: Based on PJM cost allocation criteria, AG1-471 currently does not receive cost allocation towards this upgrade. As changes to the PJM process occur (such as other projects withdrawing from the cycle or reducing in size) AG1-471 could receive cost allocation. Although AG1-471 may not presently have cost responsibility for this upgrade, AG1-471 is a potential Aggregate Pool Contributor.

Description: Increase the maximum operating temperature of the 954 MCM ACSS transmission line conductor (3.8 miles) in the Spurlock-Stuart 345 kV line to 392 degrees F.

Flowgates Addressed by this Reinforcement

Facility	Contingency
09STUART-7SPURLOCK 345.0 kV Ckt 1 line	(Any)

New Ratings

Facility	Rating Set	Rating Type	Rating Value
09STUART-7SPURLOCK 345.0 kV Ckt 1 line	SUM	A	1821.0 MVA
09STUART-7SPURLOCK 345.0 kV Ckt 1 line	SUM	B	1877.0 MVA
09STUART-7SPURLOCK 345.0 kV Ckt 1 line	SUM	C	1946.0 MVA

System Reinforcement

TO	RTEP ID / TO ID	Title	Total Cost ($USD)	Allocated Cost ($USD)	Time Estimate
EKPC	(Pending) / EKPC-tc1-r0020a	Dayton Power & Light addresses its limiting elements (EKPC limits are 1777/1792/1792 for Rate A/B/C).	$0	$0	TBD

Note: This reinforcement is fictitious and will not be cost allocated to projects. It is listed for information purposes only.

Description: Dayton Power & Light addresses its limiting elements (EKPC limits are 1777/1792/1792 for Rate A/B/C).

Flowgates Addressed by this Reinforcement	
Facility	Contingency
09STUART-7SPURLOCK 345.0 kV Ckt 1 line	(Any)

New Ratings			
Facility	Rating Set	Rating Type	Rating Value
09STUART-7SPURLOCK 345.0 kV Ckt 1 line	(All)	B	1792.0 MVA

System Reinforcement					
TO	RTEP ID / TO ID	Title	Total Cost ($USD)	Allocated Cost ($USD)	Time Estimate
EKPC	n5780.3 / EKPC-tc1-r0020b	Replace the 1500A interconnection metering CTs at Spurlock Station with 2000A equipment.	$175,000	$0	12 to 15 Months

Potential Aggregate Contributor

Note: Based on PJM cost allocation criteria, AG1-471 currently does not receive cost allocation towards this upgrade. As changes to the PJM process occur (such as other projects withdrawing from the cycle or reducing in size) AG1-471 could receive cost allocation. Although AG1-471 may not presently have cost responsibility for this upgrade, AG1-471 is a potential Aggregate Pool Contributor.

Description: Replace the 1500A interconnection metering CTs at Spurlock Station with 2000A equipment.

Flowgates Addressed by this Reinforcement	
Facility	Contingency
09STUART-7SPURLOCK 345.0 kV Ckt 1 line	(Any)

New Ratings			
Facility	Rating Set	Rating Type	Rating Value
09STUART-7SPURLOCK 345.0 kV Ckt 1 line	SUM	A	1777.0 MVA
09STUART-7SPURLOCK 345.0 kV Ckt 1 line	SUM	B	1867.0 MVA
09STUART-7SPURLOCK 345.0 kV Ckt 1 line	SUM	C	1910.0 MVA

System Reinforcement					
TO	RTEP ID / TO ID	Title	Total Cost ($USD)	Allocated Cost ($USD)	Time Estimate
Dayton	n5780.2 / DAYr190041	Reconductor Stuart substation conductor with twin bundle 1033 Curlew ACCR conductor Reconductor Stuart Substation conductor with a bundled 795 hi-temperature conductor.	$650,000	$0	18 to 24 Months

Potential Aggregate Contributor

Note: Based on PJM cost allocation criteria, AG1-471 currently does not receive cost allocation towards this upgrade. As changes to the PJM process occur (such as other projects withdrawing from the cycle or reducing in size) AG1-471 could receive cost allocation. Although AG1-471 may not presently have cost responsibility for this upgrade, AG1-471 is a potential Aggregate Pool Contributor.

Flowgates Addressed by this Reinforcement	
Facility	Contingency
09STUART-7SPURLOCK 345.0 kV Ckt 1 line	(Any)

New Ratings			
Facility	Rating Set	Rating Type	Rating Value
09STUART-7SPURLOCK 345.0 kV Ckt 1 line	(All)	A	1882.0 MVA
09STUART-7SPURLOCK 345.0 kV Ckt 1 line	(All)	B	2062.0 MVA
09STUART-7SPURLOCK 345.0 kV Ckt 1 line	(All)	C	1958.0 MVA

System Reinforcement					
TO	RTEP ID / TO ID	Title	Total Cost ($USD)	Allocated Cost ($USD)	Time Estimate
Dayton	n5780.1 / DAYr190040	Replace Stuart substation riser conductor with 2500AAC (parallel)	$300,000	$0	12 to 18 Months

Potential Aggregate Contributor

Note: Based on PJM cost allocation criteria, AG1-471 currently does not receive cost allocation towards this upgrade. As changes to the PJM process occur (such as other projects withdrawing from the cycle or reducing in size) AG1-471 could receive cost allocation. Although AG1-471 may not presently have cost responsibility for this upgrade, AG1-471 is a potential Aggregate Pool Contributor.

Flowgates Addressed by this Reinforcement	
Facility	**Contingency**
09STUART-7SPURLOCK 345.0 kV Ckt 1 line	(Any)

New Ratings			
Facility	**Rating Set**	**Rating Type**	**Rating Value**
09STUART-7SPURLOCK 345.0 kV Ckt 1 line	(All)	A	1561.0 MVA
09STUART-7SPURLOCK 345.0 kV Ckt 1 line	(All)	B	1800.0 MVA
09STUART-7SPURLOCK 345.0 kV Ckt 1 line	(All)	C	1800.0 MVA

System Reinforcement					
TO	**RTEP ID / TO ID**	**Title**	**Total Cost ($USD)**	**Allocated Cost ($USD)**	**Time Estimate**
Dayton	n5780 / DAYr190039	Reconductor Stuart-Spurlock line with twin bundle 1033 Curlew ACCR conductor.	$25,000,000	$0	18 to 36 Months

Potential Aggregate Contributor

Note: Based on PJM cost allocation criteria, AG1-471 currently does not receive cost allocation towards this upgrade. As changes to the PJM process occur (such as other projects withdrawing from the cycle or reducing in size) AG1-471 could receive cost allocation. Although AG1-471 may not presently have cost responsibility for this upgrade, AG1-471 is a potential Aggregate Pool Contributor.

Description: Reconductor Stuart-Spurlock line with twin bundle 1033 Curlew ACCR conductor.

Flowgates Addressed by this Reinforcement	
Facility	**Contingency**
09STUART-7SPURLOCK 345.0 kV Ckt 1 line	(Any)

New Ratings			
Facility	**Rating Set**	**Rating Type**	**Rating Value**
09STUART-7SPURLOCK 345.0 kV Ckt 1 line	(All)	A	1339.0 MVA
09STUART-7SPURLOCK 345.0 kV Ckt 1 line	(All)	B	1556.0 MVA
09STUART-7SPURLOCK 345.0 kV Ckt 1 line	(All)	C	1556.0 MVA

System Reinforcement					
TO	**RTEP ID / TO ID**	**Title**	**Total Cost ($USD)**	**Allocated Cost ($USD)**	**Time Estimate**
EKPC	n7773.1 / EKPC-tc1-r0004b	Change the 69 kV current transformer settings associated with circuit breaker S7-654 from 600A to at least 800A.	$10,000	$0	Sep 25 2024

Contingent

Note: Based on PJM cost allocation criteria, AG1-471 currently does not receive cost allocation towards this upgrade. As changes to the PJM process occur (such as other projects withdrawing from the cycle or reducing in size) AG1-471 could receive cost allocation. Although AG1-471 may not presently have cost responsibility for this upgrade, AG1-471 may need this upgrade in-service to be deliverable to the PJM system. If AG1-471 desires to come into service prior to completion of the upgrade, the Project Developer will need to request PJM to perform an interim study to determine if they would be deliverable for all or a portion of their output for each delivery year until the upgrade is complete.

Description: Change the 69 kV current transformer settings associated with circuit breaker S7-654 from 600A to at least 800A.

Flowgates Addressed by this Reinforcement	
Facility	**Contingency**
2FERGUSON SO-2SOMERSET KU 69.0 kV Ckt 1 line	(Any)

New Ratings			
Facility	**Rating Set**	**Rating Type**	**Rating Value**
2FERGUSON SO-2SOMERSET KU 69.0 kV Ckt 1 line	(All)	A	154.0 MVA
2FERGUSON SO-2SOMERSET KU 69.0 kV Ckt 1 line	(All)	B	180.0 MVA
2FERGUSON SO-2SOMERSET KU 69.0 kV Ckt 1 line	(All)	C	185.0 MVA

System Reinforcement					
TO	RTEP ID / TO ID	Title	Total Cost ($USD)	Allocated Cost ($USD)	Time Estimate
LGEE	(Pending) / LGEE_TC1_15519	Invalid - P7 contingency 69kV not monitored	$0	$0	TBD

Note: This reinforcement is fictitious and will not be cost allocated to projects. It is listed for information purposes only.

Description: Invalid - P7 contingency 69kV not monitored

Flowgates Addressed by this Reinforcement	
Facility	Contingency
2FERGUSON SO-2SOMERSET KU 69.0 kV Ckt 1 line	EKPC_P7-1_COOP 161 DBL 2_SRT-A

System Reinforcement					
TO	RTEP ID / TO ID	Title	Total Cost ($USD)	Allocated Cost ($USD)	Time Estimate
EKPC	n6232 / EKPC-tc1-r0003a	Replace the 500 MCM copper jumpers at the Somerset substation using 750 MCM copper or equivalent	$250,000	$0	Dec 31 2024

Contingent

Note: Based on PJM cost allocation criteria, AG1-471 currently does not receive cost allocation towards this upgrade. As changes to the PJM process occur (such as other projects withdrawing from the cycle or reducing in size) AG1-471 could receive cost allocation. Although AG1-471 may not presently have cost responsibility for this upgrade, AG1-471 may need this upgrade in-service to be deliverable to the PJM system. If AG1-471 desires to come into service prior to completion of the upgrade, the Project Developer will need to request PJM to perform an interim study to determine if they would be deliverable for all or a portion of their output for each delivery year until the upgrade is complete.

Description: Replace the 500 MCM copper jumpers at the Somerset substation using 750 MCM copper or equivalent

Flowgates Addressed by this Reinforcement	
Facility	Contingency
2SOMERSET-2SOMERSET KU 69.0 kV Ckt 1 line	(Any)

New Ratings			
Facility	Rating Set	Rating Type	Rating Value
2SOMERSET-2SOMERSET KU 69.0 kV Ckt 1 line	(All)	A	146.0 MVA
2SOMERSET-2SOMERSET KU 69.0 kV Ckt 1 line	(All)	B	152.0 MVA
2SOMERSET-2SOMERSET KU 69.0 kV Ckt 1 line	(All)	C	154.0 MVA

System Reinforcement					
TO	RTEP ID / TO ID	Title	Total Cost ($USD)	Allocated Cost ($USD)	Time Estimate
LGEE	(Pending) / LGEE_TC1_15524	Load shedding of 10% PC load is allowed for P7 contingency	$0	$0	TBD

Note: This reinforcement is fictitious and will not be cost allocated to projects. It is listed for information purposes only.

Description: Load shedding of 10% PC load is allowed for P7 contingency

Flowgates Addressed by this Reinforcement	
Facility	Contingency
5ELIHU-5COOPER2 161.0 kV Ckt 1 line	EKPC_P7-1_LAURL 161 DBL_SRT-A

System Reinforcement					
TO	**RTEP ID / TO ID**	**Title**	**Total Cost ($USD)**	**Allocated Cost ($USD)**	**Time Estimate**
LGEE	(Pending) / LGEE_TC1_15510	Upgrade terminal equipment at Elihu 161kV associated with the Elihu-Cooper (EKPC) 161kV line to a minimum SE rating of 1200 amps.	$100,000	$0	TBD

Contingent

Note: Based on PJM cost allocation criteria, AG1-471 currently does not receive cost allocation towards this upgrade. As changes to the PJM process occur (such as other projects withdrawing from the cycle or reducing in size) AG1-471 could receive cost allocation. Although AG1-471 may not presently have cost responsibility for this upgrade, AG1-471 may need this upgrade in-service to be deliverable to the PJM system. If AG1-471 desires to come into service prior to completion of the upgrade, the Project Developer will need to request PJM to perform an interim study to determine if they would be deliverable for all or a portion of their output for each delivery year until the upgrade is complete.

Description: Upgrade terminal equipment at Elihu 161kV associated with the Elihu-Cooper (EKPC) 161kV line to a minimum SE rating of 1200 amps.

