Generation Interconnection System Impact Study Report

For

PJM Generation Interconnection Request Queue Position AC2-036

Ravenswood-East Bashan Switch 69 kV

January 2019

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: (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. 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 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 or merchant transmission upgrade, may also contribute to the need for the same network reinforcement.

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

Hecate Energy Great Bend, LLC proposes to interconnect PJM Project #AC2-036, a 20.0 MW (12.0 MW Capacity) solar generating facility in Meigs County, OH (see Figure 2). The point of interconnection is on the Ravenswood – East Bashan Switch 69 kV section of AEP's Ravenswood – Hemlock 69 kV circuit (see Figure 1).

The requested in service date is June 1, 2020.

Attachment Facilities

Point of Interconnection (Ravenswood – East Bashan Switch 69 kV)

To accommodate the interconnection on the Ravenswood – East Bashan Switch 69 kV section of the Ravenswood – Hemlock 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 Figure 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.

New Switching Station Work:

- Construct 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. Installation of associated protection and control equipment, 69 kV line risers, SCADA, and 69 kV revenue metering will also be required (see Figure 1).
    - **Estimated Station Cost: $3,500,000**

Direct Connection Cost Estimate

The total preliminary cost estimate for Direct Connection work is given in the following tables below.

For AEP building Direct Connection cost estimates:

Description	Total Cost
Ravenswood-East Bashan Switch 69 kV T-Line Cut In	$700,000
Total	**$700,000**

Table 1

Non-Direct Connection Cost Estimate

The total preliminary cost estimate for Non-Direct Connection work is given in the following tables below:

For AEP building Direct Connection cost estimates:

Description	Estimated Cost
69 kV Revenue Metering	$200,000
Install line protection and controls at the New 69 kV Switching Station.	$850,000
Upgrade line protection and controls at the Ravenswood 69 kV substation to coordinate with the new 69 kV switching station.	$200,000
Upgrade line protection and controls at the Hemlock 69 kV substation to coordinate with the new 69 kV switching station.	$200,000
Total	**$1,450,000**

Table 2

Interconnection Customer Requirements

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

Requirement from the PJM Open Access Transmission Tariff:

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.

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

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

Network Impacts

The Queue Project AC2-036 was evaluated as a 20.0 MW (Capacity 12.0 MW) injection tapping the Ravenswood – East Bashan Switch 69 kV line in the AEP area. Project AC2-036 was evaluated for compliance with applicable reliability planning criteria (PJM, NERC, NERC Regional Reliability Councils, and Transmission Owners). Project AC2-036 was studied with a commercial probability of 100%. Potential network impacts were as follows:

Base Case Used

Summer Peak Analysis – 2020 Case

Contingency Descriptions

The following contingencies resulted in overloads:

Contingency Name	Description
'248_B2_TOR5081_AC1-182 A'	CONTINGENCY '248_B2_TOR5081_AC1-182 A' OPEN BRANCH FROM BUS 246732 TO BUS 247080 CKT Z1 / 246732 05BASHAN 69.0 247080 05WBASHNSS 69.0 Z1 OPEN BRANCH FROM BUS 246735 TO BUS 247090 CKT 1 / 246735 05COOLVL 69.0 247090 05E.BASHSS 69.0 1 OPEN BRANCH FROM BUS 247090 TO BUS 926810 CKT 1 / 247090 05E.BASHSS 69.0 926810 AC1-082 TAP 69.0 1 OPEN BRANCH FROM BUS 247090 TO BUS 247080 CKT 1 / 247090 05E.BASHSS 69.0 247080 05WBASHNSS 69.0 1 END

Table 3

Generator Deliverability

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

AC2-036 Multiple Facility Contingency												
		Contingency	Affected	Facility	Bus		Loading		Rating		MW	FG
#	Type	Name	Area	Description	From	To	Initial	Final	Type	MVA	Con.	App.
1	N-1	'248_B2_TOR5081_AC1-182 A'	AEP - AEP	05RACINE-05LAKIN 69 kV line	244761	244756	89.16	100.47	ER	44	5.28	1

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

(Results of the steady-state voltage studies should be inserted here)

None

Short Circuit

(Summary of impacted circuit breakers)

New circuit breakers found to be over-duty:

None

Stability and Reactive Power Requirement

(Results of the dynamic studies should be inserted here)

AC1-082 and AC2-036 unit tripping is observed for P1.01, P1.04, P1.09, P1.14, P4.01, P4.02, P4.03, P4.04, P4.06, P4.07, P4.10, P5.02 faults. The LVRT settings for the AC1-082 and AC2-036 projects need to be updated to resolve the tripping, or actual clearing times once obtained from the transmission owner should be used to perform re-study. Also, AC2-036 project needs to be re-studied once Racine Hydro plant return date is confirmed. Installation of Power system stabilizer (PSS) at Racine Hydro could improve the damping. PJM recommends considering the PSS installation before AC2-036 project goes into service.

See full Stability Report in Appendix 2 at the end of this report.

Affected System Analysis & Mitigation

LGEE Impacts:

None

MISO Impacts:

None

Duke, Progress & TVA Impacts:

None

OVEC 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.

