FILED
October 18, 2019
INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

IN THE MATTER OF THE PETITION BY SPEEDWAY SOLAR, LLC FOR CERTAIN DETERMINATIONS BY THE COMMISSION WITH RESPECT TO ITS JURISDICTION OVER PETITIONER'S ACTIVITIES AS A GENERATOR OF ELECTRIC POWER	))))))	**CAUSE NO. 45230**

SPEEDWAY SOLAR, LLC'S CONSOLIDATED INITIAL REPORT AND THIRD QUARTER 2019 REPORT

This Consolidated Initial Report and Third Quarter 2019 Report ("Report") is filed as required by the Commission's Order in this Cause issued on September 18, 2019, in Cause No. 45230 (the "Order"). The Order requires Speedway Solar, LLC ("Speedway") to file an initial report within 30 days of the Order and to file quarterly reports within 30 days of the end of each quarter during the period prior to achieving commercial operation. Because the initial report is due on October 18, 2019, and the Third Quarter 2019 Report is due on October 30, 2019, Speedway files this Report that consolidates the initial report and the Third Quarter 2019 report for purposes of administrative efficiency. The information in the initial report mirrors the information in the Third Quarter 2019 report. Filing one consolidated report serves administrative efficiency by allowing the Commission to review only one report instead of two duplicate reports. Further, counsel for Speedway has informed counsel for the Office of Utility Consumer Counselor of its intent to file a consolidated initial report and report for the Third Quarter 2019, and counsel for the OUCC expressed no objection to Speedway filing a consolidated report.

20547634.1

This Report provides the required information to the extent such information is known and available. The requested information is as follows:

(1) Project ownership and name(s) of the Facility.

The owner of the project is Speedway Solar, LLC. The name of the Facility is Speedway Solar.

(2) Name, title, address, and phone number(s) for primary contact person(s) for the Facility.

Peter K. Endres
Development Manager
Ranger Power LLC
20 Jay Street, #900
Brooklyn, NY 11201
(216) 538-5420

(3) Number and location of solar panels deployed.

Speedway Solar has not yet installed any solar panels at the project site. Based on preliminary design, Speedway Solar will have approximately 677,000 solar panels.

(4) Anticipated total output of the Facility.

The anticipated output of Speedway Solar is 199 MWac.

(5) Manufacturer, model number, and operational characteristics of solar panels.

Speedway Solar is currently evaluating solar panel options and has not yet finalized the type of solar panels to be used.

(6) Connecting utility(s).

The connecting utility will be Duke Energy.

(7) Copy of any Interconnection System Impact Studies prepared by MISO.

The DPP Phase I and Phase II System Impact Studies prepared by MISO were attached to the testimony of Peter K. Endres as Petitioner's Attachment PKE-9. The MISO DPP Phase III System Impact Study is attached to this Report.

(8) Expected in-service (commercial operation) date.

The expected commercial operation date is no later than December 31, 2023.

(9) An estimate of the engineering/construction timeline and critical milestones for the Facility.

An estimate of the engineering/construction timeline and critical milestones for the Facility are set forth below:

Start of construction: Q3 2022

Collection system completion: Q2 2023

Solar panel mechanical completion: Q3 2023

Project transmission line and substation completion: Q2 2023

Project commercial operation: no later than December 31, 2023

(10) The status of the LGIA with MISO.

The LGIA is expected to be completed by January 2020.

(11) The information listed under the Subsequent Reports section, to the extent such information is available.

Finding 6(B) of the Order requires the following information be reported in subsequent reports to the Commission. Responses are provided to the extent known and available.

(i) Any changes to the information provided in the Initial Report.

Not applicable.

(ii) Any reports of Interconnection System Impact Studies not previously submitted to the Commission.

The MISO DPP Phase III System Impact Study is attached to this Report.

(iii) Copy of the LGIA as filed with FERC.

The LGIA has not yet been finalized.

(iv) Notice of the establishment of an independent financial instrument, including its form and amount.

This has not been established yet.

(v) Achievement of construction milestones described in the LGIA and such events as the procurement of major equipment, the receipt of major permits material to the construction and operation of the Facility, construction start-up, initial energization, and commercial operation.

Not applicable.

(vi) When commercial operation is achieved, the nameplate capacity, term, and identity of a purchaser for any contracts then existing for utility sales, contingency plans (if any) detailing response plans to emergency conditions as required by state or local units of government, the interconnecting transmission owner and/or MISO, and the Facility's certified (or accredited) dependable capacity rating.

Not applicable.

VERIFICATION

The undersigned, Adam Cohen, being first duly sworn upon his oath states that he is the President of Speedway Solar, LLC; that he prepared or supervised the preparation of Speedway Solar, LLC's Consolidated Initial Report and Third Quarter 2019 Report; and that the statements contained therein are true to the best of his knowledge, information and belief.

By: ______________________
Adam Cohen

STATE OF NEW YORK)
) **SS:**
COUNTY OF Kings)

Subscribed and sworn to before me, a Notary Public in and for said State and County, this 16 day of October, 2019.

