GEN-2015-016

Impact Restudy for

Generator Modification

(Turbine Change)

Published on October 2018

By Generator Interconnection

REVISION HISTORY

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION	COMMENTS
8/24/2018	Generator Interconnection		
9/11/2018	Generator Interconnection	Updated language for low-wind/no-wind condition	
10/04/18	Generator Interconnection	Low-wind/no-wind analysis was updated.	

EXECUTIVE SUMMARY

The GEN-2015-016 Interconnection Customer has requested a modification to its Interconnection Request. SPP has performed this system impact restudy to determine the effects of changing wind turbine generators from the previously studied one hundred (100) Vestas2.0 MW wind turbine generators for an aggregate nameplate capacity of 200.0MW to forty-eight (48) Gamesa 3.55MW and eleven (11) Gamesa 2.625MW for an aggregate nameplate capacity of 199.275 MW. The point of interconnection (POI) for GEN-2015-016 remains as a tap on the Centerville – Marmaton 161kV line.

This study was performed to determine whether the request for modification is considered Material. To determine this, study models that included Interconnection Requests through DISIS-2015-002 were used that analyzed the timeframes of 2016 winter, 2017 summer, and 2025 summer models.

Power flow analysis was not performed.

The restudy showed that the stability analysis has determined with all previously assigned Network Upgrades in service, generators in the monitored areas remained stable and within the pre-contingency, voltage recovery, and post fault voltage recovery criterion of 0.7pu to 1.2pu for the entire modeled disturbances. Additionally, the project wind farm was found to stay connected during the contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements of FERC Order #661A. The requested modification is not considered Material.

A power factor analysis and a low-wind/no-wind condition analysis were performed for this modification request. The facility will be required to maintain a 95% lagging (providing VARs) and 95% leading (absorbing VArs) power factor at the POI. Additionally, the project may require a 12.2 MVAr shunt reactance as measured at its substation 161 kV bus to offset the capacitive effect on the transmission network caused by the project's transmission line and collector system during low-wind/no-wind conditions. Reactive compensation can be provided either by discrete reactive devices or by the generator itself if it possesses that capability.

With the assumptions outlined in this report and with all the required network upgrades from the DISIS 2015-002 in place, GEN-2015-016 with forty-eight (48) Gamesa 3.55MW and eleven (11) Gamesa 2.625MW wind turbine generators should be able to interconnect reliably to the SPP transmission grid.

It should be noted that this study analyzed the requested modification to change generator technology, manufacturer, and layout. This study analyzed many of the most probable contingencies, but it is not an all-inclusive list and cannot account for every operational situation. It is likely that the customer may be required to reduce its generation output to 0 MW, also known as curtailment, under certain system conditions to allow system operators to maintain the reliability of the transmission network.

Nothing in this study should be construed as a guarantee of transmission service or delivery rights. If the customer wishes to obtain deliverability to final customers, a separate request for transmission service must be requested on Southwest Power Pool's OASIS by the customer.

CONTENTS

SECTION 1: INTRODUCTION

GEN-2015-016 Impact Restudy is a generation interconnection study performed to study the impacts of interconnecting the project shown in Table I-1. This restudy evaluates the requested modification to change from one hundred (100) Vestas 2.0 MW wind turbine generators to forty-eight (48) Gamesa 3.55MW and eleven (11) Gamesa 2.625MW wind turbine generators.

TABLE 2-1: INTERCONNECTION REQUEST

Request	Capacity (MW)	Generator Model	Point of Interconnection
GEN-2015-016	199.275	Gamesa 3.55MW and Gamesa 2.625MW (wind)	Tap on Centerville 161 kV (543065) to Marmaton 161 kV (532934) Line

The prior-queued, equally-queued and lower queued requests shown in Table I-2 were included in this study and the wind farms were dispatched to 100% of rated capacity.

TABLE 2-2: GROUP 8 PRIOR AND LATER QUEUED INTERCONNECTION REQUESTS

Request	Capacity (MW)	Generator Model	Point of Interconnection
GEN-2002-004	199.5	GE.1.5MW	Latham 345kV (532800)
GEN-2005-013	199.8	Vestes V90 1.8MW	Caney River 345kV (532780)
GEN-2007-025	299.2	GE 1.6MW	Viola 345kV (532798)
GEN-2008-013	300	G.E. 1.68MW	Hunter 345kV (515476)
GEN-2008-021	1261 Summer 1283 Winter	GENROU	Wolf Creek 345kV (532797)
GEN-2008-098	100.8	Vestas V100 1.8MW	Tap on the Wolf Creek – LaCygne 345kV line (560004)
GEN-2009-025	59.8	Siemens 2.3MW	Tap on the Deerck – Sincblk 69KV line (515528)
GEN-2010-003	100.8	Vestas V100 1.8MW	Tap on the Wolf Creek – LaCygne 345kV line (560004)
GEN-2010-005	299.2	GE 1.6MW	Viola 345kV (532798)
ASGI-2010-006	150	GE1.5MW	Remington 138kV (301369)
GEN-2010-055	4.8	GENROU	Wekiwa 138kV (509757)
GEN-2011-057	150.4	GE 1.6MW	Creswell 138kV (532981)
KCPL Distributed: Osawatomie	76.0	GENROU (543078)	Paola 161kV
GEN-2012-032	300	Vestas V112 3.0MW	Tap Rose Hill-Sooner 345kV (562318)
GEN-2012-033	98.8	GE 1.62MW	Tap Bunch Creek-South 4th 138kV(562303)
GEN-2012-041	85 Summer 121.5 Winter	GENROU	Tap Rose Hill-Sooner 345kV (562318)