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

New System Reinforcements

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

#	Overloaded Facility	Upgrade Description	Schedule	Estimated Cost
N-1	05RACINE-05LAKIN 69 kV line	The following work will be required to relieve the Racine – Lakin 69kV line overload: Rebuild/Reconductor 2.40 miles of the ACSR ~ 167.8 ~ 6/1 ~ PIGEON (3/0) conductor section 2. PJM Network Upgrade N5527.	An approximate construction time would be 24 to 36 months after signing an interconnection agreement.	**$3.6 Million**
			Total New Network Upgrade	**$3,600,000**

Table 4

Interconnection Capacity Transfer Rights (ICTRs) Note:

Presently, AC2-036 receives zero ICTRs (preliminary) for this 69 kV upgrade in AEP.

AEP and PJM West LDAs are not "modeled" LDAs in the 2021 BRA which means no CETLs are calculated for these LDAs.

These ICTRs are Preliminary since the next available BRA for the customer to bid ICTRs is the upcoming 2022 BRA. The AC2-036 customer's ICTRs should be based on the 2022 BRA CETL results which will not be posted until 5/1/19 due to the 2022 BRA being delayed this year.

The AC2-036 ICTRs will need to be confirmed once the 2022 BRA Planning parameters are posted.

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)

(Summary form of Cost allocation for transmission lines and transformers will be inserted here if any)

None

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 be between 24 to 36 months after signing an interconnection agreement.

Conclusion

Based upon the results of this Impact Study, the construction of the 20.0 MW (12.0 MW Capacity) solar generating facility of Hecate Energy (PJM Project #AC2-036) will require the following additional interconnection charges. This plan of service will interconnect the proposed solar generating facility in a manner that will provide operational reliability and flexibility to both the AEP system and the Hecate Energy generating facility.

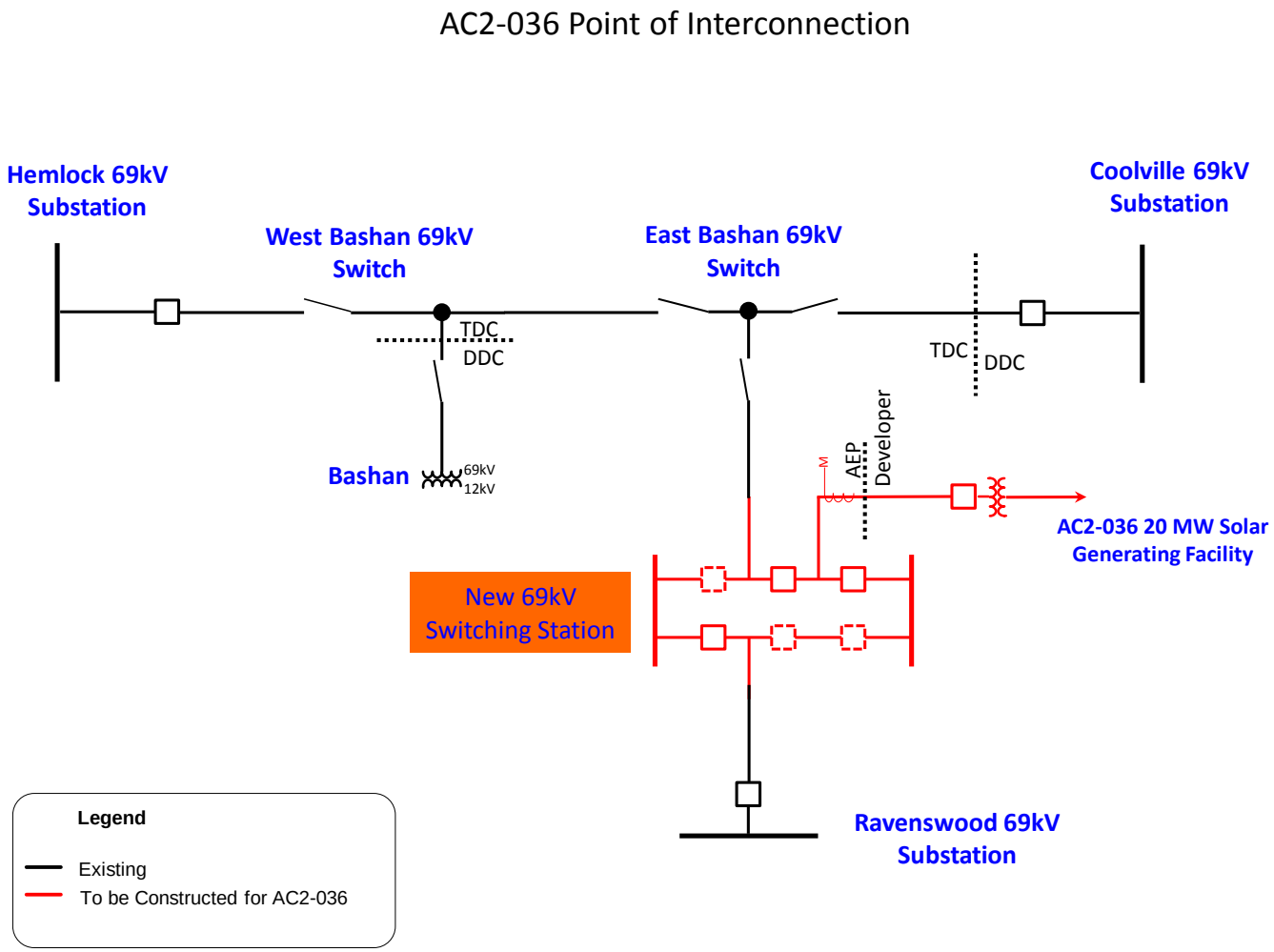
Cost Breakdown for Point of Interconnection (Ravenswood-East Bashan Switch 69 kV)			
Type of Network Upgrade	**Network Upgrade #**	**Description**	**Cost**
Attachment Cost	n5827	New 69 kV Switching Station	$3,500,000
Direct Connection Cost Estimate	n5828	Ravenswood-East Bashan Switch 69 kV T-Line Cut In	$700,000
Direct Connection Cost Estimate	n5829	69 kV Revenue Metering	$200,000
Non-Direct Connection Cost Estimate	n5830	Install line protection and controls at the New 69 kV Switching Station.	$850,000
Non-Direct Connection Cost Estimate	n5831	Upgrade line protection and controls at the Ravenswood 69 kV substation to coordinate with the new 69 kV switching station.	$200,000
Non-Direct Connection Cost Estimate	n5832	Upgrade line protection and controls at the Hemlock 69 kV substation to coordinate with the new 69 kV switching station.	$200,000
Non-Direct Connection Cost Estimate	n5527	The following work will be required to relieve the Racine – Lakin 69kV line overload: 2.4 mile section of the Copper #2 conductor between Racine and Lakin 69 kV stations which will need to be rebuilt.	$3,600,000
		Total Estimated Cost for Project AC2-036	**$9,250,000**