____
Signature

Caitlin P. Reivers
Printed

My Commission Expires:
9/11/2021

My County of Residence
Orange

CAITLIN P. REIVERS
NOTARY PUBLIC-STATE OF NEW YORK
No. 01RE6364252
Qualified In Orange County
My Commission Expires 09-11-2021

Respectfully submitted,

Michael T. Griffiths (26384-49)

BINGHAM GREENEBAUM DOLL LLP
2700 Market Tower
10 West Market Street
Indianapolis, IN 46024
(317) 635-8900 (telephone)
(317) 236-9907 (facsimile)
mgriffiths@bgdlegal.com

Attorney for Petitioner,
Speedway Solar, LLC

CERTIFICATE OF SERVICE

The undersigned hereby certifies that a copy of the foregoing was electronically delivered this 18th day of October, 2019, to the following:

Office of Utility Consumer Counselor
115 West Washington Street
Suite 1500 South
Indianapolis, Indiana 46204
lhitzbradley@oucc.in.gov
infomgt@oucc.in.gov

An attorney for Petitioner,
Speedway Solar, LLC

Final Report
MISO DPP 2017 August Central Area Study Phase III Report

Revision 2

July 17th, 2019

MISO
720 City Center
Drive Carmel
Indiana 46032
http://www.misoenergy.org

Contents

1. Executive Summary

This report presents the results of a System Impact Study (SIS) performed to evaluate the interconnection of the generators in the DPP 2017 August Central Area Phase III (Central Area DPP3). The study was performed under the direction of MISO and reviewed by an ad hoc study group. The ad hoc study group was formed to review the study scope, methodology, models and results. The ad hoc study group consisted of representatives from the interconnection customers and the following utility companies – Ameren, American Electric Power, Big Rivers Electric Corporation, City of Springfield (IL) Water Light & Power, Columbia (MO) Water and Light, Commonwealth Edison, Duke Energy Midwest, Hoosier Energy, Indianapolis Power & Light, MISO, Northern Indiana Public Service, PJM, Southern Illinois Power Cooperative, and Vectren.

1.1. Project List

The original interconnection requests for DPP 2017 August Central Area had a total of 46 generation projects. Projects J797, J802, J804, J828, J854, J881, J882, and J920 withdrew prior to the start of DPP Phase I. Projects J467, J795, J827, J851, J872, and J887 withdrew during Decision Point I. Projects J478, J714, J824, and J835 withdrew and J848 reduced to 235 MW during Decision Point II. Therefore, there are 28 generation projects with a combined nameplate rating of 4,335.04 MW (ERIS) / 3,869.94 MW (NRIS). The detailed list of Central Area DPP3 is shown below in Table 1, and the Phase III study was kicked off on April 18th, 2019.

Table 1: List of DPP 2017 August Central Area Phase III Projects

Project	Fuel Type	Transmission Owner	County	State	Service Requested	MW	POI
J715	Wind	AMIL	Marshall	IL	NRIS	98	McLean County-Oglesby - 138kV Line 1382
J750	Wind	CWLP	Morgan	IL	NRIS	150	Westchester 138kV Substation
J800	Solar	AMIL	White	IL	NRIS	250	Crossville West Substation 138kV Nus
J805	Solar	DEI	Shelby	IN	NRIS	199	Gwynneville 345kV Substation
J808	Solar	AMIL	Randolph	IL	NRIS	99	Aster Substation 138kV Bus
J811	Solar	AMIL	Fayette	IL	NRIS	99	Ramsey East 138kV Substation
J813	Solar	AMIL	Clay	IL	NRIS	250	Louisville South Substation 138kV Bus
J815	Solar	AMIL	Christian	IL	NRIS	250	Taylorville South-Austin 138kV Line
J817	Solar	AMMO	Warren	MO	NRIS	139	Warrenton 161kV Substation
J826	Wind	AMIL	McLean	IL	NRIS	100	Weedman Substation 138kV Bus
J829	Solar	DEI	Sullivan	IN	NRIS	250	Dresser - Merom 345kV Line
J837	Wind	NIPSCO	White	IN	NRIS	200.1	Reynolds 345kV Substation

Project	Fuel Type	Transmission Owner	County	State	Service Requested	MW	POI
J838	Wind	NIPSCO	White	IN	NRIS	100	Reynolds 345kV Substation
J842	Wind	SIGE	Gibson	IN	NRIS	200	Gibson - Brown 345kV Line
J843	Wind	DEI	Gibson	IN	NRIS	200	Gibson - Francisco 345kV Line
J844	Wind	ATXI	Knox	IL	ERIS	147	Sandburg Substation 138kV Bus
J845	Wind	AMIL	Ford	IL	NRIS	120	Gibson City South - Paxton East 138kV Line
J847	Solar	NIPSCO	Jasper	IN	NRIS	90	Schafer Tap 138kV Substation
J848	Wind	ATXI	Christian	IL	NRIS	235	Pana Substation 138kV Bus
J853	Solar	AMIL	White	IL	NRIS	149	Norris City North Substation 138kV Bus
J856	Solar	SIGE	Vanderburgh	IN	NRIS	80	Scott (TWP 138/69) 138 kV Substation
J859	Solar	AMIL	Cass	IL	NRIS	149.94	Frederick North - Meredosia East 138kV Line
J883	Wind	NIPSCO	Pulaski	IN	NRIS	80	Monticello-East Winamac
J884	Solar	AMIL	McLean	IL	NRIS	100	Brokaw - Gibson City South 138kV Line
J903	Solar	DEI	Henry	IN	NRIS	100	Greensboro 138 kV Substation
J912	Solar	ATXI	Christian	IL	NRIS	100	Pana Substation 138kV Bus
J913	Solar	NIPSCO	White	IN	NRIS	200	Reynolds 345kV Substation
J949	Solar	ATXI	Coles	IL	NRIS	200	Kansas Substation 138kV Bus #3

1.2. Total Network Upgrades

The cost allocation of Network Upgrades for the projects in the DPP 2017 August Central Phase III reflects responsibilities for mitigating system impacts. The total cost of network upgrades is listed in Table 2 below. The costs for Network Upgrades are planning-level estimates and subject to revision in the facility studies.

