Generation Interconnection System Impact Study Report

For

PJM Generation Interconnection Request Queue Position AB2-102

"Cumberland 230 kV"

May 2017

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 Interconnection Customer 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

Calpine Mid-Atlantic Development, LLC, the Interconnection Customer (IC), has proposed a 230 MW Maximum Facility Output (MFO) 225 MW Capacity (MWC) simple cycle combustion turbine generating facility to be located in Millville, New Jersey. PJM studied AB2-102 as a 68 MW** injection into the Atlantic City Electric Company (ACE) system at the Cumberland 230 kV Substation and evaluated it for compliance with reliability criteria for summer peak conditions in 2020. The planned in-service date, as stated during the project kick-off call, is June 1, 2020.

** At the Interconnection Customer's request, 157 MWs of Capacity Interconnection Rights (CIRs) from the deactivated Cedar 2, Missouri Ave CT: B, C, & D and the Middle Energy Center: 1, 2 & 3 units were transferred to this AB2-102 project.

Point of Interconnection

The Interconnection Customer requested that the AB2-102 project utilize the same Point of Interconnection as their prior queue position P06 (see Attachment 1).

Transmission Owner Scope of Work

Other than the relay work below, no additional Transmission Owner work is required as the AB2-102 project will utilize the Attachment Facilities and Point of Interconnection created by Interconnection Customer's prior queue project P06.

Required Relaying and Communications

Relay replacement of the bus relays at the Cumberland 230 kV Substation will be required. The estimated time to complete this work is **18 months** and will cost **$200,000**.

Interconnection Customer Scope of Work

The Interconnection Customer is responsible for all design and construction related to activities on their side of the Point of Interconnection. Site preparation, including grading and an access road, as necessary, is assumed to be by the IC. Route selection, line design, and right-of-way acquisition of the direct connect facilities is not included in this report, and is the responsibility of the IC. Protective relaying and metering design and installation must comply with ACE's applicable standards. The IC is also required to provide revenue metering and real-time telemetering data to PJM in conformance with the requirements contained in PJM Manuals M-01 and M-14 and the PJM Tariff.

ACE Interconnection Customer Scope of Direct Connection Work Requirements

- ACE requires that an IC circuit breaker is located within 500 feet of the ACE substation to facilitate the relay protection scheme between ACE and the IC at the Point of Interconnection (POI).

Metering

Three phase 230 kV revenue metering points will need to be established. ACE will purchase and install all metering instrument transformers as well as construct a metering structure. The secondary wiring connections at the instrument transformers will be completed by ACE's metering technicians. The metering control cable and meter cabinets will be supplied and installed by ACE. ACE will install conduit for the control cable between the instrument transformers and the metering enclosure. The location of the metering enclosure will be determined in the construction phase. ACE will provide both the Primary and the Backup meters. ACE's meter technicians will program and install the Primary & Backup solid state multi-function meters for each new metering position. Each meter will be equipped with load profile, telemetry, and DNP outputs. The IC will be provided with one meter DNP output for each meter. ACE will own the metering equipment for the interconnection point, unless the IC asserts its right to install, own, and operate the metering system.

The Interconnection Customer will be required to make provisions for a voice quality phone line within approximately 3 feet of each Company metering position to facilitate remote interrogation and data collection.

It is the IC's responsibility to send the data that PJM and ACE requires directly to PJM. The IC will grant permission for PJM to send ACE the following telemetry that the IC sends to PJM: real time MW, MVAR, volts, amperes, generator status, and interval MWH and MVARH.

Special Operating Requirements

1. ACE will require the capability to remotely disconnect the generator from the grid by communication from its System Operations facility. Such disconnection may be facilitated by a generator breaker, or other method depending upon the specific circumstances and the evaluation by ACE.

2. It is the Interconnection Customer's responsibility to send the data that PJM and ACE require directly to PJM. The Interconnection Customer will grant permission for PJM to send to ACE the following telemetry that the Interconnection Customer sends to PJM: real time MW, MVAR, volts, amperes, generator/status, and interval MWH and MVARH.

3. The Interconnection Customer will be required to make provisions for a voice quality phone line within approximately 3 feet of each ACE metering position to facilitate remote interrogation and data collection.

4. ACE reserves the right to charge the Interconnection Customer operation and maintenance expenses to maintain the Interconnection Customer attachment facilities, including metering and telecommunications facilities, owned by ACE.