Table 5

The estimates 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.

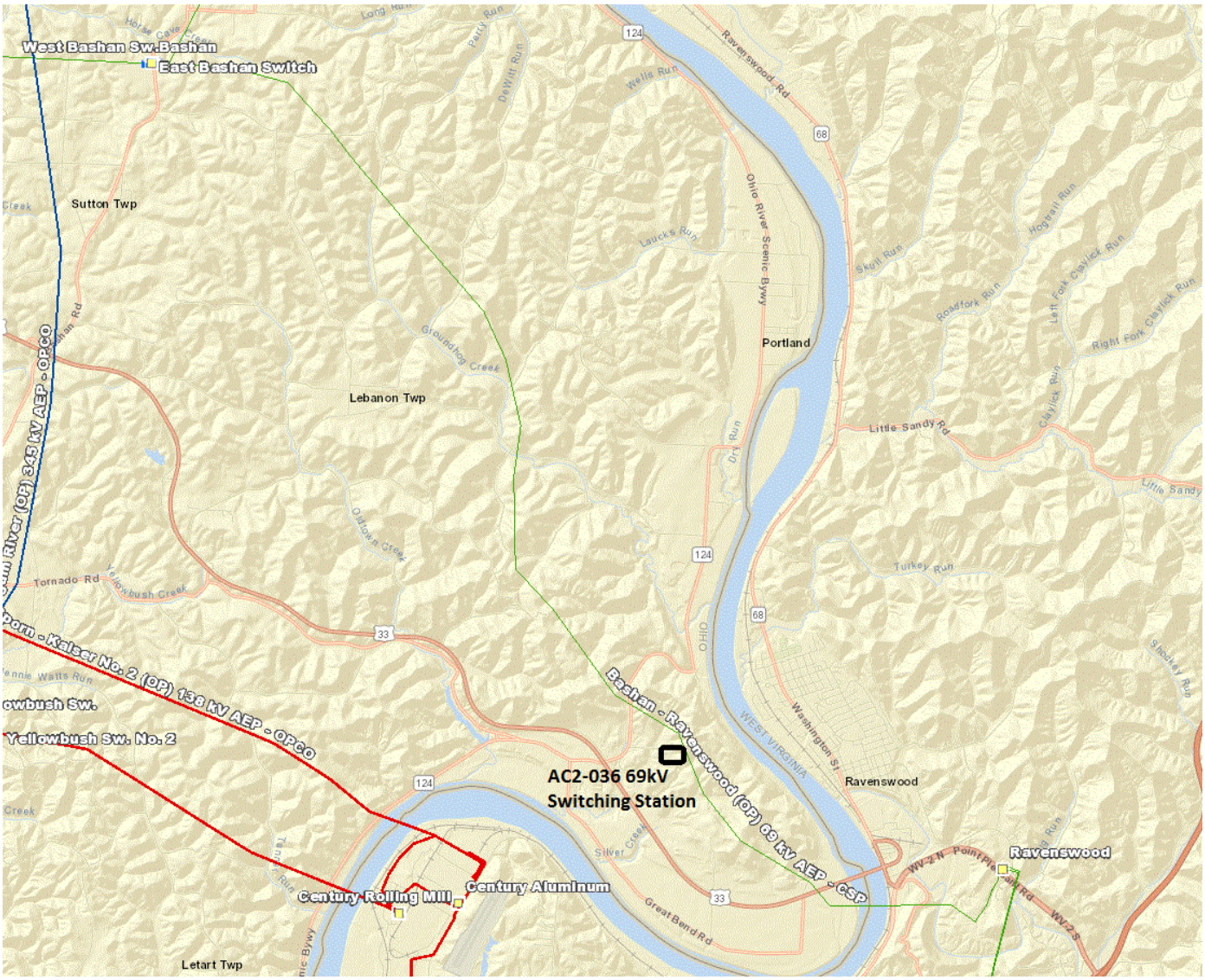
Figure 1: Point of Interconnection (Ravenswood – East Bashan Switch 69 kV)

Single-Line Diagram



Remote Stations not completely shown

Figure 2: Point of Interconnection (Ravenswood – East Bashan Switch 69 kV)



Appendix 1

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.