Table 2: Total Cost of Network Upgrades for DPP 2017 August Central Phase III Projects

Project	ERIS Network Upgrades ($)				NRIS Network Upgrades ($)	Interconnection Facilities ($)		Shared Network Upgrades ($)	Total Network Upgrade Cost ($)	M2 ($)	M3 ($)	M4 ($)
	Thermal	Stability	Short Circuit	Affected System	Deliverability	TO Network Upgrades	TO – Owned Direct Assigned					
a	b	c	d	e	f	g	h	i	j = b+c+d+f+g+i	$4,000/MW	(10% of (j) from Phase I) – M2	(20% of (j) from Phase II) – M2 – M3
J715	$0	$0	$0	$0	$0	$7,435,000	$775,000	$0	$7,435,000	$400,000.00	$144,990.00	$495,010.00
J750	$0	$0	$0	$0	$0	$3,669,481	$0	$0	$3,669,481	$600,000.00	$0.00	$53,170.00
J800	$0	$0	$0	$0	$138,700	$730,000	$737,000	$0	$868,700	$1,000,000.00	$0.00	$1,220,000.00
J805	$7,200,000	$0	$0	$0	$0	$1,346,706	$3,026,518	$0	$8,546,706	$796,000.00	$0.00	$644,000.00
J808	$0	$0	$0	$0	$0	$979,100	$758,700	$0	$979,100	$396,000.00	$0.00	$0.00
J811	$3,423,750	$0	$0	$1,967,640	$0	$438,000	$1,089,000	$0	$3,861,750	$396,000.00	$652,436.00	$0.00
J813	$0	$0	$0	$4,405,820	$0	$690,000	$775,000	$0	$690,000	$1,100,000.00	$354,640.00	$0.00
J815	$852,000	$0	$0	$3,936,510	$0	$7,435,000	$775,000	$0	$8,287,000	$1,000,000.00	$0.00	$1,006,366.00
J817	$0	$0	$0	$650,000	$0	$3,627,000	$592,000	$0	$3,627,000	$556,000.00	$29,000.00	$585,000.00
J826	$0	$0	$0	$0*	$0	$1,133,000	$520,000	$0	$1,133,000	$470,000.00	$129,450.00	$0.00
J829	$0	$0	$0	$5,796,000*	$149,150	$13,723,359	$1,724,639	$0	$13,872,509	$1,000,000.00	$1,014,231.00	$1,685,769.00
J837	$0	$0	$0	$0	$0	$1,656,762	$0	$0	$1,656,762	$804,000.00	$0.00	$0.00
J838	$0	$0	$0	$63,000	$0	$1,656,762	$0	$0	$1,656,762	$804,000.00	$0.00	$0.00
J842	$0	$0	$0	$0	$315,400	$0	$14,964,863	$0	$315,400	$800,000.00	$221,268.20	$960,962.20
J843	$0	$0	$0	$0	$346,750	$14,841,851	$1,871,804	$0	$15,188,601	$800,000.00	$1,233,269.00	$1,966,731.00
J844	$0	$0	$0	$0	$0	$2,740,000	$967,000	$0	$2,740,000	$1,200,000.00	$0.00	$0.00
J845	$0	$0	$0	$0*	$0	$7,482,000	$775,000	$0	$7,482,000	$480,000.00	$1,152,216.50	$0.00
J847	$0	$0	$0	$0	$0	$0	$0	$0	$0	$360,000.00	$0.00	$0.00
J848	$2,661,750	$0	$0	$3,860,410	$0	$0	$1,055,000	$0	$2,661,750	$1,000,000.00	$277,842.00	$1,649,608.000
J853	$0	$0	$0	$0	$0	$0	$1,188,000	$0	$0	$596,000.00	$0.00	$0.00
J856	$0	$0	$0	$0	$0	$0	$1,552,504	$0	$0	$320,000.00	$0.00	$6,989.60
J859	$0	$0	$0	$0	$0	$7,441,000	$775,000	$0	$7,441,000	$600,000.00	$0.00	$486,830.00
J883	$0	$0	$0	$0	$0	$16,990,565	$0	$0	$16,990,565	$320,000.00	$480,000.00	$800,000.00
J884	$0	$0	$0	$268,900	$0	$1,425,000	$507,000	$0	$1,425,000	$400,000.00	$543,297.50	$96,702.50
J903	$0	$0	$0	$0	$0	$469,762	$1,067,394	$0	$469,762	$400,000.00	$0.00	$0.00
J912	$562,500	$0	$0	$0	$0	$848,000	$1,055,000	$0	$1,410,500	$400,000.00	$0.00	$317,754.00
J913	$0	$0	$0	$0	$0	$1,656,762	$0	$0	$1,656,762	$800,000.00	$0.00	$0.00
J949	$0	$0	$0	$4,304,830*	$0	$0	$1,037,000	$0	$0	$400,000.00	$596,890.00	$0.00

Notes:

- ∗ The in-service date of the proposed mitigation is after the in-service date of the generator project. An interim study is required to determine possible additional upgrades or service level until the mitigation project is in-service.
- ^ Upgrade costs and cost allocation for one or more mitigation projects are yet to be determined.