Additional Interconnection Customer Responsibilities

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.

Summer Peak Analysis - 2020

Transmission Network Impacts

Potential transmission network impacts are as follows:

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

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

Steady-State Voltage Requirements

To be performed during later study phases.

Short Circuit

No issues identified.

Stability and Reactive Power Requirement

No issues identified. See Attachment 2 for full report.

Light Load Analysis - 2020

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

Facilities Study Estimate

7 months: $100,000

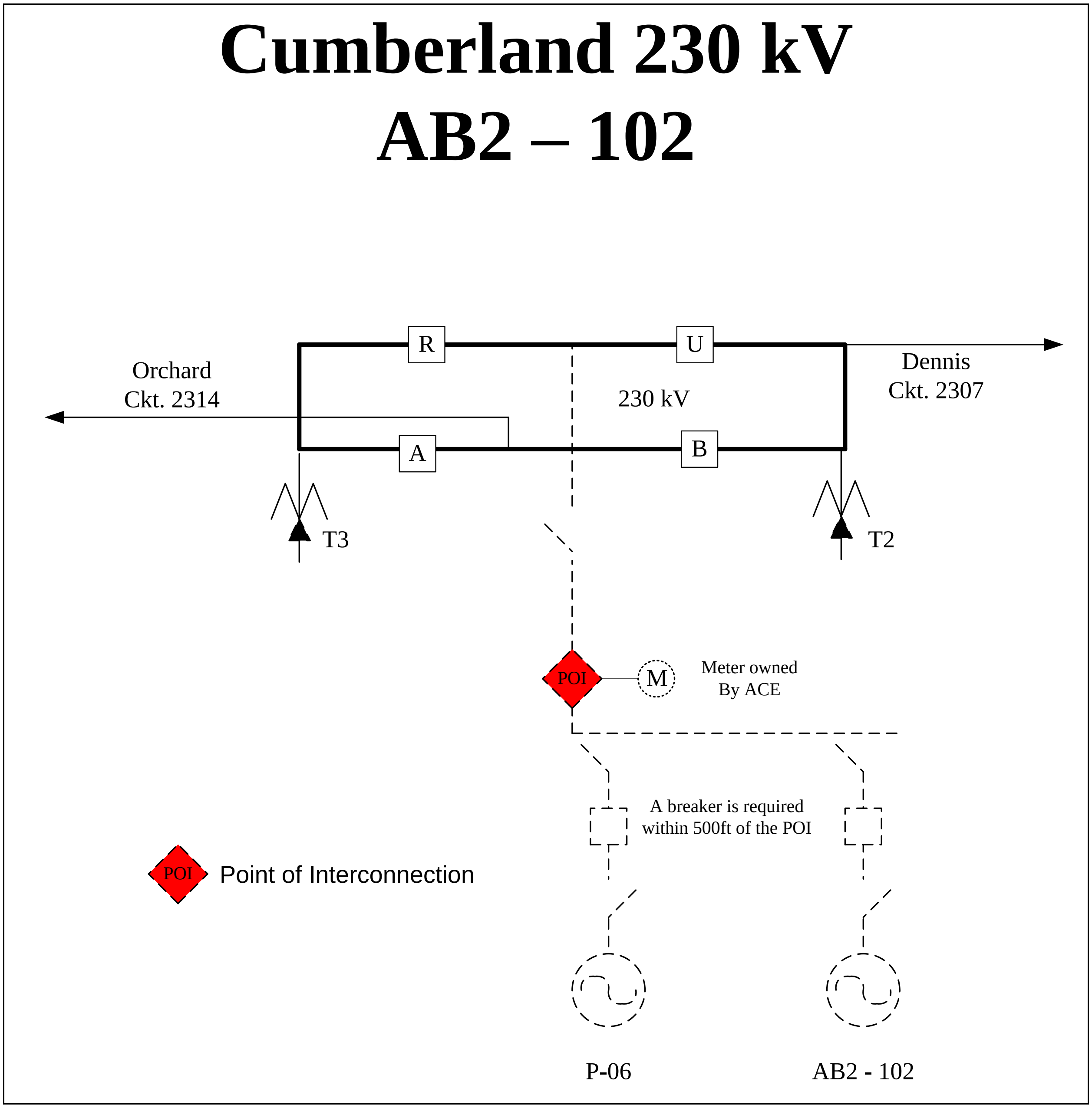
Delivery of Energy Portion of Interconnection Request

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.

