



Generation Interconnection

Feasibility Study Report

for

Queue Project AF2-308

CENTRAL HARDIN-STEPHENSBURG 69 KV

28 MW Capacity / 28 MW Energy

July 2020

Table of Contents

- 1 Introduction..... 4
- 2 Preface..... 4
- 3 General 5
- 4 Point of Interconnection..... 6
- 5 Cost Summary 6
- 6 Transmission Owner Scope of Work..... 7
 - 6.1 Attachment Facilities..... 7
 - 6.2 Direct Connection Cost Estimate..... 7
 - 6.3 Non-Direct Connection Cost Estimate..... 7
- 7 Incremental Capacity Transfer Rights (ICTRs) 8
- 8 Interconnection Customer Requirements..... 8
- 9 Revenue Metering and SCADA Requirements 8
 - 9.1 PJM Requirements..... 8
 - 9.2 Meteorological Data Reporting Requirements..... 8
 - 9.3 Interconnected Transmission Owner Requirements..... 9
- 10 Summer Peak - Load Flow Analysis10
 - 10.1 Generation Deliverability11
 - 10.2 Multiple Facility Contingency11
 - 10.3 Contribution to Previously Identified Overloads.....11
 - 10.4 Potential Congestion due to Local Energy Deliverability.....11
 - 10.5 System Reinforcements - Summer Peak Load Flow - Primary POI.....12
 - 10.6 Flow Gate Details.....13
 - 10.6.1 Index 114
 - 10.6.2 Index 215
 - 10.7 Queue Dependencies16
 - 10.8 Contingency Descriptions.....17
- 11 Light Load Analysis.....18
- 12 Short Circuit Analysis.....18
- 13 Stability and Reactive Power Assessment.....18
- 14 Affected Systems18
 - 14.1 LG&E.....18

14.2	MISO	18
14.3	TVA.....	18
14.4	Duke Energy Progress.....	18

1 Introduction

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

2 Preface

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

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

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

3 General

The Interconnection Customer (IC), has proposed a Storage generating facility located in Hardin County, Kentucky. The installed facilities will have a total capability of 28 MW with 28 MW of this output being recognized by PJM as Capacity. The proposed in-service date for this project is September 01, 2023. This study does not imply a TO commitment to this in-service date.

Queue Number	AF2-308
Project Name	CENTRAL HARDIN-STEPHENSBURG 69 KV
State	Kentucky
County	Hardin
Transmission Owner	EKPC
MFO	28
MWE	28
MWC	28
Fuel	Storage
Basecase Study Year	2023

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

4 Point of Interconnection

AF2-308 will interconnect with the EKPC transmission system tapping the Central Hardin to Stephenson 69 kV line.

5 Cost Summary

The AF2-308 project will be responsible for the following costs:

Description	Total Cost
Total Physical Interconnection Costs	\$4,745,000
Total System Network Upgrade Costs	\$140,000
Total Costs	\$4,885,000

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

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

6 Transmission Owner Scope of Work

6.1 Attachment Facilities

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

	Total Cost
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 panel) at the new Long Grove Road switching station, to accept the IC generator lead line/bus (Estimated time to implement is 24 months)	\$725,000
Total Attachment Facility Costs	\$725,000

6.2 Direct Connection Cost Estimate

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

Description	Total Cost
Construct a new 69 kV switching station (Long Grove Road Switching) to facilitate connection of the IC solar generation project to the existing Central Hardin-Stephensburg 69 kV line (Estimated time to implement is 24 months)	\$2,765,000
Total Direct Connection Facility Costs	\$2,765,000

6.3 Non-Direct Connection Cost Estimate

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

Description	Total Cost
Construct facilities to loop the existing Central Hardin-Stephensburg 69 kV line into the new Long Grove Road switching station (Estimated time to implement is 24 months)	\$125,000
Modify relays and/or settings at Central Hardin substation for the existing line to the new Long Grove Road switching station (Estimated time to implement is 9 months)	\$45,000
Modify relays and/or settings at Stephensburg substation for the existing line to the new Long Grove Road switching station (Estimated time to implement is 9 months)	\$45,000
Install OPGW on the Long Grove Road-Central Hardin 69 kV line (4.15 miles) (Estimated time to implement is 15 months)	\$1,010,000
Total Non-Direct Connection Facility Costs	\$1,225,000

7 Incremental Capacity Transfer Rights (ICTRs)

Will be determined at a later study phase

8 Interconnection Customer Requirements

It is understood that the Interconnection Customer (IC) is responsible for all costs associated with this interconnection. The costs above are reimbursable to the Transmission Owner. The cost of the IC's generating plant and the costs for the line connecting the generating plant to the Point of Interconnection are not included in this report; these are assumed to be the IC's responsibility.