Analyses performed demonstrate the following transmission facilities are required to reliably interconnect this group of generators to the transmission system. Energy Resource Interconnection Service (ERIS) Network Upgrades and Network Resource Interconnection Service (NRIS) Network Upgrades are shown in

Table 3. Shared Network Upgrades are shown in Table 4.

Table 3: ERIS & NRIS Upgrades (Planning level cost estimates)

Network Upgrade	TO	GI projects requiring upgrade for ERIS	GI projects requiring upgrade for NRIS	Cost of solution ($)
Reconductor Bluff City Tap to Ramsey East (14 miles)	AMIL	J811, J815, J848, J912		$7,500,000
Replace two 345 kV breakers on the Duff – Francisco 345 kV line	DEI/SIGE		J800, J829, J842, J843	$950,000
Upgrade/Reconductor Morristown to Van Buren 69 kV (4.8 miles)	DEI	J805		$7,200,000

Note:

1) Details pertaining to upgrades, costs, and the execution plan for interconnection of the generating facility at the POI will be documented in the Facility Study for Interconnecting Generator.
2) Facilities that have been included as base case assumptions and the level of interconnection service that would be conditional upon these facilities being in service will be documented in the GIA (Generator Interconnection Agreement) for each respective GI request successfully achieving GIA execution.

2. Model Development and Study Assumptions

2.1. Base Case Models

The origin of the DPP 2017 August Central models is the MTEP17 models with the Bench Cases including all pre-queued projects and associated network upgrades, while the Study Cases contain all of the interconnection requests in DPP 2017 August Central Phase III, in addition to all the facilities in the Bench Cases.

- Bench Cases
  - BenchCase-MISO17_2022_SH90__TA_Pass3-DPP 2017-Aug_Central_190206
  - BenchCase-MISO17_2022_SUM__TA_Pass3-DPP 2017-Aug_Central_190206
- Study Cases
  - StudyCase-MISO17_2022_SH90__TA_Pass3-DPP 2017-Aug_Central_190206
  - StudyCase-MISO17_2022_SUM__TA_Pass3-DPP 2017-Aug_Central_190206

2.2. Monitored Elements

Under NERC category P0 conditions (system intact) branches were monitored for loading above the normal rating (PSS®E Rating A), and for NERC category P1-P7 conditions branches were monitored for emergency rating (PSS®E Rating B). Voltage limits were specified for system intact and contingent conditions as per applicable Transmission Owner Planning Criteria.

2.3. Contingencies

The following contingencies were considered in the steady state analysis:

1) NERC Category P0 (system intact -- no contingencies)
2) NERC Category P1 contingencies
   a. Single element outages, at buses with a nominal voltage of 68 kV and above
   b. Multiple element NERC Category P1 contingencies
3) NERC Category P2-P7 contingencies
4) For all the contingencies and post-disturbance analyses, cases were solved with transformer tap adjustment enabled, area interchange adjustment disabled, phase shifter adjustment disabled (fixed) and switched shunt adjustment enabled.

2.4. Study Methodology

Non-linear (AC) contingency analysis was performed on the benchmark and study cases, and the incremental impact of the DPP 2017 August Central generating facilities was evaluated by comparing the steady state performance of the transmission system in the Bench and Study Cases. Analyses used PSS®E version 33.9.0 and TARA version 1802.

2.5. Performance Criteria

A branch is considered a thermal constraint if the following conditions are met:

1) The generator has a larger than twenty percent (20%) sensitivity factor on the overloaded facilities under post-contingent condition (see NERC TPL) or five percent (5%) sensitivity factor under system-intact condition, or
2) The overloaded facility or the overload-causing contingency is at generator's outlet, or
3) The megawatt impact due to the generator is greater than or equal to twenty percent (20%) of the applicable rating (normal or emergency) of the overloaded facility, or
4) For any other constrained facility, where none of the Study Generators have a megawatt impact greater than or equal to 20% of the line rating individually, however the cumulative megawatt impact of the group of study generators is greater than 20% of the rating of the facility, then only the study generators whose individual megawatt impact is greater than 5% of the rating of the facility will be responsible for mitigating the cumulative megawatt impact constraint, or
5) Impacts on Affected Systems would be classified as Injection constraints based on the Affected Systems' criteria, or

6) Any other applicable Transmission Owner FERC filed Local Planning Criteria are met.

A bus is considered a voltage constraint if both of the following conditions are met:

1) The bus voltage is outside of the applicable normal or emergency limits for the post change case, and
2) The change in bus voltage is greater than 0.01 per unit

All generators must mitigate thermal injection constraints and voltage constraints in order to obtain any type of Interconnection Service. Further, all generators requesting Network Resource Interconnection Service (NRIS) must mitigate constraints found by using the Deliverability algorithm, to meet the system performance criteria for NERC category P1 events, if DFAX due to the study generator is equal to or greater than 5%.

