Generation Interconnection System Impact Study Report

For

PJM Generation Interconnection Request Queue Position AC2-142

Yukon-Hatfield 500 kV

(Revised)

April 2018

Preface

The intent of the System Impact Study is to determine a plan, with approximate cost and construction time estimates, to connect the subject generation interconnection project to the PJM network at a location specified by the Interconnection Customer. As a requirement for interconnection, the Interconnection Customer may be responsible for the cost of constructing: Network Upgrades, which are facility additions, or upgrades to existing facilities, that are needed to maintain the reliability of the PJM system. All facilities required for interconnection of a generation interconnection project must be designed to meet the technical specifications (on PJM web site) for the appropriate transmission owner.

In some instances an Interconnection Customer may not be responsible for 100% of the identified network upgrade cost because other transmission network uses, e.g. another generation interconnection or merchant transmission upgrade, may also contribute to the need for the same network reinforcement. 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 System Impact Study is performed.

The System Impact 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.

General

Hill Top Energy Center, LLC ("Interconnection Customer") has proposed an incremental increase (uprate) to prior queue projects AA2-173 and AB1-112 consisting of natural gas, 1x1 single shaft combined cycle generating facility located on Thomas Road in Nemacolin, Green County, PA 15351. The increased capability associated with queue position AC2-142 is achieved by using two machines on a single shaft instead of two individual steam and gas turbines. The following table shows the incremental contributions of each unit to the Maximum Facility Output (MFO):

	Queue No.	**CT1 Unit**	**ST Unit**	**Total MW**
	AA2-173	336.8	178.2	515
	AB1-112	0	20	20
	AC2-142	129.7 (Single shaft)		129.7
Total MFO MW				664.7

The installed facilities will have a total capability of 664.7 MW (MFO) with 664.7 MW of this output being recognized by PJM as Capacity Interconnection Rights (CIR). The proposed in-service date for this project is April 1, 2020. **This study does not imply a West Penn Power Company ("Transmission Owner") commitment to this in-service date.**

Point of Interconnection

This project will deliver power to the West Penn transmission system by direct injection into Hatfield substation. Please refer to Appendix 2 for a one line diagram of this interconnection.

Cost Summary and Transmission Owner's Scope of Work

There is no additional network upgrade costs associated with this AC2-142 uprate project. All attachment facilities and network upgrades necessary to support the Frostburg 138 kV project (Mason Dixon LLC) and their associated costs are shown in the AA2-173 and AB1-112 facilities study report which is published on PJM website at this link:

http://www.pjm.com/pub/planning/project-queues/facilities/aa2173_fac.pdf

For convenience, the links for the system impact study reports of both projects are shown in the following table:

Queue No.	**Link at PJM website**
AA2-173	http://www.pjm.com/pub/planning/project-queues/impact_studies/aa2173_imp.pdf
AB1-112	http://www.pjm.com/pub/planning/project-queues/impact_studies/ab1112_imp.pdf

Interconnection Customer Requirements

In addition to the West Penn Power facilities, Interconnection Customer is responsible for meeting all criteria as specified in the applicable sections of the "FirstEnergy Requirements for Transmission Connected Facilities" document, effective October 3, 2016, which can be found at this link: http://www.pjm.com/-/media/planning/plan-standards/private-fe/fcr-facilities-connection-requirements.ashx?la=en. Since this is an increase in output to the existing queue request AA2-173/AB1-112, all Interconnection Customer's requirements stated in the AA2-173 and AB1-112 System Impact Reports, Facilities Studies Reports and Agreements, shall apply to this AC2-142 queue project.

Revenue Metering and SCADA Requirements

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 Interconnection Customer's generating Resource. See PJM Manuals M-01 and M-14D, and PJM Tariff Sections 24.1 and 24.2.

FirstEnergy Requirements

The Interconnection Customer will be required to comply with all FirstEnergy Revenue Metering Requirements for Generation Interconnection Customers. The Revenue Metering Requirements

may be found within the “FirstEnergy Requirements for Transmission Connected Facilities” document located at the following links:

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

Network Impacts

The Queue Project AC2-142 was evaluated as a 129.7 MW (Capacity 129.7 MW) injection into the Hatfield 500 kV substation in the APS area. Project AC2-142 was evaluated for compliance with applicable reliability planning criteria (PJM, NERC, NERC Regional Reliability Councils, and Transmission Owners). Project AC2-142 was studied with a commercial probability of 100%. Potential network impacts were as follows:

Summer Peak Analysis - 2020

Generator Deliverability

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

None

Multiple Facility Contingency

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

None

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

Steady-State Voltage Requirements

None

Short Circuit

None

Affected System Analysis & Mitigation

NYISO Impacts:

None

Delivery of Energy Portion of Interconnection Request
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.
Only the most severely overloaded conditions are listed. 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 will study all overload conditions associated with the overloaded element(s) identified.

Not Applicable

Light Load Analysis - 2020

Light Load Studies to be conducted during later study phases (as required by PJM Manual 14B).

System Reinforcements

Short Circuit

None

Stability and Reactive Power Requirement

Mitigation is not required.

Please Note: The system stability study for the AC2-142 revealed several criteria are being not met during outages of the 500 kV lines. New operational procedures are recommended to alleviate instabilities of maintenance outages. Please refer to Appendix 3 for Dynamic Simulation Analysis Report. A summary of recommended operational procedures is provided under Section "Summary Results" of said report.

Please Note: AA2-173/AB1-112 system stability report can be found in its facilities study report.