Appendix 1

(AEP - AEP) The 05RACINE-05LAKIN 69 kV line (from bus 244761 to bus 244756 ckt 1) loads from 89.16% to 100.47% (AC power flow) of its emergency rating (44 MVA) for the single line contingency outage of '248_B2_TOR5081_AC1-182 A'. This project contributes approximately 5.28 MW to the thermal violation.

CONTINGENCY '248_B2_TOR5081_AC1-182 A'
OPEN BRANCH FROM BUS 246732 TO BUS 247080 CKT Z1 / 246732 05BASHAN 69.0 247080 05WBASHNSS 69.0 Z1
OPEN BRANCH FROM BUS 246735 TO BUS 247090 CKT 1 / 246735 05COOLVL 69.0 247090 05E.BASHSS 69.0 1
OPEN BRANCH FROM BUS 247090 TO BUS 926810 CKT 1 / 247090 05E.BASHSS 69.0 244762 05RAVENSWD 69.0 1
OPEN BRANCH FROM BUS 247090 TO BUS 247080 CKT 1 / 247090 05E.BASHSS 69.0 247080 05WBASHNSS 69.0 1
END

Bus Number	*Bus Name*	*Full Contribution*
244761	*05RACINE*	*6.33*
932241	*AC2-036 C*	*5.28*
926811	*AC1-082 C*	*12.76*

Appendix 2 – Stability Report

AC2-036 System Impact Study

Dynamic Simulation Analysis

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Executive Summary

Generator Interconnection Request AC2-036 is for a 20 MW Maximum Facility Output (MFO) solar powered generating facility with a Point of Interconnection (POI) at a tap on the East Bashan – Ravenswood 69kV circuit (same POI as AC1-082) in the AEP system, Meigs County, Ohio.

This report describes a dynamic simulation analysis of AC2-036 as part of the overall system impact study.

The load flow scenarios for the analysis were based on the RTEP 2020 Summer Peak case, modified to include applicable queue projects. AC2-036 was set to maximum power output.

AC2-036 was tested for compliance with NERC, PJM, Transmission Owner and other applicable criteria. 32 contingencies were studied, each with at least a 10 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.

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

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.

A single contingency (P1.14) out of 32 contingencies tested on the 2020 peak load case met the following stability criteria:

a) AC2-036 is able to ride through the faults (except for faults where protective action trips a generator(s)),

b) The system with AC2-036 included is transiently stable and post-contingency oscillations are positively damped with a damping margin of at least 3%.

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.

Insufficient damping was observed for P1.13 fault.

- The same contingencies were run without AC2-036 in service and similar results were observed. Therefore insufficient damping is not attributable to addition of AC2-036.
- The same contingencies were run without Racine Unit 1 in service and the insufficient damping was not observed.

AC1-082 and AC2-036 unit tripping is observed for P1.01, P1.04, P1.09, P1.14, P4.01, P4.02, P4.03, P4.04, P4.06, P4.07, P4.10, P5.02 faults. The LVRT settings for the AC1-082 and AC2-036 projects need to be updated to resolve the tripping, or actual clearing times once obtained from the transmission owner should be used to perform re-study. Also, AC2-036 project needs to be re-studied once Racine Hydro plant return date is confirmed. Installation of Power system stabilizer (PSS) at Racine Hydro could improve the damping. PJM recommends considering the PSS installation before AC2-036 project goes into service.

1. Introduction

Generator Interconnection Request AC2-036 is for a 20 MW Maximum Facility Output (MFO) solar powered generating facility with a Point of Interconnection (POI) at a tap on the East Bashan – Ravenswood 69kV circuit (same POI as AC1-082) in the AEP system, Meigs County, Ohio.

This analysis is effectively a screening study to determine whether the addition of AC2-036 will meet the dynamics requirements of the NERC, PJM and Transmission Owner reliability standards.

In this report the AC2-036 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 AC2-036 is for a 20 MW Maximum Facility Output (MFO) solar powered generating facility with a Point of Interconnection (POI) at a tap on the East Bashan – Ravenswood 69kV circuit (same POI as AC1-082) in the AEP system, Meigs County, Ohio.

The dynamic model for the AC2-036 plant is based on the TMEIC REGCAU1, REECBU1 & REPCAU1 generic PSS/E version 33 user defined models.

Figure 1 shows the simplified one-line diagram of the AC1-082 loadflow model. Table 1 lists the parameters given in the impact study data and the corresponding parameters of the AC2-036 loadflow model.

Additional project details are provided in Attachments 1 through 4:

- Attachment 1 contains the Impact Study Data which details the proposed AC1-082 project.
- Attachment 2 shows the one line diagram of the AEP system in the vicinity of AC1-082.
- Attachment 3 provides a diagram of the PSS/E model in the vicinity of AC1-082.
- Attachment 4 gives the PSS/E loadflow and dynamic models of the AC1-082 plant.