3. Thermal Analysis

The thermal analysis results for 2022 Summer Peak and Shoulder show generator projects J805, J811, J815, J848, and J912 causing constraints. The details pertaining to the thermal analysis can be found in Appendix A – ABB System Impact Study, Appendix B – Ameren System Impact Study, and Appendix C – MISO ERIS Analysis.

3.1. J805

The thermal analysis identified the generator to contribute to the following constraint:

1. Morristown to Van Buren 69 kV line

Per MISO cost allocation rules, the project receives cost allocation for upgrades required to mitigate the above listed constraint. The planned upgrade is to rebuild or reconductor 4.8 miles of the line. Cost estimate is $7.2 million. The project is allocated 100% of the cost for $7.2 million.

3.2. J811

The thermal analysis identified the generator to contribute to the following constraint:

1. Avena Tap to Ramsey 138 kV line

Per MISO cost allocation rules, the project receives cost allocation for upgrades required to mitigate the above listed constraint. The planned upgrade is to reconductor 14 miles of the line. Cost estimate is $7.5 million. The project is allocated 45.65% of the cost for $3.424 million.

3.3. J815

The thermal analysis identified the generator to contribute to the following constraint:

1. Avena Tap to Ramsey 138 kV line

Per MISO cost allocation rules, the project receives cost allocation for upgrades required to mitigate the above listed constraint. The planned upgrade is to reconductor 14 miles of the line. Cost estimate is $7.5 million. The project is allocated 11.36% of the cost for $852,000.

3.4. J848

The thermal analysis identified the generator to contribute to the following constraint:

1. Avena Tap to Ramsey 138 kV line

Per MISO cost allocation rules, the project receives cost allocation for upgrades required to mitigate the above listed constraint. The planned upgrade is to reconductor 14 miles of the line. Cost estimate is $7.5 million. The project is allocated 35.49% of the cost for $2.662 million.

3.5. J912

The thermal analysis identified the generator to contribute to the following constraint:

1. Avena Tap to Ramsey 138 kV line

Per MISO cost allocation rules, the project receives cost allocation for upgrades required to mitigate the above listed constraint. The planned upgrade is to reconductor 14 miles of the line. Cost estimate is $7.5 million. The project is allocated 7.50% of the cost for $562,000.

4. Voltage Analysis

The voltage analysis results for 2022 Summer Peak and Shoulder show that the study generators do not cause any voltage violations. The details pertaining to the voltage analysis can be found in Appendix A – ABB System Impact Study, Appendix B – Ameren System Impact Study, and Appendix C – MISO ERIS Analysis.

5. Stability Analysis

Stability analysis did not show any stability issues. However, a few the standard library dynamics models provided require additional tuning for future models and analysis. Further details pertaining to the stability analysis can be found in Appendix A – ABB System Impact Study and Appendix B – Ameren System Impact Study.

5.1. J826

MISO project J826 failed to ride through close-in 3-phase faults cleared in primary clearing time. Sustained high voltages due to substantial increases in the reactive power generation resulted in trips by the voltage protection models. FERC Order 661-A requires that the post-fault voltages recover to the pre-fault voltages. For each of these projects, there were scenarios where the post-fault voltages failed to recover to the pre-fault voltages. These high voltages are deemed to be unacceptable based on the FERC Order 661-A. This issue was not present when using user-defined dynamics models. The standard library dynamics model must be tuned correctly to mitigate this issue.

5.2. J829

J829 real power output drops two times following some local MTEP faults. This performance doesn't cause any other issues in the rest of the system and doesn't cause any criteria violation. The standard library dynamics model must be tuned correctly to mitigate this concern.

5.3. J844

MISO project J844 failed to ride through close-in 3-phase faults cleared in primary clearing time. Sustained high voltages due to substantial increases in the reactive power generation resulted in trips by the voltage protection models. FERC Order 661-A requires that the post-fault voltages recover to the pre-fault voltages. For each of these projects, there were scenarios where the post-fault voltages failed to recover to the pre-fault voltages. These high voltages are deemed to be unacceptable based on the FERC Order 661-A. This issue was not present when using user-defined dynamics models. The standard library dynamics model must be tuned correctly to mitigate this issue.

5.4. J845

MISO project J845 failed to ride through close-in 3-phase faults cleared in primary clearing time. Sustained high voltages due to substantial increases in the reactive power generation resulted in trips by the voltage protection models. FERC Order 661-A requires that the post-fault voltages recover to the pre-fault voltages. For each of these projects, there were scenarios where the post-fault voltages failed to recover to the pre-fault voltages. These high voltages are deemed to be unacceptable based on the FERC Order 661-A. This issue was not present when using user-defined dynamics models. The standard library dynamics model must be tuned correctly to mitigate this issue.

5.5. J847

During local 3ph faults, J847 inverter terminal frequency increased above 63 HZ, which triggered its frequency relay to trip the unit. J847 frequency relay settings need to be reviewed and adjusted by the project developer to ensure that J847 stays online following local 3ph faults.

6. Short Circuit Analysis

Short circuit analysis was performed utilizing ASPEN software. Single line to ground faults and three phase faults were evaluated for pre- and post-project cases (similar to Bench and Study models). Short circuit study of indicates that study generators do not have adverse impacts on circuit breaker capability. The details pertaining to the short circuit analysis are presented in Appendix A – ABB System Impact Study and Appendix B – Ameren System Impact Study.

