Generation Interconnection

Feasibility Study Report

for

Queue Project AF2-389

POKAGON-COREY 69 KV

30 MW Capacity / 50 MW Energy

July 2020

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1 Introduction

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

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.

An Interconnection Customer 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.

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

3 General

The Interconnection Customer (IC), has proposed a Solar generating facility located in Cass County, Michigan. The installed facilities will have a total capability of 50 MW with 30 MW of this output being recognized by PJM as Capacity. The proposed in-service date for this project is October 31, 2023. This study does not imply a TO commitment to this in-service date.

Queue Number	**AF2-389**
Project Name	POKAGON-COREY 69 KV
State	Michigan
County	Cass
Transmission Owner	AEP
MFO	50
MWE	50
MWC	30
Fuel	Solar
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

AF2-389 will interconnect with the AEP transmission system via a new switching station cut into the Hospital tap switch – Stone Lake section of the Pokagon – Stone Lake 69 kV circuit.

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

Installation of the generator lead first span exiting the POI station, including the first structure outside the AEP fence, will also be included in AEP's scope. In the case where the generator lead is a single span, the structure in the customer station will be the customer's responsibility.

5 Cost Summary

The AF2-389 project will be responsible for the following costs:

Description	Total Cost
Total Physical Interconnection Costs	$9,383,000
Total System Network Upgrade Costs	$65,200
Total Costs	**$9,448,200**

The estimates provided in this report are preliminary in nature, as they were determined without the benefit of detailed engineering studies. Final estimates will require an on-site review and coordination to determine final construction requirements. In addition, Stability analysis will be completed during the Facilities Study stage. It is possible that a need for additional upgrades could be identified by these studies.

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

The total physical interconnection costs is given in the tables below:

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.

Description	Total Cost
69 kV Revenue Metering	$ 318,000
Generator lead first span exiting the POI station, including the first structure outside the fence	$ 320,000
Total Attachment Facility Costs	**$ 638,000**

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
A new three (3) circuit breaker 69 kV switching station physically configured in a breaker and half bus arrangement but operated as a ring-bus will be constructed (see Attachment 1). Installation of associated protection and control equipment, 69 kV line risers, and SCADA will be required.	$8,040,000
Total Direct Connection Facility Costs	**$8,040,000**

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
Pokagon – Stone Lake 69 kV T-Line Cut in	$615,000
Review Protection and Control Settings at the Pokagon 69 kV substation	$45,000
Review Protection and Control Settings at the Stone Lake 69 kV substation	$45,000
Total Non-Direct Connection Facility Costs	**$705,000**

7 Incremental Capacity Transfer Rights (ICTRs)

Will be determined at a later study phase

8 Schedule

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

9 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.

10 Revenue Metering and SCADA Requirements

10.1 PJM Requirements

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

10.2 Meteorological Data Reporting Requirements

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

- Back Panel temperature (Fahrenheit)
- Irradiance (Watts/meter^2)
- Ambient air temperature (Fahrenheit) – (Accepted, not required)
- Wind speed (meters/second) – (Accepted, not required)
- Wind direction (decimal degrees from true north) – (Accepted, not required)

10.3 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/

11 Summer Peak - Load Flow Analysis

The Queue Project AF2-389 was evaluated as a 50.0 MW (Capacity 30.0 MW) injection tapping the Pokagon to Corey 69 kV line in the AEP area. Project AF2-389 was evaluated for compliance with applicable reliability planning criteria (PJM, NERC, NERC Regional Reliability Councils, and Transmission Owners). Project AF2-389 was studied with a commercial probability of 53.0 %. Potential network impacts were as follows:

11.1 Generation Deliverability

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

None

11.2 Multiple Facility Contingency

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

None

11.3 Contribution to Previously Identified Overloads

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

ID	FROM BUS#	FROM BUS	kV	FROM BUS AREA	TO BUS#	TO BUS	kV	TO BUS AREA	CKT ID	CONT NAME	Type	Rating MVA	PRE PROJECT LOADING %	POST PROJECT LOADING %	AC|DC	MW IMPACT
95961999	243265	05COREY	138.0	AEP	243346	05MOTTV	138.0	AEP	1	AEP_P2-2_#9208_05KENZIE 138_2	bus	185.0	110.56	114.59	DC	7.45
95962014	243346	05MOTTV	138.0	AEP	243287	05E.ELKHART	138.0	AEP	1	AEP_P2-2_#9208_05KENZIE 138_2	bus	185.0	101.6	106.48	DC	9.02