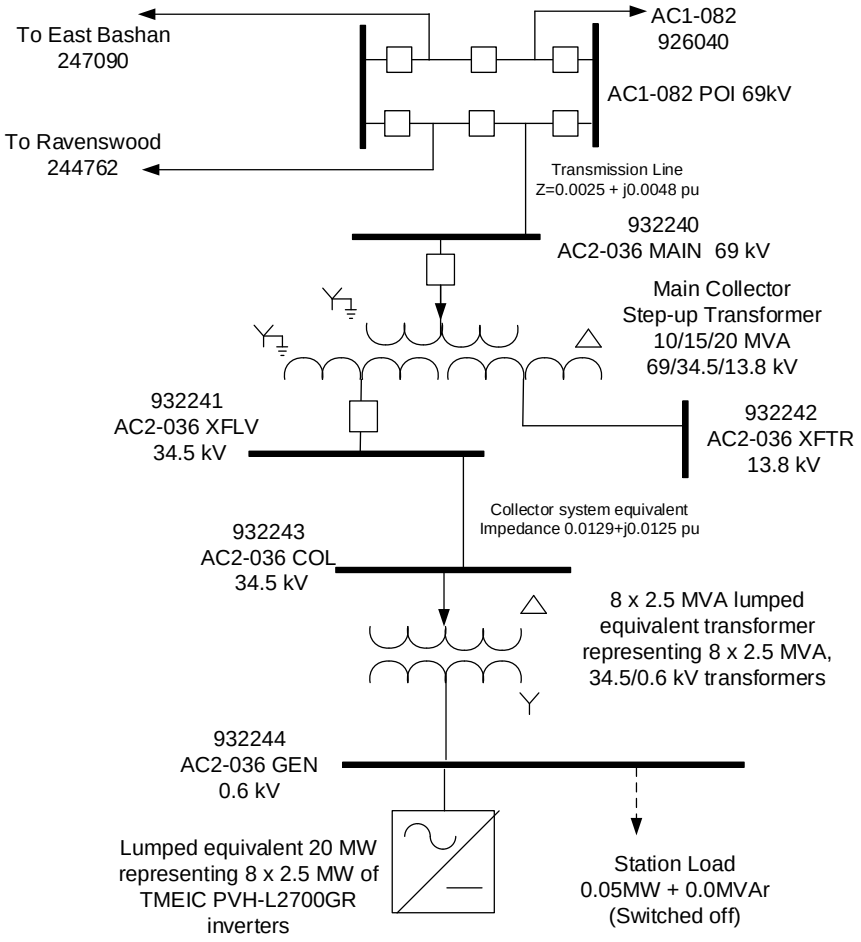

Figure 1: AC2-036 Plant Model

Table 1: AC2-036 Plant Model

	Impact Study Data	Model
Inverters	8 × 2.5 MW TMEIC PVH-L2700GR Solar Inverters MVA base = 2.7 MVA Vt = 0.6 kV	Lumped equivalent representing 8 × 2.5 MW TMEIC PVH-L2700GR Solar Inverters Pgen 20 MW Pmax 20 MW Pmin 0 MW Qmax 6.57 MVAr Qmin -6.57 MVAr Mbase 21.6 MVA Zsorce @Mbase 0.0 + j999.999 pu
GSU transformer	8 x 34.5/0.6 kV two winding transformers Transformer base = 2.5 MVA Rating = 3 MVA Impedance = 0.006626 + j0.057117 pu @ MVA base Number of taps = n/a Tap step size = n/a	Lumped equivalent representing 8 x 34.5/0.6 kV 2.5 MVA two winding transformers Transformer base = 20 MVA Rating = 24 MVA Impedance = 0.006626 + j0.057117 pu @ MVA base Number of taps = 5 Tap step size = 2.5%

	Impact Study Data	Model
Collector step-up transformer	1 x 69/34.5/13.8 kV three winding transformer Transformer base = 10 MVA Rating = 10/15/20 MVA Impedances: High – Low = 0.002026 + j0.074973 pu High – Tertiary = 0.003963 + j0.146646 pu Low – Tertiary = 0.001629 + j0.060278 pu All impedances @ MVA base Number of taps = n/a Tap step size = n/a	1 x 69/34.5/13.8 kV three winding transformer Transformer base = 10 MVA Rating = 10/15/20 MVA Impedances: High – Low = 0.002026 + j0.074973 pu High – Tertiary = 0.003963 + j0.146646 pu Low – Tertiary = 0.001629 + j0.060278 pu All impedances @ MVA base Number of taps = 5 Tap step size = 2.5%
Auxiliary load	none	none
Station load	0.05 MW + 0.0 MVAr on LV side of GSU	0.05 MW + 0.0 MVAr (switched out)
Collector System Equivalent	positive sequence impedance: 0.0129 + j0.0125 pu charging susceptance: j0.0005 all impedances @ 100 MVA base	positive sequence impedance: 0.0129 + j0.0125 pu charging susceptance: j0.0005 all impedances @ 100 MVA base

	Impact Study Data	Model
Transmission Line	positive sequence impedance: 0.0025 + j0.0048 pu charging susceptance: j0.000069 all impedances @ 100 MVA base	positive sequence impedance: 0.0025 + j0.0048 pu charging susceptance: j0.000069 all impedances @ 100 MVA base

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 peak load case with the following modifications:

a) Addition of all applicable queue projects prior to AC2-036.

b) Addition of AC2-036 queue project.

c) Removal of withdrawn and subsequent queue projects in the vicinity of AC2-036.

