AFFECTED SYSTEM IMPACT ANALYSIS

AECI GIA-68

Published May 2020

By SPP Generator Interconnections Dept.

REVISION HISTORY

Date	Author	Change Description
5/1/2020	SPP	Affected System Impact Analysis for AECI GIA-68 Report Revision 0 Issued

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EXECUTIVE SUMMARY

The AECI interconnection request GIA-68 was submitted to the AECI queue on 5/24/2018 and entered the facility study queue 4/11/2019. In accordance with the Joint Operating Agreement between SPP and AECI, SPP was requested to study GIA-68 to determine the impacts to the SPP transmission system on or around its proposed in-service date of 10/1/2021.

This impact analysis is to determine if any constraints exist given the interconnection requests and network upgrades currently expected to be in-service by 10/1/2021. As SPP currently uses cluster close date to determine queue priority, GIA-68 is considered lower queued to both the DISIS-2017-001 and DISIS-2017-002 with a window close of 11/30/2017. The results provided in this impact analysis may need to be updated at a later date once the results of the higher queued DISIS clusters are known.

Transient stability and short circuit analysis may be provided as an addendum to this report at a later date.

The affected system impact analysis has determined that no network upgrades would be required for GIA-68 to interconnect all 200 MW of generation with Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS) under the assumptions stated in this report. It should be noted that full interconnection service may require Network Upgrades, should higher queued interconnection requests proceed to commercial operation. The impacts of higher queued interconnection requests will not be known until the completion of the higher queued impact studies.

While this impact study analyzed many of the most probable contingencies, it is not an all-inclusive list that can account for every operational situation. Nothing in this impact study should be construed as a guarantee of delivery or transmission service. If the customer(s) wishes to move power across the facilities of SPP, a separate request for transmission service must be made on Southwest Power Pool's OASIS by the Customer(s).

INTRODUCTION

An Affected System Impact Analysis shall evaluate the impact of the proposed interconnection on the reliability of the Transmission System. An impact analysis may include steady-state power flow, transient stability, and short-circuit analyses. An impact analysis will consider the Base Case[1], as well as all Interconnection Requests in the SPP and Affected System Queues and all generating facilities (and with respect to (ii and iii) below, any identified Network Upgrades associated with such higher queued interconnection) that, on the date the impact analysis is commenced:

i. Are directly interconnected to the Transmission System;
ii. Are interconnected to Affected Systems and may have an impact on the Interconnection Request;
iii. Have a pending higher queued Interconnection Request to interconnect to the Transmission System; or
iv. Have no Interconnection Queue Position but have executed a GIA or requested that an unexecuted GIA be filed with FERC.

The results of this analysis are informational only. In the event GIA-68 would like to interconnect into the system at a time earlier than completion of the required higher queued studies, the customer may request an interim analysis. The interim analysis will determine the amount of available interconnection capacity available prior to a definitive analysis being performed.

[1] The Base Case (also referred to as the BASE case) refers to the latest ITP model utilized by the Generation Interconnection department for study.

SCOPE AND ASSUMPTIONS

Only SPP interconnection requests which have proceeded to facility study, are in GIA negotiation, or have executed their GIA/Interim GIA were considered in this analysis. To reduce the need for a restudy of this analysis, particular attention was taken to exclude higher queued projects which, due to the amount of interconnection costs currently allocated, are likely to withdraw. The interconnection requests which were explicitly omitted from this analysis are as follows:

- GEN-2016-153
- GEN-2016-162
- GEN-2016-163

The DISIS-2016-002 interconnection requests listed above are considered higher queued to GIA-68. For that reason, if any of the above requests go into commercial operation, a restudy may be required to determine if the results of this impact analysis remain valid. Please note that restudy costs are borne by the interconnection customer.

Stability Analysis

Initial stability analysis was completed using the 2016 MMWG model series with all DISIS-2016-002-0 Interconnection Requests and their respective network upgrades were added. As the DISIS-2016-002-1 was conducted for only group 6 and the DISIS-2016-002-2 was not yet complete, it was necessary to use the initial study assumptions (DISIS-2016-002-0) and network upgrades for the analysis.

SPP conducted the stability analysis under the assumption that GIA-68 and the neighboring projects of GIA-77 and GIA-78 were in group 8. A mutual set of dynamic contingencies (i.e. faults) were developed and applied to all requests. Under the study assumptions conducted, no constraints were identified for GIA-68. However, as there is a known stability issue in the Wolf Creek area, SPP intends to refresh the stability analysis at a future date for all three AECI requests to ensure no stability constraints exist under the updated study assumptions.