Flowgates Addressed by this Reinforcement	
Facility	**Contingency**
5ELIHU-5COOPER2 161.0 kV Ckt 1 line	EKPC_P1-2_LAUR-L DAM161_SRT-A

New Ratings			
Facility	**Rating Set**	**Rating Type**	**Rating Value**
5ELIHU-5COOPER2 161.0 kV Ckt 1 line	SUM	A	267.0 MVA
5ELIHU-5COOPER2 161.0 kV Ckt 1 line	SUM	B	335.0 MVA

System Reinforcement					
TO	**RTEP ID / TO ID**	**Title**	**Total Cost ($USD)**	**Allocated Cost ($USD)**	**Time Estimate**
LGEE	(Pending) / LGEE_TC1_15525	Load shedding of 10% PC load is allowed for P4 contingency	$0	$0	TBD

Note: This reinforcement is fictitious and will not be cost allocated to projects. It is listed for information purposes only.

Description: Load shedding of 10% PC load is allowed for P4 contingency

Flowgates Addressed by this Reinforcement	
Facility	**Contingency**
5ELIHU-5COOPER2 161.0 kV Ckt 1 line	EKPC_P4-5_LAURL S50-1024_SRT-A

System Reinforcement					
TO	**RTEP ID / TO ID**	**Title**	**Total Cost ($USD)**	**Allocated Cost ($USD)**	**Time Estimate**
EKPC	n7771.2 / EKPC-tc1-r0014a	Increase the maximum operating temperature of the Laurel County-Laurel Dam 161 kV line section 795 MCM conductor to 212 degrees F (~4.47 miles)	$1,035,000	$0	Sep 25 2024

Contingent

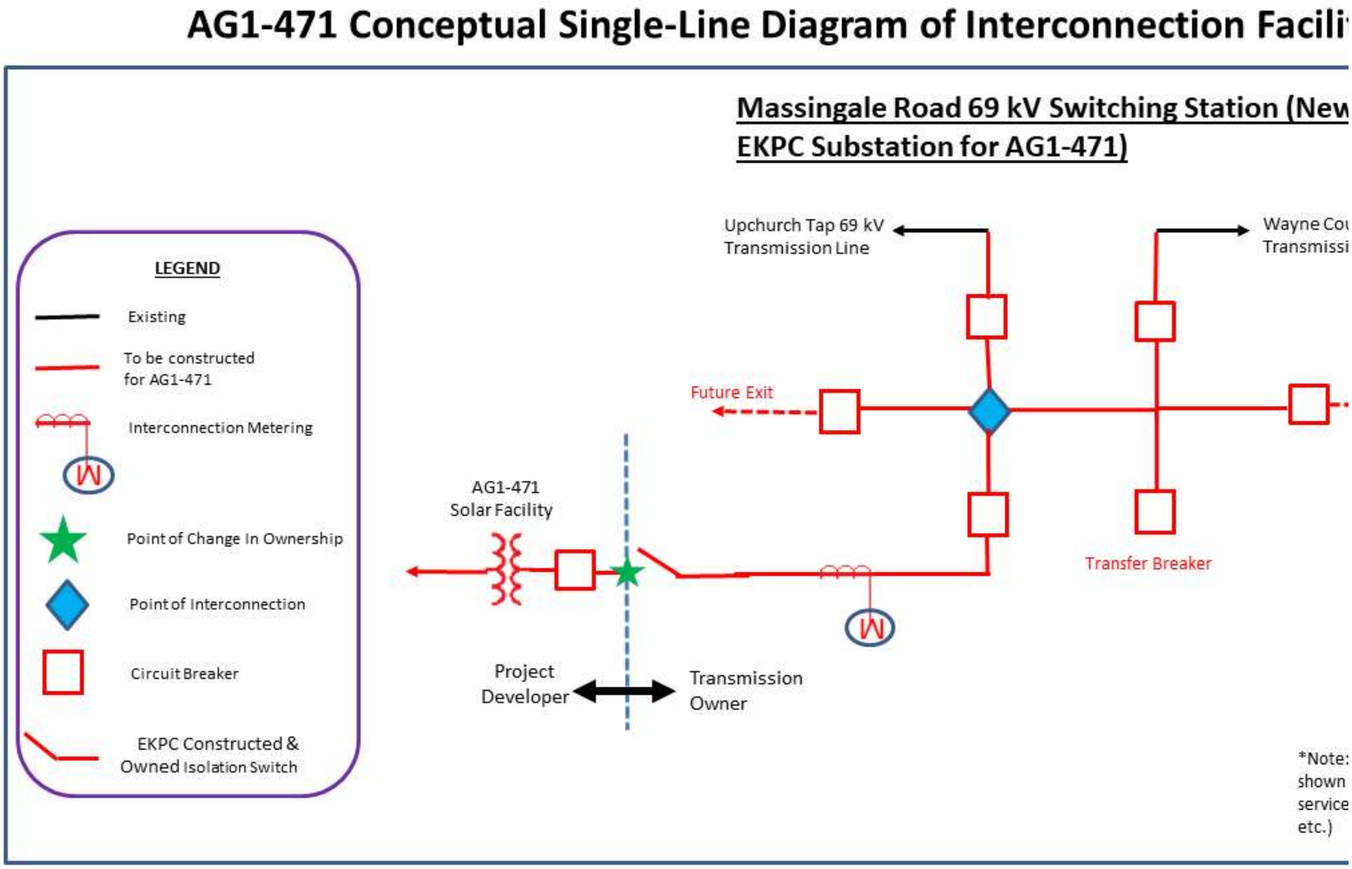
Note: Based on PJM cost allocation criteria, AG1-471 currently does not receive cost allocation towards this upgrade. As changes to the PJM process occur (such as other projects withdrawing from the cycle or reducing in size) AG1-471 could receive cost allocation. Although AG1-471 may not presently have cost responsibility for this upgrade, AG1-471 may need this upgrade in-service to be deliverable to the PJM system. If AG1-471 desires to come into service prior to completion of the upgrade, the Project Developer will need to request PJM to perform an interim study to determine if they would be deliverable for all or a portion of their output for each delivery year until the upgrade is complete.

Description: Increase the maximum operating temperature of the Laurel County-Laurel Dam 161 kV line section 795 MCM conductor to 212 degrees F (~4.47 miles)

Flowgates Addressed by this Reinforcement	
Facility	**Contingency**
5LAUREL CO-5LAUREL DAM 161.0 kV Ckt 1 line	(Any)

New Ratings			
Facility	**Rating Set**	**Rating Type**	**Rating Value**
5LAUREL CO-5LAUREL DAM 161.0 kV Ckt 1 line	(All)	A	258.0 MVA
5LAUREL CO-5LAUREL DAM 161.0 kV Ckt 1 line	(All)	B	298.0 MVA
5LAUREL CO-5LAUREL DAM 161.0 kV Ckt 1 line	(All)	C	298.0 MVA

Attachments



Download all tables in report

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[1] Winter load flow analysis will be performed starting in Transition Cycle #2.

AG1-471 Phase II Study Report

v1.00 released 2024-12-18 14:18

Up Church-Wayne County 69 kV
36.0 MW Capacity / 60.0 MW Energy

Introduction

This Phase II System Impact Study Report (PH2) has been prepared in accordance with the PJM Open Access Transmission Tariff, Part VII, Subpart D, section 310 for New Service Requests (projects) in Transition Cycle #1. The Project Developer/Eligible Customer (developer) is Barrelhead Solar, LLC, and the Transmission Provider (TP) is PJM Interconnection, LLC (PJM). The interconnected Transmission Owner (TO) is East Kentucky Power Cooperative, Inc..

Preface

The Phase II System Impact Study is conducted on an aggregate basis within a New Services Request's Cycle, and results are provided in both (i) a single Cycle executive summary format and (ii) an individual project-level basis. The Phase II System Impact Study Results (for both the executive summary and individual reports) will be publicly available on PJM's website. Developers must obtain the results from the website.

In accordance with PJM Manual 14H, section 4.5, PJM takes the following actions during the Phase II System Impact Study:

1. PJM will retool load flow results from Phase I System Impact Study (summer peak, winter peak[1] and light load) based on decisions made by Project Developers or Eligible Customers during Decision Point I.
2. PJM will conduct any required voltage analyses.
3. PJM will perform short circuit and stability analyses as required.
4. PJM will coordinate with the Affected System to confirm which projects in PJM Cycle will require Affected System studies. If the Affected System Operator indicates that an Affected System study is required, PJM will:
    a. Notify the Project Developer or Eligible Customer of the need for an Affected System study and the requirement to execute an Affected System study agreement with the impacted Affected System Operator, and;
    b. Include the results of the Affected System Operator's Affected System Study in the Phase II System Impact Study results, if applicable and available
5. The Phase II System Impact Study Results will be publicly available on PJM's website. Project Developers and Eligible Customers must obtain the results from the website.

The Transmission Owner takes the following actions during the Phase II System Impact Study:

1. Verify Interconnection Facilities and Network Upgrades required to accommodate the New Service Request.
2. Perform a Facilities Study. The Facilities Study in Phase II System Impact Study phase will be for the physical Interconnection Facilities. The Facilities Study requirements are outlined in Attachment C of PJM Manual 14H. The study will be conducted pursuant to Tariff, Part VII, Subpart D, section 307(A)(7).

Decision Point II Requirements

At the close of Phase II System Impact Study, PJM will initiate Decision Point II (DP2). During DP2, the Project Developer will have 30 days to decide whether to proceed with their project. If the Project Developer elects to proceed, they should provide the elements defined in the PJM Open Access Transmission Tariff, Part VII, Subpart D, section 311.A. Additional information on these elements is available in PJM Manual 14H sections 4.6, 6, and 7.

Allowable project modifications at Decision Point II are defined in PJM Open Access Transmission Tariff, Part VII, Subpart D, section 311.B. Additional information regarding allowable project modifications can be found in PJM Manual 14H, section 9.8.

Adverse Test Eligibility

This New Service Request does not meet the Adverse Study Impact Criteria and has the option to either move forward in the Cycle process or withdraw at DP2 with Readiness Deposit #1 forfeited. See adverse study impact calculation below.

This section details whether a Project Developer or Eligible Customer qualifies for the Adverse Study Impact clause outlined in the PJM OATT, Part VII, Subpart D, section 311.B and Manual 14H, section 6.2.2. In order to qualify for an Adverse Study Impact at Decision Point II, the Network Upgrade cost from Phase I to Phase II must:

1. Increase overall by 25% or more
2. Increases by more than $10,000 per MW (Includes Costs identified in Affected System studies)

If a New Service Request meets the criteria above and chooses to withdraw the request, PJM will refund the cumulative Readiness Deposit amounts paid at the Application Phase and at Decision Point I (RD1 and RD2, respectively).

The below calculations show the computation of this New Service Request's Adverse Study Impact

$$\text{DP2 Adverse Eligibility} = \frac{\text{DP2 Adverse Cost Alloc}}{\text{DP1 Adverse Cost Alloc}} > 1.25 \quad \text{AND} \quad \frac{(\text{DP2 Adverse Cost Alloc - DP1 Adverse Cost Alloc})}{\text{Project Size}} > \$10{,}000 \text{ per MW}$$

$$\text{DP2 Adverse Eligibility} = \frac{\$15{,}527{,}069}{\$22{,}351{,}084} = 0.69 \quad \text{AND} \quad \frac{(\$15{,}527{,}069 \text{ - } \$22{,}351{,}084)}{60.0} = \$\text{-}113{,}734 \text{ per MW}$$

General

The Project Developer has proposed a Solar generating facility located in the East Kentucky Power Cooperative, Inc. zone — Wayne County, Kentucky. The installed facilities will have a total capability of 60.0 MW with 36.0 MW of this output being recognized by PJM as Capacity.

Project Information	
New Service Request Number	**AG1-471**
Project Name	Up Church-Wayne County 69 kV
Project Developer Name	Barrelhead Solar, LLC
State	Kentucky
County	Wayne
Transmission Owner	East Kentucky Power Cooperative, Inc.
MFO	60.0 MW
MWE	60.0 MW
MWC	36.0 MW
Fuel Type	Solar
Basecase Study Year	2027

Physical Interconnection Facility Study

Received

The transmission owner has completed the Physical Interconnection Facilities Study. This report is available for download.

Point of Interconnection

AG1-471 will interconnect on the EKPC transmission system tapping the Upchurch to Wayne County 69 kV line.

Cost Summary

The table below shows a summary of the total cost estimates for this New Service Request project. In Phase II SIS, the interconnected Transmission Owner has performed a facilities study for both the Transmission Owner Interconnection Facilities (TOIF) and Physical Interconnection Network Upgrades. The System Reliability Network Upgrade shown in the table are planning level cost estimates which are subject to change as a result of a facility study performed by the TO during Phase III System Impact Study.

Based on the Phase II SIS results, the AG1-471 project has the following allocation of costs for interconnection. The cost contribution towards Readiness Deposit #3 are also shown below.

