GENERATOR INTERCONNECTION AFFECTED SYSTEM IMPACT RESTUDY REPORT

AECI GIA-61 (ASGI-2018-001)

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By SPP Generator Interconnections Dept.

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INTRODUCTION

The purpose of this Affected System Impact Restudy was to determine the impact of GIA-61 on the SPP transmission system due to changes in the study assumptions used in the Affected System Impact Study report posted in March 2019.[1] Changes from prior study assumptions include the withdrawal of higher queued interconnection requests, network upgrades, topology, and load. This restudy report supersedes and replaces prior affected system impact studies for GIA-61.

While results from this analysis will be considered final, a restudy may be required should significant changes to the study assumptions occur[2].

SPP utilized Siemens Power Technologies International PSS®E Version 33.11.0, PSS®E MUST, and PowerGEM's TARA 2002 for this analysis.

SPP worked with Electric Power Engineers Inc. (EPE) to update power flow cases to reflect the groups under study and developed a total of twenty-eight (28) cases, specifically 14 Base Cases (BC) and 14 Transfer Cases (TC). SPP and EPE performed power flow analysis on the study models to determine if the transmission system could accommodate the injection from the current study generation interconnection request without violating SPP's transmission planning criteria outlined below in the Study Methodology Criteria section.

This Affected System Impact Study (ASIS) was conducted consistent with the Southwest Power Pool (SPP) Open Access Transmission Tariff (OATT) and SPP Business Practices to determine impacts to the SPP transmission system.

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[1] The Affected System Study report posted in March 2019 acknowledged the potential for a required restudy. See page 2 of March 2019 study report posted at: https://opsportal.spp.org/documents/studies/files/2018_Generation_Studies/ASGI-2018-001_ASIS_RESTUDY_FINAL.pdf

[2] Significant changes to study assumptions include but are not limited to interconnection request withdrawals and/or changes to higher queued network upgrades included in the base case.

REVISION HISTORY

Date	Author	Change Description
3/24/2021	SPP	ASGI-2018-001 Affected System Impact Restudy Report Issued
3/25/2021	SPP	Minor edits to introduction

POWER FLOW ANALYSIS

BASE CASE MODEL BUILD AND DISPATCH

The DISIS-2017-001 BASE cases were used as the starting point for this restudy as the DISIS-2017-001 BASE cases included the most up-to-date higher queued generation interconnection requests, load, topology, and transmission facility ratings at the time this restudy was initiated.

DISIS-2017-001 BASE models:

- Year 1 (2019) Winter Peak (19WP)
- Year 2 (2020) Spring (20G)
- Year 2 (2020) Summer Peak (20SP)
- Year 5 (2024) Light (24L)
- Year 5 (2024) Summer Peak (24SP)
- Year 5 (2024) Winter Peak (24WP)
- Year 10 (2029) Summer Peak (29SP)

The DISIS-2017-001 BASE cases contain all higher and equally queued interconnection requests to the DISIS-2017-001 cluster; however, not all interconnection requests are dispatched. To create the GIA-61 BASE cases, interconnection requests were modeled as out of service if they did not already exist in the ITP cases. Unless otherwise indicated, in-scope interconnection requests were added or modified in the BASE model to reflect their requested capacity per service type. Appendix A and Appendix B outline the current study and higher queued in-scope interconnection requests included in the GIA-61 BASE cases, respectively. The GIA-61 BASE cases contain all higher and equally queued network upgrades to GIA-61. Appendix C outlines the network upgrades included in the GIA-61 BASE cases.

Also included in the GIA-61 BASE cases are the current study upgrades assigned by AECI, listed in **Table 2**. These upgrades were added to all seasonal models with the exception of the Darlington – Stanberry 69 kV uprate, which was added to seasonal models summer 2021 and later.

Table 3: Current Study Assigned AECI Network Upgrades

Network Upgrade	Status
Rebuild Gentry-Fairport 161 kV	Complete
Rebuild Nodaway-Gentry 161 kV	Complete
Upgrade Maryville 161/69 kV Transformer	Complete
Uprate Darlington to Stanberry 69 kV	Summer 2021
Rebuild Darlington to Fairport 69 kV	Complete
Rebuild Maryville – Maryville 161 kV	Complete

GROUPING

Appendix A and Appendix B interconnection requests are assigned into sixteen (16) active regional groups. **Table 1** outlines all active groups. Please note that groups 5 and 11 are inactive.