Summer Peak Load Flow Analysis Reinforcements

New System Reinforcements
(Upgrades required to mitigate reliability criteria violations, i.e. Network Impacts, initially caused by the addition of this project generation)

None

Contribution to Previously Identified System Reinforcements
(Overloads initially caused by prior Queue positions with additional contribution to overloading by this project. This project may have a % allocation cost responsibility which will be calculated and reported for the Impact Study)

None

Light Load Load Flow Analysis Reinforcements

New System Reinforcements
(Upgrades required to mitigate reliability criteria violations, i.e. Network Impacts, initially caused by the addition of this project generation)

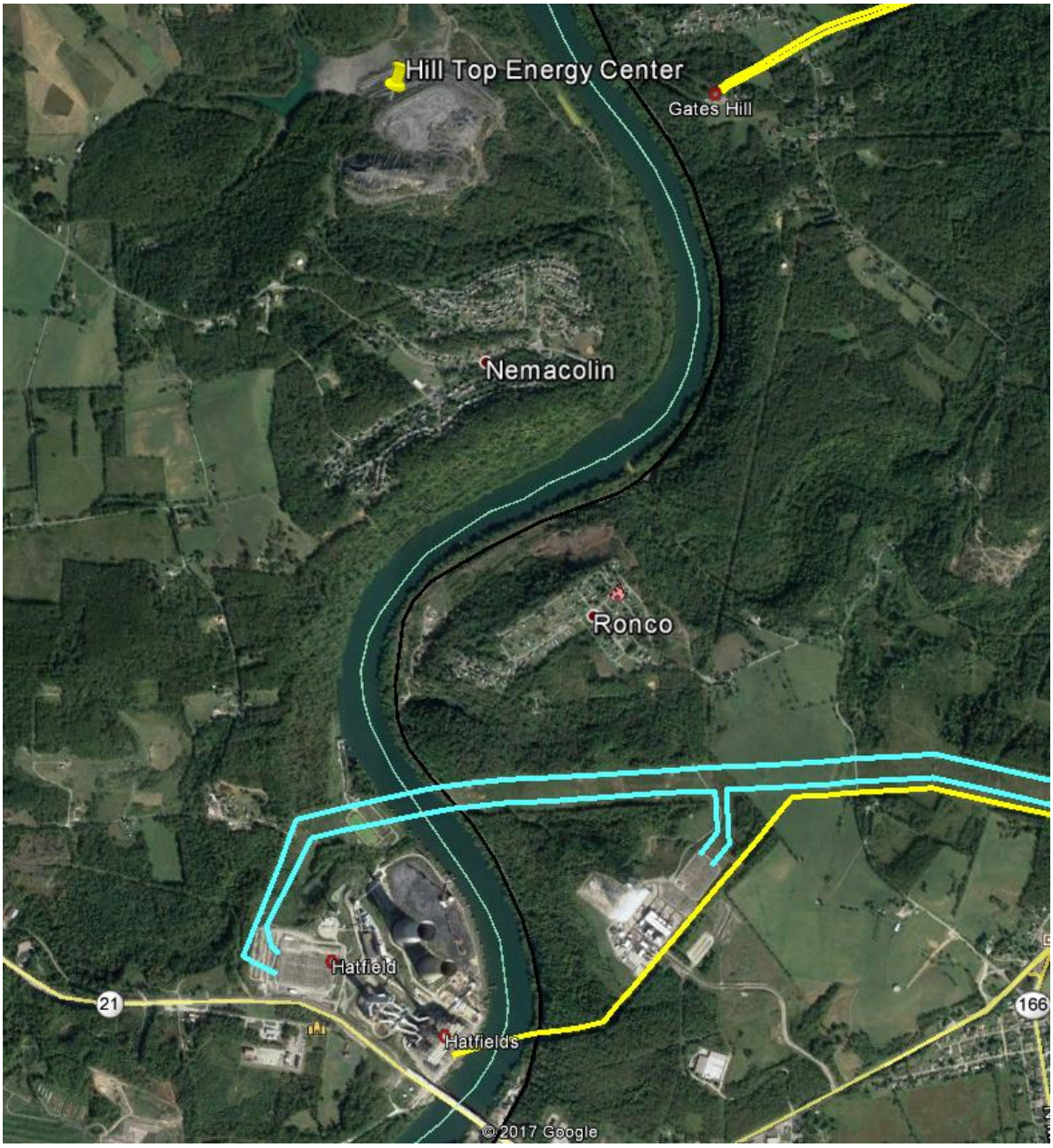
None

Contribution to Previously Identified System Reinforcements
(Overloads initially caused by prior Queue positions with additional contribution to overloading by this project. This project may have a % allocation cost responsibility which will be calculated and reported for the Impact Study)