Cost Summary		
Description	**Cost Allocated to AG1-471**	**Cost Subject to Readiness***
Transmission Owner Interconnection Facilities (TOIF)	$718,000	$0
Other Scope	$0	$0
Physical Interconnection Network Upgrades		
Stand Alone Network Upgrades	$7,050,000	$7,050,000
Network Upgrades	$6,137,000	$6,137,000
System Reliability Network Upgrades		
Steady State Thermal & Voltage (SP & LL)	$2,340,069	$2,340,069
Transient Stability	$0	$0
Short Circuit	$0	$0
Transmission Owner Analysis		
SubRegional	$0	$0
Distribution	$0	$0
Affected System Study Reinforcements	$0	$0
Total	$16,245,069	$15,527,069

* Contributes to calculation for Readiness Deposit #3 (RD3). See Readiness Deposit section of report for additional detail.

Definitions

Transmission Owner Interconnection Facilities: Facilities that are owned, controlled, operated and maintained by the Transmission Owner on the Transmission Owner's side of the Point of Change of Ownership to the Point of Interconnection, including any modifications, additions or upgrades made to such facilities and equipment, that are necessary to physically and electrically interconnect the Generating Facility with the Transmission System or interconnected distribution facilities.

Stand Alone Network Upgrades: Network Upgrades, which are not part of an Affected System, which a Project Developer may construct without affecting day-to-day operations (e.g. taking a transmission outage) of the Transmission System during their construction.

Network Upgrades: Modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider's overall Transmission System for the general benefit of all users of such Transmission System. Network Upgrades have no impact or potential impact on the Transmission System until the final tie-in is complete.

Notes

Note 1: PJM Open Access Transmission Tariff (OATT), Part VII, Subpart D, section 307.5 outlines cost allocation rules. The rules are further clarified in PJM Manual 14H, section 4.2.6. PJM shall identify the New Service Requests in the Cycle contributing to the need for the required Network Upgrades within the Cycle. All New Service Requests that contribute to the need for a Network Upgrade will receive cost allocation for that upgrade pursuant to each New Service Request's contribution to the reliability violation identified on the transmission system in accordance with PJM Manuals.

Note 2: There will be no inter-Cycle cost allocation for Interconnection Facilities or Network Upgrades identified in the System Impact Study costs identified in a Cycle; all such costs shall be allocated to New Service Requests in that Cycle.

Note 3: For Project Developers with System Reinforcements listed: If this project presents cost allocation to a System Reinforcement indicates $0, then please be aware that as changes to the interconnection process occur, such as other projects withdrawing, reducing in size, etc, the cost responsibilities can change and a cost allocation may be assigned to this project. In addition, although this project presents cost allocation to a System Reinforcement is presently $0, this project may need this system reinforcement completed to be deliverable to the PJM system. If this project desires to come into service prior to completion of the system reinforcement, the Project Developer will need to request PJM to perform an interim study to determine if they would be deliverable for all or a portion of their output for each delivery year until the system reinforcement is complete.

Note 4: Please see the 'Affected Systems Studies' section of this Phase 2 SIS report for details on your project's need for an Affected Systems Study. If your project requires an Affected Systems Study, the Affected Systems impacts may not be available from the Affected System Operator at the time of the PJM Phase II SIS. Therefore, the cost in this section would not reflect any required upgrades by the Affected System until the study is completed. If your project requires an Affected Systems Study and your results are not provided for Phase II SIS, PJM anticipates providing them in the Phase III SIS per Tariff Part VII.D.312.

Readiness Deposit

Per Tariff Part VII, Subpart D, section 311 (Decision Point II) A.1.b and PJM Manual 14H, section 6.2, Readiness Deposit #3 (RD3) are funds committed by the Project Developer or Eligible Customer based upon the applicable contribution to Network Upgrades as defined below. Readiness Deposits are not used to fund studies nor to offset Security.

During Decision Point II (DP2), the Project Developer or Eligible Customer is required to submit Readiness Deposit #3, which is calculated as 20% of cost allocation for required Phase II Network Upgrades minus Readiness Deposit #1 & Readiness Deposit #2.

Note 1: "Network Upgrades" referred to in the calculation include both (i) the Physical Interconnection Network Upgrades and (ii) the System Reliability Network Upgrades as shown in the Cost Summary table.

Note 2: Readiness Deposit #1 (RD1) = ($4,000 * Project Size (MW))

Note 3: Readiness Deposit #2 (RD2) = 10% of cost allocation for required Network Upgrades minus RD1. Readiness Deposit #2 (RD2) can be zero, but may not be a negative number.

Note 4: Readiness Deposit #3 can be zero, but may not be a negative number.

Readiness Deposit #3 Due for Project AG1-471

Readiness Deposit #3 has been calculated for the AG1-471 project based on the Phase II System Impact Study results and is shown in the table below. This Readiness Deposit #3 must be provided at Decision Point II through either a wire transfer or letter of credit per Manual 14H, Section 6.2.

Readiness Deposit

Project ID	20% of cost allocation for Phase II Network Upgrades	Sum of Readiness Deposit #1 & Readiness Deposit #2 Received (RD1+RD2)	Readiness Deposit #3 (RD3) for AG1-471 Project due at DP2
	A	**B**	**A - B**
AG1-471	$3,105,414	$2,235,108	$870,306

Note: Failure to provide an acceptable form of Readiness Deposit #3 by the end of Decision Point II will result in withdrawal and termination of the New Service Request.

For additional detail regarding Readiness Deposit Refunds, reference PJM Manual 14H, section 6.2.1. The Readiness Deposit Letter of Credit template can be found here.

Transmission Owner Scope of Work

EKPC will construct a 69 kV Main and Transfer switching station and a new 69 kV loop-in tap from the EKPC Wayne County-Upchurch 69 kV line to accommodate the direct connection of the PD’s substation facilities to the EKPC transmission system. EKPC will also construct a 69 kV disconnect switch structure which will be the POI interface.

EKPC will also complete the required non-direct connection network upgrades at existing EKPC substations, which are system protection changes necessary at the Wayne County and Summer Shade substations to accommodate the addition of this new facility, and installation of OPGW on the existing 69 kV line sections from the new Massingale Road switching station to the Wayne County and Summer Shade substations in order to provide necessary communications infrastructure for EKPC.

The total preliminary cost estimate for the Transmission Owner scope of work (including TOIF and Physical Interconnection Network Upgrades) is given in the table below. These costs do not include CIAC Tax Gross-up.

Transmission Owner Build Option

Network Upgrades

RTEP ID	Description	Direct		Indirect		Total Cost ($USD)	Allocated Cost ($USD)
		Labor	**Materials**	**Labor**	**Materials**		
(Pending)	Remote Relay Settings at Summer Shade Sub	$55,000	$1,000	$6,000	$1,000	$63,000	$63,000
(Pending)	Remote Relay Settings at Wayne County Sub	$55,000	$1,000	$6,000	$1,000	$63,000	$63,000
(Pending)	Interconnection Substation Tie-In	$254,000	$244,000	$50,000	$6,000	$554,000	$554,000
(Pending)	Fiber Installation in Existing ROW	$3,510,000	$1,401,000	$491,000	$55,000	$5,457,000	$5,457,000

Stand-Alone Network Upgrades

RTEP ID	Description	Direct		Indirect		Total Cost ($USD)	Allocated Cost ($USD)
		Labor	**Materials**	**Labor**	**Materials**		
(Pending)	Massingale Road Substation	$2,987,000	$3,359,000	$634,000	$70,000	$7,050,000	$7,050,000

Transmission Owner Interconnection Facilities

RTEP ID	Description	Direct		Indirect		Total Cost ($USD)	Allocated Cost ($USD)
		Labor	**Materials**	**Labor**	**Materials**		
(Pending)	Transmission Owner Interconnection Facilities	$378,000	$268,000	$65,000	$7,000	$718,000	$718,000

Developer Build Option

Project Developer has the option ("Option to Build") to assume responsibility for the design, procurement and construction of Transmission Owner Interconnection Facilities and/or Stand-Alone Network Upgrades.

If Option to Build is elected, the Project Developer must fulfill additional requirements in accordance to PJM Manual 14C, section 5.1 and PJM Manual 14H, section 8.6.2.

The cost estimates for eligible facilities and Option to Build oversight are highlighted below:

Network Upgrades

RTEP ID	Description	Direct		Indirect		Total Cost ($USD)	Allocated Cost ($USD)
		Labor	Materials	Labor	Materials		
(Pending)	Remote Relay Settings at Summer Shade Sub	$55,000	$1,000	$6,000	$1,000	$63,000	$63,000
(Pending)	Remote Relay Settings at Wayne County Sub	$55,000	$1,000	$6,000	$1,000	$63,000	$63,000
(Pending)	Fiber Installation in Existing ROW	$3,510,000	$1,401,000	$491,000	$55,000	$5,457,000	$5,457,000
(Pending)	Interconnection Substation Tie-In	$254,000	$244,000	$50,000	$6,000	$554,000	$554,000

Other

RTEP ID	Description	Direct		Indirect		Total Cost ($USD)	Allocated Cost ($USD)
		Labor	Materials	Labor	Materials		
(Pending)	Transmission Owner Interconnection Facilities ...	$66,000	$14,000	$9,000	$9,000	$98,000	$98,000
(Pending)	New Interconnection Substation (Oversight)	$630,000	$153,000	$84,000	$84,000	$951,000	$951,000

Build Option Price Comparison

Build Option	Total Cost	Allocated Cost
Transmission Owner Build Option	$13,905,000	$13,905,000
Developer Build Option	$7,186,000	$7,186,000

Based on the scope of work for the Interconnection Facilities, it is expected to take 25 month(s) after the signing of a Generator Interconnection Agreement (as this is a FERC connection) and construction kickoff call to complete the installation of the physical connection work. This assumes that there will be no environmental issues with any of the new properties associated with this project, that there will be no delays in acquiring the necessary permits for implementing the defined interconnection work, and that all system outages will be allowed when requested.

The schedule for any required Network Impact Reinforcements will be more clearly identified in the Phase II and Phase III System Impact Studies.

EKPC anticipates that it will take 25 to 25 months after the signing of the Generator Interconnection Agreement and the project kickoff call is subsequently held to complete the physical interconnection projects. This assumes no delays due to permitting or environmental issues, and that all necessary outages can be taken as needed to maintain this schedule.

Transmission Owner Analysis

No violations.

Developer Requirements

The developer is responsible for all design and construction related activities on the developer’s side of the Point of Change in Ownership. EKPC interconnection requirements can be found here. Refer to AG1-471 Physical Interconnection Facilities Study for additional requirements found in the General Section of the report.

To the extent that these Applicable Technical Requirements and Standards may conflict with the terms and conditions of the Tariff, the Tariff shall control.

Revenue Metering and SCADA Requirements

PJM Requirements

The developer will be required to install equipment necessary to provide Revenue Metering (KWH, KVARH) and real time data (KW, KVAR) for their generating Resource. See PJM Manual 01, PJM Manual 14D, and PJM Tariff Part IX, Subpart B, Appendix 2, section 8.

Meteorological Data Reporting Requirement

The solar generation facility shall provide the Transmission Provider with site-specific meteorological data including:

- Temperature (degrees Fahrenheit)
- Atmospheric Pressure (hectopascals)
- Irradiance
- Forced outage data

Transmission Owner Requirements

The Project Developer will be required to comply with all interconnected Transmission Owner's revenue metering requirements located at the following link: PJM - Transmission Owner Engineering & Construction Standards and in the Physical Interconnection Facilities Study.

Summer Peak Analysis

The New Service Request was evaluated as a 60.0 MW (36.0 MW Capacity) injection in the EKPC area. Project was evaluated for compliance with applicable reliability planning criteria (PJM, NERC, NERC Regional Reliability Councils, and Transmission Owners). Potential summer peak period network impacts were as follows:

Note: The capacity portion of Generation Interconnection Requests are evaluated for single or N-1 contingencies. The full energy output of Generation Interconnection Requests are evaluated for multiple facility contingencies (double circuit tower line, fault with a stuck breaker, and bus fault).

The following flowgates remain after considering the topology reinforcements required by the cycle.