11.4 Potential Congestion due to Local Energy Deliverability

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

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

ID	FROM BUS#	FROM BUS	kV	FROM BUS AREA	TO BUS#	TO BUS	kV	TO BUS AREA	CKT ID	CONT NAME	Type	Rating MVA	PRE PROJECT LOADING %	POST PROJECT LOADING %	AC|DC	MW IMPACT
95529298	243412	05STURGI	69.0	AEP	255331	17HOWE	69.0	NIPS	1	AEP_P1-2_#5577	operation	47.0	130.37	134.13	DC	3.92

11.5 System Reinforcements - Summer Peak Load Flow

ID	Idx	Facility	Upgrade Description	Cost
95962014	2	05MOTTV 138.0 kV - 05E.ELKHART 138.0 kV Ckt 1	AEP AEPI0031a (334) : A Sag Study will be required on the 7.8 mile section of ACSR 477 26/7 HAWK line to mitigate the overload . New Rating after the Sag Study: S/N: 185 MVA S/E: 257 MVA. Depending on the sag study results, cost for this upgrade is expected to be between $31,200 (No remediations required just sag study) and $23.4 million (complete line re-conductor/rebuild required). Time Estimate: a) Sag Study: 6-12 months b) Rebuild: The standard time required for construction differs from state to state. An approximate construction time would be 24 to 36 months after signing an interconnection agreement. Project Type : FAC Cost : $31,200 Time Estimate : 6-12 Months	$31,200
95961999	1	05COREY 138.0 kV - 05MOTTV 138.0 kV Ckt 1	AEP AEPI0030a (332) : A Sag Study will be required on the 8.5 mile section of ACSR 477 26/7 HAWK line to mitigate the overload . New Rating after the Sag Study: S/N: 185 MVA S/E: 257 MVA. Depending on the sag study results, cost for this upgrade is expected to be between $34,000 (No remediations required just sag study) and $12.75 million (complete line re-conductor/rebuild required). Time Estimate: a) Sag Study: 6-12 months b) Rebuild: The standard time required for construction differs from state to state. An approximate construction time would be 24 to 36 months after signing an interconnection agreement. Project Type : FAC Cost : $34,000 Time Estimate : 6-12 Months	$34,000
			TOTAL COST	**$65,200**

11.6 Flow Gate Details

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

11.6.1 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
95961999	243265	05COREY	AEP	243346	05MOTTV	AEP	1	AEP_P2-2_#9208_05KENZIE 138_2	bus	185.0	110.56	114.59	DC	7.45

Bus #	Bus	Gendeliv MW Impact	Type	Full MW Impact
247966	05WTRV SLR E	0.1344	Adder	0.16
936141	AD2-020 C O1	8.9811	50/50	8.9811
936142	AD2-020 E O1	5.5279	50/50	5.5279
943021	AE2-325 C	4.5486	50/50	4.5486
943022	AE2-325 E	3.0251	50/50	3.0251
944161	AF1-084 C	6.6348	50/50	6.6348
944162	AF1-084 E	3.7896	50/50	3.7896
944961	AF1-161 C	3.6272	50/50	3.6272
944962	AF1-161 E	3.6272	50/50	3.6272
945111	AF1-176 C O1	75.7804	50/50	75.7804
945112	AF1-176 E O1	70.2507	50/50	70.2507
957891	AF2-083 C O1	58.4124	50/50	58.4124
957892	AF2-083 E O1	14.6031	50/50	14.6031
960981	AF2-389 C	4.4694	50/50	4.4694
960982	AF2-389 E	2.9796	50/50	2.9796
961051	AF2-396 O1	53.2940	50/50	53.2940
WEC	WEC	0.0035	Confirmed LTF	0.0035
NEWTON	NEWTON	0.0247	Confirmed LTF	0.0247
FARMERCITY	FARMERCITY	0.0002	Confirmed LTF	0.0002
CALDERWOOD	CALDERWOOD	0.0094	Confirmed LTF	0.0094
NY	NY	0.0028	Confirmed LTF	0.0028
CBM-W1	CBM-W1	0.9883	Confirmed LTF	0.9883
PRAIRIE	PRAIRIE	0.0413	Confirmed LTF	0.0413
O-066	O-066	0.0336	Confirmed LTF	0.0336
CHEOAH	CHEOAH	0.0090	Confirmed LTF	0.0090
TILTON	TILTON	0.0176	Confirmed LTF	0.0176
G-007	G-007	0.0062	Confirmed LTF	0.0062
MADISON	MADISON	0.0645	Confirmed LTF	0.0645
GIBSON	GIBSON	0.0191	Confirmed LTF	0.0191
BLUEG	BLUEG	0.0538	Confirmed LTF	0.0538
TRIMBLE	TRIMBLE	0.0173	Confirmed LTF	0.0173
CATAWBA	CATAWBA	0.0056	Confirmed LTF	0.0056