Request	Capacity (MW)	Generator Model	Point of Interconnection
GEN-2013-012	4 x 168.0MW Summer 4 x 215MW Winter	GENROU (514910) (514911) (514912) (514942)	Redbud 345kV (514909)
GEN-2013-029	300	Vestas V100 VCSS 2MW (583753, 583756)	Renfrow 345kV(515543)
GEN-2014-001	200.6	GE 1.7MW 100m (583853,583856)	Tap Wichita to Emporia Energy Center 345kV (562476)
GEN-2014-028	35 (Uprate) (Pgen=259W/256S)	GENROU	Riverton 161kV (547469)
GEN-2014-064	248.4	GE 2.3MW	Otter 138kV (514708)
ASGI-2014-014	56.4W/54.3S	GENROU	Ferguson 69kV (512664)
GEN-2015-001	200.0	Vestas V110 2.0MW	Ranch Road 345kV
GEN-2015-016	200.0	Vestas V110 2.0MW	Tap Centerville – Marmaton 161kV
GEN-2015-024	220.0	GE 2.0MW	Tap on Thistle to Wichita 345kV, ckt1&2 (560033)
GEN-2015-025	220.0	GE 2.0MW	Tap on Thistle to Wichita 345kV, ckt1&2 (560033)
GEN-2015-028	3.0 uprate to GEN-2009-025 for total 62.8MW	Siemens 2.3MW with Power Boost (115kW => 2.415MW)	Nardins 69kV
GEN-2015-030	200.1	GE 2.3MW	Sooner 345kV
ASGI-2015-004	54.300 Summer 56.364 Winter	GENSAL	Coffeyville Municipal Light & Power Northern Industrial Park Substation 69kV (512735)
GEN-2016-009	29	Allen Bradley 14.5MW Steam Turbine	OSGE 2 (514742)
GEN-2016-022	151.8	Vestas GS 3.45MW	RANCHRD7 (515576)
GEN-2016-031	201.3	Vestas GS 3.3MW	RANCHRD7 (515576)
GEN-2016-032	200	Vestas V110 2.0MW	G16-032-TAP (560077)
GEN-2016-060	149.5	GE 2.3 MW	SC10BEL4 (533063)
GEN-2016-061	250.7	GE 2.3 MW	G16-061-TAP (560084)
GEN-2016-068	140	GE 2.0 MW	WOODRNG7 (514715)
GEN-2016-071	200.1	GE 2.5 MW	CHILOCCO4 (521198)
GEN-2016-073	220	GE 2.0	G1524&G1525T (560033)

The study included a stability analysis of the interconnection request. Contingencies that resulted in a prior-queued project tripping off-line, if any, were re-run with the prior-queued project's voltage and frequency tripping relays disabled. Also a low-wind/no-wind analysis was performed on this project since it is a non-synchronous resource. The analyses were performed on three seasonal models, the modified versions of the 2016 winter peak, the 2017 summer peak, and the 2025 summer peak cases. The stability analysis determines the impacts of the new interconnecting project on the stability and voltage recovery of the nearby systems and the ability of the interconnecting project to meet FERC Order 661A. If problems with stability or voltage recovery are identified, the need for reactive compensation or system upgrades is investigated. The three-phase faults and the single line-to-ground faults listed in Table III-1 were used in the stability analysis.

Power factor analysis results are in Appendix B

The low-wind/no-wind analysis determines the capacitive effect at the POI caused by the project's collector system and transmission line capacitance. A reactive compensation size was determined to offset the capacitive effect and to maintain zero Mvar flow at the POI when the plant generators and capacitors are off-line such as might be seen in low-wind or no-wind conditions.

SECTION 2: FACILITIES

A one-line drawing for the GEN-2015-016 generation interconnection request is shown below.

FIGURE 2-1: GEN-2015-016 ONE-LINE DIAGRAM (EXISTING)

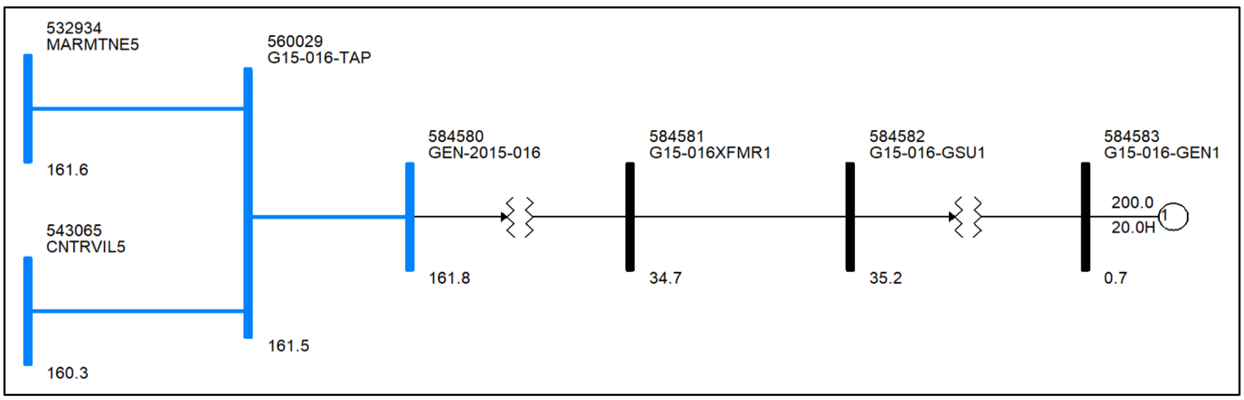
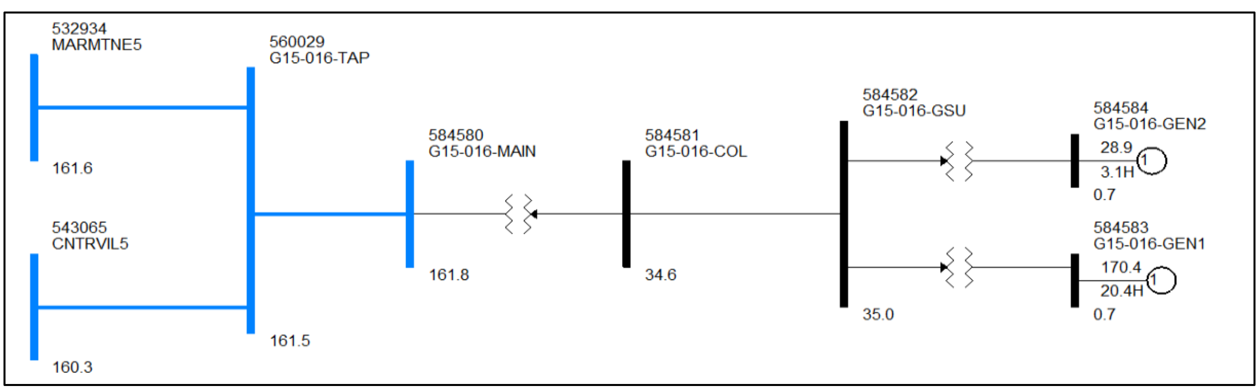