Based on electrical connectivity to transmission in the Northwestern Missouri region, SPP assigned GIA-61 to group 13.

Table 1: Active SPP Groupings

Group #	Area	Group #	Area
1	Woodward, OK	10	Southeast OK/Northeast TX
2	Hitchland, OK	12	Northwest AR
3	Spearville, KS	13	Northwest MO
4	Northwest KS	14	South Central OK
6	South TX Panhandle/New Mexico	15	East SD
7	Southwest OK	16	West ND
8	North OK/South Central KS	17	West SD
9	Nebraska	18	East ND

DISPATCH OF BASE AND TRANSFER CASES

The following procedures are based on SPP Business Practice 7250:

The number of base cases (BC) and transfer cases (TC) required for each impact study depends on the service requested and fuel type of the current study requests. As GIA-61 represents a High Variable Energy Resource (HVER) requesting Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS), SPP developed an HVER dispatch scenario and an NRIS dispatch scenario. In total, 28 cases were required, as shown in **Table 2**.

Table 2: GIA-61 Study Cases

Seasonal Case	ERIS HVER	NRIS
+1 Winter Peak (i.e. 19WP)	1 per group	1 per study
+1 Spring (i.e. 20G)	1 per group	1 per group
+1 Summer Peak (i.e. 20SP)	1 per group	1 per study
+5 Light Load (i.e. 24L)	1 per group	1 per group
+5 Summer Peak (i.e. 24SP)	1 per group	1 per study
+5 Winter Peak (i.e. 24WP)	1 per group	1 per study
+10 Summer Peak (i.e. 29SP)	1 per group	1 per study
GIA-61	28 cases (14 BC/14TC)	

ERIS DISPATCH

To create the ERIS base cases, SPP dispatched all in-scope higher queued generators listed in Appendix B per **Table 3**. For SPP generation, the change in generation was offset using non-study SPP conventional generation based on a Load Ratio Share (LRS) and scaled using a block order. For AECI generation, the change in generation as offset using non-study AECI conventional generation based on LRS and scaled using a block order. For the remaining generation, SPP offset the change in generation using LRS and scaled proportionally to the respective host RTO footprint.

To create the ERIS transfer cases, SPP dispatched the current study generator listed in Appendix A per **Table 3**. The change in generation was offset using non-study AECI conventional generation based on LRS and scaled using a block order.

NRIS DISPATCH

To create the NRIS base cases, EPE dispatched all in-scope higher queued generators listed in Appendix B per **Table 3**. For changes to non-SPP generation, for each RTO region, EPE used the system swing to offset the change in generation and scaled proportionally to the appropriate RTO footprint.

To create the NRIS transfer cases, EPE dispatched the current study generator listed in Appendix A per **Table 3**. SPP used the system swing to offset the change in generation and scaled the AECI area proportionally until the system swing was within range.

Table 3: SPP Dispatch Criteria

Dispatch Type	Season	Service Type	Renewable in group	Renewable out group	Conventional in group	Conventional out group
ERIS HVER	All	All	100%	0%	0%	0%
ERIS LVER	Peak	All	20%	20%	100%	100%
NRIS	Spring and Light Load	NRIS	100%	20%	100%	20%
	Peak	NRIS	100%	100%	100%	100%

* SPP did not dispatch up existing higher queued units with firm service if Pgen > SPP Dispatch Criteria

STUDY METHODOLOGY/CRITERIA

Solve Parameters

- Fixed slope decoupled Newton-Raphson
- Tap adjustment – stepping
- Switch shunt adjustments – enable all
- ERIS: Area interchange enabled
- NRIS: Area interchange disabled
- Adjust phase shift
- Adjust DC taps
- VAR limits – apply immediately
- Model solved within five iterations

Thermal Overloads

SPP identified ERIS constraints by performing AC Contingency Calculation (ACCC) analysis using Siemens Power Technologies International PSS®E Version 33.11.0 and PSS®E MUST. EPE identified NRIS constraints by performing AC Contingency Calculation (ACCC) analysis using PowerGem's TARA 2002.