None

Attachment 1



Attachment 2

Specialist Consultants
to the Electricity Industry

AB2-102 System Impact Study

Dynamic Simulation Analysis

Prepared by **Timothy Gorman**
PSC Australia

For **PJM Interconnection, LLC**

Reference **AB2-102-3-0**

Date **March 08, 2017**

Revision Table

Revision	Issue Date	Description
0	March 08, 2017	Initial Issue

Reviewers

Name	Interest	Date
Christopher Spencer	Peer Review	March 08, 2017

Approval

Name	Position	Date
Christopher Spencer	Senior Power Systems Engineer	March 08, 2017

TABLE OF CONTENTS

Executive Summary

Generator Interconnection Request AB2-102 is for a 230 MW Maximum Facility Output (MFO) natural gas combustion turbine plant. AB2-102 is an addition to the Cumberland Energy Center with a Point of Interconnection (POI) at the existing Cumberland 230 kV Substation in the Atlantic City Electric (AE) transmission system, Millville, New Jersey.

This report describes a dynamic simulation analysis of AB2-102 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. AB2-102 was set to maximum power output.

AB2-102 was tested for compliance with NERC, PJM, Transmission Owner and other applicable criteria. 54 contingencies were studied, each with at least a 20 second simulation time period. Studied scenarios included:

a) Steady state operation (20 second simulation);
b) Three phase faults with normal clearing time;
c) Single phase faults with stuck breaker;
d) Single phase faults placed at 80% of the line with delayed (Zone 2) clearing at line end remote from fault due to primary communications/relaying failure.
e) Single-phase faults resulting in tower failure

No relevant bus or High Speed Reclosing (HSR) contingencies were found.

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.

For the all 54 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 AB2-102 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 the fault.

Post-fault oscillations were evident at bus DENNSVC [228231] for all contingencies, which stabilized before the end of the 20 second simulations. A run of all contingencies without the addition of AB2-102 determined that the oscillations were not due to the addition of AB2-102.

Non-convergence was observed at bus DENNSVC [228231] for contingency 3N.14 during fault clearing. The same non-convergence was observed without the addition of AB2-102, therefore the non-convergence is not attributable to the addition of AB2-102.

No mitigations were found to be required.

1. Introduction

Generator Interconnection Request AB2-102 is for a 230 MW Maximum Facility Output (MFO) natural gas combustion turbine plant. AB2-102 is an addition to the Cumberland Energy Center with a Point of Interconnection (POI) at the existing Cumberland 230 kV Substation in the Atlantic City Electric (AE) transmission system, Millville, New Jersey. This analysis is effectively a screening study to determine whether the addition of AB2-102 will meet the dynamics requirements of the NERC, PJM and Transmission Owner reliability standards.

In this report the AB2-102 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.

2. Description of Project

Generator Interconnection Request AB2-102 is for a 230 MW Maximum Facility Output (MFO) natural gas combustion turbine plant. AB2-102 is an addition to the Cumberland Energy Center with a Point of Interconnection (POI) at the existing Cumberland 230 kV Substation in the Atlantic City Electric (AE) transmission system, Millville, New Jersey.

Figure 1 shows the simplified single-line diagram of the AB2-102 loadflow model.

Table 1 lists the parameters given in the impact study data and the corresponding parameters of the AB2-102 loadflow model.