FIGURE 2-2: GEN-2015-016 ONE-LINE DIAGRAM (NEW CONFIGURATION)



SECTION 3: STABILITY ANALYSIS

Transient stability analysis is used to determine if the transmission system can maintain angular stability and ensure bus voltages stay within planning criteria bandwidth during and after a disturbance while considering the addition of a generator interconnection request.

MODEL PREPARATION

Transient stability analysis was performed using modified versions of the 2015 series of Model Development Working Group (MDWG) dynamic study models including the 2016 winter peak, the 2017 summer peak, and the 2025 summer peak seasonal models. The cases are then loaded with prior queued interconnection requests and network upgrades assigned to those interconnection requests. Finally the prior queued and study generation are dispatched into the SPP footprint. Initial simulations are then carried out for a no-disturbance run of twenty (20) seconds to verify the numerical stability of the model.

DISTURBANCES

Forty-seven (47) contingencies were identified for use in this study and are listed in Table 3-1. These contingencies included three-phase faults and single-phase line faults at locations defined by SPP. Single-phase line faults were simulated by applying fault impedance to the positive sequence network at the fault location to represent the effect of the negative and zero sequence networks on the positive sequence network. The fault impedance was computed to give a positive sequence voltage at the specified fault location of approximately 60% of pre-fault voltage. This method is in agreement with SPP current practice.

Except for transformer faults, the typical sequence of events for a three-phase and a single-phase fault is as follows:

1. apply fault at particular location
2. continue fault for five (5) cycles, clear the fault by tripping the faulted facility
3. after an additional twenty (20) cycles, re-close the previous facility back into the fault
4. continue fault for five (5) additional cycles
5. trip the faulted facility and remove the fault

Transformer faults are typically modeled as three-phase faults, unless otherwise noted. The sequence of events for a transformer fault is as follows:

1. apply fault for five (5) cycles
2. clear the fault by tripping the affected transformer facility (unless otherwise noted there will be no re-closing into a transformer fault)

TABLE 3-1: CONTINGENCIES EVALUATED

Fault Name	Description
FLT24-3PH	3 phase fault on the G15-016 TAP (560029) to Marmaton (532934) 161 kV circuit 1 line, near G15-016
	a. Apply fault at the G15-016 138 kV bus.
	b. Clear fault after 5 cycles by tripping the faulted line.
	c. Wait 20 cycles, and then re-close the line in (b) back into the fault.
	d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT25-3PH	3 phase fault on the G15-016 TAP (560029) to Centerville (543065) 161 kV circuit 1 line, near G15-016
	a. Apply fault at the G15-016 138 kV bus.
	b. Clear fault after 5 cycles by tripping the faulted line.
	c. Wait 20 cycles, and then re-close the line in (b) back into the fault.
	d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT26-3PH	3 phase fault on the Marmaton (532934) 161/(533639) 69/(532955) 13.2 kV transformer near Marmaton 161 kV
	a. Apply fault at the Marmaton 161 kV bus.
	b. Clear fault after 5 cycles by tripping the faulted line.
FLT27-3PH	3 phase fault on the Franklin (532938) to Litchfield (532932) 161 kV circuit 1 line, near Franklin
	a. Apply fault at the Franklin 161 kV bus.
	b. Clear fault after 5 cycles by tripping the faulted line.
	c. Wait 20 cycles, and then re-close the line in (b) back into the fault.
	d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT28-3PH	3 phase fault on the Franklin (532938) 161/(533876) 69/(533122) 13.2 kV transformer, near Franklin 161 kV
	a. Apply fault at the Franklin 161 kV bus.
	b. Clear fault after 5 cycles by tripping the faulted line.
FLT29-3PH	3 phase fault on the Neosho (532937) to Marmaton (532934) 161 kV circuit 1 line, near Marmaton
	a. Apply fault at the Marmaton 161 kV bus.

	b. Clear fault after 5 cycles by tripping the faulted line.
	c. Wait 20 cycles, and then re-close the line in (b) back into the fault.
	d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT30-3PH	3 phase fault on the Neosho (532937) to Baker (532926) 161 kV circuit 1 line, near Neosho
	a. Apply fault at the Neosho 161 kV bus.
	b. Clear fault after 5 cycles by tripping the faulted line.
	c. Wait 20 cycles, and then re-close the line in (b) back into the fault.
	d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT31-3PH	3 phase fault on the Neosho (532793) to LaCygne (542981) 345 kV circuit 1 line, near Neosho
	a. Apply fault at the Neosho 345 kV bus.
	b. Clear fault after 5 cycles by tripping the faulted line.
	c. Wait 20 cycles, and then re-close the line in (b) back into the fault.
	d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT32-3PH	3 phase fault on the Centennial (543067) to Paola (543069) 161 kV circuit 1 line, near Centennial
	a. Apply fault at the Centennial161 kV bus.
	b. Clear fault after 5 cycles by tripping the faulted line.
	c. Wait 20 cycles, and then re-close the line in (b) back into the fault.
	d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9001-3PH	3 phase fault on the Marmaton (532934) to Franklin (532938) 161 kV line, near Marmaton
	a. Apply fault at the Marmaton 116 kV bus.
	b. Clear fault after 5 cycles by tripping the faulted line.
	c. Wait 20 cycles, and then re-close the line in (b) back into the fault.
	d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

RESULTS

The stability analysis was performed and the results are summarized in Table 3-2. Based on the stability results and with all network upgrades in service, GEN-2015-016 did not cause any stability problems and remained stable for all faults studied. No generators tripped or went unstable, and voltages recovered to acceptable levels.