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

e) Merchant transmission project X3-028 set online and at maximum power import into PJM.

The AC2-036initial conditions are listed in Table 2, indicating maximum power output.

Table 2: AC2-036initial conditions

Bus	Name	Unit	PGEN (MW)	QGEN (MVAr)	ETERM (pu)	POI Voltage (pu)
932244	AC2-036 GEN1	1	20.0	-2.1	1.0139	1.0148

Generation within the PJM500 system (area 225 in the PSS/E case) and within the vicinity of AC2-036 was dispatched online at maximum output (PMAX). The dispatch of generation in the vicinity of AC2-036 is given in Attachment 5.

[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 6 list the contingencies that were studied, with representative worst case total clearing times provided by PJM. Each contingency was studied over at least a 10 second simulation time interval.

The studied contingencies include:

a) Steady state operation (20 second);

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.

No relevant bus, tower, or high speed reclosing (HSR) contingencies were found.

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

- AC1-082/AC2-036 POI 69 kV
- Ravenswood 69 kV
- Hemlock 69 kV
- Racine Hydro 69 kV

The one line diagram of the AEP network in the vicinity of AC1-082 is included in Attachment 2.

Clearing times listed in Tables 3 to 6 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 stability case directly by using the ASCC fault calculation method and zero/positive sequence impedance ratio provided by PJM.

5. Evaluation Criteria

This study is focused on AC2-036, 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) AC2-036 is able to ride through the faults (except for faults where protective action trips a generator(s)),

b) The system with AC2-036 included should be transiently stable and post-contingency oscillations are positively damped with a damping margin of at least 3%.

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.

6. Summary of Results

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

Insufficient damping was observed for P1.13 fault.

- The same contingencies were run without AC2-036 in service and similar results were observed. Therefore insufficient damping is not attributable to addition of AC2-036.
- The same contingencies were run without Racine Unit 1 in service and the insufficient damping was not observed.

AC1-082 and AC2-036 unit tripping is observed for P1.01, P1.04, P1.09, P1.14, P4.01, P4.02, P4.03, P4.04, P4.06, P4.07, P4.10, P5.02 faults. The LVRT settings for the AC1-082 and AC2-036 projects need to be updated to resolve the tripping, or actual clearing times once obtained from the transmission owner should be used to perform re-study. Also, AC2-036 project needs to be re-studied once Racine Hydro plant return date is confirmed. Installation of Power system stabilizer (PSS) at Racine Hydro could improve the damping. PJM recommends considering the PSS installation before AC2-036 project goes into service.

7. Recommendations and Mitigations

AC1-082 and AC2-036 unit tripping is observed for P1.01, P1.04, P1.09, P1.14, P4.01, P4.02, P4.03, P4.04, P4.06, P4.07, P4.10, P5.02 faults. The LVRT settings for the AC1-082 and AC2-036 projects need to be updated to resolve the tripping, or actual clearing times once obtained from the transmission owner should be used to perform re-study. Also, AC2-036 project needs to be re-studied once Racine Hydro plant return date is confirmed. Installation of Power system stabilizer (PSS) at Racine Hydro could improve the damping. PJM recommends considering the PSS installation before AC2-036 project goes into service.

Table 3: Steady State Operation

Fault ID	Duration	Result No Mitigation
P0.01	Steady state 20 sec	Stable

Table 4: Three-phase Faults with Normal Clearing

Fault ID	Fault description	Clearing Time (Cycles) Faulted end / Remote end	Result No Mitigation
P1.01	Fault at AC1-082 POI 69 kV on AC1-082 circuit resulting in additional loss of AC1-082 unit.	6 / 60	AC1-082, AC2-036 tripped
P1.02	Fault at AC1-082 POI 69 kV on Ravenswood circuit.	6 / 60	Stable
P1.03	Fault at AC1-082 POI 69 kV on East Bashan Switch – West Bashan Switch – Hemlock circuit resulting in additional loss of East Bashan Switch – Coolville circuit and all equipment at East Bashan Switch, West Bashan Switch, Bashan, and Coolville.	6 / 60	Stable
P1.04	Fault at Ravenswood 69 kV on AC1-082 POI circuit.	6 / 60	AC2-036 tripped
P1.05	Fault at Ravenswood 69 kV on Ravenswood 14.4 MVAR capacitor bank.	8.5	Stable
P1.06	Fault at Ravenswood 69 kV on Ravenswood 69/12 kV transformer resulting in additional loss of Ravenswood – AC1-082 POI circuit, Ravenswood 14.4 MVAR capacitor bank, Ravenswood – Ripley circuit and Ravenswood – Mill Run circuit.	7	Stable
P1.07	Fault at Ravenswood 69 kV on Mill Run – Cottageville – Racine Hydro circuit resulting in additional loss of all equipment at Mill Run and Cottageville.	6	Stable
P1.08	Fault at Ravenswood 69 kV on Ripley – Leon AP circuit resulting in additional loss of all equipment at Ripley.	6 / 60	Stable
P1.09	Fault at Hemlock 69 kV on West Bashan Switch – East Bashan Switch – AC1-082 POI circuit resulting in additional loss of all equipment at West Bashan Switch, Bashan, East Bashan Switch, and Coolville.	6 / 60	AC2-036 tripped
P1.10	Fault at Hemlock 69 kV on Meigs Station circuit.	6 / 60	Stable
P1.11[2]	Fault at Hemlock 69 kV on Hemlock 14.4 MVAR capacitor bank.	6 / 60	Stable
P1.12[3]	Fault at Hemlock 69 kV on Hemlock 69/12 kV transformer.	6 / 60	Stable

