# Generation Interconnection

# Feasibility Study Report

# for

# Queue Project AF1-162

# INEZ 138 KV

# 60 MW Capacity / 100 MW Energy

January, 2020

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# 1 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.

PJM utilizes manufacturer models to ensure the performance of turbines is properly captured during the simulations performed for stability verification and, where applicable, for compliance with low voltage ride through requirements. Turbine manufacturers provide such models to their customers. The list of manufacturer models PJM has already validated is contained in Attachment B of Manual 14G. Manufacturer models may be updated from time to time, for various reasons such as to reflect changes to the control systems or to more accurately represent the capabilities turbines and controls which are currently available in the field. Additionally, as new turbine models are developed, turbine manufacturers provide such new models which must be used in the conduct of these studies. PJM needs adequate time to evaluate the new models in order to reduce delays to the System Impact Study process timeline for the Interconnection Customer as well as other Interconnection Customers in the study group. Therefore, PJM will require that any Interconnection Customer with a new manufacturer model must supply that model to PJM, along with a $10,000 fully refundable deposit, no later than three (3) months prior to the starting date of the System Impact Study (See Section 4.3 for starting dates) for the Interconnection Request which shall specify the use of the new model. The Interconnection Customer will be required to submit a completed dynamic model study request form (Attachment B-1 of Manual 14G) in order to document the request for the study.

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.

## 2 General

The Interconnection Customer (IC), has proposed a Storage facility located in Martin County, Kentucky. The installed facilities will have a MFO capability of 100 MW with 60 of new request MW of this output being recognized by PJM as capacity. The  storage facility will be capable of charging from the grid. Note that this project is an increase to the Interconnection Customer's AF1-130 project, which will share the generator lead and Point of Interconnection. The combined MFO will be 300 MW, with the combined Capacity of 193.9 MW. The conduct of light load analysis as required under the PJM planning process is not performed during the Generation Interconnection Feasibility Study phase of the PJM study process.  Additional reinforcement requirements for this Interconnection Request may be defined during the conduct of the light load analysis which shall be performed following execution of the System Impact Study agreement.

| **Queue Number** | **AF1-162** |
|---|---|
| **Project Name** | INEZ 138 KV |
| **State** | Kentucky |
| **County** | Martin |
| **Transmission Owner** | AEP |
| **MFO** | 300 |
| **MWE** | 100 |
| **MWC** | 60 |
| **Fuel** | Storage |
| **Basecase Study Year** | 2023 |

## 2.1 Point of Interconnection

AF1-162 will interconnect with the AEP transmission system via a direct connection to the Inez 138 kV station utilizing the same generation lead as previous queue position AF1-130.

Note: It is assumed that the 138 kV revenue metering system, gen lead and Protection & Control Equipment that will be installed for #AF1-130 will be adequate for the additional generation requested in AF1-162. Depending on the timing of the completion of the AF1-130 interconnection construction relative to the AF1-162 completion, there may (or may not) be a need to review and revise relay settings for the increased generation of AF1-162.

An Alternate Point of Interconnection was not studied.

## 2.2 Cost Summary

The AF1-162 project will be responsible for the following costs:

| Description | Total Cost |
|---|---|
| **Attachment Facilities** | $0 |
| **Direct Connection Network Upgrade** | $0 |
| **Non Direct Connection Network Upgrades** | $0 |
| **Total Costs** | $0 |

In addition, the AF1-162 project may be responsible for a contribution to the following costs

| Description | Total Cost |
|---|---|
| **System Upgrades** | $0 |

Cost allocations for these upgrades will be provided in the System Impact Study Report.

# 3 Transmission Owner Scope of Work

# 4 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 |
|---|---|
| | $0 |
| **Total Attachment Facility Costs** | $0 |

# 5 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 |
|---|---|
| | $0 |
| **Total Direct Connection Facility Costs** | $0 |

# 6 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 |
|---|---|
| | $0 |
| **Total Non-Direct Connection Facility Costs** | $0 |

# 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 Agreement execution.

# 9 Interconnection Customer Requirements

It is understood that the Interconnection Customer is responsible for all costs associated with this interconnection. The costs above are reimbursable to AEP. The cost of the Interconnection Customer's generating plant and the costs for the line connecting the generating plant to the Inez 138 kV station are not included in this report; these are assumed to be the Interconnection Customer 's responsibility.

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

In addition, if the Interconnection Customer considers use of the Option to Build, they should consult the guidance AEP has posted at:
https://www.aep.com/assets/docs/requiredpostings/TransmissionStudies/docs/2019/MerchantGenerationGuidelinesPJMoptiontoBuild.pdf

# 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 AEP Requirements

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

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

## 11 Network Impacts

The Queue Project AF1-162 was evaluated as a 100.0 MW (Capacity 60.0 MW) injection at the Inez 138 kV substation in the AEP area. Project AF1-162 was evaluated for compliance with applicable reliability planning criteria (PJM, NERC, NERC Regional Reliability Councils, and Transmission Owners). Project AF1-162 was studied with a commercial probability of 0.53. Potential network impacts were as follows:

# Summer Peak Load Flow

## 12 Generation Deliverability

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

None

## 13 Multiple Facility Contingency

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

None

## 14 Contribution to Previously Identified Overloads

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

None

## 15 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.

None

## 16 Flow Gate Details

The following appendices contain additional information about each flowgate presented in the body of the report. For each appendix, a description of the flowgate and its contingency was included for convenience. However, the intent of the appendix section is to provide more information on which projects/generators have contributions to the flowgate in question. Although this information is not used "as is" for cost allocation purposes, it can be used to gage other generators impact. It should be noted the generator contributions presented in the appendices sections are full contributions, whereas in the body of the report, those contributions take into consideration the commercial probability of each project.

# Affected Systems

# 17 Affected Systems

## 17.1 LG&E

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

## 17.2 MISO

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

## 17.3 TVA

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

## 17.4 Duke Energy Progress

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

## 17.5 NYISO

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

# Short Circuit

## 18 Short Circuit

The following Breakers are overduty

None