Complete sets of plots for the stability analysis are available on request.

TABLE 3-2: STABILITY ANALYSIS RESULTS

Fault ID	2016WP	2017SP	2025SP
FLT24-3PH	Stable	Stable	Stable
FLT25-3PH	Stable	Stable	Stable
FLT26-3PH	Stable	Stable	Stable
FLT27-3PH	Stable	Stable	Stable
FLT28-3PH	Stable	Stable	Stable
FLT29-3PH	Stable	Stable	Stable
FLT30-3PH	Stable	Stable	Stable
FLT31-3PH	Stable	Stable	Stable
FLT32-3PH	Stable	Stable	Stable
FLT9001-3PH	Stable	Stable	Stable
FLT9002-3PH	Stable	Stable	Stable
FLT9003-3PH	Stable	Stable	Stable
FLT9004-3PH	Stable	Stable	Stable
FLT9005-3PH	Stable	Stable	Stable
FLT9006-3PH	Stable	Stable	Stable
FLT9007-3PH	Stable	Stable	Stable
FLT9008-3PH	Stable	Stable	Stable
FLT9009-3PH	Stable	Stable	Stable
FLT9010-3PH	Stable	Stable	Stable
FLT9013-3PH_25SP	N/A	N/A	Stable
FLT92-1PH	Stable	Stable	Stable
FLT93-1PH	Stable	Stable	Stable
FLT9011-SB	Stable	Stable	Stable
FLT9012-SB	Stable	Stable	Stable

FLT9014-SB	Stable	Stable	Stable
FLT9003-PO1	Stable	Stable	Stable
FLT9004-PO1	Stable	Stable	Stable
FLT9005-PO1	Stable	Stable	Stable
FLT9006-PO1	Stable	Stable	Stable
FLT9001-PO2	Stable	Stable	Stable
FLT26-PO2	Stable	Stable	Stable
FLT29-PO2	Stable	Stable	Stable
FLT9013-PO2_25SP	N/A	N/A	Stable
FLT9001-PO3	Stable	Stable	Stable
FLT29-PO3	Stable	Stable	Stable
FLT9010-PO4	Stable	Stable	Stable
FLT9005-PO5	Stable	Stable	Stable

FERC LVRT COMPLIANCE

FERC Order #661A places specific requirements on wind farms through its Low Voltage Ride Through (LVRT) provisions. For Interconnection Agreements signed after December 31, 2006, wind farms shall stay on line for faults at the POI that draw the voltage down at the POI to 0.0 pu.

Contingencies 9 and 10 in Table 3-1 simulated the LVRT contingencies. GEN-2015-016 met the LVRT requirements by staying on line and the transmission system remaining stable.

SECTION 4: POWER FACTOR ANALYSIS

A subset of the stability faults was used as power flow contingencies to determine the power factor requirements for the wind farm to maintain scheduled voltage at the POI. The voltage schedule was set equal to the voltages at the POI before the project is added, with a minimum of 1.0 per unit. A fictitious reactive power source replaced the study project to maintain scheduled voltage during all studied contingencies. The MW and Mvar injections from the study project at the POI were recorded and the resulting power factors were calculated for all contingencies for summer peak and winter peak cases. The most leading and most lagging power factors determine the minimum power factor range capability that the study project must install before commercial operation.

Per FERC and SPP Tariff requirements, if the power factor needed to maintain scheduled voltage is less than 0.95 lagging, then the requirement is limited to 0.95 lagging. The lower limit for leading power factor requirement is also 0.95. If a project never operated leading under any contingency, then the leading requirement is set to 1.0. The same applies on the lagging side.

The power factor analysis showed a need for reactive capability by the study project at the POI. The final power factor requirement in the Generator Interconnection Agreement (GIA) will be the pro-forma 0.95 lagging to 0.95 leading at the POI, and this requirement is shown in Table 4-1. The detailed power factor analysis tables are in Appendix B.

TABLE 4-1: STABILITY ANALYSIS RESULTS

Request	Size (MW)	Generator Model	Point of Interconnection	Final PF Requirement at POI	
				Lagging [b]	Leading [c]
GEN-2015-016	199.275	Gamesa 3.55MW and Gamesa 2.625MW (wind)	Tap on Centerville 161 kV (543065) to Marmaton 161 kV (532934) Line	0.95[d]	0.95[e]

Notes:

a. The table shows the minimum required power factor capability at the point of interconnection that must be designed and installed with the plant. The power factor capability at the POI includes the net effect of the generators, transformers, line impedances, and any reactive compensation devices installed on the plant side of the meter. Installing more capability than the minimum requirement is acceptable.

b. Lagging is when the generating plant is supplying reactive power to the transmission grid, like a shunt capacitor. In this situation, the alternating current sinusoid “lags” behind the alternating voltage sinusoid, meaning that the current peaks shortly after the voltage.

c. Leading is when the generating plant is taking reactive power from the transmission grid, like a shunt reactor. In this situation, the alternating current sinusoid “leads” the alternating voltage sinusoid, meaning that the current peaks shortly before the voltage.

d. Electrical need is lower, but PF requirement limited to 0.95 by FERC order.

e. The most leading power factor determined through analysis was 1.00.

SECTION 5: REDUCED GENERATION ANALYSIS

Interconnection requests for wind generation projects that interconnect on the SPP system are analyzed for the capacitive charging effects during reduced generation conditions (unsuitable wind speeds, curtailment, etc.) at the generation site.