7. Affected System Impact Study

The details pertaining to the AECI, PJM, and SPP Affected Systems studies are in Appendix D – AECI Affected System Study, Appendix E – PJM Affected System Study, and Appendix F – SPP System Impact Study.

7.1. J715

No mitigations were found to be required for this generator.

7.2. J750

No mitigations were found to be required for this generator.

7.3. J800

No mitigations were found to be required for this generator.

7.4. J805

No mitigations were found to be required for this generator.

7.5. J808

No mitigations were found to be required for this generator.

7.6. J811

The PJM Study identified the generator to contribute to the following constraint:

1. Casey – Sullivan 345 kV line

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the above listed constraint. The planned upgrade is to rebuild or reconductor the Ameren portion of the Casey – Sullivan 345 kV line. Cost estimate is $30 million. The project is allocated 6.3% of the cost for $1.890 million. Additionally, the AEP portion of the line will need to be rebuilt/reconductored. Cost estimate is $700,000. The project is allocated 11.09% of the cost for $77,640.

7.7. J813

The PJM Study identified the generator to contribute to the following constraint:

1. Casey – Sullivan 345 kV line

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the above listed constraint. The planned upgrade is to rebuild or reconductor the Ameren portion of the Casey – Sullivan 345 kV line. Cost estimate is $30 million. The project is allocated 14.11% of the cost for $4.232 million. Additionally, the AEP portion of the line will need to be rebuilt/reconductored. Cost estimate is $700,000. The project is allocated 24.83% of the cost for $173,820.

7.8. J815

The PJM Study identified the generator to contribute to the following constraint:

1. Casey – Sullivan 345 kV line

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the above listed constraint. The planned upgrade is to rebuild or reconductor the Ameren portion of the Casey – Sullivan 345 kV line. Cost estimate is $30 million. The project is allocated 11.39% of the cost for $3.417 million. Additionally, the AEP portion of the line will need to be rebuilt/reconductored. Cost estimate is $700,000. The project is allocated 20.04% of the cost for $140,310.

The PJM Study identified the generator to contribute to the following constraint:

1. Pontiac – Loretto 345 kV line

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the above listed constraint. The planned upgrade is to replace bus disconnect switches and replacing a line switch. Cost estimate is $1 million. The project is allocated 37.92% of the cost for $379,200.

7.9. J817

The AECI Study identified the generator to contribute to the following constraint:

1. Warrenton – Big Creek 161 kV line

The planned upgrade is to rebuild or reconductor 0.45 miles with 954 ACSR. Cost estimate is $650,000.

7.10. J826

The PJM Study identified the generator to contribute to the following constraint:

1. Eugene - Dequin 345 kV line

The planned upgrade to mitigate the constraint is to reconductor the 345 kV line (PJM project B2777). The in-service date of the planned upgrade is after the in-service date of the project. An interim study is required to determine impact.

7.11. J829

The PJM Study identified the generator to contribute to the following constraints:

1. Dequin - Meadow 345 kV line Circuit 1
2. Dequin - Meadow 345 kV line Circuit 2

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the above listed constraints. The planned upgrade is to build a new 765 kV line from Sullivan to Reynolds. Cost estimate is $464 million. The project is allocated 1.20% of the cost for $5.796 million.

The PJM Study identified the generator to contribute to the following constraint:

1. Eugene - Dequin 345 kV line

The planned upgrade to mitigate the constraint is to reconductor the 345 kV line (PJM project B2777). The in-service date of the planned upgrade is after the in-service date of the project. An interim study is required to determine impact.

7.12. J837

No mitigations were found to be required for this generator.

7.13. J838

The PJM Study identified the generator to contribute to the following constraint:

1. Twin Branch - Argenta 345 kV line

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the above listed constraint. An engineering study will need to be conducted to determine if the relay thermal limit settings at Twin Branch can be adjusted. A new relay package will be required if the relay thermal settings cannot be adjusted. Cost estimate is $825,000. The project is allocated 7.66% of the cost for $63,000.

7.14. J842

No mitigations were found to be required for this generator.

7.15. J843

No mitigations were found to be required for this generator.

7.16. J844

No mitigations were found to be required for this generator.

7.17. J845

The PJM Study identified the generator to contribute to the following constraint:

1. Eugene - Dequin 345 kV line

The planned upgrade to mitigate the constraint is to reconductor the 345 kV line (PJM project B2777). The in-service date of the planned upgrade is after the in-service date of the project. An interim study is required to determine impact.

7.18. J847

No mitigations were found to be required for this generator.

7.19. J848

The PJM Study identified the generator to contribute to the following constraint:

1. Casey – Sullivan 345 kV line

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the above listed constraint. The planned upgrade is to rebuild or reconductor the Ameren portion of the Casey – Sullivan 345 kV line. Cost estimate is $30 million. The project is allocated 11.23% of the cost for $3.370 million. Additionally, the AEP portion of the line will need to be rebuilt/reconductored. Cost estimate is $700,000. The project is allocated 19.77% of the cost for $138,410.

The PJM Study identified the generator to contribute to the following constraint:

1. Pontiac – Loretto 345 kV line

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the above listed constraint. The planned upgrade is to replace bus disconnect switches and replacing a line switch. Cost estimate is $1 million. The project is allocated 35.2% of the cost for $352,000.

7.20. J853

No mitigations were found to be required for this generator.

7.21. J856

No mitigations were found to be required for this generator.