Summer Peak Analysis

Area	Facility Description	Contingency Name	Contingency Type	DC|AC	Final Cycle Loading	Rating (MVA)	Rating Type	MVA to Mitigate
EKPC/LGEE	5COOPER2-5ELIHU 161.0 kV Ckt 1 line	EKPC_P4-5_LAURL S50-1024_SRT-A	Breaker	AC	133.61	277.0	B	370.11
DAY/EKPC	7SPURLOCK-09STUART 345.0 kV Ckt 1 line	DEOK_P2-3_1537_MELDAHL345_SRT-A	Breaker	AC	119.57	1532.0	B	1831.83
DAY/EKPC	7SPURLOCK-09STUART 345.0 kV Ckt 1 line	DEOK_P2-3_1535_MELDAHL345_SRT-A	Breaker	AC	119.57	1532.0	B	1831.8
DAY/EKPC	7SPURLOCK-09STUART 345.0 kV Ckt 1 line	DEOK_P2-3_1539_MELDAHL345_SRT-A	Breaker	AC	119.55	1532.0	B	1831.43
EKPC/LGEE	5COOPER2-5ELIHU 161.0 kV Ckt 1 line	EKPC_P1-2_LAUR-L DAM161_SRT-A	Single	AC	111.55	277.0	B	309.01
DAY/EKPC	7SPURLOCK-09STUART 345.0 kV Ckt 1 line	Base Case	Single	AC	100.84	1240.0	A	1250.44
DAY/EKPC	7SPURLOCK-09STUART 345.0 kV Ckt 1 line	DEOK_P1_ZIMMER-MELDAHL 34576_SRT-A	Single	AC	100.2	1532.0	B	1535.08
EKPC/LGEE	2SOMERSET KU-2FERGUSON SO 69.0 kV Ckt 1 line	EKPC_P7-1_COOP 161 DBL 2_SRT-A	Tower	AC	155.93	105.0	B	163.73
EKPC/LGEE	5COOPER2-5ELIHU 161.0 kV Ckt 1 line	EKPC_P7-1_LAURL 161 DBL_SRT-A	Tower	AC	133.61	277.0	B	370.11
EKPC/LGEE	4MARION CO-4LEBANON 138.0 kV Ckt 1 line	EKPC_P7-1_COOP 161 DBL 2_SRT-A	Tower	AC	111.75	220.0	B	245.86
EKPC	5MARION CO-4MARION CO 161.0/138.0 kV Ckt 1 transformer	EKPC_P7-1_COOP 161 DBL 2_SRT-A	Tower	AC	105.36	234.0	B	246.54

The following flowgates were eliminated after considering the topology reinforcements required by the cycle.

(No impacts were found for this analysis)

Summer 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 an Upgrade Request into the New Service Request process.

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 an Upgrade Request, a subsequent analysis will be performed which shall study all overload conditions associated with the overloaded element(s) identified.

The following flowgates remain after considering the topology reinforcements required by the cycle.

Summer Potential Congestion due to Local Energy Deliverability

Area	Facility Description	Contingency Name	Contingency Type	DC|AC	Final Cycle Loading	Rating (MVA)	Rating Type	MVA to Mitigate	MW Contribution
DAY/EKPC	7SPURLOCK-09STUART 345.0 kV Ckt 1 line	Base Case	OP	AC	123.4	1240.0	A	1530.17	5.22
EKPC/LGEE	5COOPER2-5ELIHU 161.0 kV Ckt 1 line	Base Case	OP	AC	116.63	219.0	A	255.41	10.38
EKPC	5LAUREL DAM-5LAUREL CO 161.0 kV Ckt 1 line	P2-3-228_SRT-S	OP	AC	106.37	211.0	B	224.45	6.28
LGEE/OVEC	7TRIMBL REAC-06CLIFTY 345.0 kV Ckt 1 line	AEP_P1-2_#10136_SRT-A	OP	AC	110.53	1451.0	B	1603.74	7.43
EKPC/LGEE	4MARION CO-4LEBANON 138.0 kV Ckt 1 line	Base Case	OP	AC	104.47	187.0	A	195.36	3.52
EKPC	5MARION CO-4MARION CO 161.0/138.0 kV Ckt 1 transformer	Base Case	OP	AC	102.02	192.0	A	195.88	3.52

The following flowgates were eliminated after considering the topology reinforcements required by the cycle.

(No impacts were found for this analysis)

Winter Peak Analysis

PJM will start performing Winter Peak analysis in Transition Cycle #2.

Winter Potential Congestion due to Local Energy Deliverability

PJM will start performing Winter Peak analysis in Transition Cycle #2.

Light Load Analysis

Light Load Analysis is Not Required.

Light Load Potential Congestion due to Local Energy Deliverability

Light Load Analysis is Not Required.

Short Circuit Analysis

Based on PJM Short Circuit Analysis, this project did not contribute >1% fault duty to previously identified overduty breakers, nor did it cause any new overduty breakers.

Stability Analysis

Analysis Complete - No Issues

Executive Summary

New Service Requests (projects) in PJM Transition Cycle 1, Cluster 25 are listed in Table 1 below. This report will cover the dynamic analysis of Cluster 25 projects.

This analysis is effectively a screening study to determine whether the addition of the Cluster 25 projects will meet the dynamics requirements of the NERC, EKPC and PJM reliability standards.

The load flow scenario for the analysis was based on the RTEP 2027 summer peak load case, modified to include applicable projects. Cluster 25 projects have been dispatched online at maximum power output, and voltage schedules set to achieve near unity power factor at the high side of the main transformer.

Cluster 25 projects were tested for compliance with NERC, PJM, Transmission Owner and other applicable criteria. Steady-state condition and 142 contingencies were studied, each with a 20 second simulation time period. Studied faults included:

a) Steady-state operation (20 second run);

b) Three-phase faults with normal clearing time;

c) Single-phase bus faults with normal clearing time;

d) Single-phase faults with stuck breaker;

e) 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;

f) Single-phase faults with loss of multiple-circuit tower line.

No relevant high speed reclosing (HSR) contingencies were identified for this study.

For all simulations, the Cluster 25 projects 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 2027 peak load case:

a) Cluster 25 projects were able to ride through the faults (except for faults where protective action trips a generator(s)),

b) The system with Cluster 25 projects included is transiently stable and 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.

AG-353, AG1-354 and AG1-471 meet the 0.95 leading and lagging PF requirement.

Fictitious voltage response at AF1-083 generator terminal bus at fault clearance caused the generator terminal voltage to exceed 1.2 pu for longer than 0.019 seconds resulting in the unit being tripped by voltage relay instance 94415404. The relay pickup time was extended to 0.05 seconds to resolve tripping of the unit.

Fictitious voltage response at AF1-050 generator terminal bus at fault clearance caused the generator terminal voltage to exceed 1.2 pu for longer than 0.0292 seconds resulting in the unit being tripped by voltage relay instance 94382404. The relay pickup time was extended to 0.05 seconds to resolve tripping of the unit.

AG1-471 generator unit remained in High Voltage Ride Through mode for several contingencies. As a result, the AG1-471 generator terminal voltage remained at approximately 1.12 pu after fault recovery causing the voltage relay stage set to 1.1 pu for 10 seconds to pick up and trip AG1-471 generating unit. Modifying CON(J+1): Vup to 1.16 pu of the REECA1 model resolved the issue of AG1-471 getting stuck in HVRT mode and resolved the tripping of the unit.

The stability study results in this report are considered preliminary, as PJM is actively performing simulations to assess the impacts of potential dynamic model parameter changes required to address identified stability issues. Additionally, feedback from the Transmission Owner is being incorporated into the stability study. The study will be finalized at the conclusion of Phase III of Transition Cycle 1.

No mitigations were found to be required.

Table 1: TC1 Cluster 25 Projects

Cluster	Project	Fuel Type	Transmission Owner	MFO	MWE	MWC	Point of Interconnection
25	AG1-353	Solar	EKPC	98	98	58.8	Greene County - Marion County 161 kV
	AG1-354	Solar	EKPC	150.0	150.0	90.0	Summershade - Green County 161 kV
	AG1-471	Solar	EKPC	60.0	60.0	36.0	Up Church-Wayne County 69 kV

Reactive Power Analysis

The reactive power capability of AG1-471 meets the 0.95 leading and lagging PF requirement at the high side of the main transformer.

Steady-State Voltage Analysis

Steady State Voltage Analysis is Not Required.

New Service Request Dependencies

The New Service Requests below are listed in one or more dispatch for the overloads identified in this report. These projects contribute to the loading of the overloaded facilities identified in this report. The percent overload of a facility and cost allocation you may have towards a particular reinforcement could vary depending on the action of other projects. The status of each project at the time of the analysis is presented in the table. This list may change as other projects withdraw or modify their requests. This table is valid for load flow analyses only.

New Service Requests Dependencies

Project ID	Project Name	Status
AC1-074	Jacksonville-Renaker 138kV I	Under Construction
AC1-089	Hillsboro-Wildcat 138kV	In Service
AC2-075	Jacksonville-Renaker 138 kV	Under Construction
AD2-048	Cynthia-Headquarters 69 kV	Under Construction
AD2-072	Van Arsdell-Mercer Industrial 69kV	Withdrawn
AE1-143	Marion County 161 kV	Engineering & Procurement
AE2-071	Patton Rd-Summer Shade 69 kV	In Service
AE2-138	Avon-North Clark 345 kV	Active
AE2-210	Avon-North Clark 345 kV	Active
AE2-221	Clinton-Stuart 345 kV	Engineering & Procurement
AE2-254	Garrard County-Tommy-Gooch 69 kV	In Service
AE2-275	J.K. Smith-Fawkes 138 kV	Active
AE2-308	Three Forks-Dale 138 kV	Active
AE2-339	Avon 138 kV	Engineering & Procurement
AF1-038	Sewellton Jct-Webbs Crossroads 69 kV	Engineering & Procurement
AF1-050	Summer Shade - Green County 161 kV	Engineering & Procurement
AF1-083	Green County-Saloma 161 kV	Engineering & Procurement
AF1-116	Marion County 161 kV	Active
AF1-203	Patton Rd-Summer Shade 69 kV	In Service
AF1-233	Flemingsburg – Spurlock 138kV	Active
AF2-090	Central Hardin 138 kV	Withdrawn
AF2-111	North Clark-Spurlock 345 kV	Active
AF2-260	Stephensburg-Central Hardin 69 kV	Active
AF2-306	Hope-Blevins Valley Tap 69 kV	Engineering & Procurement
AF2-307	Hope-Belvins Valley Tap 69 kV	Active
AF2-308	Central Hardin-Stephensburg 69 kV	Withdrawn
AF2-309	Central Hardin-Stephensburg 69 kV	Withdrawn
AF2-348	North Clark-Spurlock 345 kV	Active
AF2-355	West Gerrard-J.K. Smith 345 kV	Active
AF2-365	Munfordville KU Tap-Horse Cave Jct. 69 kV	Active
AF2-391	Central Hardin 69 kV	Active
AG1-066	Bonnyman 69 kV	Active
AG1-067	Temple Hill 69 kV	Active
AG1-070	Bon Ayr 69 kV	Active
AG1-071	Bon Ayr 69 kV	Active
AG1-320	Glendale-Stephensburg 69 kV	Active
AG1-341	Summer Shade 161 kV	Active
AG1-353	Green County-Marion County 161 kV	Active
AG1-354	Summershade-Green County 161 kV	Active
AG1-405	Walnut Grove-Asahi 69 kV	Active
AG1-406	Walnut Grove-Asahi 69 kV	Active

AG1-526	West Garrard 345 kV	Active

Affected Systems

In Phase II of the Cycle, PJM provides the Affected System Operator any updates on the PJM projects that require an Affected Systems Study based on their response at DP1. New Service Requests that require an Affected Systems Study are required to enter into an Affected Systems Study Agreement with the Affected System Operator, as applicable, prior to the close of DP2 or they will be withdrawn from the Cycle.

If the Project Developer already entered into the necessary agreement and the results are available, PJM will supply them in the Phase II SIS report. See below for the status of any required Affected Systems Study. A status of “Pending” means that the study is not yet completed by the Affected System Operator. If your project requires an Affected Systems Study and your results are not provided for Phase II SIS, PJM anticipates providing them in the Phase III SIS per Tariff Part VII.D.312.

Midcontinent Independent System Operator (MISO)	**Study Pending**
New York Independent System Operator (NYISO)	**Not required**
Tennessee Valley Authority (TVA)	**Not required**
Louisville Gas & Electric (LG&E)	**Study Pending**
Duke Energy Carolinas (DUKE)	**Not required**
Duke Energy Progress - East (CPLE)	**Not required**
Duke Energy Progress - West (CPLW)	**Not required**

System Reinforcements

Based on the Phase II analysis results, this project has potential cost responsibility for the following System Reinforcements:

AG1-471 System Reinforcements Cost Breakdown:

Type	TO	RTEP ID / TO ID	Title	MW Impact	Percent Allocation	Allocated Cost ($USD)
Load Flow	EKPC	n8368.2 / EKPC-tc1-r0012b	Rebuild the Cooper-Elihu 161 kV line section using 795 MCM ACSS conductor (4.2 miles)	12.1 MW	28.3%	$2,319,838
Load Flow	EKPC	n8364.1 / EKPC-tc1-r0009b	Replace the 636 MCM ACSR conductor in the Marion County-KU Lebanon 138 kV line with 954 MCM ACSS conductor.	5.2 MW	10.1%	$20,232
Load Flow	LGEE	(Pending) / LGEE_TC1_15527	Load shedding of 10% PC load is allowed for P2 contingency	5.2 MW	10.1%	$0
Load Flow	LGEE	(Pending) / LGEE_TC1_15521	Load shedding of 10% PC load is allowed for P7 contingency	5.2 MW	3.8%	$0
Grand Total:						**$2,340,070**

System Reinforcement

Type	TO	RTEP ID / TO ID	Title	Total Cost ($USD)	Allocated Cost ($USD)	Time Estimate
Load Flow	EKPC	n8368.2 / EKPC-tc1-r0012b	Rebuild the Cooper-Elihu 161 kV line section using 795 MCM ACSS conductor (4.2 miles)	$8,195,000	$2,319,838	30 to 36 Months

Contributor

Description: Rebuild the Cooper-Elihu 161 kV line section using 795 MCM ACSS conductor (4.2 miles)

Flowgates Addressed by this Reinforcement

Facility	Contingency
5ELIHU-5COOPER2 161.0 kV Ckt 1 line	(Any)

New Ratings			
Facility	**Rating Set**	**Rating Type**	**Rating Value**
5ELIHU-5COOPER2 161.0 kV Ckt 1 line	(All)	A	308.0 MVA
5ELIHU-5COOPER2 161.0 kV Ckt 1 line	(All)	B	373.0 MVA
5ELIHU-5COOPER2 161.0 kV Ckt 1 line	(All)	C	373.0 MVA

Cost Allocation			
Project	**MW Impact**	**Percent Allocation**	**Allocated Cost ($USD)**
AG1-353	12.9 MW	30.1%	$2,469,443
AG1-354	17.8 MW	41.6%	$3,405,719
AG1-471	12.1 MW	28.3%	$2,319,838

System Reinforcement						
Type	**TO**	**RTEP ID / TO ID**	**Title**	**Total Cost ($USD)**	**Allocated Cost ($USD)**	**Time Estimate**
Load Flow	EKPC	n8364.1 / EKPC-tc1-r0009b	Replace the 636 MCM ACSR conductor in the Marion County-KU Lebanon 138 kV line with 954 MCM ACSS conductor.	$200,000	$20,232	Dec 31 2024

Contributor

Description: Replace the 636 MCM ACSR conductor in the Marion County-KU Lebanon 138 kV line with 954 MCM ACSS conductor.