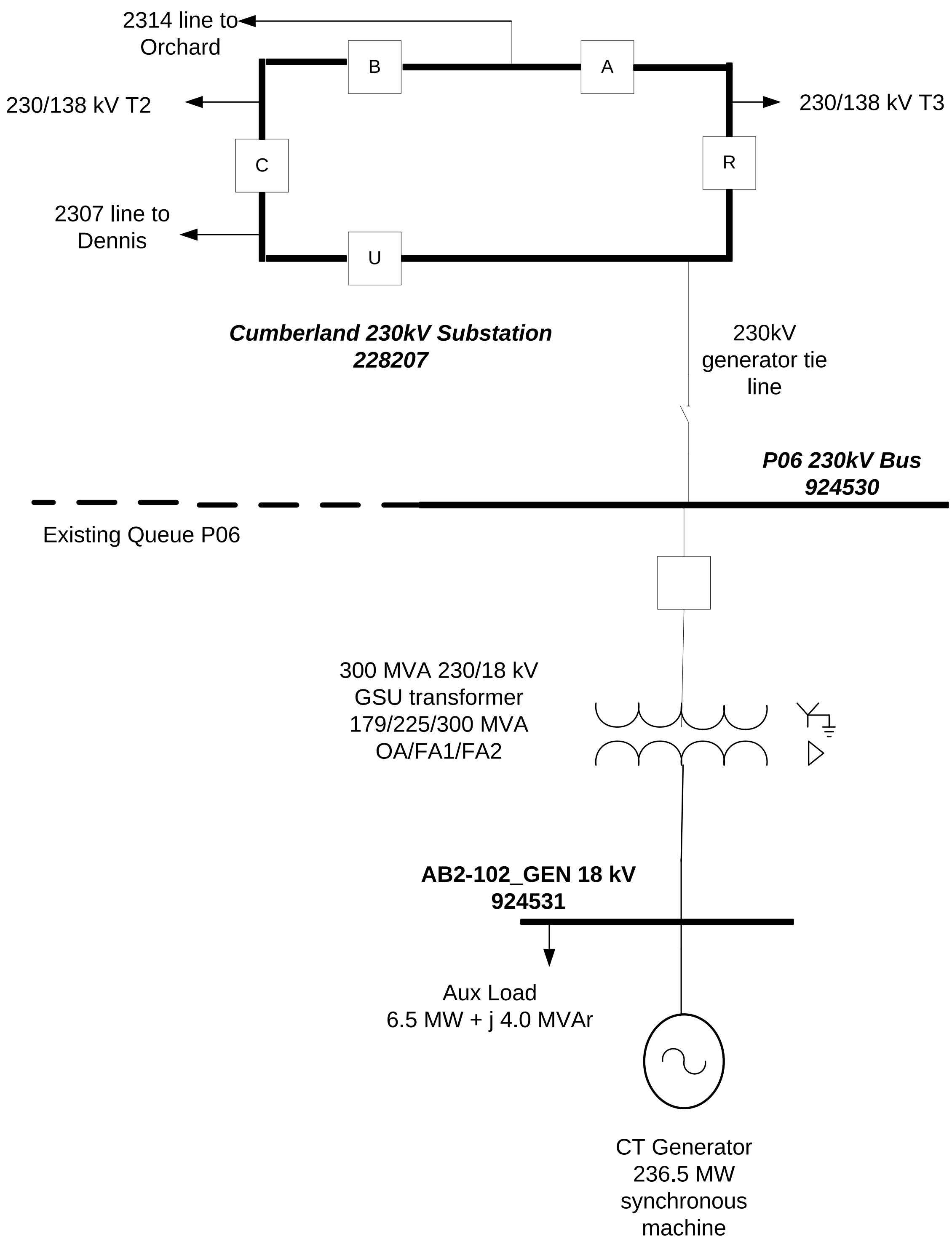


Figure 1: AB2-102 Plant Model

Table 1: AB2-102 Plant Model

	Impact Study Data	Model
Turbine Type	1 x 236.5 MW Combustion Turbine MVA base = 273 MVA Terminal Voltage = 18 kV Unsaturated sub-transient reactance = 0.215 pu @ MVA base	1 x 236.5 MW Combustion Turbine PGEN 236.5 MW PMAX 236.5 MW PMIN 0 MW QMAX 140 MVAr[1] QMIN -100 MVAr MBASE 273 MVA ZSOURCE 0.0032 + j0.215 pu @ MBASE
GSU transformer	1 x 230/18 kV two winding transformers YNd1 Rating = 300 MVA Transformer base = 300 MVA Impedance = 0.0025 + j0.10 pu @ MVA base Number of taps = N/A Tap step size = N/A	1 x 230/18 kV two winding transformers YNd1 Rating = 300 MVA Transformer base = 300 MVA Impedance = 0.0025 + j0.10 pu @ MVA base Number of taps = 5 Tap step size = 2.5%
Auxiliary load	6.5 MW + 4.0 MVAr	6.5 MW + j4.0 MVAr
Station load	Not applicable	NA
Transmission line	Not provided	Impedance= 0.0 + j0.001 pu & total charging susceptance = j0.0 pu @ 230 kV and 100 MVA base

[1] The Leading and lagging values are from D Curve provided for AB2-102.