[2] This contingency was not run as Hemlock 14.4 MVAR capacitor is not modeled in PSSE.
[3] This contingency was not run as Hemlock 69/12 kV transformer is not modeled in PSSE.

Fault ID	Fault description	Clearing Time (Cycles) Faulted end / Remote end	Result No Mitigation
P1.13	Fault at Racine Hydro 69 kV on Lakin circuit (Racine Hydro in Service)	5.5	Oscillations observed for Racine units
P1.14	Fault at AC1-082 POI 69 kV on AC2-036 circuit resulting in loss of AC2-036 unit.	6 / 60	AC1-082, AC2-036 tripped

Table 5: Single-phase Faults With Stuck Breaker

Fault ID	Fault description	Clearing Time Primary faulted end / Delayed faulted end / Primary remote end (Cycles)	Result No Mitigation
P4.01	Fault at AC1-082 POI 69 kV on AC1-082 circuit resulting in loss of AC1-082 units. Breaker stuck to AC2-036 circuit. Fault cleared with no additional loss.	6 / 18 / 60	AC2-036 tripped
P4.02	Fault at AC1-082 POI 69 kV on AC1-082 circuit resulting in loss of AC1-082. Breaker stuck to East Bashan 69 kV Switch. Fault cleared with loss of AC1-082 POI – East Bashan Switch - West Bashan Switch – Hemlock circuit, and loss of all equipment at East Bashan Switch, West Bashan Switch, Bashan, and Coolville.	6 / 18 / 60	AC2-036 tripped
P4.03	Fault at AC1-082 POI 69 kV on Ravenswood circuit. Breaker stuck to AC2-036 69kV circuit. Fault cleared with loss of AC2-036 unit	6 / 18 / 60	AC2-036 tripped
P4.04	Fault at AC1-082 POI 69 kV on Ravenswood circuit. Breaker stuck to East Bashan Switch 69 kV circuit. Fault cleared with loss AC1-082 POI – East Bashan Switch - West Bashan Switch – Hemlock circuit, and loss of all equipment at East Bashan Switch, West Bashan Switch, Bashan, and Coolville, additional loss of AC1-082, AC2-036 units.	6 / 18 / 60	AC2-036 tripped
P4.05	Fault at AC1-082 POI 69 kV on East Bashan Switch – West Bashan Switch – Hemlock circuit. loss of all equipment at East Bashan Switch, West Bashan Switch, Bashan, and Coolville in normal clearing. Breaker stuck to AC1-082 circuit. Fault cleared with loss of AC1-082 unit.	6 / 18 / 60	Stable
P4.06	Fault at AC1-082 POI 69 kV on East Bashan Switch – West Bashan Switch – Hemlock circuit. Breaker stuck to Ravenswood circuit. Fault cleared with loss of AC1-082 POI – Ravenswood circuit, and loss of all equipment at East Bashan Switch, West Bashan Switch, Bashan, and Coolville, additional loss of AC1-082, AC2-036 units	6 / 18 / 60	AC2-036 tripped
P4.07	Fault at Ravenswood 69 kV on AC1-082 POI circuit. Breaker stuck to Ravenswood 69 kV bus. Fault cleared with loss of Ravenswood 69/12 kV transformer, Ravenswood 14.4 MVAR capacitor bank, Ravenswood – Mill Run circuit, and Ravenswood – Ripley circuit.	6 / 18 / 60	AC2-036 tripped