Flowgates Addressed by this Reinforcement	
Facility	**Contingency**
4LEBANON-4MARION CO 138.0 kV Ckt 1 line	(Any)

New Ratings			
Facility	**Rating Set**	**Rating Type**	**Rating Value**
4LEBANON-4MARION CO 138.0 kV Ckt 1 line	SUM	A	202.0 MVA
4LEBANON-4MARION CO 138.0 kV Ckt 1 line	SUM	B	248.0 MVA
4LEBANON-4MARION CO 138.0 kV Ckt 1 line	SUM	C	248.0 MVA

Cost Allocation			
Project	**MW Impact**	**Percent Allocation**	**Allocated Cost ($USD)**
AG1-353	26.8 MW	52.4%	$104,791
AG1-354	19.2 MW	37.5%	$74,978
AG1-471	5.2 MW	10.1%	$20,232

System Reinforcement						
Type	**TO**	**RTEP ID / TO ID**	**Title**	**Total Cost ($USD)**	**Allocated Cost ($USD)**	**Time Estimate**
Load Flow	EKPC	n5780.3 / EKPC-tc1-r0020b	Replace the 1500A interconnection metering CTs at Spurlock Station with 2000A equipment.	$1,235,000	$0	18 to 21 Months

Potential Aggregate Contributor

Note: Based on PJM cost allocation criteria, AG1-471 currently does not receive cost allocation towards this upgrade. As changes to the PJM process occur (such as other projects withdrawing from the cycle or reducing in size) AG1-471 could receive cost allocation. Although AG1-471 may not presently have cost responsibility for this upgrade, AG1-471 is a potential Aggregate Pool Contributor.

Description: Replace the 1500A interconnection metering CTs at Spurlock Station with 2000A equipment.

Flowgates Addressed by this Reinforcement	
Facility	**Contingency**
09STUART-7SPURLOCK 345.0 kV Ckt 1 line	(Any)

New Ratings			
Facility	**Rating Set**	**Rating Type**	**Rating Value**
09STUART-7SPURLOCK 345.0 kV Ckt 1 line	SUM	A	1777.0 MVA
09STUART-7SPURLOCK 345.0 kV Ckt 1 line	SUM	B	1867.0 MVA
09STUART-7SPURLOCK 345.0 kV Ckt 1 line	SUM	C	1910.0 MVA

System Reinforcement						
Type	**TO**	**RTEP ID / TO ID**	**Title**	**Total Cost ($USD)**	**Allocated Cost ($USD)**	**Time Estimate**
Load Flow	Dayton	n5780.1 / DAYr190040	Replace Stuart substation riser conductor with 2500AAC (parallel)	$300,000	$0	12 to 18 Months

Potential Aggregate Contributor

Note: Based on PJM cost allocation criteria, AG1-471 currently does not receive cost allocation towards this upgrade. As changes to the PJM process occur (such as other projects withdrawing from the cycle or reducing in size) AG1-471 could receive cost allocation. Although AG1-471 may not presently have cost responsibility for this upgrade, AG1-471 is a potential Aggregate Pool Contributor.

Description: Replace Stuart substation riser conductor with 2500AAC (parallel)

Flowgates Addressed by this Reinforcement	
Facility	**Contingency**
09STUART-7SPURLOCK 345.0 kV Ckt 1 line	(Any)

New Ratings			
Facility	**Rating Set**	**Rating Type**	**Rating Value**
09STUART-7SPURLOCK 345.0 kV Ckt 1 line	(All)	A	1561.0 MVA
09STUART-7SPURLOCK 345.0 kV Ckt 1 line	(All)	B	1800.0 MVA
09STUART-7SPURLOCK 345.0 kV Ckt 1 line	(All)	C	1800.0 MVA

System Reinforcement						
Type	**TO**	**RTEP ID / TO ID**	**Title**	**Total Cost ($USD)**	**Allocated Cost ($USD)**	**Time Estimate**
Load Flow	Dayton	n5780 / DAYr190039	Reconductor Stuart-Spurlock line with twin bundle 1033 Curlew ACCR conductor.	$47,681,589	$0	36 to 48 Months

Potential Aggregate Contributor

Note: Based on PJM cost allocation criteria, AG1-471 currently does not receive cost allocation towards this upgrade. As changes to the PJM process occur (such as other projects withdrawing from the cycle or reducing in size) AG1-471 could receive cost allocation. Although AG1-471 may not presently have cost responsibility for this upgrade, AG1-471 is a potential Aggregate Pool Contributor.

Description: Reconductor Stuart-Spurlock line with twin bundle 1033 Curlew ACCR conductor.

Flowgates Addressed by this Reinforcement	
Facility	**Contingency**
09STUART-7SPURLOCK 345.0 kV Ckt 1 line	(Any)

New Ratings			
Facility	**Rating Set**	**Rating Type**	**Rating Value**
09STUART-7SPURLOCK 345.0 kV Ckt 1 line	(All)	A	1339.0 MVA
09STUART-7SPURLOCK 345.0 kV Ckt 1 line	(All)	B	1556.0 MVA
09STUART-7SPURLOCK 345.0 kV Ckt 1 line	(All)	C	1556.0 MVA

System Reinforcement						
Type	**TO**	**RTEP ID / TO ID**	**Title**	**Total Cost ($USD)**	**Allocated Cost ($USD)**	**Time Estimate**
Load Flow	Dayton	n5780.2 / DAYr190041	Reconductor Stuart substation conductor with twin bundle 1033 Curlew ACCR conductor Reconductor Stuart Substation conductor with a bundled 795 hi-temperature conductor.	$650,000	$0	18 to 24 Months

Potential Aggregate Contributor

Note: Based on PJM cost allocation criteria, AG1-471 currently does not receive cost allocation towards this upgrade. As changes to the PJM process occur (such as other projects withdrawing from the cycle or reducing in size) AG1-471 could receive cost allocation. Although AG1-471 may not presently have cost responsibility for this upgrade, AG1-471 is potential Aggregate Pool Contributor.

Description: Reconductor Stuart substation conductor with twin bundle 1033 Curlew ACCR conductor Reconductor Stuart Substation conductor with a bundled 795 hi-temperature conductor.

Flowgates Addressed by this Reinforcement

Facility	Contingency
09STUART-7SPURLOCK 345.0 kV Ckt 1 line	(Any)

New Ratings

Facility	Rating Set	Rating Type	Rating Value
09STUART-7SPURLOCK 345.0 kV Ckt 1 line	(All)	A	1882.0 MVA
09STUART-7SPURLOCK 345.0 kV Ckt 1 line	(All)	B	2062.0 MVA
09STUART-7SPURLOCK 345.0 kV Ckt 1 line	(All)	C	1958.0 MVA

System Reinforcement

Type	TO	RTEP ID / TO ID	Title	Total Cost ($USD)	Allocated Cost ($USD)	Time Estimate
Load Flow	EKPC	n7773.1 / EKPC-tc1-r0004b	Change the 69 kV current transformer settings associated with circuit breaker S7-654 from 600A to at least 800A.	$345,000	$0	9 to 12 Months

Contingent

Note: Based on PJM cost allocation criteria, AG1-471 currently does not receive cost allocation towards this upgrade. As changes to the PJM process occur (such as other projects withdrawing from the cycle or reducing in size) AG1-471 could receive cost allocation. Although AG1-471 may not presently have cost responsibility for this upgrade, AG1-471 may need this upgrade in-service to be deliverable to the PJM system. If AG1-471 desires to come into service prior to completion of the upgrade, the Project Developer will need to request PJM to perform an interim study to determine if they would be deliverable for all or a portion of their output for each delivery year until the upgrade is complete.

Description: Change the 69 kV current transformer settings associated with circuit breaker S7-654 from 600A to at least 800A.

Flowgates Addressed by this Reinforcement

Facility	Contingency
2FERGUSON SO-2SOMERSET KU 69.0 kV Ckt 1 line	(Any)

New Ratings

Facility	Rating Set	Rating Type	Rating Value
2FERGUSON SO-2SOMERSET KU 69.0 kV Ckt 1 line	(All)	A	154.0 MVA
2FERGUSON SO-2SOMERSET KU 69.0 kV Ckt 1 line	(All)	B	180.0 MVA
2FERGUSON SO-2SOMERSET KU 69.0 kV Ckt 1 line	(All)	C	185.0 MVA

System Reinforcement

Type	TO	RTEP ID / TO ID	Title	Total Cost ($USD)	Allocated Cost ($USD)	Time Estimate
Load Flow	LGEE	(Pending) / LGEE_TC1_15519	Invalid - P7 contingency 69kV not monitored by LGEE	$0	$0	TBD

Note: This reinforcement is fictitious and will not be cost allocated to projects. It is listed for information purposes only.

Description: Invalid - P7 contingency 69kV not monitored by LGEE

Flowgates Addressed by this Reinforcement

Facility	Contingency
2FERGUSON SO-2SOMERSET KU 69.0 kV Ckt 1 line	(Any)
2SOMERSET-2SOMERSET KU 69.0 kV Ckt 1 line	(Any)

System Reinforcement

Type	TO	RTEP ID / TO ID	Title	Total Cost ($USD)	Allocated Cost ($USD)	Time Estimate
Load Flow	LGEE	(Pending) / LGEE_TC1_15527	Load shedding of 10% PC load is allowed for P2 contingency	$0	$0	TBD

Contributor

Description: Load shedding of 10% PC load is allowed for P2 contingency

Flowgates Addressed by this Reinforcement	
Facility	**Contingency**
4LEBANON-4MARION CO 138.0 kV Ckt 1 line	(Any)

System Reinforcement						
Type	**TO**	**RTEP ID / TO ID**	**Title**	**Total Cost ($USD)**	**Allocated Cost ($USD)**	**Time Estimate**
Load Flow	LGEE	(Pending) / LGEE_TC1_15521	Load shedding of 10% PC load is allowed for P7 contingency	$0	$0	TBD

Contributor

Description: Load shedding of 10% PC load is allowed for P7 contingency

Flowgates Addressed by this Reinforcement	
Facility	**Contingency**
4LEBANON-4MARION CO 138.0 kV Ckt 1 line	(Any)

System Reinforcement						
Type	**TO**	**RTEP ID / TO ID**	**Title**	**Total Cost ($USD)**	**Allocated Cost ($USD)**	**Time Estimate**
Load Flow	LGEE	(Pending) / LGEE_TC1_15510	Upgrade terminal equipment at Elihu 161kV associated with the Elihu-Cooper (EKPC) 161kV line to a minimum SE rating of 1200 amps.	$300,000	$0	TBD

Contingent

Note: Based on PJM cost allocation criteria, AG1-471 currently does not receive cost allocation towards this upgrade. As changes to the PJM process occur (such as other projects withdrawing from the cycle or reducing in size) AG1-471 could receive cost allocation. Although AG1-471 may not presently have cost responsibility for this upgrade, AG1-471 may need this upgrade in-service to be deliverable to the PJM system. If AG1-471 desires to come into service prior to completion of the upgrade, the Project Developer will need to request PJM to perform an interim study to determine if they would be deliverable for all or a portion of their output for each delivery year until the upgrade is complete.

Description: Upgrade terminal equipment at Elihu 161kV associated with the Elihu-Cooper (EKPC) 161kV line to a minimum SE rating of 1200 amps.