Thermal overloads are determined for system intact (n-0) (greater than or equal to 100% of Rate A - normal) and for contingency (N-1) (greater than or equal to 100% of Rate B – emergency) conditions.

The methodology below is based on SPP Business Practice 7250:

Energy Resource Interconnection Service (ERIS):
For ERIS, SPP screens overloads to determine which generator interconnection requests have at least

- 3% Distribution Factor (DF) for system intact conditions (n-0),
- 20% DF upon outage-based conditions (N-1), or
- 3% DF on contingent elements that resulted in a non-converged solution.

Network Resource Interconnection Service (NRIS):
For NRIS, SPP screens overloads to determine which generator interconnection requests have at least 3% Distribution Factor (DF) for system intact conditions (n-0), outage-based conditions (N-1), or on contingent elements that resulted in a non-converged solution.

Contingencies

The contingency set includes all SPP control area branches and ties 69 kV and above, first tier Non-SPP control area branches and ties 115 kV and above, any defined contingencies for these control areas, and generation unit outages for the SPP control areas with SPP reserve share program redispatch.

- All branches, ties, shunts, and generators within the following areas:
    - SPP Internal Areas for 65kV – 999kV facilities:
        - 515 – 546, 640, 641, 642, 645, 650, 652, 659
    - SPP External Areas for 100kV – 999kV facilities:
        - 327, 330, 351, 356, 502-504, 600, 615, 620, 627, 635, 672, 680
- NERC, SPP, and Tier 1 Permanent Contingent Flowgates
- SPP T.O. Specific P1, P2, P4, and P5 TPL-004-1 Contingencies
- SPP T.O. Specific Op Guide Implementation

Monitored Facilities

The monitored elements include all SPP control area branches, ties, and buses 69 kV and above, and all first tier Non-SPP control area branches and ties 69 kV and above. NERC Power Transfer Distribution Flowgates for SPP and first tier Non-SPP control areas are monitored. Additional NERC SPP monitors flowgates in second tier or greater non-SPP control areas. SPP performed voltage monitoring for SPP control area buses 69 kV and above.

- All branches (thermal)/ buses(voltage) and ties within the following areas:
    - SPP Internal Areas for 65kV – 999kV facilities:
        - 515 – 546, 640 – 659
- NERC, SPP, and Tier 1 Permanent Monitor Flowgates (thermal)

Voltage

For non-converged power flow solutions that caused by a lack of voltage support, appropriate transmission support will be determined to mitigate the constraint.

After all thermal overload and voltage support mitigations are determined; a full ACCC analysis is then performed to determine voltage constraints. The following voltage performance guidelines are used in accordance with the Transmission Owner local planning criteria.

Table 4: SPP Areas (69 kV+)

Transmission Owner	Voltage Criteria (System Intact)	Voltage Criteria (Contingency)
AEPW	0.95 – 1.05 pu	0.92 – 1.05 pu
GRDA		0.90 – 1.05 pu
KACY		
SWPA		
OKGE		
OMPA		
WFEC		
SWPS		
MIDW		
SUNC		
KCPL		
INDN		
SPRM		
NPPD		
WAPA		
WERE L-V		0.93 – 1.05 pu
WERE H-V		0.95 – 1.05 pu
EMDE L-V		0.90 – 1.05 pu
EMDE H-V		0.92 – 1.05 pu
LES		0.90 – 1.05 pu
OPPD		

Table 5: SPP Buses with more stringent voltage criteria

Bus Name/Number	Voltage Criteria (System Intact)	Voltage Criteria (Contingency)
TUCO 230kV 525830	0.925 – 1.05 pu	0.925 – 1.05 pu
Wolf Creek 345kV 532797	0.985 – 1.03 pu	0.985 – 1.03 pu
FCS 646251	1.001 – 1.047 pu	1.001 – 1.047 pu

Table 6: Affected System Areas (115kV+)

Transmission Owner	Voltage Criteria (System Intact)	Voltage Criteria (Contingency)
AECI	0.95 – 1.05 pu	0.90 – 1.05 pu
EES-EAI		
LAGN		
EES		
AMMO		
CLEC		
LAFA		
LEPA		
XEL		
MP		
SMMPA		
GRE		0.90 – 1.10 pu
OTP		0.90 – 1.05 pu
OTP-H (115kV+)	0.97 – 1.05 pu	0.92 – 1.10 pu
ALTW	0.95 – 1.05 pu	0.90 – 1.05 pu
MEC		
MDU		
SPC		0.95 – 1.05 pu
DPC		0.90 – 1.05 pu
ALTE		

The constraints identified through the voltage scan are then screened for the following for each interconnection request.