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 are based on PJM's Regional Transmission Planning Process[1] and discussions with PJM.
The selected load flow scenarios were the RTEP 2020 Light Load case with the following modifications:

a) Addition of all applicable queue projects prior to AB2-102.

b) Addition of AB2-102 queue project.

c) Removal of withdrawn and subsequent queue projects in the vicinity of AB2-102.

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

e) Merchant transmission projects X3-028 and S57/S58 set online and at maximum power import into PJM.

The AB2-102 initial conditions are listed in Table 2, indicating maximum power output, with 0.97 pu voltage at the generator bus.

Table 2: AB2-102 machine initial conditions

Scenario	Bus	Name	Unit	PGEN (MW)	QGEN (MVar)	ETERM (pu)	POI Voltage (pu)
1	924531	AB2-102 GEN	1	236.5 MW	-84.22	0.97	1.0013

Generation within the vicinity of AB2-102 was dispatched online at maximum output (PMAX).

[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.

4. Fault Cases

Table 3 to Table 7 list the contingencies that were studied, with representative worst case total clearing times provided by PJM. Each contingency was studied over a 20 second simulation time interval.

The studied contingencies include:

a) Steady state operation (20 second simulation);

b) Three-phase faults with normal clearing time;

c) Single-phase faults with stuck breaker;

d) Single-phase faults placed at 80% of the line with delayed (Zone 2) clearing at line end remote from fault due to primary communications/relay failure.

e) Single-phase faults resulting in tower failure

No relevant Bus or High Speed Reclosing (HSR) contingencies were identified.

Buses at which the faults listed above will be applied are:

- Cumberland 230 kV
- Cumberland 138 kV
- Dennis 230 kV
- Orchard 230 kV

The three phase faults with normal clearing time were performed under network intact conditions.

Additional delayed (Zone 2) clearing at remote and faults were applied on lines from Dennis 230 kV, Orchard 230 kV, Union 138 kV, and Sherman 138 kV towards the queue project.

A complete list of the contingencies that were studied and the one-line diagram of the AE network in the vicinity of AB2-102 is included in Attachment 2.

Clearing times listed in Tables 3 to 7 are as per revision 19 of "*2016 Revised Clearing times for each PJM company*" spreadsheet.

The positive sequence fault impedances for single line to ground faults were derived from the 2020 Light Load case.

5. Evaluation Criteria

This study is focused on AB2-102, 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 AB2-102 included should be transiently stable with post-contingency oscillations positively damped with a margin of at least 3%.

b) The AB2-102 generator is able to ride through the faults (except for faults where protective action trips the 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 the fault.

6. Summary of Results

Plots from the dynamic simulations are provided in Attachment 6 with results summarized in Tables 3 to 7.

All fault contingencies tested on the 2020 Light Load case met the recovery criteria:

a) AB2-102 was able to ride through the faults (except for faults where protective action tripped a generator(s)),

b) 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.

Post-fault oscillations were evident at bus DENNSVC [228231] for all contingencies, which stabilized before the end of the 20 second simulations. A run of all contingencies without the addition of AB2-102 determined that the oscillations were not due to the addition of AB2-102.

7. Recommendations and Mitigations

No adverse impacts attributable to the queue project under study were found and as such, no mitigations were found to be required.

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 (Cycles)	Result No mitigation
3N.01	Fault at Cumberland 230 kV on AB2-102 circuit (trips AB2-102 and P06).	7	Stable
3N.02	Fault at Cumberland 230 kV on Orchard circuit (2314).	7	Stable
3N.03	Fault at Cumberland 230 kV on 230/138 kV Transformer 2.	7	Stable
3N.04	Fault at Cumberland 230 kV on Dennis circuit (2307).	7	Stable
3N.05	Fault at Cumberland 230 kV on Cumberland 230/138 kV Transformer 3.	7	Stable
3N.06	Fault at Cumberland 138 kV on Cumberland 230/138 kV Transformer 3.	9	Stable
3N.07	Fault at Cumberland 138 kV on Sherman circuit (1415).	9	Stable
3N.08	Fault at Cumberland 138 kV on Cumberland 230/138 kV Transformer 2.	9	Stable
3N.09	Fault at Cumberland 138 kV on Union circuit (1416).	9	Stable
3N.10	Fault at Cumberland 138 kV on Cumberland 138/13.8 kV Transformer 1 (trips Cumberland CT).	9	Stable
3N.11	Fault at Dennis 230 kV on Cumberland circuit (2307).	7	Stable
3N.12	Fault at Dennis 230 kV on Dennis 230/138 kV Transformer 2.	7	Stable
3N.13	Fault at Dennis 230 kV on Dennis 100 MVAr capacitor bank.	7	Stable
3N.14	Fault at Dennis 230 kV on Dennis 150 MVAr SVC connected via transformer T1.	7	Stable
3N.15	Fault at Orchard 230 kV on Cumberland circuit (2314).	7	Stable
3N.16	Fault at Orchard 230 kV on Churchtown circuit (2309). Additional loss of Orchard 500/230 kV Transformer T1.	7	Stable
3N.17	Fault at Orchard 230 kV on Cardiff circuit.	7	Stable
3N.18	Fault at Orchard 500 kV on Orchard 500/230 kV T1. Additional loss of Orchard - Churchtown circuit (2309).	7	Stable