Flowgates Addressed by this Reinforcement	
Facility	**Contingency**
5ELIHU-5COOPER2 161.0 kV Ckt 1 line	(Any)

New Ratings			
Facility	**Rating Set**	**Rating Type**	**Rating Value**
5ELIHU-5COOPER2 161.0 kV Ckt 1 line	SUM	A	267.0 MVA
5ELIHU-5COOPER2 161.0 kV Ckt 1 line	SUM	B	335.0 MVA

System Reinforcement						
Type	**TO**	**RTEP ID / TO ID**	**Title**	**Total Cost ($USD)**	**Allocated Cost ($USD)**	**Time Estimate**
Load Flow	LGEE	(Pending) / LGEE_TC1_15524	Load shedding of 10% PC load is allowed for P7 contingency	$0	$0	TBD

Note: This reinforcement is fictitious and will not be cost allocated to projects. It is listed for information purposes only.

Description: Load shedding of 10% PC load is allowed for P7 contingency

Flowgates Addressed by this Reinforcement	
Facility	**Contingency**
5ELIHU-5COOPER2 161.0 kV Ckt 1 line	(Any)

System Reinforcement						
Type	**TO**	**RTEP ID / TO ID**	**Title**	**Total Cost ($USD)**	**Allocated Cost ($USD)**	**Time Estimate**
Load Flow	LGEE	(Pending) / LGEE_TC1_15525	Load shedding of 10% PC load is allowed for P4 contingency	$0	$0	TBD

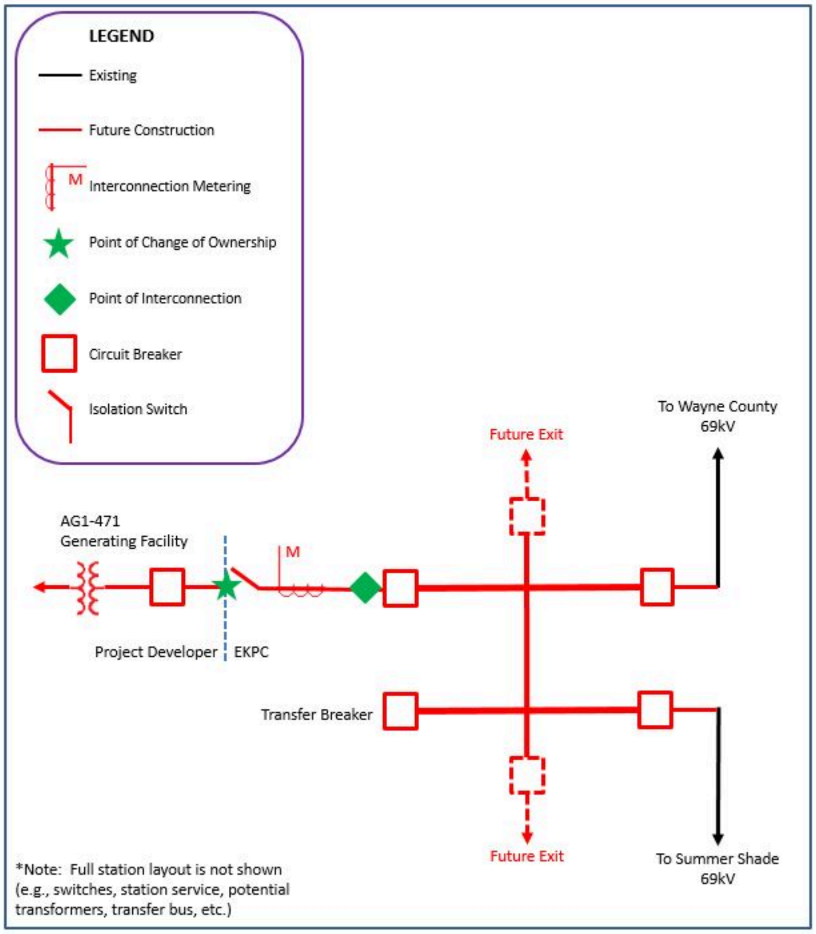
Note: This reinforcement is fictitious and will not be cost allocated to projects. It is listed for information purposes only.

Description: Load shedding of 10% PC load is allowed for P4 contingency

Flowgates Addressed by this Reinforcement	
Facility	**Contingency**
5ELIHU-5COOPER2 161.0 kV Ckt 1 line	(Any)

Attachments

AG1-471 Conceptual One-Line Diagram of Interconnection Facilities
Massingale Road 69kV Switch Station



Download all tables in report

[1] Winter load flow analysis will be performed starting in Transition Cycle #2.

AG1-471 Phase III Study Report

v1.00 released 2025-09-18 17:08

Up Church-Wayne County 69 kV

32.4 MW Capacity / 54.0 MW Energy

Introduction

This Phase III System Impact Study Report (PH3) has been prepared in accordance with the PJM Open Access Transmission Tariff, Part VII, Subpart D, section 312 for New Service Requests (projects) in Transition Cycle 1. The Project Developer/Eligible Customer (developer) is Barrelhead Solar, LLC, and the Transmission Provider (TP) is PJM Interconnection, LLC (PJM). The interconnected Transmission Owner (TO) is East Kentucky Power Cooperative, Inc..

Preface

New Service Requests meeting the requirements of Tariff, Part VII, Subpart D, Decision Point II, were included in the Phase III System Impact Study. The Phase III System Impact Study is conducted on an aggregate basis within a New Services Request's Cycle, and results are provided in both (i) a single Cycle executive summary format and (ii) an individual project-level basis. The Phase III System Impact Study Results (for both the executive summary and individual reports) will be publicly available on PJM's website. Developers must obtain the results from the website.

In accordance with PJM Manual 14H, section 4.7, PJM takes the following actions during the Phase III System Impact Study:

1. PJM will retool load flow, short circuit and stability results based on decisions made by Project Developers or Eligible Customers during Decision Point II.
2. PJM will coordinate with Affected System Operators to conduct any studies required to determine the final impact of a New Service Request on any Affected System and will include the final Affected System Study results in the Phase III System Impact Study, if available from the Affected System.
3. The Phase III System Impact Study Results will be publicly available on PJM's website; Project Developers and Eligible Customers must obtain the results from the website.
4. PJM will tender draft final agreements to Project Developers or Eligible Customers.

The Transmission Owner takes the following actions during the Phase III System Impact Study:

1. Verify Interconnection Facilities and Network Upgrades required to accommodate the New Service Request.
2. Perform a Facilities Study. The Facilities Study in Phase III System Impact Study phase will be for the System Reliability Network Upgrades. The Facilities Study requirements are outlined in Attachment C of PJM Manual 14H. The study will be conducted pursuant to Tariff, Part VII, Subpart D, section 307(A)(7).

Decision Point III Requirements

At the close of Phase III System Impact Study, PJM will initiate Decision Point III (DP3). During DP3, the Project Developer will have 30 days to decide whether to proceed with their project. If the Project Developer elects to proceed, they should provide the elements defined in the PJM Open Access Transmission Tariff, Part VII, Subpart D, section 313.A. Additional information on these elements is available in PJM Manual 14H sections 4.8, 6, and 7.

As stated in PJM Tariff, Part VII, Subpart D, section 313.C, New Service Requests may not be changed or modified in any way for any reason during Decision Point III. A New Service Request must be withdrawn and resubmitted in a subsequent Cycle to the extent a Project Developer or Eligible Customer wants to make any changes to such New Service Request at this point in the Cycle process.

Adverse Test Eligibility

This New Service Request does not meet the Adverse Study Impact Criteria and has the option to either move forward in the Cycle process or withdraw at DP3 with cumulative Readiness Deposits forfeited. See adverse study impact calculation below.

This section details whether a Project Developer or Eligible Customer qualifies for the Adverse Study Impact clause outlined in the PJM OATT, Part VII, Subpart D, section 313.B and Manual 14H, section 6.2.2. In order to qualify for an Adverse Study Impact at Decision Point III, the Network Upgrade cost from Phase II to Phase III must:

1. Increase overall by 35% or more

2. Increases by more than $25,000 per MW (Includes Costs identified in Affected System studies)

If a New Service Request meets the criteria above and chooses to withdraw the request, PJM will refund the cumulative Readiness Deposit amounts paid at the Application Phase, Decision Point I, and Decision Point II (RD1, and RD2 and RD3, respectively).

The below calculations show the computation of this New Service Request's Adverse Study Impact

$$\text{DP3 Adverse Eligibility} = \frac{\text{DP3 Adverse Cost Alloc}}{\text{DP2 Adverse Cost Alloc}} > 1.35 \qquad \text{AND} \qquad \frac{(\text{ DP3 Adverse Cost Alloc - DP2 Adverse Cost Alloc })}{\text{Project Size}} > \$25{,}000 \text{ per MW}$$

$$\text{DP3 Adverse Eligibility} = \frac{\$18{,}539{,}864}{\$15{,}527{,}069} = 1.19 \qquad \text{AND} \qquad \frac{(\,\$18{,}539{,}864\text{ - }\$15{,}527{,}069\,)}{54.0} = \$55{,}793 \text{ per MW}$$

General

The Project Developer has proposed a Solar generating facility located in the East Kentucky Power Cooperative, Inc. zone — Wayne County, Kentucky. The installed facilities will have a total capability of 54.0 MW with 32.4 MW of this output being recognized by PJM as Capacity.

Project Information

New Service Request Number:	AG1-471
Project Name:	Up Church-Wayne County 69 kV
Project Developer Name:	Barrelhead Solar, LLC
State:	Kentucky
County:	Wayne
Transmission Owner:	East Kentucky Power Cooperative, Inc.
MFO:	54.0
MWE:	54.0
MWC:	32.4
Fuel Type:	Solar
Basecase Study Year:	2027

Physical Interconnection Facility Study

Report Available

The transmission owner has completed the Physical Interconnection Facilities Study. This report is available for download.

Point of Interconnection

AG1-471 will interconnect on the East Kentucky Power Cooperative, Inc. transmission system tapping the Upchurch to Wayne County 69 kV line.

Cost Summary

The table below shows a summary of the total cost estimates for this New Service Request project. In Phase III SIS, the interconnected Transmission Owner has performed a facilities study for the required System Reliability Network Upgrades. The Facilities Studies for the Transmission Owner Interconnection Facilities (TOIF) and Physical Interconnection Network Upgrades were performed by the Transmission Owner in Phase II and are available for download on PJM.com (see General Section for document links).

Based on the Phase III SIS results, the AG1-471 project has the following allocation of costs for interconnection. The Security amount required at DP3 is also shown below.

Cost Summary

Description	Cost Allocated to AG1-471	Cost Subject to Security
Transmission Owner Interconnection Facilities (TOIF)	$718,000	$718,000
Other Scope	$0	$0
Option to Build Oversight	$0	$0
Physical Interconnection Network Upgrades		
Stand Alone Network Upgrades	$7,050,000	$7,050,000
Network Upgrades	$6,137,000	$6,137,000
System Reliability Network Upgrades		
Steady State Thermal & Voltage (SP & LL)	$0	$0
Transient Stability	$0	$0
Short Circuit	$0	$0
Transmission Owner Analysis		
SubRegional	$0	$0
Distribution	$0	$0
Affected System Study Reinforcements		
AFS - PJM Violatons	$0	$0
AFS - Non-PJM Violations	$5,352,864	$0
Total	**$19,257,864**	**$13,905,000**

* Contributes to calculation for Security. See Security Section of this report for additional detail.

Definitions

Transmission Owner Interconnection Facilities: Facilities that are owned, controlled, operated and maintained by the Transmission Owner on the Transmission Owner's side of the Point of Change of Ownership to the Point of Interconnection, including any modifications, additions or upgrades made to such facilities and equipment, that are necessary to physically and electrically interconnect the Generating Facility with the Transmission System or interconnected distribution facilities.

Stand Alone Network Upgrades: Network Upgrades, which are not part of an Affected System, which a Project Developer may construct without affecting day-to-day operations (e.g. taking a transmission outage) of the Transmission System during their construction.

Network Upgrades: Modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider's overall Transmission System for the general benefit of all users of such Transmission System. Network Upgrades have no impact or potential impact on the Transmission System until the final tie-in is complete.

Notes

Note 1: PJM Open Access Transmission Tariff (OATT), Part VII, Subpart D, section 307.5 outlines cost allocation rules. The rules are further clarified in PJM Manual 14H, section 4.2.6. PJM shall identify the New Service Requests in the Cycle contributing to the need for the required Network Upgrades within the Cycle. All New Service Requests that contribute to the need for a Network Upgrade will receive cost allocation for that upgrade pursuant to each New Service Request's contribution to the reliability violation identified on the transmission system in accordance with PJM Manuals.

Note 2: There will be no inter-Cycle cost allocation for Interconnection Facilities or Network Upgrades identified in the System Impact Study costs identified in a Cycle; all such costs shall be allocated to New Service Requests in that Cycle.