Power Flow Analysis

This power flow analysis utilized the 2017 ITP (2016 model series), which contains three seasonal models for 2021 (spring, light load, and summer peak). SPP added and redispatched higher queued interconnection requests and network upgrades expected to be in-service by 10/1/2021 which were not already included in the ITP study models.

As the Point of Interconnection (POI) for GIA-68 (Blackberry 345 kV) is only a few buses away from group 8 facilities, it may be necessary to study GIA-68 as a group 12 and group 8 request. However, for this impact analysis, GIA-68 has only been studied in group 12.

DISIS-2016-002 Assumptions

As group 8 of the DISIS-2016-002 is currently being restudied, GEN-2016-153, GEN-2016-162, and GEN-2016-163 and their associated network upgrades were intentionally excluded from this analysis. Given the proximity of these requests to GIA-68, the combined effect of GIA-68 and one or more of these projects may significant impact the transmission system.

There are no active Group 12 DISIS-2016-002 interconnection requests.

Description of Appendices

Appendix A and Appendix B outline the higher queued requests which were redispatched to create the base case (BC) and transfer cases (TC). Appendix C outlines the network upgrades which were intentionally removed or added to the models as part of the study assumptions. Appendix D details the sinks used for the Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS) dispatches respectively.

STUDY CASES

14 Base Case and 14 Transfer Cases totaling 28 total study cases are required for the AECI GIA-68 interim analysis. Please refer to the DISIS manual for additional information regarding dispatch methodology.

- LVER: Group00 (Not Required, No Conventional Requests)
- NR: Group00NR (10 total)
- HVER: GroupALL (7 per group x 1)
  - Group 12
    - 7 BC and 7 TC cases
- NR: GroupNR (2 per group x 1)
  - Group 12
    - 2 BC and 2 TC cases

POWER FLOW ANALYSIS

Power flow analysis determines if the transmission system can accommodate the injection from the request without violating thermal or voltage transmission planning criteria.

MODEL PREPARATION

Power flow analysis will use the latest models available for the study queue, which are modified versions of the 2016 series of 2017 ITP Near-Term study models including these seasonal models:

- Year 1 (2017) Winter Peak (17WP)
- Year 2 (2018) Spring (18G)
- Year 2 (2018) Summer Peak (18SP)
- Year 5 (2021) Light (21L)
- Year 5 (2021) Summer (21SP)
- Year 5 (2021) Winter (21WP) peak
- Year 10 (2026) Summer (26SP) peak

SPP uses a group dispatch methodology for both SPP and Affected System Impact Studies. SPP generator interconnection requests will be dispatched across the SPP footprint using load factor ratios. Affected system interconnection requests will be dispatched across their respective footprint using the load factor ratios.

For Variable Energy Resources (VER) (solar/wind) in each power flow case, ERIS, is evaluated for the generating plants within a geographical area of the interconnection request(s) for the VERs dispatched at 100% nameplate of maximum generation. The VERs in the remote areas is dispatched at 20% nameplate of maximum generation.

Peaking units are not dispatched in the Year 2 spring and Year 5 light, or in the "High VER" summer and winter peaks. To study peaking units' impacts, the Year 1 winter peak, Year 2 summer peak, and Year 5 summer and winter peaks, and Year 10 summer peak models are developed with peaking units dispatched at 100% of the nameplate rating and VERs dispatched at 20% of the nameplate rating. Each interconnection request is also modeled separately at 100% nameplate for certain analyses.

All generators (VER and peaking) that requested NRIS are dispatched in an additional analysis into the interconnecting Transmission Owner's (T.O.) area at 100% nameplate with ERIS only requests at 80% nameplate. This method allows for identification of network constraints that are common between regional groupings to have affecting requests share the mitigating upgrade costs throughout the cluster.

DISPATCH SCENARIOS

SPP uses scenario numbers to keep track of case sets. The initial scenario (Scenario 0) should not contain any current study network upgrades. The final scenario (Scenario 1) should contain all of the network upgrades from all groups. Scenario 1 should not result in any constraints for mitigation on the SPP transmission system.