7.22. J859
No mitigations were found to be required for this generator.

7.23. J883
No mitigations were found to be required for this generator.

7.24. J884
The PJM Study identified the generator to contribute to the following constraint:

1. Pontiac – Loretto 345 kV line

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the above listed constraint. The planned upgrade is to replace bus disconnect switches and replacing a line switch. Cost estimate is $1 million. The project is allocated 26.89% of the cost for $268,900.

7.25. J903
No mitigations were found to be required for this generator.

7.26. J912
No mitigations were found to be required for this generator.

7.27. J913
No mitigations were found to be required for this generator.

7.28. J949
The PJM Study identified the generator to contribute to the following constraint:

1. Casey – Sullivan 345 kV line

Per PJM cost allocation rules, the project receives cost allocation for upgrades required to mitigate the above listed constraint. The planned upgrade is to rebuild or reconductor the Ameren portion of the Casey – Sullivan 345 kV line. Cost estimate is $30 million. The project is allocated 13.78% of the cost for $4.135 million. Additionally, the AEP portion of the line will need to be rebuilt/reconductored. Cost estimate is $700,000. The project is allocated 24.26% of the cost for $169,830.

The PJM Study identified the generator to contribute to the following constraint:

1. Eugene - Dequin 345 kV line

The planned upgrade to mitigate the constraint is to reconductor the 345 kV line (PJM project B2777). The in-service date of the planned upgrade is after the in-service date of the project. An interim study is required to determine impact.

8. Deliverability Analysis

8.1. Introduction

Generator interconnection projects have to pass Generator Deliverability Study to be granted NRIS. If the generator is deemed not fully deliverable, the customer can choose either to change the project to an Energy Resource (ER) project or precede with the system upgrades that will make the generator fully deliverable. Generator Deliverability Study ensures that the Network Resources, on an aggregate basis, can meet the MISO aggregate load requirements during system peak condition without getting bottled up. The wind generators are tested at 100% of their maximum output level which then can be used to meet Resource Adequacy obligations, under Module E, of the MISO Transmission and Energy Market Tariff (TEMT).

MISO Generator Deliverability Study whitepaper describing the algorithm can be found in BPM 015 – Generation Interconnection, Appendix C.

8.2. Determining the MW Restriction

If one facility is overloaded based on the assessed "severe yet credible dispatch" scenario described in the study methodology, and the generator under study has a DF greater than 5%, part or all of its output is not deliverable. The restricted MW is calculated as following:

(MW restricted) = (worst loading – MW rating) / (generator sensitivity factor)

If the result is larger than the maximum output of the generator, 100% of this generator's output is not deliverable.

8.3. Deliverability Study Results

The limiting constraints (mon/con pairs) seen in the deliverability analysis for the 2022 Summer Peak case are summarized in Appendix G – MISO Deliverability Analysis.

8.3.1. J715

This generator is found to be fully deliverable for 98 MW without any network upgrades.

8.3.2. J750

This generator is found to be fully deliverable for 150 MW without any network upgrades.

8.3.3. J800

This generator is determined to be deliverable for 223.9 MW. Required upgrades to attain higher deliverable levels were identified in the NRIS analysis. **Error! Reference source not found.** shows the NRIS results and cost estimates determined in the NRIS analysis.

Table 4: NRIS Results for J800

J800 Deliverable (NRIS) Amount in 2022 Case: (Conditional on ERIS and case assumptions)	223.9 MW (89.58%)

Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades bust be mad for 100% NRIS)	Level of Service Attainable (MW)	Distribution Factor	Constraint in ERIS Analysis?	Projects Associated with ERIS Constraint	Projects Associated with NRIS Constraint	NRIS Cost Allocated to Project	Total Cost of Upgrade ($)
Francisco – Duff 345 kV	250	7.06%	No		J800, J829, J842, J843	$138,700	$950,000

8.3.4. J805

This generator is found to be fully deliverable for 199 MW without any network upgrades.

8.3.5. J808
This generator is found to be fully deliverable for 99 MW without any network upgrades.

8.3.6. J811
This generator is found to be fully deliverable for 99 MW without any network upgrades.

8.3.7. J813
This generator is found to be fully deliverable for 250 MW without any network upgrades.

8.3.8. J815
This generator is found to be fully deliverable for 250 MW without any network upgrades.

8.3.9. J817
This generator is found to be fully deliverable for 250 MW without any network upgrades.

8.3.10. J826
This generator is found to be fully deliverable for 100 MW without any network upgrades.

8.3.11. J829
This generator is determined to be deliverable for 223.9 MW. Required upgrades to attain higher deliverable levels were identified in the NRIS analysis. **Error! Reference source not found.** shows the NRIS results and cost estimates determined in the NRIS analysis.

Table 5: NRIS Results for J829

J829 Deliverable (NRIS) Amount in 2022 Case: (Conditional on ERIS and case assumptions)	223.9 MW (89.58%)

Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades bust be mad for 100% NRIS)	Level of Service Attainable (MW)	Distribution Factor	Constraint in ERIS Analysis?	Projects Associated with ERIS Constraint	Projects Associated with NRIS Constraint	NRIS Cost Allocated to Project	Total Cost of Upgrade ($)
Francisco – Duff 345 kV	250	7.63%	No		J800, J829, J842, J843	$149,150	$950,000

8.3.12. J837
This generator is found to be fully deliverable for 80 MW without any network upgrades.

8.3.13. J838
This generator is found to be fully deliverable for 40 MW without any network upgrades.

8.3.14. J842
This generator is determined to be deliverable for 179.1 MW. Required upgrades to attain higher deliverable levels were identified in the NRIS analysis. **Error! Reference source not found.** shows the NRIS results and cost estimates determined in the NRIS analysis.