None

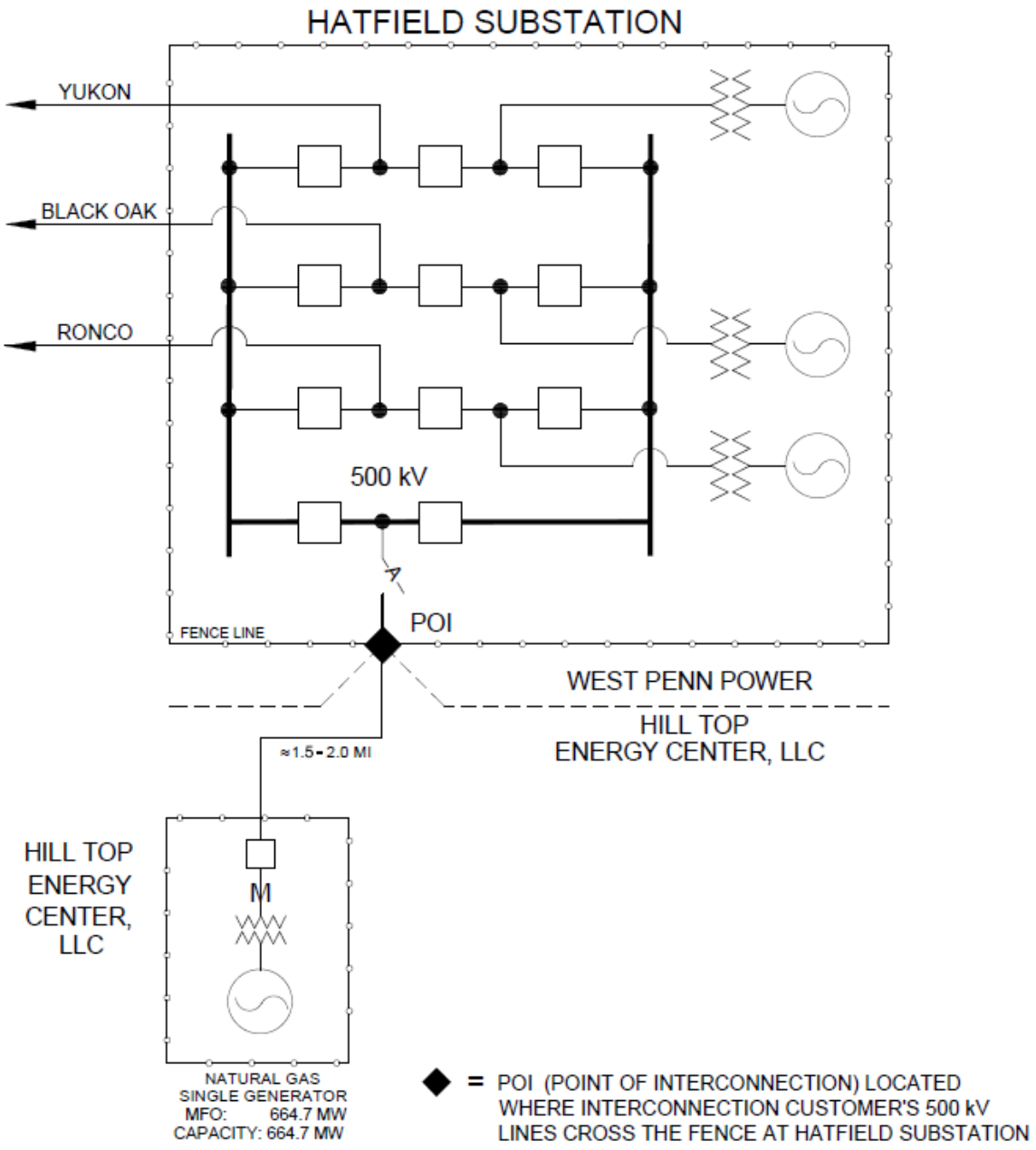
Appendix 1

Facility Location
PJM Queue Position: AC2-142



Appendix 2

Interconnection One-Line Diagram
PJM Queue Position: AC2-142



Appendix 3

Dynamic Simulation Analysis (Stability Study)
PJM Queue Position: AC2-142

Executive Summary

Generator Interconnection Request AC2-142 is for an increase in energy injection capability of the existing natural gas fueled interconnection requests AA2-173/AB1-112. The uprate increases the Maximum Facility Output (MFO) of the existing plant from 535 MW to 664.7 MW. AC2-142 consists of single-shaft 1x1 combined cycle generator with a Point of Interconnection (POI) at the Hatfield 500 kV Substation, in the Allegheny Power (APS) transmission system, Greene County, Pennsylvania.

This report describes a dynamic simulation analysis of AC2-142 as part of the overall system impact study.

The load flow scenarios for the analysis were based on the RTEP 2020 light load case, modified to include applicable queue projects. AC2-142 was dispatched at maximum power output, leading power factor and less than 1.0 pu voltage at the generator terminals.

AC2-142 was tested for compliance with NERC, PJM and other applicable criteria. 45 contingencies were studied, each with a 10 second simulation time period. Studied scenarios included:

a) Steady state operation;

b) Three-phase faults with normal clearing time on the intact network;

c) Single-phase faults with delayed clearing due to a stuck breaker;

d) 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.

For all simulations, the queue project 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.

The results indicate that for all contingencies tested on the RTEP 2020 light load case:

a) Post-contingency oscillations were positively damped with a damping margin of at least 3%

b) The AC2-142 generator was able to ride through all faults (except for faults where protective action trips a generator(s)).

c) Following fault clearing, all bus voltages recover to a minimum of 0.7 per unit after 2.5 seconds (except where protective action isolates that bus).

Appendix 3 (Continued)
Dynamic Simulation Analysis (Stability Study)
PJM Queue Position: AC2-142

d) No transmission element trips, other than those either directly connected or designed to trip as a consequence of that fault.

When using standard contingency trip times, AC1-097 was tripping offline due to excessive angle deviation for contingencies 1B.07 and 1B.08. The TO informed the PJM that clearing times could be reduced for the purpose of the study and the tripping was no longer observed.

AC1-097 was tripping offline due to excessive angle deviation for contingencies 1D.01 and 1D.04. The TO informed PJM that redundant relays were in operation on the faulted lines, rendering the contingencies unnecessary for the purpose of this study.

The stability criteria was not met for any of the four maintenance outage contingencies (with a single Ronco unit offline as per the current operational mitigation for these outages) tested on the RTEP 2020 light load case, with results showing,

- AC1-021 units, AC1-097, AC2-142 units and Ronco Units unstable for the P6 contingency MB.P1.18.
- AC1-021 units, AC1-097, AC2-142 units and Ronco Units unstable for the contingency MB.P4.10.
- AC1-021 units, AC1-097, AC2-142 units and Ronco Units unstable for the contingency MB.P4.11.

New operational mitigation for these outages has been proposed which is to reduce AC1-021 generation dispatch by 170 MW, AC1-097 by 839 MW, AC2-142 by 130MW, and open Ft.Martin-FL-8 breaker.

Mitigation was not required.