Table 5: Single-Phase Faults With Stuck Breaker

Fault ID	Fault description	Clearing Time Near & Remote (Cycles)	Result No mitigation
1B.01	Fault at Cumberland 230 kV on AB2-102 circuit (trips AB2-102 and P06). Breaker stuck to Dennis circuit (2307). Fault cleared with loss of Dennis circuit (2307).	7 / 18.5	Stable
1B.02	Fault at Cumberland 230 kV on AB2-102 circuit (trips AB2-102 and P06). Breaker stuck to Cumberland 230/138 kV T3. Fault cleared with loss of Cumberland 230/138 kV T3.	7 / 18.5	Stable
1B.03	Fault at Cumberland 230 kV on Dennis circuit (2307). Breaker stuck to AB2-102. Fault cleared with loss of AB2-102 and P06.	7 / 18.5	Stable
1B.04	Fault at Cumberland 230 kV on Dennis circuit (2307). Breaker stuck to Cumberland 230/138 kV T2. Fault cleared with loss of Cumberland 230/138 kV T2.	7 / 18.5	Stable
1B.05	Fault at Cumberland 230 kV on Cumberland 230/138 kV T2. Breaker stuck to Dennis circuit (2307). Fault cleared with loss of Dennis circuit (2307).	7 / 18.5	Stable
1B.06	Fault at Cumberland 230 kV on Cumberland 230/138 kV T2. Breaker stuck to Orchard circuit (2314). Fault cleared with loss of Orchard circuit (2314).	7 / 18.5	Stable
1B.07	Fault at Cumberland 230 kV on Orchard circuit (2314). Breaker stuck to Cumberland 230/138 kV T2. Fault cleared with loss of Cumberland 230/138 kV T2.	7 / 18.5	Stable
1B.08	Fault at Cumberland 230 kV on Orchard circuit (2314). Breaker stuck to Cumberland 230/138 kV T3. Fault cleared with loss of Cumberland 230/138 kV T3.	7 / 18.5	Stable
1B.09	Fault at Dennis 230 kV on Cumberland circuit (2307). Breaker stuck to Dennis 230/138 kV T2. Fault cleared with loss of Dennis 230/138 kV T2.	7 / 18.5	Stable
1B.10	Fault at Dennis 230 kV on Cumberland circuit (2307). Breaker G stuck. Fault cleared without loss of any additional circuits.	7 / 18.5	Stable
1B.11	Fault at Dennis 230 kV on Dennis 230/138 kV T2. Breaker stuck to Cumberland circuit (2307). Fault cleared with loss of Cumberland circuit (2307).	7 / 18.5	Stable
1B.12	Fault at Dennis 230 kV on Dennis 230/138 kV T2. Breaker D stuck. Fault cleared with loss of Dennis 100 MVAr capacitor bank and Dennis 150 MVAr SVC connected via transformer T1.	7 / 18.5	Stable
1B.13	Fault at Cumberland 138 kV on Cumberland 230/138 kV T2. Breaker stuck to Union circuit (1416). Fault cleared with loss of Union circuit (1416).	9 / 23	Stable
1B.14	Fault at Cumberland 138 kV on Cumberland 230/138 kV T2. Breaker stuck to Sherman circuit (1415). Fault cleared with loss of Sherman circuit (1415).	9 / 23	Stable
1B.15	Fault at Cumberland 138 kV on Union circuit (1416). Breaker stuck to Cumberland 230/138 kV T2. Fault cleared with loss of Cumberland 230/138 kV T2.	9 / 23	Stable