MODEL PREPARATION

The project generators and capacitors (if any), and all other wind projects that share the same POI, were turned off in the base case. The resulting reactive power injection into the transmission network comes from the capacitance of the project's transmission lines and collector cables. This reactive power injection is measured at the POI. Reactive compensation was simulated at the study project substation low voltage bus to bring the MVAr flow into the POI down to approximately zero. Reactive compensation can be provided either by discrete reactive devices or by the generator itself if it possesses that capability.

RESULTS

A final reactive compensation requirement for each of the studied interconnection requests is shown in Table 5-1. One line drawings used in the analysis are shown in Appendix D: Low Wind Analysis.

TABLE 5-1: SUMMARY OF REACTIVE COMPENSATION REQUIREMENTS

Request	Capacity	POI	Approximate Reactive Compensation Required
GEN-2015-016	199.275 MW	Tap on Centerville 161 kV (543065) to Marmaton 161 kV (532934) Line	12.2 MVAr

The results shown are for the 2025 summer case. The other two cases (2016 winter and 2017 summer) were almost identical since the generation plant design is the same in all cases.

SECTION 6: SHORT CIRCUIT ANALYSIS

The short circuit analysis was performed on the 2017 & 2025 Summer Peak power flow cases using the PSS/E ASCC program. Since the power flow model does not contain negative and zero sequence data, only three-phase symmetrical fault current levels were calculated at the point of interconnection up to and including five levels away.

Short Circuit Analysis was conducting using flat conditions with the following PSS/E ASCCC program settings:

- BUS VOLTAGES SET TO 1 PU AT 0 PHASE ANGLE
- GENERATOR P=0, Q=0
- TRANSFORMER TAP RATIOS=1.0 PU and PHASE ANGLES=0.0
- LINE CHARGING=0.0 IN +/-/0 SEQUENCE
- LOAD=0.0 IN +/- SEQUENCE, CONSIDERED IN ZERO SEQUENCE
- LINE/FIXED/SWITCHED SHUNTS=0.0 AND MAGNETIZING ADMITTANCE=0.0 IN +/-/0 SEQUENCE
- DC LINES AND FACTS DEVICES BLOCKED
- TRANSFORMER ZERO SEQUENCE IMPEDANCE CORRECTIONS IGNORED

Results
The results of the short circuit analysis are shown in Appendix C.

SECTION 7: CONCLUSION

The SPP GEN-2015-016 Impact Restudy evaluated the impact of interconnecting the project shown below in Table 6-1.

TABLE 6-1: INTERCONNECTION REQUEST

Request	Capacity (MW)	Generator Model	Point of Interconnection
GEN-2015-016	199.275	Gamesa 3.55MW and Gamesa 2.625MW (wind)	Tap on Centerville 161 kV (543065) to Marmaton 161 kV (532934) Line

With all Base Case Network Upgrades in service, previously assigned Network Upgrades in service, and required capacitor banks in service, the GEN-2015-016 project was found to remain on line, and the transmission system was found to remain stable for all conditions studied. The requested modification is not considered Material.

A low-wind/no-wind condition analysis was performed for this modification request. The project may require approximately 12.2 MVAr of reactive compensation as measured at its substation 161kV bus. This reactive compensation is necessary to offset the capacitive effect on the transmission network caused by the project's transmission line and collector system during low-wind or no-wind conditions. Reactive compensation can be provided either by discrete reactive devices or by the generator itself if it possesses that capability.

Low Voltage Ride Through (LVRT) analysis showed the study generators did not trip offline due to low voltage when all Network Upgrades are in service.

Any changes to the assumptions made in this study, for example, one or more of the previously queued requests withdraw, may require a re-study at the expense of the Customer.

Nothing in this System Impact Study constitutes a request for transmission service or confers upon the Interconnection Customer any right to receive transmission service.

APPENDIX A: PLOTS

Available on request.

APPENDIX B: POWER FACTOR ANALYSIS

Outage Label	2016WP			2017SP			2025SP		
	QGEN (MVAr)	PF	Leading/ Lagging	(MVAr) QGEN	PF	Leading/ Lagging	(MVAr) QGEN	PF	Leading/ Lagging
NOFAULT	-14.93	0.997	Leading	-18.65	0.996	Leading	-11	0.998	Leading
FLT24	4.22	1	Lagging	-7.02	0.999	Leading	-10.34	0.999	Leading
FLT25	-21.57	0.994	Leading	-13.33	0.998	Leading	-3.68	1	Leading
FLT26	-20.14	0.995	Leading	-22.27	0.994	Leading	-9.44	0.999	Leading
FLT27	-18.53	0.996	Leading	-25.37	0.992	Leading	-14.22	0.997	Leading
FLT28	-14.79	0.997	Leading	-18.12	0.996	Leading	-10.54	0.999	Leading
FLT29	-6.72	0.999	Leading	-14.64	0.997	Leading	-1.22	1	Leading
FLT30	-10.24	0.999	Leading	-13.32	0.998	Leading	-5.45	1	Leading
FLT31	-9.96	0.999	Leading	-15.19	0.997	Leading	-6.43	0.999	Leading
FLT32	-33.17	0.986	Leading	-34.63	0.985	Leading	-26.45	0.991	Leading
FLT9001	-13.75	0.998	Leading	-21.27	0.994	Leading	-10.86	0.999	Leading
FLT9002	-21.01	0.994	Leading	-10.81	0.999	Leading	0.36	1	Lagging
FLT9003	-14.93	0.997	Leading	-8.32	0.999	Leading	0.4	1	Lagging
FLT9004	-20.37	0.995	Leading	-24.1	0.993	Leading	-16.4	0.997	Leading
FLT9005	-33.17	0.986	Leading	-34.63	0.985	Leading	-26.45	0.991	Leading
FLT9006	-14.23	0.997	Leading	-18.33	0.996	Leading	-10.64	0.999	Leading
FLT9007	-16	0.997	Leading	-19.32	0.995	Leading	-11.42	0.998	Leading
FLT9008	-16.92	0.996	Leading	-19.89	0.995	Leading	-11.79	0.998	Leading
FLT9009	-1.21	1	Leading	-7.89	0.999	Leading	2.12	1	Lagging
FLT9010	-13.64	0.998	Leading	-18.01	0.996	Leading	-18.01	0.996	Leading
FLT9013							-11	0.998	Leading