Appendix 3 (Continued)

Dynamic Simulation Analysis (Stability Study)
PJM Queue Position: AC2-142

1. Introduction

Generator Interconnection Request AC2-142 is for an increase in energy injection capability of the existing natural gas fueled interconnection requests AA2-173/AB1-112. The uprate increases the Maximum Facility Output (MFO) of the existing plant from 535 MW to 664.7 MW. AC2-142 consists of single-shaft 1x1 combined cycle generator with a Point of Interconnection (POI) at the Hatfield 500 kV Substation, in the Allegheny Power (APS) transmission system, Greene County, Pennsylvania.

This analysis is effectively a screening study to determine whether the addition of AC2-142 will meet the dynamics requirements of the NERC and PJM reliability standards.

In this report the AC2-142 project and how it is proposed to be connected to the grid are first described, followed by a description of how the project is modeled in this study. The fault cases are then described and analyzed, and lastly a discussion of the results is provided.

Appendix 3 (Continued)

Dynamic Simulation Analysis (Stability Study)
PJM Queue Position: AC2-142

2. Description of the Project

Generator Interconnection Request AC2-142 is for an increase in energy injection capability of the existing natural gas fueled interconnection requests AA2-173/AB1-112. The uprate increases the Maximum Facility Output (MFO) of the existing plant from 535 MW to 664.7 MW. AC2-142 consists of single-shaft 1x1 combined cycle generator with a Point of Interconnection (POI) at the Hatfield 500 kV Substation, in the Allegheny Power (APS) transmission system, Greene County, Pennsylvania.

Figure 1 shows the simplified one-line diagram of the AC2-142 loadflow model. Table 1 lists the parameters given in the impact study data and the corresponding parameters of the AC2-142 loadflow model.

The dynamic models for AC2-142 plant are based on standard PSS/E models supplied by PJM, as indicated by the Developer in the System Impact Study Data Form.

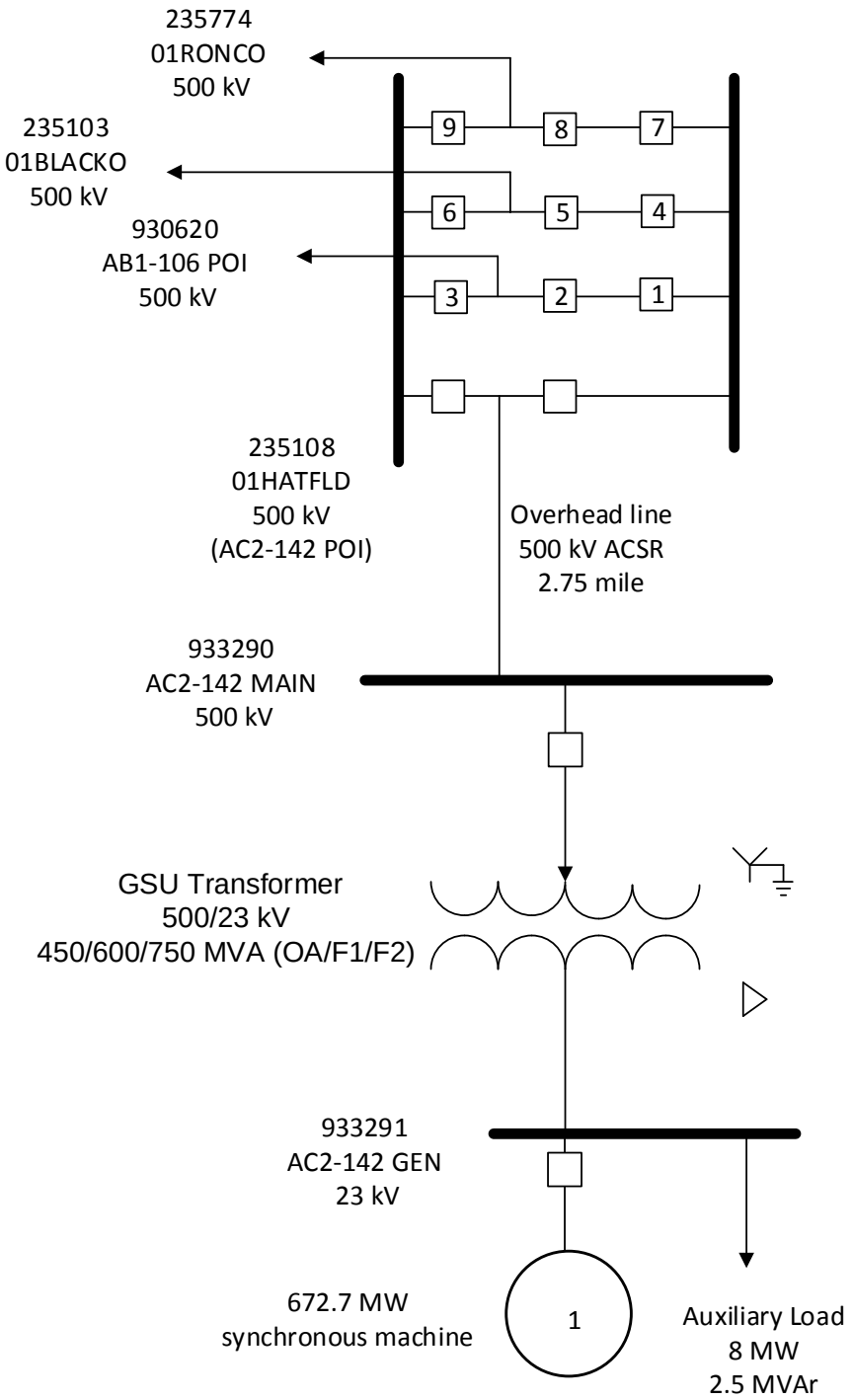
Table 1: Previous Queue Project Uprate Changes (MW)

Interconnection Request	MFO Increase (MW)	Interconnection Request Details
AA2-173	515	Original request
AB1-112 Increase	20	N/A
AC2-142 Increase	129.7	Increased capability is achieved by changing the 1x1 combined cycle power plant configuration to single shaft arrangement consisting of 1 x gas turbine plus 1 x steam turbine generators[1]
Total	664.7	