Table 6: NRIS Results for J842

J842 Deliverable (NRIS) Amount in 2022 Case: (Conditional on ERIS and case assumptions)	179.1 MW (89.57%)

Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades bust be mad for 100% NRIS)	Level of Service Attainable (MW)	Distribution Factor	Constraint in ERIS Analysis?	Projects Associated with ERIS Constraint	Projects Associated with NRIS Constraint	NRIS Cost Allocated to Project	Total Cost of Upgrade ($)
Francisco – Duff 345 kV	200	20.09%	No		J800, J829, J842, J843	$315,400	$950,000

8.3.15. J843

This generator is determined to be deliverable for 179.1 MW. Required upgrades to attain higher deliverable levels were identified in the NRIS analysis. **Error! Reference source not found.** shows the NRIS results and cost estimates determined in the NRIS analysis.

Table 7: NRIS Results for J843

J843 Deliverable (NRIS) Amount in 2022 Case: (Conditional on ERIS and case assumptions)	179.1 MW (89.57%)

Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades bust be mad for 100% NRIS)	Level of Service Attainable (MW)	Distribution Factor	Constraint in ERIS Analysis?	Projects Associated with ERIS Constraint	Projects Associated with NRIS Constraint	NRIS Cost Allocated to Project	Total Cost of Upgrade ($)
Francisco – Duff 345 kV	200	22.14%	No		J800, J829, J842, J843	$346,750	$950,000

8.3.16. J845

This generator is found to be fully deliverable for 52 MW without any network upgrades.

8.3.17. J847

This generator is found to be fully deliverable for 90 MW without any network upgrades.

8.3.18. J848

This generator is found to be fully deliverable for 235 MW without any network upgrades.

8.3.19. J853

This generator is found to be fully deliverable for 149 MW without any network upgrades.

8.3.20. J856

This generator is found to be fully deliverable for 250 MW without any network upgrades.

8.3.21. J859

This generator is found to be fully deliverable for 149.94 MW without any network upgrades.

8.3.22. J883

This generator is found to be fully deliverable for 80 MW without any network upgrades.

8.3.23. J884

This generator is found to be fully deliverable for 100 MW without any network upgrades.

8.3.24. J903

This generator is found to be fully deliverable for 100 MW without any network upgrades.

8.3.25. J912

This generator is found to be fully deliverable for 100 MW without any network upgrades.

8.3.26. J913

This generator is found to be fully deliverable for 160 MW without any network upgrades.

8.3.27. J949

This generator is found to be fully deliverable for 170 MW without any network upgrades.

9. Shared Network Upgrades Analysis

Shared Network Upgrade (SNU) test for Network Upgrades driven by higher queued interconnection projects was performed for this System Impact Study. No SNUs were identified for DPP 2017 August Central Area Projects.

10. Cost Allocation

The cost allocation of Network Upgrades for the study group reflects responsibilities for mitigating system impacts based on Interconnection Customer-elected level of Network Resource Interconnection service as of the Final System Impact Study report date.

10.1. Cost Assumptions for Network Upgrades

The cost estimate for each network upgrade identified in System Impact Study was provided by the corresponding transmission owning company.

10.2. Cost Allocation Methodology

The costs of Network Upgrades (NU) for a set of generation projects (one or more sub-groups or entire group with identified NU) are allocated based on the MW impact from each project on the constrained facilities in the Study Case.

<u>Cost Allocation Methodology for Thermal Constraints</u>

1. With all Study Group generation projects dispatched in the Post Case, all thermal constraints are identified.
2. Distribution factor from each project on each constraint is obtained.
3. For each thermal constraint, the maximum MW contribution (increasing flow) from each project is then calculated in the Post Case without any network upgrades.
4. For each thermal constraint, the cost estimates for one or a subset of NU are provided by the corresponding Transmission Owner.
5. Then the cost of each NU is allocated based on the pro rata share of the MW contribution from each project on the constraints mitigated or partly mitigated by this NU. The methodology to determine the cost allocation of one NU is:

$$\frac{Project\ A\ cost\ portion\ of\ NU}{Cost\ of\ NU} = \frac{Max(Proj.A\ MW\ contribution\ on\ constraint)}{\sum_i Max(Proj.i\ MW\ contrution\ on\ constraint)}$$

6. The total NU costs for each project are calculated if more than one NU is required.

11. Revision History

<u>Revision 1 - 7/12/2019</u>

Initial GI-DPP-2017-AUG Central Phase III SIS Final Report posting.

<u>Revision 2 - 7/17/2019</u>

Corrected Ameren Transmission entity titles and Ameren POI names in Table 1: List of DPP 2017 August Central Area Phase III Projects.

Appendix A – ABB System Impact Study

Appendix B – Ameren System Impact Study

Appendix C – MISO ERIS Analysis

Appendix D – AECI Affected System Study

Appendix E – PJM Affected System Study

Appendix F – SPP Affected System Study

Appendix G – MISO Deliverability Analysis