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

1. An Interconnection Customer entering the New Services Queue on or after October 1, 2012 with a proposed new Customer Facility that has a Maximum Facility Output equal to or greater than 100 MW shall install and maintain, at its expense, phasor measurement units (PMUs). See Section 8.5.3 of Appendix 2 to the Interconnection Service Agreement as well as section 4.3 of PJM Manual 14D for additional information.
2. The Interconnection Customer may be required to install and/or pay for metering as necessary to properly track real time output of the facility as well as installing metering which shall be used for billing purposes. See Section 8 of Appendix 2 to the Interconnection Service Agreement as well as Section 4 of PJM Manual 14D for additional information.

9 Revenue Metering and SCADA Requirements

9.1 PJM Requirements

The Interconnection Customer will be required to install equipment necessary to provide Revenue Metering (KWH, KVARH) and real time data (KW, KVAR) for IC's generating Resource. See PJM Manuals M-01 and M-14D, and PJM Tariff Section 8 of Attachment O.

9.2 Meteorological Data Reporting Requirements

Solar generation facilities shall provide the Transmission Provider with site-specific meteorological data including:

- Back Panel temperature (Fahrenheit)
- Irradiance (Watts/meter²)
- Ambient air temperature (Fahrenheit) – (Accepted, not required)

- Wind speed (meters/second) – (Accepted, not required)
- Wind direction (decimal degrees from true north) – (Accepted, not required)

9.3 Interconnected Transmission Owner Requirements

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

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

10 Summer Peak - Load Flow Analysis

The Queue Project AF2-308 was evaluated as a 28.0 MW (Capacity 28.0 MW) injection tapping the Central Hardin to Stephenson 69 kV line in the EKPC area. Project AF2-308 was evaluated for compliance with applicable reliability planning criteria (PJM, NERC, NERC Regional Reliability Councils, and Transmission Owners). Project AF2-308 was studied with a commercial probability of 53.0 %. Potential network impacts were as follows:

10.1 Generation Deliverability

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

None

10.2 Multiple Facility Contingency

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

None

10.3 Contribution to Previously Identified Overloads

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

ID	FROM BUS#	FROM BUS	kV	FROM BUS AREA	TO BUS#	TO BUS	kV	TO BUS AREA	CK T ID	CONT NAME	Type	Rating MVA	PRE PROJECT LOADIN G %	POST PROJECT LOADIN G %	AC D C	MW IMPAC T
10193085 4	34128 7	2CENT HARDIN	69. 0	EKPC	34171 3	2KARGL E	69. 0	EKPC	1	EKPC_P1- 2_CHARD - HARD138	single	98.0	116.55	128.57	DC	11.78
10023468 5	34171 3	2KARGL E	69. 0	EKPC	32451 9	2ETOW N KU	69. 0	LGEE	1	EKPC_P1- 2_CHARD - HARD138	single	76.0	131.74	147.23	DC	11.78

10.4 Potential Congestion due to Local Energy Deliverability

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

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

ID	FROM BUS#	FROM BUS	kV	FROM BUS AREA	TO BUS#	TO BUS	kV	TO BUS AREA	CK T ID	CONT NAME	Type	Rating MVA	PRE PROJECT LOADIN G %	POST PROJECT LOADIN G %	AC D C	MW IMPAC T
10193085 3	34128 7	2CENT HARDIN	69. 0	EKPC	34171 3	2KARGL E	69. 0	EKPC	1	EKPC_P1- 2_CHARD - HARD138	operation	98.0	141.4	153.42	DC	11.78
10023468 4	34171 3	2KARGL E	69. 0	EKPC	32451 9	2ETOW N KU	69. 0	LGEE	1	EKPC_P1- 2_CHARD - HARD138	operation	76.0	163.78	179.27	DC	11.78

10.5 System Reinforcements - Summer Peak Load Flow - Primary POI

ID	Idx	Facility	Upgrade Description	Cost
101930854	1	2CENT HARDIN 69.0 kV - 2KARGLE 69.0 kV Ckt 1	EKPC-r0086a (1453) : Increase the maximum operating temperature of the 556 MCM ACSR conductor in the Central Hardin-Kargle 69 kV line section to 302 degrees F (0.6 miles) Project Type : FAC Cost : \$40,000 Time Estimate : 6.0 Months	\$40,000
100234685	2	2KARGLE 69.0 kV - 2ETOWN KU 69.0 kV Ckt 1	EKPC-r0090a (1462) : Increase the maximum operating temperature of the 556 MCM ACSR conductor in the Kargle-KU Elizabethtown 69 kV line section to 302 degrees F (1.45 miles) Project Type : FAC Cost : \$100,000 Time Estimate : 9.0 Months NonPJMArea (1606) : The external (i.e. Non-PJM) Transmission Owner, LGEE, will not evaluate this violation until the impact study phase. Project Type : FAC Cost : \$0 Time Estimate : N/A Months	\$100,000
			TOTAL COST	\$140,000

10.6 Flow Gate Details

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

10.6.1 Index 1

ID	FROM BUS#	FROM BUS	FROM BUS AREA	TO BUS#	TO BUS	TO BUS AREA	CKT ID	CONT NAME	Type	Rating MVA	PRE PROJECT LOADING %	POST PROJECT LOADING %	AC DC	MW IMPACT
101930854	341287	2CENT HARDIN	EKPC	341713	2KARGLE	EKPC	1	EKPC_P1-2_CHARHARD138	single	98.0	116.55	128.57	DC	11.78