[1] Per AC2-142 Feasibility study report

Appendix 3 (Continued)

Dynamic Simulation Analysis (Stability Study)
PJM Queue Position: AC2-142



Appendix 3 (Continued)

Dynamic Simulation Analysis (Stability Study)
PJM Queue Position: AC2-142

	Impact Study Data	Model
Combined CT and ST	1 × 672.7 MW combined cycle generator. MVA base = 760 MVA Vt = 23 kV Unsaturated sub-transient reactance = 0.22 pu @ MVA base	1 x 672.7 MW combined cycle generator Pgen 672.7 MW Pmax 672.7 MW Pmin 0 MW Qmax 324.4 MVAr Qmin -221.0 MVAr Mbase 760 MVA Zsource 0.0036 + j0.22 pu @ Mbase
GSU Transformer	1 x 500/23 kV YNd two winding transformer Rating = 450/600/750 MVA (OA/F1/F2) Transformer base = 450 MVA Impedance = 0.0018 + j 0.09 pu @ 450 MVA Number of taps = 5 Tap step size = 2.5%	1 x 500/23 kV YNd two winding transformer Rating = 450/600/750 MVA (OA/F1/F2) Transformer base = 450 MVA Impedance = 0.0018 + j 0.09 pu @ 450 MVA Number of taps = 5 Tap step size = 2.5%
Auxiliary Load	8 MW + 2.5 MVAr Connected to low voltage side of the GSU	8 MW + 2.5 MVAr Connected to low voltage side of the GSU
Transmission Line	2.75 miles at 500 kV Total positive sequence impedance: 0.00004 + j0.00074 pu @ 100 MVA Total positive sequence charging susceptance: 0.0526 pu @ 100 MVA	2.75 miles at 500 kV Total positive sequence impedance: 0.00004 + j0.00074 pu @ 100 MVA Total positive sequence charging susceptance: 0.0526 pu @ 100 MVA

Appendix 3 (Continued)

Dynamic Simulation Analysis (Stability Study)
PJM Queue Position: AC2-142

3. Loadflow and Dynamics Case Setup

The dynamics simulation analysis was carried out using PSS/E Version 33.7.0.

The load flow scenarios and fault cases for this study were based on PJM's Regional Transmission Planning Process[1] and discussions with PJM.

The selected load flow scenarios was the RTEP 2020 light load case with the following modifications:

a) Addition of all applicable queue projects prior to AC2-142.

b) Addition of AC2-142 queue project.

c) Removal of withdrawn and subsequent queue projects in the vicinity of AC2-142.

d) Dispatch of units in the PJM system in order to maintain slack generators within limits.

Generation within the PJM500 system (area 225 in the PSS/E case) and within the vicinity of AC2-142 was dispatched online at maximum output (PMAX). The dispatch within the First Energy area is given in Attachment 5.

The AC2-142 initial conditions are listed in Table 2, indicating maximum power output and leading power factor.

Table 2: AC1-051 initial conditions

Bus	Name	Unit	PGEN (MW)	QGEN (MVar)	ETERM (pu)	POI Voltage (pu)
930681	AC2-142 GEN 23.000	1	672.7	33.6	1.0	1.05

[1] Manual 14B: PJM Region Transmission Planning Process, Rev 33, May 5 2016, Attachment G : PJM Stability, Short Circuit, and Special RTEP Practices and Procedures.

Appendix 3 (Continued)

Dynamic Simulation Analysis (Stability Study)
PJM Queue Position: AC2-142

4. Fault Cases

AC2-142 was tested for compliance with NERC, PJM and other applicable criteria. 46 contingencies were studied, each with a 10 second simulation time period. Table 2 to Table 6 list the contingencies that were studied which include:

a) Steady state operation;

b) Three-phase faults with normal clearing time on the intact network;

c) Single-phase faults with delayed clearing due to a stuck breaker;

d) Single-phase faults with delayed clearing (Zone 2) at line end closest to AC2-142 POI;

Buses at which the faults listed above were applied are:

- Hatfield 500 kV (POI)
- Ronco 500 kV
- Rhodes Land 500 kV
- Yukon 500 kV

Clearing times for contingencies 1B.07 and 1B.08 were as per instructions from the TO, with the remaining clearing times listed as per revision 19 of *2016 Revised Clearing times for each PJM company* spreadsheet and as per PJM instruction.

For all simulations, the queue projects under study, along with the rest of the PJM system, were required to ride through the fault, with all states returning to an acceptable new condition following the disturbance.

Appendix 3 (Continued)

Dynamic Simulation Analysis (Stability Study)
PJM Queue Position: AC2-142

5. Evaluation Criteria

This study is focused on AC2-142, along with the rest of the PJM system, maintaining synchronism and having all states return to an acceptable new condition following the disturbance. The recovery criteria applicable to this study are as per PJM's Regional Transmission Planning Process:

a) The system with AC2-142 included is transiently stable with post-contingency oscillations positively damped with a margin of at least 3%.

b) The AC2-142 generators are able to ride through the faults (except for faults where protective action trips a generator(s)).

c) Following fault clearing, all bus voltages recover to a minimum of 0.7 per unit after 2.5 seconds (except where protective action isolates that bus).

d) No transmission element trips, other than those either directly connected or designed to trip as a consequence of that fault.

Appendix 3 (Continued)

Dynamic Simulation Analysis (Stability Study)
PJM Queue Position: AC2-142

6. Summary of Results

Plots from the dynamic simulations are provided in Attachment 6, with results summarized in Table 3 to Table 6.

The results indicate that for the 45 fault contingencies tested on the 2020 light load case:

a) Post-contingency oscillations were positively damped with a damping margin of at least 3%

b) The AC1-097 generator was able to ride through all faults (except for faults where protective action trips a generator(s)).

c) Following fault clearing, all bus voltages recover to a minimum of 0.7 per unit after 2.5 seconds (except where protective action isolates that bus).

d) No transmission element trips, other than those either directly connected or designed to trip as a consequence of that fault.