- 3% DF on the contingent element and
- 2% change in pu voltage

IDENTIFICATION AND MITIGATION OF NETWORK CONSTRAINTS

SPP works with affected Transmission Owners to identify the limiting element for each constraint and determine the appropriate mitigation.

ERIS THERMAL NON-CONVERGED CONSTRAINT IDENTIFICATION AND MITIGATION

While low voltage was observed near the Rock Creek Wind Farm, Evergy confirmed that non-convergence in this area was due to a reactive modeling error at this facility. Once resolved, SPP confirmed that there were no non-converged constraints meeting mitigation criteria.

ERIS THERMAL SYSTEM INTACT AND CONTINGENCY CONSTRAINT IDENTIFICATION AND MITIGATION

As observed in **Table 7**, the same set ERIS constraints observed in the original impact study were observed again in this restudy. The change in model series (2017 ITP DISIS-2016-002 BASE to 2019 ITP DISIS-2017-001 BASE) did not adversely affect the impact study results.

It should be noted that while the Evergy facilities related to the Maryville – Maryville 161 kV tie are rated sufficiently for the observed need, the AECI equipment limits the rating for this line at 278 MVA. While no action is required by SPP at this time for this facility, the interconnection customer may be required to upgrade the AECI facilities in accordance with their Generation Interconnection Agreement (GIA).

Table 7: ERIS Thermal Constraints and Mitigation

Monitored Facility	Mitigation
Maryville – Braddyville 161 kV Ckt 1	Rebuild Maryville – Braddyville 161 kV Ckt 1
Creston – Maryville 161 kV Ckt 1	Reconductor Creston – Maryville 161 kV Ckt 1

ERIS VOLTAGE CONSTRAINT IDENTIFICATION AND MITIGATION

No ERIS voltage constraints met mitigation criteria.

NRIS THERMAL NON-CONVERGED CONSTRAINT IDENTIFICATION AND MITIGATION

Some NRIS non-convergent constraints were observed in the ACCC analysis.

NRIS non-convergent constraints related to contingencies on the Council Bluff to S3456 345 kV line were related to incorrect modeling of the POI for J1122. The correct modeling of the POI for J1122 mitigated these non-convergent issues.

For remaining NRIS non-convergent issues, EPE checked the DFAX of the project against the contingent elements and found that none of those elements met the criteria for mitigation.

NRIS THERMAL SYSTEM INTACT AND CONTINGENCY CONSTRAINT IDENTIFICATION AND MITIGATION

Table 8 summarizes system intact and contingency thermal constraints identified during the NRIS analysis.

Table 8 : NRIS Thermal Constraints and Mitigation

Monitored Facility	Mitigation
Maryville to Midway 161 kV	Rebuild Maryville to Midway 161 kV
Midway to Avenue City 161 kV	Rebuild Midway to Avenue City 161 kV
Avenue City to St Joseph 161 kV	Rebuild Avenue City to St Joseph 161 kV
Nashua 345/161 kV Transformer	Add 2nd Nashua 345/161 kV Transformer
Nashua to Roanridge 161 kV	Rebuild Nashua to Roanridge 161 kV
Council Bluffs to S3456 345 kV	Constraints only occur in 19WP and SPP determined that these upgrades are not required under the study circumstances as load changes in later cases mitigate the overloads.
Warrenburg to WAFBW 161 kV	

NRIS VOLTAGE CONSTRAINT IDENTIFICATION AND MITIGATION

No NRIS voltage constraints met mitigation criteria.

POWER FLOW ANALYSIS

The results of the power flow analysis for interconnection requests under study are embedded in

Table 9.