APPENDIX C: SHORT CIRCUIT ANALYSIS

17SP

Bus Dist. From POI	BUS NUMBER	BUS NAME	Voltage (kV)	AREA	ZONE	3 Phase Fault Current (kA)		Difference (ON - OFF)	
						GenON	GenOFF	Change	%
0	560029	G15-016-TAP	161	536	1536	7.424	5.727	1.697	29.63%
1	532934	MARMTNE5	161	536	1536	8.010	6.927	1.083	15.63%
1	543065	CNTRVIL5	161	541	1550	6.198	5.566	0.632	11.35%
1	584580	G15-016-MAIN	161	541	541	6.619	N/A	N/A	N/A
2	532937	NEOSHO 5	161	536	1536	21.358	21.067	0.291	1.38%
2	532938	FRANKLIN	161	536	1536	8.512	8.281	0.231	2.79%
2	533639	MARMATN2	69	536	1536	7.926	7.585	0.341	4.50%
2	543069	PAOLA 5	161	541	1550	10.026	9.750	0.276	2.83%
2	587560	ASGI1603	161	541	1550	10.026	9.750	0.276	2.83%
3	532926	BAKER 5	161	536	1536	8.436	8.344	0.092	1.10%
3	547469	RIV4525	161	544	1561	23.608	23.554	0.053	0.23%
3	532793	NEOSHO 7	345	536	1536	15.984	15.881	0.102	0.64%
3	533021	NEOSHO 4	138	536	1536	23.001	22.764	0.237	1.04%
3	533020	NEOSHOS4	138	536	1536	23.001	22.764	0.237	1.04%
3	532932	LITCH 5	161	536	1536	11.136	10.919	0.217	1.99%
3	533876	FRANKLIN	69	536	1536	8.966	8.849	0.117	1.33%
3	533640	MCKEE 2	69	536	1536	4.058	3.975	0.083	2.09%
3	533647	UN1ELSM2	69	536	1536	7.133	6.872	0.261	3.80%
3	543066	S.OTTWA5	161	541	1550	6.674	6.641	0.033	0.49%
3	543067	CENTENL5	161	541	1550	10.012	9.791	0.220	2.25%
3	543112	OSAWAT 5	161	541	1550	9.643	9.392	0.252	2.68%
3	533022	NEOSHON4	138	536	1536	23.001	22.764	0.237	1.04%
3	533768	NEOSHO 2	69	536	1536	18.598	18.507	0.090	0.49%
4	547467	ORO110 5	161	544	1564	19.319	19.263	0.057	0.30%
4	547487	HOC404 5	161	544	1561	12.933	12.921	0.013	0.10%
4	547498	STL439 5	161	544	1563	24.389	24.348	0.041	0.17%
4	547503	RIV452T	161	544	1561	23.197	23.146	0.051	0.22%
4	547541	RIV167 2	69	544	1561	17.194	17.182	0.012	0.07%
4	300739	7BLACKBE	345	330	304	12.072	12.051	0.021	0.17%
4	510380	DELWARE7	345	520	547	11.370	11.347	0.022	0.20%
4	532780	CANEYRV7	345	536	1537	9.667	9.651	0.016	0.17%
4	542981	LACYGNE7	345	541	1544	24.933	24.903	0.030	0.12%
4	533008	TV1MNDV4	138	536	1536	6.780	6.762	0.018	0.27%
4	547476	ASB349 5	161	544	1564	13.048	12.911	0.137	1.06%
4	533765	LITCH 2	69	536	1536	12.651	12.512	0.139	1.11%
4	533767	MULBERY2	69	536	1536	7.868	7.791	0.077	0.98%
4	533774	SHEFFLD2	69	536	1536	4.024	3.985	0.039	0.98%
4	533645	SE9HIAT2	69	536	1536	3.626	3.563	0.063	1.77%
4	533654	ZILAJCT2	69	536	1536	5.440	5.335	0.106	1.98%
4	543055	SEOTTWA5	161	541	1550	6.785	6.756	0.029	0.43%
4	543068	WAGSTAF5	161	541	1550	13.469	13.358	0.111	0.83%
4	533005	NEPARSN4	138	536	1536	11.704	11.632	0.072	0.62%
4	533696	LABETTS2	69	536	1536	5.701	5.690	0.011	0.19%
4	533703	ORDNJCT2	69	536	1536	7.650	7.632	0.018	0.24%
4	533758	CRAWFOR2	69	536	1536	6.618	6.595	0.023	0.35%
5	547470	JOP145 5	161	544	1563	17.473	17.441	0.032	0.18%
5	547490	FIR417 5	161	544	1564	14.403	14.355	0.048	0.34%
5	547494	OAK432 5	161	544	1564	17.435	17.391	0.044	0.25%
5	547534	ORO110 2	69	544	1564	17.519	17.503	0.016	0.09%
5	512631	MIAMI 5	161	523	554	9.150	9.144	0.006	0.06%
5	547486	HOC404 4	138	544	1561	6.397	6.393	0.004	0.06%
5	547601	HOC404 2	69	544	1561	9.541	9.538	0.003	0.04%
5	547483	JOP389 5	161	544	1563	19.714	19.691	0.023	0.12%
5	547501	RIV453 5	161	544	1561	22.381	22.335	0.046	0.21%
5	547502	RIV167 5	161	544	1561	21.893	21.848	0.045	0.21%
5	547523	JOP 59 T	69	544	1563	9.600	9.599	0.002	0.02%
5	547530	COL 94 2	69	544	1561	6.363	6.362	0.001	0.02%
5	547555	GAL278 2	69	544	1561	15.656	15.646	0.010	0.07%
5	547602	RIV406 2	69	544	1561	15.289	15.280	0.009	0.06%