Note 3: For Project Developers with System Reinforcements listed: If this project presents cost allocation to a System Reinforcement indicates $0, then please be aware that as changes to the interconnection process occur, such as other projects withdrawing, reducing in size, etc, the cost responsibilities can change and a cost allocation may be assigned to this project. In addition, although this project presents cost allocation to a System Reinforcement is presently $0, this project may need this system reinforcement completed to be deliverable to the PJM system. If this project desires to come into service prior to completion of the system reinforcement, the Project Developer will need to request PJM to perform an interim deliverability study to determine if they would be deliverable for all or a portion of their output for each delivery year until the system reinforcement is complete.

Security Requirement

Per Tariff Part VII, Subpart D, section 313 (Decision Point III) A.1.a and PJM Manual 14H, section 8.6.1, Project Developers and Eligible Customers are required to provide Security in a form acceptable to PJM at Decision Point III which runs concurrently with the projects' Final Agreement Negotiation Phase. Security may be in the form of cash, letter of credit, or other form of Security acceptable to PJM (see PJM M14H, Section 6.4).

Security is calculated for a New Service Request based on the Network Upgrade costs allocated pursuant to the Phase III System Impact Study results.

Note 1: "Network Upgrades" referred to in the calculation include both (i) the Physical Interconnection Network Upgrades and (ii) the System Reliability Network Upgrades as shown in the Cost Summary table.

Security Due for AG1-471

Security has been calculated for the AG1-471 project(s) based on the Phase III System Impact Study results and is shown in the table below. This Security must be provided at Decision Point III through either a wire transfer or letter of credit or other form of Security deemed acceptable by PJM per Manual 14H, Section 6.4.

Security Due for AG1-471

Project(s):	AG1-471
Final Agreement Security (A):	$13,905,000
Portion of Costs Already Paid (B):	$0
Net Security Due at DP3:	$A - B = \$13{,}905{,}000$

Note: Failure to provide an acceptable form of Security by the end of Decision Point III will result in withdrawal and termination of the New Service Request.

Transmission Owner Scope of Work

EKPC will construct a 69 kV Main and Transfer switching station and a new 69 kV loop-in tap from the EKPC Wayne County-Upchurch 69 kV line to accommodate the direct connection of the PD's substation facilities to the EKPC transmission system. EKPC will also construct a 69 kV disconnect switch structure which will be the POI interface.

EKPC will also complete the required network upgrades at existing EKPC substations, which are system protection changes necessary at the Wayne County and Summer Shade substations to accommodate the addition of this new facility, and installation of OPGW on the existing 69 kV line sections from the new Massingale Road switching station to the Wayne County and Summer Shade substations in order to provide necessary communications infrastructure for EKPC.

The total preliminary cost estimate for the Transmission Owner scope of work (including TOIF and Physical Interconnection Network Upgrades) is given in the table below. These costs do not include CIAC Tax Gross-up.

Network Upgrades

RTEP ID	Description	Direct		Indirect		Total Cost ($USD)	Allocated Cost ($USD)
		Labor	Materials	Labor	Materials		
n9513.0	Revise Relay Settings at Summer Shade S…	$55,000	$1,000	$6,000	$1,000	$63,000	$63,000
n9512.0	Revise Relay Settings at Wayne County S…	$55,000	$1,000	$6,000	$1,000	$63,000	$63,000
n9511.0	Loop existing Upchurch Tap - Wayne Cou…	$254,000	$244,000	$50,000	$6,000	$554,000	$554,000
n9510.0	Install new overhead optical ground wir…	$3,510,000	$1,401,000	$491,000	$55,000	$5,457,000	$5,457,000

Stand-Alone Network Upgrades							
RTEP ID	Description	Direct		Indirect		Total Cost ($USD)	Allocated Cost ($USD)
		Labor	Materials	Labor	Materials		
n9514.0	Massingale Road Substation: Construct n…	$2,987,000	$3,359,000	$634,000	$70,000	$7,050,000	$7,050,000

Transmission Owner Interconnection Facilities							
RTEP ID	Description	Direct		Indirect		Total Cost ($USD)	Allocated Cost ($USD)
		Labor	Materials	Labor	Materials		
(Pending)	One (1) 69 kV generator lead line to incl…	$378,000	$268,000	$65,000	$7,000	$718,000	$718,000

Based on the scope of work for the Interconnection Facilities, it is expected to take 25 month(s) after the signing of a Generator Interconnection Agreement (as this is a FERC connection) and construction kickoff call to complete the installation of the physical connection work. This assumes that there will be no environmental issues with any of the new properties associated with this project, that there will be no delays in acquiring the necessary permits for implementing the defined interconnection work, and that all system outages will be allowed when requested.

Note that the TO findings were made from a conceptual review of this project. A more detailed review of the connection facilities and their cost will be identified in a future study phase. Further note that the cost estimate data provided should be considered high level estimates since it was produced without a detailed engineering review. The Project Developer will be responsible for the actual cost of construction. TO herein reserves the right to return to any issues in this document and, upon appropriate justification, request additional monies to complete any reinforcements to the transmission systems.

Remote Terminal Work: During Phase 2 of the PJM interconnection process, TO’s System Protection Engineering Department will review transmission line protection as well as anti-islanding required to accommodate the new generation and interconnection substation. System Protection Engineering will determine the minimal acceptable protection requirements to reliably interconnect the proposed generating facility with the transmission system. The review is based on maintaining system reliability by reviewing TO’s protection requirements with the known transmission system configuration which includes generating facilities in the area. This review may determine that transmission line protection and communication upgrades are required at remote substations.

EKPC anticipates that it will take 25 months after the signing of the Generator Interconnection Agreement and the project kickoff call is subsequently held to complete
the physical interconnection projects. This assumes no delays due to permitting or environmental issues, and that all necessary outages can be taken as needed to maintain this schedule.

Transmission Owner Analysis

No Transmission Owner impacts identified.

Developer Requirements

The developer is responsible for all design and construction related activities on the developer’s side of the Point of Change in Ownership. EKPC interconnection requirements can be found here. Refer to AG1-471 Physical Interconnection Facilities Study for additional requirements found in the General Section of the report.

To the extent that these Applicable Technical Requirements and Standards may conflict with the terms and conditions of the Tariff, the Tariff shall control.

Revenue Metering and SCADA Requirements

PJM Requirements

The developer will be required to install equipment necessary to provide Revenue Metering (KWH, KVARH) and real time data (KW, KVAR) for their generating Resource. See PJM Manual 01, PJM Manual 14D, and PJM Tariff Part IX, Subpart B, Appendix 2, section 8.

Meteorological Data Reporting Requirement

The solar generation facility shall provide the Transmission Provider with site-specific meteorological data including:

- Temperature (degrees Fahrenheit)
- Atmospheric Pressure (hectopascals)
- Irradiance
- Forced outage data

Transmission Owner Requirements

The Project Developer will be required to comply with all interconnected Transmission Owner's revenue metering requirements located at the following link: PJM - Transmission Owner Engineering & Construction Standards and in the Physical Interconnection Facilities Study.

Summer Peak Analysis

The New Service Request was evaluated as a 52.2 MW (32.4 MW Capacity) injection in the EKPC area. Project was evaluated for compliance with applicable reliability planning criteria (PJM, NERC, NERC Regional Reliability Councils, and Transmission Owners). Potential summer peak period network impacts were as follows:

Note: The capacity portion of Generation Interconnection Requests are evaluated for single or N-1 contingencies. The full energy output of Generation Interconnection Requests are evaluated for multiple facility contingencies (double circuit tower line, fault with a stuck breaker, and bus fault).

The following flowgates remain after considering the topology reinforcements required by the cycle.

Search

Summer Peak Analysis

Area	Facility Description	Contingency Name	Contingency Type	DC|AC	Final Cycle Loading	Rating (MVA)
EKPC/LGEE	5COOPER2-5ELIHU 161.0 kV Ckt 1 line	EKPC_P4-5_LAURL S50-1024_SRT-A	Breaker	AC	117.61 %	277
EKPC/LGEE	5COOPER2-5ELIHU 161.0 kV Ckt 1 line	EKPC_P4-5_LAURL S50-1014_SRT-A	Breaker	AC	117.26 %	277
EKPC/LGEE	5COOPER2-5ELIHU 161.0 kV Ckt 1 line	EKPC_P2-2_LAUREL CO 161_SRT-A	Bus	AC	117.26 %	277
EKPC/LGEE	2SOMERSET KU-2FERGUSON SO 69.0 kV Ckt 1 line	EKPC_P7-1_COOP 161 DBL 2_SRT-A	Tower	AC	133.1 %	105
EKPC/LGEE	5COOPER2-5ELIHU 161.0 kV Ckt 1 line	EKPC_P7-1_LAURL 161 DBL_SRT-A	Tower	AC	117.62 %	277

The following flowgates were eliminated after considering the topology reinforcements required by the cycle.

(No impacts were found for this analysis)

Summer 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 an Upgrade Request into the New Service Request process.

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 an Upgrade Request, a subsequent analysis will be performed which shall study all overload conditions associated with the overloaded element(s) identified.

The following flowgates remain after considering the topology reinforcements required by the cycle.

(No impacts were found for this analysis)

The following flowgates were eliminated after considering the topology reinforcements required by the cycle.

(No impacts were found for this analysis)

Winter Peak Analysis

PJM will start performing Winter Peak analysis in Transition Cycle 2.

Winter Potential Congestion due to Local Energy Deliverability

PJM will start performing Winter Peak analysis in Transition Cycle 2.

Light Load Analysis

Light Load Analysis is Not Required.

Light Load Potential Congestion due to Local Energy Deliverability

Light Load Analysis is Not Required.

Short Circuit Analysis

The Phase III Short circuit analysis was conducted for the following two study scenarios

- Scenario 1 - TC1 Projects Impact;
- Scenario 2 - TC1 Topology-Changing Upgrade Impacts;

The starting TC1 Phase III short circuit case is an updated Phase II case that accounted for the DPII outcomes (project changes & withdrawals) and other pre-TC1 changes. The starting Phase III case was utilized for the Scenario 1 studies to determine the impact of TC1 projects without modeling any topology-changing upgrades required for TC1. To conduct the Scenario 2 studies, the required topology-changing upgrades from the latest Load Flow & Stability studies were incorporated into the Scenario 1 case and utilized for the Scenario 2 studies to determine the impact of the topology-changing upgrades on the short circuit results from Scenario 1

Based on PJM Short Circuit Analysis, this project did not contribute >1% fault duty to previously identified overduty breakers, nor did it cause any new overduty breakers.

Stability Analysis

Analysis Complete - No Issues

Executive Summary
New Service Requests (projects) in PJM Transition Cycle 1, Cluster 25 are listed in Table 1 below. This report will cover the dynamic analysis of Cluster 25 projects.
This analysis is effectively a screening study to determine whether the addition of the Cluster 25 projects will meet the dynamics requirements of the NERC, EKPC and PJM reliability standards.
The load flow scenario for the analysis was based on the RTEP 2027 summer peak load case, modified to include applicable projects. Cluster 25 projects have been dispatched online at maximum power output, and voltage schedules set to achieve near unity power factor at the high side of the main transformer.
Cluster 25 projects were tested for compliance with NERC, PJM, Transmission Owner and other applicable criteria. Steady-state condition and 133 contingencies were studied, each with a 20 second simulation time period. Studied faults included:

a) Steady-state operation (20 second run);
b) Three-phase faults with normal clearing time;
c) Single-phase bus faults with normal clearing time;
d) Single-phase faults with stuck breaker;
e) 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;
f) Single-phase faults with loss of multiple-circuit tower line.

No relevant high speed reclosing (HSR) contingencies were identified for this study.
For all simulations, the Cluster 25 projects 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 2027 peak load case:

a) Cluster 25 projects were able to ride through the faults (except for faults where protective action trips a generator(s)),

b) The system with Cluster 25 projects included is transiently stable and 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.

AG1-354 and AG1-471 meet the 0.95 leading and lagging PF requirement.

AG1-471 generator unit remained at High Voltage Ride Through mode for several contingencies. As a result, the AG1-471 generator terminal voltage remained at approximately 1.12 pu after fault recovery which exceeds the range of 0.95 pu – 1.05 pu. This issue caused the voltage relay stage set to 1.1 pu for 10 seconds to pick up and trip AG1-471 generating unit. Modifying CON(J+1): Vup to 1.16 pu of the REECA1 model resolved the issue of AG1-471 getting stuck in HVRT mode and resolved the tripping of the unit. The AG1-471 developer confirmed that the proposed settings .

No mitigations were found to be required.

Table 1: TC1 Cluster 25 Projects

Cluster	Project	Fuel Type	Transmission Owner	MFO	MWE	MWC	Point of Interconnection
25	AG1-354	Solar	EKPC	150.0	150.0	90.0	Summershade - Green County 161 kV
	AG1-471	Solar	EKPC	54.0	54.0	32.4	Up Church-Wayne County 69 kV

Reactive Power Analysis

The reactive power capability of AG1-471 meets the 0.95 leading and lagging PF requirement at the high side of the main transformer.

Steady-State Voltage Analysis

Steady State Voltage Analysis is Not Required.