Table 9: Power Flow Analysis Results

Results	
Thermal Constraints	ERIS Thermal Results.xlsx NRIS Thermal Results.xlsx
Voltage Constraints	N/A

LIMITED OPERATION AVAILABILITY

SPP will coordinate with Associated Electric Cooperative, Inc. (AECI) to determine the appropriate level of Limited Operation in accordance with the AECI's Open Access Transmission Tariff, Joint Operating Agreement Among and Between SPP and AECI, and the customer's Generation Interconnection Agreement.

COST ALLOCATION

Preliminary cost estimates provided in this analysis are subject to change, pending the Transmission Owner Facilities Studies.

SPP utilizes the one-year-out spring seasonal model for Variable Energy Resources (VERs). The five-year-out summer peak seasonal model is used for conventional fuel type generators. If both fuel types are being studied, both sets of models are utilized. Project distribution factors on the identified upgrades, under system intact conditions, are used to determine cost allocation. The impact each generation interconnection request has on each upgrade project is weighted by the size of each request. Finally, the costs due by each request for a particular project are then determined by allocating the portion of each request's impact over the impact of all affecting requests.

For example, assume that there are three Generation Interconnection requests, X, Y, and Z that are responsible for the costs of Upgrade Project '1'. Given that their respective power transfer distribution factors (PTDF) for the project have been determined, the cost allocation for Generation Interconnection request 'X' for Upgrade Project 1 is found by the following set of steps and formulas:

- Request X, Upgrade Project 1 = PTDF (%)(X) * MW(X) = X1
- Request Y, Upgrade Project 1 = PTDF (%)(Y) * MW(Y) = Y1
- Request Z, Upgrade Project 1 = PTDF (%)(Z) * MW(Z) = Z1

Allocation of Cost for a particular project:

$$\text{Request X's Project 1 Cost Allocation (\$)} = \frac{\text{Network Upgrade Project 1 Cost (\$)} * X1}{X1 + Y1 + Z1}$$

Repeat previous for each responsible GI request for each Project.

It should be noted that network upgrades associated with higher-queued projects are also considered as contingent upgrades. These facilities have been included in the models for this study and are assumed to be in service. This list may not be all-inclusive. While current study interconnection customers do not have cost responsibility for contingent upgrades, they may later be assigned cost if higher-queued customers withdraw their interconnection request or terminate their interconnection agreement. The network upgrades associated with higher-queued projects are listed in Appendix C**.**

Table 10: ERIS and NRIS Upgrades Required for Interconnection Service

Upgrade Type	Upgrade	Length	Rate Cost
ERIS	Reconductor Maryville to Creston 161 kV	62.34	$ 14,900,000
ERIS	Rebuild Maryville to Braddyville 161 kV	16.74	$ 18,652,900
NRIS	Rebuild Maryville to Midway 161 kV	19.45	$ 21,500,000
NRIS	Rebuild Midway to Avenue City 161 kV	20.35	$ 21,500,000
NRIS	Rebuild Avenue City to St Joseph 161 kV	3.5	$ 4,900,000
NRIS	Add 2nd Nashua 345/161 kV Transformer	0	$ 8,500,000
NRIS	Rebuild Nashua to Roanridge 161 kV	6.1	$ 9,150,000

ERIS	$ 33,552,900
NRIS	$ 65,550,000
Total	$ 99,102,900

CONCLUSION

A power flow analysis was performed to determine the impact of GIA-61 on the SPP transmission system. The results of the power flow analysis identified several constraints that require mitigation. Please refer to **Table 10** for and cost allocation of assigned network upgrades.

In no way does this study guarantee operation for all periods. It should be noted that although this study analyzed many of the most probable contingencies, it is not an all-inclusive list and cannot account for every operational situation. Because of this, it is likely that the Customer(s) may be required to reduce their generation output to **0 MW** under certain system conditions to allow system operators to maintain the reliability of the transmission network.

APPENDICES

APPENDIX A

Table 11: Current Study Interconnection Request

Generation Interconnection Number	Group	Type	G PMAX	SP PMAX	WP PMAX	Service	GEN Area	Point of Interconnection
GIA-61	13	Wind	242	242	242	ER/NR	AECI	Maryville 161 kV

APPENDIX B

Higher Queued Projects.xlsx

APPENDIX C

Higher Queued Network Upgrades.›

APPENDIX D

MISO Projects Inadvertently Exclud