Bus Dist. From POI	BUS NUMBER	BUS NAME	Voltage (kV)	AREA	ZONE	3 Phase Fault Current (kA)		Difference (ON - OFF)	
						GenON	GenOFF	Change	%
5	547690	GLF339 2	69	544	1561	8.833	8.830	0.003	0.03%
5	300740	7SPORTSM	345	330	305	24.000	23.995	0.006	0.02%
5	300949	7JASPER	345	330	304	10.518	10.510	0.008	0.08%
5	510406	N.E.S.-7	345	520	547	18.765	18.751	0.014	0.08%
5	510379	DELWARE4	138	520	547	10.635	10.620	0.015	0.14%
5	532781	CANEYWF7	345	536	1537	9.409	9.394	0.015	0.16%
5	532800	LATHAMS7	345	536	1537	10.273	10.259	0.015	0.14%
5	532799	WAVERLY7	345	536	1536	14.474	14.470	0.005	0.03%
5	542965	W.GRDNR7	345	541	1544	25.287	25.257	0.030	0.12%
5	542968	STILWEL7	345	541	1544	24.461	24.425	0.037	0.15%
5	533003	LIBERTY4	138	536	1536	7.088	7.070	0.018	0.26%
5	547477	CJ 366 5	161	544	1564	12.710	12.661	0.050	0.39%
5	547491	PUR421 5	161	544	1564	9.913	9.874	0.040	0.40%
5	533756	AQUARS 2	69	536	1536	7.674	7.621	0.054	0.71%
5	533769	PITNAC 2	69	536	1536	11.191	11.076	0.115	1.04%
5	533771	ROUSE 2	69	536	1536	9.066	8.993	0.072	0.80%
5	533773	SE8CLEM2	69	536	1536	3.969	3.930	0.039	0.98%
5	533644	SE4DEVO2	69	536	1536	3.562	3.502	0.060	1.72%
5	533621	ALLEN 2	69	536	1536	5.414	5.335	0.080	1.49%
5	533650	UN8HUMB2	69	536	1536	3.942	3.880	0.062	1.61%
5	543077	PLSTVAL5	161	541	1550	9.827	9.810	0.017	0.18%
5	543057	BUCYRUS5	161	541	1550	19.301	19.208	0.094	0.49%
5	533001	ALTOONA4	138	536	1536	7.544	7.500	0.045	0.59%
5	533672	ALTAMNS2	69	536	1536	3.817	3.812	0.006	0.14%
5	533695	LABETTE2	69	536	1536	3.828	3.822	0.006	0.15%
5	533702	ORDNCE 2	69	536	1536	5.636	5.625	0.011	0.19%
5	533704	PARSONS2	69	536	1536	4.583	4.575	0.007	0.16%
5	533772	SE1GREE2	69	536	1536	5.523	5.502	0.021	0.38%

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Bus Dist. From POI	BUS NUMBER	BUS NAME	Voltage (kV)	AREA	ZONE	3 Phase Fault Current		Difference (ON - OFF)	
						GenON	GenOFF	Change	%
0	560029	G15-016-TAP	161	536	1536	7.853	6.142	1.712	27.87%
1	532934	MARMTNE5	161	536	1536	8.988	7.891	1.097	13.90%
1	543065	CNTRVIL5	161	541	1550	6.323	5.729	0.595	10.38%
1	584580	G15-016-MAIN	161	541	541	6.914	N/A	N/A	N/A
2	532937	NEOSHO 5	161	536	1536	21.303	21.002	0.301	1.43%
2	532938	FRANKLIN	161	536	1536	8.595	8.393	0.202	2.40%
2	533639	MARMATN2	69	536	1536	8.404	8.031	0.373	4.64%
2	532998	MARMATN4	138	536	1536	7.410	6.831	0.579	8.48%
2	543069	PAOLA 5	161	541	1550	10.077	9.825	0.252	2.56%
2	587560	ASGI1603	161	541	1550	10.077	9.825	0.252	2.56%
3	532926	BAKER 5	161	536	1536	8.432	8.345	0.087	1.04%
3	547469	RIV4525	161	544	1561	23.596	23.546	0.050	0.21%
3	532793	NEOSHO 7	345	536	1536	16.050	15.941	0.110	0.69%
3	533021	NEOSHO 4	138	536	1536	23.099	22.825	0.274	1.20%
3	533020	NEOSHOS4	138	536	1536	23.099	22.825	0.274	1.20%
3	532932	LITCH 5	161	536	1536	11.186	10.996	0.190	1.73%
3	533876	FRANKLIN	69	536	1536	8.946	8.837	0.109	1.23%
3	533640	MCKEE 2	69	536	1536	4.138	4.049	0.090	2.21%
3	533647	UN1ELSM2	69	536	1536	7.741	7.429	0.312	4.21%
3	532997	ALLEN 4	138	536	1536	6.348	6.065	0.284	4.67%
3	543066	S.OTTWA5	161	541	1550	6.687	6.655	0.032	0.48%
3	543067	CENTENL5	161	541	1550	10.050	9.849	0.202	2.05%
3	543112	OSAWAT 5	161	541	1550	9.689	9.459	0.230	2.43%
3	533022	NEOSHON4	138	536	1536	23.099	22.825	0.274	1.20%
3	533768	NEOSHO 2	69	536	1536	18.639	18.531	0.108	0.58%
4	547467	ORO110 5	161	544	1564	19.207	19.156	0.051	0.26%
4	547487	HOC404 5	161	544	1561	12.937	12.925	0.012	0.10%
4	547498	STL439 5	161	544	1563	24.337	24.300	0.037	0.15%
4	547503	RIV452T	161	544	1561	23.184	23.136	0.048	0.21%
4	547541	RIV167 2	69	544	1561	18.191	18.178	0.014	0.07%
4	300739	7BLACKBE	345	330	304	12.033	12.012	0.022	0.18%
4	510380	DELWARE7	345	520	547	11.437	11.410	0.027	0.23%
4	532780	CANEYRV7	345	536	1537	9.704	9.686	0.018	0.18%
4	542981	LACYGNE7	345	541	1544	25.057	25.028	0.028	0.11%
4	533008	TV1MNDV4	138	536	1536	6.868	6.837	0.031	0.45%
4	547476	ASB349 5	161	544	1564	13.022	12.903	0.119	0.92%
4	533765	LITCH 2	69	536	1536	12.630	12.502	0.128	1.02%
4	533767	MULBERY2	69	536	1536	7.863	7.790	0.073	0.94%
4	533774	SHEFFLD2	69	536	1536	4.034	3.993	0.041	1.03%
4	533645	SE9HIAT2	69	536	1536	3.679	3.610	0.068	1.89%
4	533654	ZILAJCT2	69	536	1536	7.482	7.232	0.250	3.45%
4	532996	TIOGA 4	138	536	1536	6.099	5.911	0.188	3.17%
4	533621	ALLEN 2	69	536	1536	10.677	10.265	0.412	4.01%
4	543055	SEOTTWA5	161	541	1550	6.798	6.770	0.028	0.42%
4	543068	WAGSTAF5	161	541	1550	13.476	13.374	0.102	0.76%
4	533005	NEPARSN4	138	536	1536	11.987	11.865	0.122	1.03%
4	533696	LABETTS2	69	536	1536	6.988	6.967	0.021	0.30%
4	533703	ORDNJCT2	69	536	1536	8.667	8.637	0.030	0.34%
4	533758	CRAWFOR2	69	536	1536	6.643	6.616	0.027	0.41%
5	547470	JOP145 5	161	544	1563	17.390	17.361	0.029	0.17%
5	547490	FIR417 5	161	544	1564	14.324	14.280	0.043	0.30%
5	547494	OAK432 5	161	544	1564	17.334	17.294	0.040	0.23%
5	547534	ORO110 2	69	544	1564	17.721	17.705	0.017	0.09%
5	512631	MIAMI 5	161	523	554	9.150	9.144	0.006	0.06%
5	547486	HOC404 4	138	544	1561	6.381	6.378	0.004	0.06%
5	547601	HOC404 2	69	544	1561	9.614	9.609	0.004	0.04%
5	547483	JOP389 5	161	544	1563	19.671	19.650	0.020	0.10%
5	547501	RIV453 5	161	544	1561	22.366	22.322	0.043	0.19%