Bus #	Bus	Gendeliv MW Impact	Type	Full MW Impact
952821	J762	13.4600	PJM External (MISO)	13.4600
957961	AF2-090 C	29.7580	80/20	29.7580
959691	AF2-260 C O1	19.1730	80/20	19.1730
960171	AF2-308	11.7765	80/20	11.7765
960181	AF2-309 C	17.6648	80/20	17.6648
960741	AF2-365 C O1	1.6191	80/20	1.6191
961001	AF2-391 C O1	40.8773	80/20	40.8773
WEC	WEC	0.0438	Confirmed LTF	0.0438
CPLE	CPLE	0.0814	Confirmed LTF	0.0814
CBM-W2	CBM-W2	3.5708	Confirmed LTF	3.5708
NY	NY	0.0061	Confirmed LTF	0.0061
CBM-W1	CBM-W1	1.5387	Confirmed LTF	1.5387
TVA	TVA	0.7840	Confirmed LTF	0.7840
CBM-S2	CBM-S2	0.9768	Confirmed LTF	0.9768
CBM-S1	CBM-S1	2.8457	Confirmed LTF	2.8457
MADISON	MADISON	0.8588	Confirmed LTF	0.8588
MEC	MEC	0.4147	Confirmed LTF	0.4147
BLUEG	BLUEG	1.1024	Confirmed LTF	1.1024
TRIMBLE	TRIMBLE	0.3066	Confirmed LTF	0.3066

10.6.2 Index 2

ID	FROM BUS#	FROM BUS	FROM BUS AREA	TO BUS#	TO BUS	TO BUS AREA	CKT ID	CONT NAME	Type	Rating MVA	PRE PROJECT LOADING %	POST PROJECT LOADING %	AC DC	MW IMPACT
100234685	341713	2KARGLE	EKPC	324519	2ETOWN KU	LGEE	1	EKPC_P1- 2_CHAR- HARD138	single	76.0	131.74	147.23	DC	11.78

Bus #	Bus	Gendeliv MW Impact	Type	Full MW Impact
952821	J762	13.4600	PJM External (MISO)	13.4600
957961	AF2-090 C	29.7580	80/20	29.7580
959691	AF2-260 C O1	19.1730	80/20	19.1730
960171	AF2-308	11.7765	80/20	11.7765
960181	AF2-309 C	17.6648	80/20	17.6648
960741	AF2-365 C O1	1.6191	80/20	1.6191
961001	AF2-391 C O1	40.8773	80/20	40.8773
WEC	WEC	0.0438	Confirmed LTF	0.0438
CPLE	CPLE	0.0814	Confirmed LTF	0.0814
CBM-W2	CBM-W2	3.5708	Confirmed LTF	3.5708
NY	NY	0.0061	Confirmed LTF	0.0061
CBM-W1	CBM-W1	1.5387	Confirmed LTF	1.5387
TVA	TVA	0.7840	Confirmed LTF	0.7840
CBM-S2	CBM-S2	0.9768	Confirmed LTF	0.9768
CBM-S1	CBM-S1	2.8457	Confirmed LTF	2.8457
MADISON	MADISON	0.8588	Confirmed LTF	0.8588
MEC	MEC	0.4147	Confirmed LTF	0.4147
BLUEG	BLUEG	1.1024	Confirmed LTF	1.1024
TRIMBLE	TRIMBLE	0.3066	Confirmed LTF	0.3066

10.7 Queue Dependencies

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

Queue Number	Project Name	Status
AF2-090	Central Hardin 138 kV	Active
AF2-260	Stephensburg 69 kV	Active
AF2-308	Central Hardin-Stephensburg 69 kV	Active
AF2-309	Central Hardin-Stephensburg 69 kV	Active
AF2-365	Munfordville KU Tap-Horse Cave Jct. 69 kV	Active
AF2-391	Central Hardin 69 kV	Active
J762	MISO	MISO

10.8 Contingency Descriptions

Contingency Name	Contingency Definition
EKPC_P1-2_CHARD-HARD138	CONTINGENCY 'EKPC_P1-2_CHARD-HARD138' /* CENTRAL HARDIN - KU HARDIN OPEN BRANCH FROM BUS 324261 TO BUS 342568 CKT 1 /* 324261 4HARDN 138.00 342568 4CENT HARDIN138.00 END

11 Light Load Analysis

Light Load Studies (As applicable)

To be determined during later study phases.

12 Short Circuit Analysis

The following Breakers are overdutied:

To be determined during later study phases.

13 Stability and Reactive Power Assessment

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

To be determined during later study phases.

14 Affected Systems

14.1 LG&E

LG&E Impacts to be determined during later study phases (as applicable).

14.2 MISO

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

14.3 TVA

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

14.4 Duke Energy Progress

Duke Energy Progress Impacts to be determined during later study phases (as applicable).