Fault ID	Fault description	Clearing Time Primary faulted end / Delayed faulted end / Primary remote end (Cycles)	Result No Mitigation
P4.08	Fault at Ravenswood 69 kV on Ravenswood 14.4 MVAR capacitor bank. Breaker stuck to Ravenswood 69 kV bus. Fault cleared with loss of Ravenswood 69/12 kV transformer, Ravenswood – AC1-082 POI circuit, Ravenswood – Mill Run circuit, and Ravenswood – Ripley circuit.	6 / 18 / 60	Stable
P4.09	Fault at Ravenswood 69 kV on Ravenswood 69/12 kV transformer resulting in additional loss of Ravenswood – AC1-082 POI circuit, Ravenswood 14.4 MVAR capacitor bank, and Ravenswood – Ripley circuit. Breaker H stuck to Ravenswood 69 kV bus. Fault cleared with loss of Ravenswood – Mill Run - Cottageville – Racine Hydro circuit, and loss of all equipment at Mill Run and Cottageville.	6 / 18 / 60	Stable
P4.10	Fault at Ravenswood 69 kV on Ravenswood 69/12 kV transformer resulting in additional loss of Ravenswood – Mill Run circuit, Ravenswood 14.4 MVAR capacitor bank, and Ravenswood – Ripley circuit. Breaker F stuck to Ravenswood 69 kV bus. Fault cleared with loss of Ravenswood – AC1-082 POI circuit.	6 / 18 / 60	AC2-036 tripped
P4.11	Fault at Ravenswood 69 kV on Ravenswood 69/12 kV transformer resulting in additional loss of Ravenswood – Mill Run circuit, Ravenswood 14.4 MVAR capacitor bank, and Ravenswood – AC1-082 POI circuit. Breaker G stuck to Ravenswood 69 kV bus. Fault cleared with loss of Ravenswood – Ripley – Leon AP circuit, and loss of all equipment at Ripley.	6 / 18 / 60	Stable
P4.12	Fault at Ravenswood 69 kV on Mill Run – Cottageville – Racine Hydro circuit. Breaker stuck to Ravenswood 69 kV bus. Fault cleared with loss of Ravenswood 69/12 kV transformer, Ravenswood 14.4 MVAR capacitor bank, Ravenswood – AC1-082 POI circuit, Ravenswood – Ripley circuit, and loss of all equipment at Mill Run and Cottageville.	6 / 18 / 60	Stable
P4.13	Fault at Ravenswood 69 kV on Ripley – Leon AP circuit. Breaker stuck to Ravenswood 69 kV bus. Fault cleared with loss of Ravenswood 69/12 kV transformer, Ravenswood 14.4 MVAR capacitor bank, Ravenswood – AC1-082 POI circuit, Ravenswood – Mill Run circuit, and loss of all equipment at Ripley.	6 / 18 / 60	Stable

Fault ID	Fault description	Clearing Time Primary faulted end / Delayed faulted end / Primary remote end (Cycles)	Result No Mitigation
P4.14	Fault at Hemlock 69 kV on West Bashan Switch – East Bashan Switch – AC1-082 POI circuit. Breaker stuck to Hemlock 69 kV bus. Fault cleared with loss of Hemlock 69/12 kV transformer, Hemlock 14.4 MVAR capacitor bank, Hemlock – Meigs Station circuit, and loss of all equipment at West Bashan Switch, East Bashan Switch, Coolville, and East Bashan Switch.	6 / 18 / 60	Stable
P4.15	Fault at Hemlock 69 kV on Meigs Station circuit. Breaker stuck to Hemlock 69 kV bus. Fault cleared with loss of Hemlock 69/12 kV transformer, Hemlock 14.4 MVAR capacitor bank, and Hemlock – West Bashan Switch circuit.	6 / 18 / 60	Stable
P4.16[4]	Fault at Hemlock 69 kV on Hemlock 14.4 MVAR capacitor bank. Breaker stuck to Hemlock 69 kV bus. Fault cleared with loss of Hemlock 69/12 kV transformer, Hemlock – West Bashan Switch circuit, and Hemlock – Meigs Station circuit.	6 / 18 / 60	N/A
P4.17[5]	Fault at Hemlock 69 kV on Hemlock 69/12 kV transformer. Breaker stuck to Hemlock 69 kV bus. Fault cleared with loss of Hemlock 14.4 MVAR capacitor bank, Hemlock – West Bashan Switch circuit, and Hemlock – Meigs Station circuit.	6 / 18 / 60	N/A
P4.18	Fault at AC1-082 POI 69 kV on AC2-036 circuit resulting in loss of AC2-036 unit. Breaker stuck to AC1-082 circuit. Fault cleared with no additional loss.	6 / 18 / 60	Stable
P4.19	Fault at AC1-082 POI 69 kV on AC2-036 circuit resulting in loss of AC2-036 unit. Breaker stuck to Ravenswood circuit. Fault cleared with loss of AC1-082 POI – Ravenswood circuit.	6 / 18 / 60	Stable

[4] This contingency was not run as Hemlock 14.4 MVAR capacitor is not modeled in PSSE.
[5] This contingency was not run as Hemlock 69/12 kV transformer is not modeled in PSSE.

Table 6: Single-phase Faults With Delayed (Zone 2) Clearing at line end closest to AC1-082 POI

Fault ID	Fault description	Clearing Time (Cycles)	Result No Mitigation
P5.01	Fault at 80% of line from AC1-082 POI on East Bashan Switch – West Bashan Switch – Hemlock circuit. Delayed clearing at AC1-082 POI. Fault cleared with loss of East Bashan Switch – Coolville circuit and all equipment at East Bashan Switch, West Bashan Switch, Bashan, and Coolville.	6 / 60	Stable
P5.02	Fault at 80% of line from AC1-082 POI on Ravenswood circuit. Delayed clearing at AC1-082 POI.	6 / 60	AC2-036 tripped
P5.03	Fault at 80% of line from Ravenswood 69 kV on Ripley – Leon circuit. Delayed clearing at Ravenswood 69 kV. Fault cleared with loss of all equipment at Ripley.	6 / 60	Stable
P5.04	Fault at 80% of line from Ravenswood 69 kV on Mill Run – Cottageville – Racine Hydro circuit. Delayed clearing at Ravenswood 69 kV. Fault cleared with loss of all equipment at Mill Run and Cottageville.	6 / 60	Stable
P5.05	Fault at 80% of line from Hemlock 69 kV on Megis circuit. Delayed clearing at Hemlock 69 kV.	6 / 60	Stable