11.6.2 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
95962014	243346	05MOTTV	AEP	243287	05E.ELKHART	AEP	1	AEP_P2-2_#9208_05KENZIE 138_2	bus	185.0	101.6	106.48	DC	9.02

Bus #	Bus	Gendeliv MW Impact	Type	Full MW Impact
246536	05MOTTVILL	0.1632	50/50	0.1632
247966	05WTRV SLR E	0.1488	Adder	0.18
936141	AD2-020 C O1	9.9195	50/50	9.9195
936142	AD2-020 E O1	6.1055	50/50	6.1055
943021	AE2-325 C	5.0238	50/50	5.0238
943022	AE2-325 E	3.3412	50/50	3.3412
944161	AF1-084 C	7.4355	50/50	7.4355
944162	AF1-084 E	4.2469	50/50	4.2469
944961	AF1-161 C	4.0062	50/50	4.0062
944962	AF1-161 E	4.0062	50/50	4.0062
945111	AF1-176 C O1	80.2297	50/50	80.2297
945112	AF1-176 E O1	74.3753	50/50	74.3753
957891	AF2-083 C O1	61.8420	50/50	61.8420
957892	AF2-083 E O1	15.4605	50/50	15.4605
960981	AF2-389 C	5.4108	50/50	5.4108
960982	AF2-389 E	3.6072	50/50	3.6072
961051	AF2-396 O1	58.3080	50/50	58.3080
NEWTON	NEWTON	0.0408	Confirmed LTF	0.0408
FARMERCITY	FARMERCITY	0.0013	Confirmed LTF	0.0013
CALDERWOOD	CALDERWOOD	0.0119	Confirmed LTF	0.0119
CBM-W1	CBM-W1	1.0258	Confirmed LTF	1.0258
PRAIRIE	PRAIRIE	0.0801	Confirmed LTF	0.0801
CHEOAH	CHEOAH	0.0120	Confirmed LTF	0.0120
EDWARDS	EDWARDS	0.0063	Confirmed LTF	0.0063
TILTON	TILTON	0.0283	Confirmed LTF	0.0283
MADISON	MADISON	0.0302	Confirmed LTF	0.0302
GIBSON	GIBSON	0.0251	Confirmed LTF	0.0251
BLUEG	BLUEG	0.0677	Confirmed LTF	0.0677
TRIMBLE	TRIMBLE	0.0217	Confirmed LTF	0.0217
CATAWBA	CATAWBA	0.0063	Confirmed LTF	0.0063

11.7 Queue Dependencies

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

Queue Number	Project Name	Status
AD2-020	Valley 138 kV	Active
AE2-325	Valley 138 kV	Active
AF1-084	East Hartford-Murch 69 kV	Active
AF1-161	Valley 138 kV	Active
AF1-176	Corey 138 kV	Active
AF2-083	Ed Lowe-Kenzie Creek 138 kV	Active
AF2-389	Pokagon-Corey 69 kV	Active
AF2-396	Stinger 138 kV	Active

11.8 Contingency Descriptions

Contingency Name	Contingency Definition
AEP_P2-2_#9208_05KENZIE 138_2	CONTINGENCY 'AEP_P2-2_#9208_05KENZIE 138_2' OPEN BRANCH FROM BUS 957890 TO BUS 243322 CKT 1 / 957890 AF2-083 TAP 138 243322 05KENZIE 138 1 END
AEP_P1-2_#5577	CONTINGENCY 'AEP_P1-2_#5577' OPEN BRANCH FROM BUS 243287 TO BUS 243346 CKT 1 / 243287 05E.ELKHART 138 243346 05MOTTV 138 1 END

12 Light Load Analysis

Light Load Studies (As applicable)

Not applicable

13 Short Circuit Analysis

The following Breakers are overdutied:

To be determined during later study phases.

14 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.

15 Affected Systems

15.1 TVA

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

15.2 Duke Energy Progress

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

15.3 MISO

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

15.4 LG&E

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