When using standard contingency trip times, AC1-097 was tripping offline due to excessive angle deviation for contingencies 1B.07 and 1B.08. The Transmission Owner informed the PJM that clearing times could be reduced for the purpose of the study and the tripping was no longer observed.

AC2-142 was tripping offline due to excessive angle deviation for contingencies 1D.01 and 1D.04. The Transmission Owner informed PJM that redundant relays were in operation on the faulted lines, rendering the contingencies unnecessary for the purpose of this study.

The stability criteria was not met for any of the four maintenance outage contingencies (with a single Ronco unit offline as per the current operational mitigation for these outages) tested on the RTEP 2020 light load case, with results showing,

- AC1-021 units, AC1-097, AC2-142 units and Ronco Units unstable for the P6 contingency MB.P1.18.
- AC1-021 units, AC1-097, AC2-142 units and Ronco Units unstable for the contingency MB.P4.10.
- AC1-021 units, AC1-097, AC2-142 units and Ronco Units unstable for the contingency MB.P4.11.

New operational mitigation for these outages has been proposed which is to reduce AC1-021 generation dispatch by 170 MW, AC1-097 by 839 MW, AC2-142 by 130MW, and open Ft.Martin-FL-8 breaker.

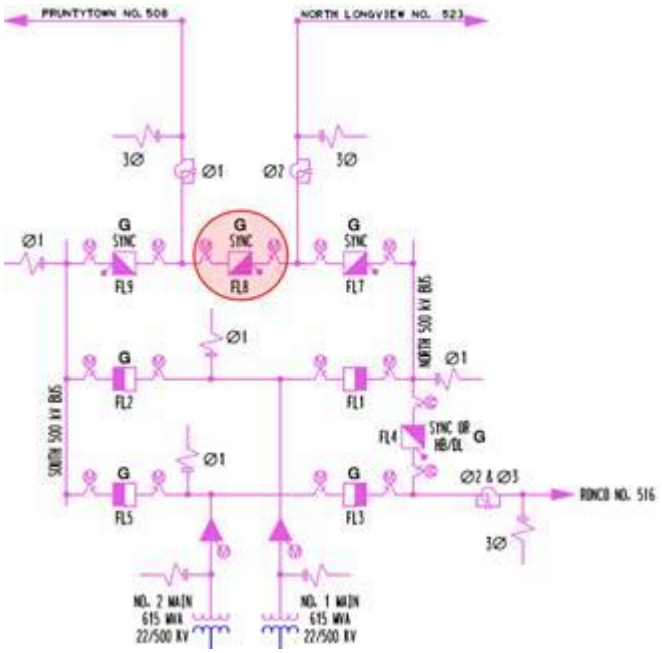
Appendix 3 (Continued)

Dynamic Simulation Analysis (Stability Study)
PJM Queue Position: AC2-142

7. Mitigation

Following new operational mitigation has been proposed to alleviate the instabilities due to mainetence outages listed in Table 8, 9 and 10.

1. Reduce AC1-021 Generation Dispatch by 170 MW, AC1-097 by 839 MW, AC2-142 by 130MW,
2. Open the Ft. Martin FL-8 Breaker



Appendix 3 (Continued)

Dynamic Simulation Analysis (Stability Study)
PJM Queue Position: AC2-142

Table 3: Steady State Operation

Fault ID	Duration	Result No mitigation
SS.01	Steady state 20 sec	Stable

Table 4: Three-phase Faults with Normal Clearing

Fault ID	Fault description	Clearing Time Near & Remote (Cycles)	Result No mitigation
3N.01	Fault at Hatfield 500 kV on AC1-097 circuit. Additional loss of AC1-097.	3	Stable
3N.02	Fault at Hatfield 500 kV on Ronco circuit.	3	Stable
3N.03	Fault at Hatfield 500 kV on Black Oak circuit.	3	Stable
3N.04	Fault at Hatfield 500 kV on Rhodes Lane circuit.	3	Stable
3N.05	Fault at Ronco 500 kV on Hatfield circuit.	3	Stable
3N.06	Fault at Ronco 500 kV on Fort Martin circuit.	3	Stable
3N.07	Fault at Ronco 500 kV on Fayette circuit. Additional loss of Fayette Units.	3	Stable
3N.08	Fault at Rhodes Lane 500 kV on Hatfield circuit.	3	Stable
3N.09	Fault at Rhodes Lane 500 kV on AC1-021 circuit. Additional loss of AC1-021.	3	Stable
3N.10	Fault at Rhodes Lane 500 kV on Yukon circuit.	3	Stable
3N.11	Fault at Yukon 500 kV on South Bend circuit.	3	Stable
3N.12	Fault at Yukon 500 kV on Rhodes Lane circuit.	3	Stable
3N.13	Fault at Yukon 500 kV on Yukon 500/138 kV Transformers 1 and 2.	3	Stable
3N.14	Fault at Yukon 500 kV on Yukon 500/138 kV Transformers 3 and 4.	3	Stable
3N.15	Fault at Hatfield 500 kV on AC2-142 circuit. Additional loss of AC2-142.	3	Stable

Appendix 3 (Continued)
Dynamic Simulation Analysis (Stability Study)
PJM Queue Position: AC2-142