Fault ID	Fault description	Clearing Time Near & Remote (Cycles)	Result No mitigation
1B.16	Fault at Cumberland 138 kV on Union circuit (1416). Breaker stuck to Cumberland CT. Fault cleared with loss of Cumberland CT.	9 / 23	Stable
1B.17	Fault at Cumberland 138 kV on Cumberland CT. Breaker stuck to Union circuit (1416). Fault cleared with loss of Union circuit (1416).	9 / 23	Stable
1B.18	Fault at Cumberland 138 kV on Cumberland CT. Breaker stuck to Cumberland 230/138 kV T3. Fault cleared with loss of Cumberland 230/138 kV T3.	9 / 23	Stable
1B.19	Fault at Cumberland 138 kV on Cumberland 230/138 kV T3. Breaker stuck to Cumberland CT. Fault cleared with loss of Cumberland CT.	9 / 23	Stable
1B.20	Fault at Cumberland 138 kV on Cumberland 230/138 kV T3. Breaker J stuck. Fault cleared by Breaker D.	9 / 23	Stable
1B.21	Fault at Cumberland 138 kV on Sherman circuit (1415). Breaker D stuck. Fault cleared by Breaker J.	9 / 23	Stable
1B.22	Fault at Cumberland 138 kV on Sherman circuit (1415). Breaker stuck to Cumberland 230/138 kV T2. Fault cleared by loss of Cumberland 230/138 kV T2.	9 / 23	Stable
1B.23	Fault at Orchard 230 kV on Cumberland circuit (2314). Breaker stuck to Churchtown circuit (2309). Fault cleared with additional loss of Churchtown circuit (2309) and Orchard 500/230 kV T1.	7 / 18.5	Stable
1B.24	Fault at Orchard 230 kV on Cardiff circuit. Breaker E stuck. Fault cleared with no additional losses.	7 / 18.5	Stable
1B.25	Fault at Orchard 230 kV on Orchard 500/230 kV T1. Additional loss of Orchard - Churchtown circuit. Breaker D stuck. Fault cleared with no additional losses.	7 / 18.5	Stable
1B.26	Fault at Orchard 230 kV on Orchard 500/230 kV T1. Additional loss of Orchard - Churchtown circuit. Breaker stuck to Cumberland circuit (2314). Fault cleared with loss of Cumberland circuit (2314).	7 / 18.5	Stable
1B.27	Fault at Orchard 230 kV on Churchtown circuit. Additional loss of Orchard 500/230 kV T1. Breaker stuck to Cumberland circuit. Fault cleared with additional loss of Cumberland circuit.	7 / 18.5	Stable
1B.28	Fault at Orchard 230 kV on Churchtown circuit. Additional loss of Orchard 500/230 kV T1. Breaker D stuck. Fault cleared with no additional losses.	7 / 18.5	Stable

Table 6: Single-phase Faults With Delayed (Zone 2) Clearing at line end closest to AB2-102 POI

Fault ID	Fault description	Clearing Time normal & delayed (Cycles)	Result No mitigation
1D.01	Fault at 80% of line from Cumberland 230 kV to Dennis (2307). Delayed clearing at Cumberland 230 kV.	7 / 38	Stable
1D.02	Fault at 80% of line from Cumberland 230 kV to Orchard (2314). Delayed clearing at Cumberland 230 kV.	7 / 38	Stable
1D.03	Fault at 80% of line from Cumberland 138 kV to Union (1416). Delayed clearing at Cumberland 138 kV.	9 / 41	Stable
1D.04	Fault at 80% of line from Cumberland 138 kV to Sherman (1415). Delayed clearing at Cumberland 138 kV.	9 / 41	Stable

Table 7: Single-phase Faults Resulting in Tower Failure

Fault ID	Fault description	Clearing Time Near & Remote (Cycles)	Result No mitigation
1T.01	Fault at Cumberland 230 kV on Orchard circuit 1 resulting in tower failure. Fault cleared with loss of Cumberland to Sherman 138 kV. Contingency 'AE2TOWER'	9	Stable
1T.02	Fault at Cumberland 230 kV on Dennis circuit 1 resulting in tower failure. Fault cleared with loss of Cumberland – Sherman 138 kV. Contingency 'AE4TOWER'	9	Stable
1T.03	Fault at Orchard 230 kV on Churchtown circuit 1 resulting in tower failure. Fault cleared with loss of Churchtown to UPITTS 138 kV. Contingency 'AE13TOWER'	9	Stable