Bus Dist. From POI	BUS NUMBER	BUS NAME	Voltage (kV)	AREA	ZONE	3 Phase Fault Current		Difference (ON - OFF)	
						GenON	GenOFF	Change	%
5	547502	RIV167 5	161	544	1561	21.875	21.833	0.042	0.19%
5	547523	JOP 59 T	69	544	1563	9.717	9.715	0.002	0.02%
5	547530	COL 94 2	69	544	1561	6.444	6.443	0.002	0.03%
5	547555	GAL278 2	69	544	1561	16.010	15.998	0.011	0.07%
5	547602	RIV406 2	69	544	1561	16.041	16.030	0.011	0.07%
5	547690	GLF339 2	69	544	1561	9.092	9.088	0.004	0.04%
5	300740	7SPORTSM	345	330	305	24.147	24.142	0.005	0.02%
5	300949	7JASPER	345	330	304	10.451	10.443	0.008	0.08%
5	510406	N.E.S.-7	345	520	547	18.856	18.839	0.017	0.09%
5	510379	DELWARE4	138	520	547	10.819	10.798	0.021	0.19%
5	532781	CANEYWF7	345	536	1537	9.443	9.426	0.017	0.18%
5	532800	LATHAMS7	345	536	1537	10.322	10.306	0.017	0.16%
5	532799	WAVERLY7	345	536	1536	14.528	14.523	0.005	0.03%
5	542965	W.GRDNR7	345	541	1544	26.047	26.020	0.027	0.10%
5	542968	STILWEL7	345	541	1544	24.610	24.576	0.033	0.14%
5	533003	LIBERTY4	138	536	1536	7.232	7.199	0.034	0.47%
5	547477	CJ 366 5	161	544	1564	12.644	12.600	0.044	0.35%
5	547491	PUR421 5	161	544	1564	9.801	9.766	0.035	0.36%
5	533756	AQUARS 2	69	536	1536	7.683	7.631	0.053	0.69%
5	533769	PITNAC 2	69	536	1536	11.178	11.071	0.107	0.97%
5	533771	ROUSE 2	69	536	1536	9.084	9.015	0.070	0.77%
5	533773	SE8CLEM2	69	536	1536	3.979	3.939	0.041	1.03%
5	533644	SE4DEVO2	69	536	1536	3.611	3.546	0.065	1.84%
5	533650	UN8HUMB2	69	536	1536	4.933	4.806	0.128	2.65%
5	533001	ALTOONA4	138	536	1536	8.586	8.447	0.139	1.64%
5	533646	TIOGA 2	69	536	1536	7.518	7.339	0.179	2.44%
5	533638	LEHIGTP2	69	536	1536	6.445	6.286	0.159	2.53%
5	533641	MONARCH2	69	536	1536	7.976	7.741	0.235	3.04%
5	543077	PLSTVAL5	161	541	1550	9.857	9.840	0.017	0.18%
5	543057	BUCYRUS5	161	541	1550	19.289	19.202	0.086	0.45%
5	533672	ALTAMNS2	69	536	1536	4.292	4.282	0.010	0.24%
5	533695	LABETTE2	69	536	1536	4.432	4.422	0.011	0.24%
5	533702	ORDNCE 2	69	536	1536	6.303	6.285	0.018	0.29%
5	533704	PARSONS2	69	536	1536	5.403	5.389	0.014	0.27%
5	533772	SE1GREE2	69	536	1536	5.552	5.529	0.023	0.42%

APPENDIX D: LOW WIND ANALYSIS

FIGURE D-1: GEN-2015-016 WITH GENERATION OFF AND REACTIVE COMPENSATION