Table 5: Single-phase Faults With Stuck Breaker

Fault ID	Fault description	Clearing Time Normal & Delayed (Cycles)	Result No mitigation
1B.01	Fault at Hatfield 500 kV on AC1-097 circuit. Breaker 8 stuck. Fault cleared with loss of Ronco circuit. Additional loss of AC1-097.	3 / 12	Stable
1B.02	Fault at Hatfield 500 kV on Ronco circuit. Breaker 8 stuck. Fault cleared with loss of AC1-097 circuit. Additional loss of AC1-097.	3 / 12	Stable
1B.03	Fault at Hatfield 500 kV on Black Oak circuit. Breaker 5 stuck. Fault cleared without additional losses.	3 / 12	Stable
1B.04	Fault at Hatfield 500 kV on Rhodes Lane circuit. Breaker 2 stuck. Fault cleared without additional losses.	3 / 12	Stable
1B.05	Fault at Ronco 500 kV on Hatfield circuit. Breaker 1 stuck. Fault cleared with loss of Fort Martin circuit. Additional loss of Fayette Units.	3 / 12	Stable
1B.06	Fault at Ronco 500 kV on Hatfield circuit. Breaker 3 stuck. Fault cleared with loss of Fayette circuit. Additional loss of Fayette units and Fort Martin circuit.	3 / 12	Stable
1B.07	Fault at Ronco 500 kV on Fort Martin circuit. Breaker 1 stuck. Fault cleared with loss of Hatfield circuit. Additional loss of Fayette units.	3 / 10[4]	Stable
1B.08	Fault at Ronco 500 kV on Fort Martin circuit. Breaker 2 stuck. Fault cleared with loss of Fayette circuit. Additional loss of Fayette units and Hatfield circuit..	3 / 10[4]	Stable
1B.09	Fault at Ronco 500 kV on Fayette circuit. Breaker 2 stuck. Fault cleared with loss of Fort Martin circuit. Additional loss of Fayette Units and Hatfield circuit.	3 / 12	Stable
1B.10	Fault at Ronco 500 kV on Fayette circuit. Breaker 3 stuck. Fault cleared with loss of Hatfield circuit. Additional loss of Fayette Units and Fort Martin circuit.	3 / 12	Stable
1B.11	Fault at Rhodes Lane 500 kV on Hatfield circuit. Breaker stuck to Yukon circuit. Fault cleared with loss of Yukon circuit. Additional loss of AC1-021.	3 / 12	Stable
1B.12	Fault at Rhodes Lane 500 kV on Hatfield circuit. Breaker stuck to AC1-121 circuit. Fault cleared with loss of AC1-021 circuit. Additional loss of AC1-021 and Yukon circuit.	3 / 12	Stable

[4] Clearing times provided by TO and implemented in the study due to tripping of AC1-097 when using standard tripping times.

Appendix 3 (Continued)
Dynamic Simulation Analysis (Stability Study)
PJM Queue Position: AC2-142

Table 5: Single-phase Faults With Stuck Breaker

Fault ID	Fault description	Clearing Time Normal & Delayed (Cycles)	Result No mitigation
1B.01	Fault at Hatfield 500 kV on AC1-097 circuit. Breaker 8 stuck. Fault cleared with loss of Ronco circuit. Additional loss of AC1-097.	3 / 12	Stable
1B.02	Fault at Hatfield 500 kV on Ronco circuit. Breaker 8 stuck. Fault cleared with loss of AC1-097 circuit. Additional loss of AC1-097.	3 / 12	Stable
1B.03	Fault at Hatfield 500 kV on Black Oak circuit. Breaker 5 stuck. Fault cleared without additional losses.	3 / 12	Stable
1B.04	Fault at Hatfield 500 kV on Rhodes Lane circuit. Breaker 2 stuck. Fault cleared without additional losses.	3 / 12	Stable
1B.05	Fault at Ronco 500 kV on Hatfield circuit. Breaker 1 stuck. Fault cleared with loss of Fort Martin circuit. Additional loss of Fayette Units.	3 / 12	Stable
1B.06	Fault at Ronco 500 kV on Hatfield circuit. Breaker 3 stuck. Fault cleared with loss of Fayette circuit. Additional loss of Fayette units and Fort Martin circuit.	3 / 12	Stable
1B.07	Fault at Ronco 500 kV on Fort Martin circuit. Breaker 1 stuck. Fault cleared with loss of Hatfield circuit. Additional loss of Fayette units.	3 / 10[4]	Stable
1B.08	Fault at Ronco 500 kV on Fort Martin circuit. Breaker 2 stuck. Fault cleared with loss of Fayette circuit. Additional loss of Fayette units and Hatfield circuit..	3 / 10*	Stable
1B.09	Fault at Ronco 500 kV on Fayette circuit. Breaker 2 stuck. Fault cleared with loss of Fort Martin circuit. Additional loss of Fayette Units and Hatfield circuit.	3 / 12	Stable
1B.10	Fault at Ronco 500 kV on Fayette circuit. Breaker 3 stuck. Fault cleared with loss of Hatfield circuit. Additional loss of Fayette Units and Fort Martin circuit.	3 / 12	Stable
1B.11	Fault at Rhodes Lane 500 kV on Hatfield circuit. Breaker stuck to Yukon circuit. Fault cleared with loss of Yukon circuit. Additional loss of AC1-021.	3 / 12	Stable
1B.12	Fault at Rhodes Lane 500 kV on Hatfield circuit. Breaker stuck to AC1-121 circuit. Fault cleared with loss of AC1-021 circuit. Additional loss of AC1-021 and Yukon circuit.	3 / 12	Stable
1B.13	Fault at Rhodes Lane 500 kV on AC1-021 circuit. Breaker stuck to Hatfield circuit. Fault cleared with loss of Hatfield circuit. Additional loss of AC1-021.	3 / 12	Stable
1B.14	Fault at Rhodes Lane 500 kV on AC1-021 circuit. Breaker stuck to Yukon circuit. Fault cleared with loss of Yukon circuit. Additional loss of AC1-021.	3 / 12	Stable
1B.15	Fault at Rhodes Lane 500 kV on Yukon circuit. Breaker stuck to AC1-121 circuit. Fault cleared with loss of AC1-021 circuit. Additional loss of AC1-021.	3 / 12	Stable
1B.16	Fault at Rhodes Lane 500 kV on Yukon circuit. Breaker stuck to Hatfield circuit. Fault cleared with loss of Hatfield circuit. Additional loss of AC1-021.	3 / 12	Stable
1B.17	Fault at Yukon 500 kV on South Bend circuit. Breaker YL4 stuck. Fault cleared with loss of Yukon 500/138 kV Transformers 3 and 4.	3 / 12	Stable
1B.18	Fault at Yukon 500 kV on South Bend circuit. Breaker YL6 stuck. Fault cleared with loss of Yukon 500/138 kV Transformers 1 and 2.	3 / 12	Stable
1B.19	Fault at Yukon 500 kV on Rhodes Lane circuit. Breaker YL1 stuck. Fault cleared with loss of Yukon 500/138 kV Transformers 3 and 4.	3 / 12	Stable
1B.20	Fault at Yukon 500 kV on Rhodes Lane circuit. Breaker YL3 stuck. Fault clered with loss of Yukon 500/138 kV Transformers 1 and 2.	3 / 12	Stable
1B.21	Fault at Yukon 500 kV on Yukon 500/138 kV Transformers 1 and 2. Breaker YL6 stuck. Fault cleared with loss of South Bend circuit.	3 / 12	Stable
1B.22	Fault at Yukon 500 kV on Yukon 500/138 kV Transformers 1 and 2. Breaker YL3 stuck. Fault cleared with loss of Rhodes Lane circuit.	3 / 12	Stable
1B.23	Fault at Yukon 500 kV on Yukon 500/138 kV Transformers 3 and 4. Breaker YL1 stuck. Fault cleared with loss of Rhodes Lane circuit.	3 / 12	Stable
1B.24	Fault at Yukon 500 kV on Yukon 500/138 kV Transformers 3 and 4. Breaker YL4 stuck. Fault cleared with loss of South Bend circuit.	3 / 12	Stable
1B.25	Fault at Hatfield 500 kV on AC2-142 circuit. Breaker stuck to Hatfield 500 kV bus. Fault cleared without additional losses.	3 / 12	Stable