New Service Request Dependencies

The New Service Requests below are listed in one or more dispatch for the overloads identified in this report. These projects contribute to the loading of the overloaded facilities identified in this report. The percent overload of a facility and cost allocation you may have towards a particular reinforcement could vary depending on the action of other projects. The status of each project at the time of the analysis is presented in the table. This list may change as other projects withdraw or modify their requests. This table is valid for load flow analyses only.

New Service Requests Dependencies		
Project ID	**Project Name**	**Status**
AE1-143	Marion County 161 kV	Engineering & Procurement
AE2-071	Patton Rd-Summer Shade 69 kV	In Service
AF1-038	Sewellton Jct-Webbs Crossroads 69 kV	Engineering & Procurement
AF1-050	Summer Shade - Green County 161 kV	Engineering & Procurement
AF1-083	Green County-Saloma 161 kV	Engineering & Procurement
AF1-203	Patton Rd-Summer Shade 69 kV	In Service
AF2-365	Munfordville KU Tap-Horse Cave Jct. 69 kV	Active
AG1-070	Bon Ayr 69 kV	Active
AG1-071	Bon Ayr 69 kV	Active
AG1-341	Summer Shade 161 kV	Active
AG1-354	Summershade-Green County 161 kV	Active
AG1-405	Walnut Grove-Asahi 69 kV	Active
AG1-406	Walnut Grove-Asahi 69 kV	Active

Affected System - PJM Identified Violations

As part of PJM's analysis, PJM evaluated the potential impacts on tie line facilities between PJM and an affected system entity, which were identified per PJM planning analysis criteria. This upgrade may be required on the affected system portion of the tie line along with cost allocation of such upgrade if applicable, in coordination with the affected system. Depending on the affected system, this project may not be contingent on upgrade based on PJM planning analysis criteria, but may be contingent on this upgrade based on the Affected System Operator's planning criteria, provided in the Affected Systems Study Section, herein.

Midcontinent Independent System Operator, Inc. (MISO)	**No Impact**
New York Independent System Operator (NYISO)	**No Impact**
Tennessee Valley Authority (TVA)	**No Impact**
Louisville Gas & Electric (LG&E)	**Identified Impacts**

AG1-471 System Reinforcements:				
TO	**Trans Owner ID**	**Title**	**Category**	**Allocated Cost ($USD)**
LGEE	LGEE_TC1_15519	Invalid - P7 contingency 69kV not monitored by LGEE	Informational	$0
LGEE	LGEE_TC1_16266	LGEE AFS Analysis has determined reinforcements are not required on the Cooper - Elihu 161kV Line.	Informational	$0
LGEE	None	LGEE Summer 219/277 MVA & winter 335/335 MVA Rate A/Rate B	Informational	$0
Grand Total:				**$0**

System Reinforcement

Type	Load Flow
TO	LGEE
RTEP ID / TO ID	(Pending) / LGEE_TC1_15519
Title	Invalid - P7 contingency 69kV not monitored by LGEE
Description	Invalid - P7 contingency 69kV not monitored by LGEE EKPC emergency rating is 143 MVA on the Somerset KU - Ferguston 69kV line.
Total Cost ($USD)	$0
Allocated Cost ($USD)	$0
Time Estimate	TBD

Note: This reinforcement is fictitious and will not be cost allocated to projects. It is listed for information purposes only.

Flowgates Addressed by this Reinforcement

	Facility	Contingency
▶	2FERGUSON SO-2SOMERSET KU 69.0 kV Ckt 1 line	(Any)
▶	2SOMERSET-2SOMERSET KU 69.0 kV Ckt 1 line	(Any)

System Reinforcement

Type	Load Flow
TO	LGEE
RTEP ID / TO ID	(Pending) / LGEE_TC1_16266
Title	LGEE AFS Analysis has determined reinforcements are not required on the Cooper - Elihu 161kV Line.
Description	LGEE Affected System Analysis has determined reinforcements are not required on the Cooper - Elihu 161kV Line. Thus EKPC existing 298 MVA Rate B is adequate as LGEE is the limiting element of the line. No reinforcements are required by EKPC.
Total Cost ($USD)	$0
Allocated Cost ($USD)	$0
Time Estimate	TBD

Note: This reinforcement is fictitious and will not be cost allocated to projects. It is listed for information purposes only.

Flowgates Addressed by this Reinforcement

	Facility	Contingency
▶	5ELIHU-5COOPER2 161.0 kV Ckt 1 line	(Any)

System Reinforcement

Type	Load Flow
TO	LGEE
RTEP ID / TO ID	(Pending)
Title	LGEE Summer 219/277 MVA & winter 335/335 MVA Rate A/Rate B
Description	LGEE Summer 219/277 MVA & winter 335/335 MVA Rate A/Rate B
Total Cost ($USD)	$0
Allocated Cost ($USD)	$0

Flowgates Addressed by this Reinforcement

	Facility	Contingency
▶	5ELIHU-5COOPER2 161.0 kV Ckt 1 line	(Any)

Time Estimate TBD

Note: This reinforcement is fictitious and will not be cost allocated to projects. It is listed for information purposes only.

Duke Energy Carolinas (DUKE)	**No Impact**
Duke Energy Progress - East (CPLE)	**No Impact**
Duke Energy Progress - West (CPLW)	**No Impact**

Affected System - Non-PJM Identified Violations

In accordance with PJM Tariff Part VII, Subpart D, section 312.A.1.b and as outlined in PJM Manual 14H, Section 13, in Phase III of the Cycle, PJM coordinates with the Affected System Operators to conduct any studies required to determine the impact of the New Service Request on any Affected System and will include the Affected System Study results in Phase III System Impact Study, if available from the Affected System Operator.

If your project required an Affected System Study, the results are shown below from the Affected System Operator.

For more details, please refer to your Affected System Study report by the Affected System Operator. If the Affected System Operator identified the need for a system reinforcement on their system due to their planning criteria, Project Developer must follow the Affected System Operator Tariff for construction of the network upgrade. PJM will list any required network upgrades identified by the Affected System Operator in the PJM Project Developer’s GIA under Schedule F.

Affected System network upgrade costs are included in the Adverse Study Impact calculation for DP3. See the Adverse Test Eligibility section of this Phase III SIS report.

Midcontinent Independent System Operator, Inc. (MISO) **Identified Impacts**

Note: This reflects the Affected System studies results provided by the Affected System Operator. These results may be subject to adjustments based on the outcome of any studies in the remaining phases of the Affected System Operator's Generator Interconnection Process.

Impacted Facility	Transmission Owner	Reinforcement	Cost	Cost Allocated to AG1-471	Scenarios
• CAP BANK 138.0 - Avon East 138.0 CKT 0	DEI	Install 28.8 MVAR cap bank at Avon East sub	$3,000,000	$5,660	• MISO Voltage

New York Independent System Operator (NYISO)	**Not required**
Tennessee Valley Authority (TVA)	**Not required**
Louisville Gas & Electric (LG&E)	**Identified Impacts**

Note: This reflects the Affected System studies results provided by the Affected System Operator. These results may be subject to adjustments based on the outcome of any studies in the remaining phases of the Affected System Operator's Generator Interconnection Process.

Impacted Facility	Transmission Owner	Reinforcement	Cost	Cost Allocated to AG1-471	Scenarios
• 2CAMPBELVL 69.0 - 2TAYLOR CO 69.0 CKT 1	LGEE	Campbellsville 2 Tap - Taylor County 69 kV Line Reconductor	$950,000	$48,325	
• 2LEBANON 69.0 - 2SPRINGFL KU 69.0 CKT 1	LGEE	Lebanon - Springfield 69 kV Line Reconductor	$16,527,000	$761,020	
• 2MOREHEAD W 69.0 - 2MOREHEAD 69.0 CKT 1	LGEE	Morehead W - Morehead 69 kV Line Reconductor	$475,000	$12,083	
• 2SHELBY CO T 69.0 - 2SHELBYVIL S 69.0 CKT 1	LGEE	Shelbyville South - Shelby Co Tap 69 kV Line MOT	$682,500	$38,730	
• 2SPRINGFL KU 69.0 - 2N SPRINGFLD 69.0 CKT 1	LGEE	Springfield - North Springfield 69 kV Line MOT	$1,134,000	$51,978	
• 4TYRONE 138.0 - 4BROWN N 1 138.0 CKT 1	LGEE	Brown North - Tyrone 138 kV Line Reconductor	$60,360,000	$4,435,068	

Duke Energy Carolinas (DUKE)	**Not required**
Duke Energy Progress - East (CPLE)	**Not required**
Duke Energy Progress - West (CPLW)	**Not required**

System Reinforcements

No cost allocated system reinforcements were identified for this project in the Phase III System Impact Study load flow analysis.

Shown below are the details of the cost allocated, contingent, eliminated, topology and potential aggregate contributor reinforcements for this project. Please refer to the System Reinforcement table above and the information below for more detail.

System Reinforcement

Type	Load Flow
TO	EKPC
RTEP ID / TO ID	(Pending) / EKPC-tc1-r0004a
Title	EKPC emergency rating is 143 MVA.
Description	EKPC emergency rating is 143 MVA. LG&E: SE rating is 105 MVA.
Total Cost ($USD)	$0
Discounted Total Cost ($USD)	$0
Allocated Cost ($USD)	$0
Time Estimate	TBD

Flowgates Addressed by this Reinforcement

	Facility	Contingency
▶	2FERGUSON SO-2SOMERSET KU 69.0 kV Ckt 1 line	(Any)

Note: This reinforcement is fictitious and will not be cost allocated to projects. It is listed for information purposes only.

System Reinforcement

Type	Load Flow
TO	EKPC
RTEP ID / TO ID	(Pending) / EKPC-tc1-r0012a
Title	LGE/KU is limiting this facility. EKPC emergency rating is 298 MVA.
Description	LGE/KU is limiting this facility (LGEE Summer 219/277 MVA & winter 335/335 MVA Rate A/Rate B). EKPC emergency rating is 298 MVA. LGEE AFS for TC1 has determined they will not require an reinforcement and thus EKPC existing 298 MVA Rate B is adequate as LGEE is the limiting element of the line.
Total Cost ($USD)	$0
Discounted Total Cost ($USD)	$0
Allocated Cost ($USD)	$0
Time Estimate	TBD

Note: This reinforcement is fictitious and will not be cost allocated to projects. It is listed for information purposes only.

Flowgates Addressed by this Reinforcement

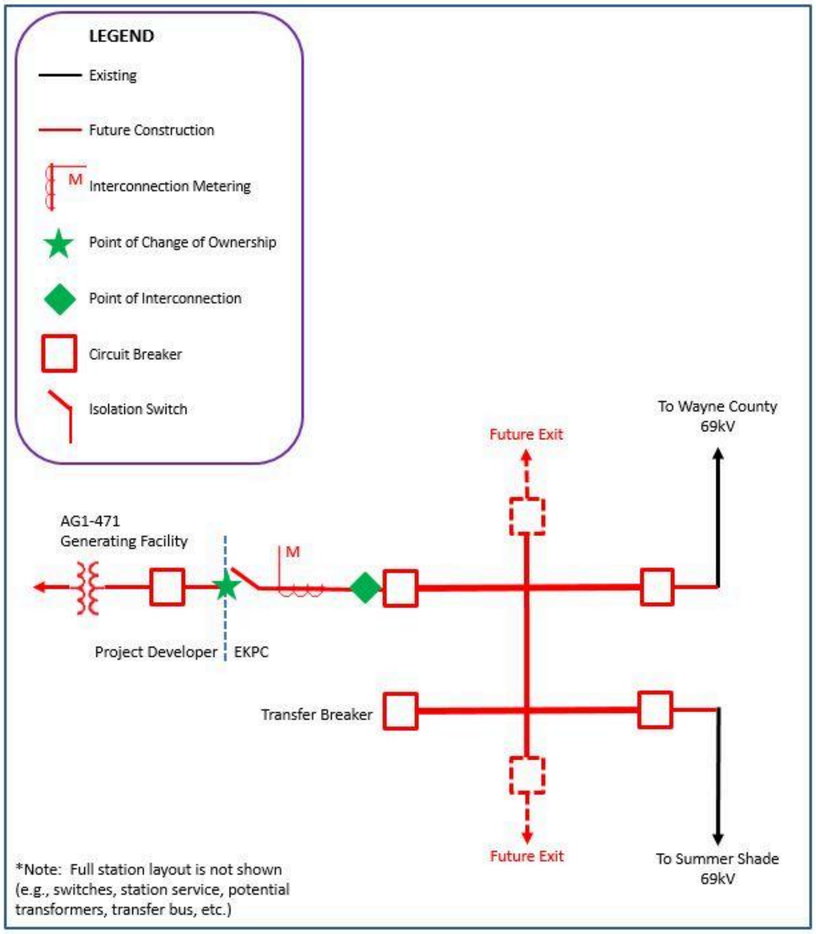
	Facility	Contingency
▶	5ELIHU-5COOPER2 161.0 kV Ckt 1 line	(Any)

Attachments

AG1-471 One Line Diagram

AG1-471 Conceptual One-Line Diagram of Interconnection Facilities

Massingale Road 69kV Switch Station



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[1] Winter load flow analysis will be performed starting in Transition Cycle 2.