[4] Clearing times provided by TO and implemented in the study due to tripping of AC1-097 when using standard tripping times.

Appendix 3 (Continued)
Dynamic Simulation Analysis (Stability Study)
PJM Queue Position: AC2-142

Table 6: Single-phase Faults With Delayed (Zone 2) Clearing at line end closest to AC1-097 POI

Fault ID	Fault description	Clearing Time Near & Remote (Cycles)	Result No mitigation
1D.01	N/A[4]	N/A	N/A
1D.02	Fault at 80% of 500 kV line from Hatfield 500 kV to Black Oak. Delayed clearing at Hatfield 500 kV.	3 / 21	Stable
1D.03	Fault at 80% of 500 kV line from Hatfield 500 kV to Rhodes Lane. Delayed clearing at Hatfield 500 kV.	3 / 21	Stable
1D.04	N/A*	N/A	N/A
1D.05	Fault at 80% of 500 kV line from Rhodes Lane 500 kV to Yukon circuit. Delayed clearing at Rhodes Lane 500 kV.	3 / 21	Stable
1D.06	Fault at 80% of 500 kV line from Yukon 500 kV to South Bend circuit. Delayed clearing at Yukon 500 kV.	3 / 21	Stable

Table 7: Three-phase Faults With Normal Clearing – Prior outage of Fort Martin–Ronco 500 kV line

Fault ID	Fault description	Clearing Time Near & Remote (Cycles)	AC1-021 No Mitigation
MA.P1.03	Fault at AC1-021 500 kV on AC1-021 – Yukon 500 kV line (with AA2-139 Unit 1 offline*)	3	Unstable, curtailed T-174/AB1-106/AC1-021 by 170MW, AC1-097 by 839 MW, AC2-142 by 130MW, to be stable
MA.P1.03	Fault at AC1-021 500 kV on AC1-021 – Yukon 500 kV line	3	Unstable, curtailed T-174/AB1-106/AC1-021 by 170MW, AC1-097 by 839 MW, AC2-142 by 130MW, to be stable

[4] Contingency not studied due to the presence of redundant protection relays on Hatfield – Ronco and Ronco – Fort Martin 500 kV circuits

* As specified in Section 5: Index and Operating Procedures for PJM RTO Operation by the document "PJM Manual 03: Transmission Operations.pdf", dated April 1, 2013.

Table 8: Three-phase Faults With Normal Clearing – Prior outage of AC1-021 –Yukon 500 kV line

(Breaker 8 at Fort Martin is open to avoid stuck breaker faults)

Fault ID	Fault description	Clearing Time Near & Remote (Cycles)	AC1-021 No Mitigation
MB.P1.17	Fault at Fort Martin 500 kV on Fort Martin – Pruntytown 500 kV line (with AA2-139 Unit 1 offline*)	3	Stable
MB.P1.18	Fault at Fort Martin 500 kV on Fort Martin – Ronco 500 kV line (with AA2-139 Unit 1 offline*)	3	Unstable, curtailed T-174/AB1-106/AC1-021 by 170MW, AC1-097 by 839 MW, AC2-142 by 130MW, to be stable
MB.P1.19	Fault at Fort Martin 500 kV on Fort Martin – North Longview 500 kV line (with AA2-139 Unit 1 offline*)	3	Stable
MB.P1.17	Fault at Fort Martin 500 kV on Fort Martin – Pruntytown 500 kV line	3	Stable
MB.P1.18	Fault at Fort Martin 500 kV on Fort Martin – Ronco 500 kV line	3	Unstable, curtailed T-174/AB1-106/AC1-021 by 170MW, AC1-097 by 839 MW, AC2-142 by 130MW, AA2-139 unit 1 offline to be stable
MB.P1.19	Fault at Fort Martin 500 kV on Fort Martin – North Longview 500 kV line	3	Stable

* Most limiting contingency, Hatfield units are all retired in the case.

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