The following scenarios are recommended for the ERIS analysis:

Scenario	Description
0	No current study network upgrades included
1	All current study network upgrades included from all groups (ERIS only)
2	Current study network upgrades required to alleviate non-converged ERIS thermal constraints
3	Current study network upgrades required to alleviate N-0 thermal ERIS constraints
4	Current study network upgrades required to alleviate N-n thermal ERIS constraints
5	Current study network upgrades required to alleviate voltage ERIS constraints

It is recommended that the ERIS analysis be completed first as these network upgrades should be included in Scenario 0 of the NRIS analysis.

The following scenarios are recommended for the NRIS analysis:

Scenario	Description
0	ERIS current study network upgrades included
1	All current study network upgrades included from all groups (ERIS and NRIS)
2	Current study network upgrades required to alleviate non-converged NRIS thermal constraints
3	Current study network upgrades required to alleviate N-0 thermal NRIS constraints
4	Current study network upgrades required to alleviate N-n thermal NRIS constraints
5	Current study network upgrades required to alleviate voltage NRIS constraints

STUDY METHODOLOGY AND CRITERIA

SOLVE PARAMETERS

All models must solve with the "tight solve" parameters prior to ACCC and TDF.

The following solution parameters should be used:

- Fixed slope decoupled Newton-Raphson
- Tap adjustment – stepping
- Switch shunt adjustments – enable all
- Area interchange control – tie lines and loads
- Adjust phase shift
- Adjust DC taps
- VAR limits – apply immediately
- Must solve within five iterations, three or less is preferred

SPP will provide a slow and tight solve idev for reference.

THERMAL OVERLOADS

Network constraints are found by using PSS/E AC Contingency Calculation (ACCC) analysis with PSS/E MUST First Contingency Incremental Transfer Capability (FCITC) analysis on the entire cluster grouping dispatched at the various levels previously mentioned.

For Energy Resource Interconnection Service (ERIS), 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 overloads are then screened to determine which of 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.

Interconnection Requests that requested Network Resource Interconnection Service (NRIS) are also studied in a separate NRIS analysis to determine if any constraint measured greater than or equal to a 3% DF. If so, these constraints are also considered for transmission reinforcement under NRIS.

Contingencies

The contingency set includes all SPP control area branches and ties 69kV 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 60kV – 999kV facilities:
    - 515 – 546, 640, 641, 642, 645, 650, 652, 659. 998, 999
  - 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 Flowgates are monitored in second tier or greater Non-SPP control areas. Voltage monitoring was performed for SPP control area buses 69 kV and above.

- All branches (thermal)/ buses(voltage) and ties within the following areas:
  - SPP Internal Areas for 60kV – 999kV facilities:
    - 515 – 546, 640 – 659, 998, 999
- NERC, SPP, and Tier 1 Permanent Monitor Flowgates (thermal)

VOLTAGE

For non-converged power flow solutions that are determined to be caused by 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.

SPP Areas (69kV+):

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
SWPA		

<table>
<tr><td>OKGE</td><td rowspan="9"></td><td rowspan="9"></td></tr>
<tr><td>OMPA</td></tr>
<tr><td>WFEC</td></tr>
<tr><td>SWPS</td></tr>
<tr><td>MIDW</td></tr>
<tr><td>SUNC</td></tr>
<tr><td>KCPL</td></tr>
<tr><td>INDN</td></tr>
<tr><td>SPRM</td></tr>
</table>

<table>
<tr><td>NPPD</td><td rowspan="8"></td><td rowspan="2"></td></tr>
<tr><td>WAPA</td></tr>
<tr><td>WERE L-V</td><td>0.93 – 1.05 pu</td></tr>
<tr><td>WERE H-V</td><td>0.95 – 1.05 pu</td></tr>
<tr><td>EMDE L-V</td><td>0.90 – 1.05 pu</td></tr>
<tr><td>EMDE H-V</td><td>0.92 – 1.05 pu</td></tr>
<tr><td>LES</td><td rowspan="2">0.90 – 1.05 pu</td></tr>
<tr><td>OPPD</td></tr>
</table>

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

<u>Affected System Areas (115kV+):</u>

<table>
<tr><th>Transmission Owner</th><th>Voltage Criteria (System Intact)</th><th>Voltage Criteria (Contingency)</th></tr>
<tr><td>AECI</td><td rowspan="9">0.95 – 1.05 pu</td><td rowspan="9">0.90 – 1.05 pu</td></tr>
<tr><td>EES-EAI</td></tr>
<tr><td>LAGN</td></tr>
<tr><td>EES</td></tr>
<tr><td>AMMO</td></tr>
<tr><td>CLEC</td></tr>
<tr><td>LAFA</td></tr>
<tr><td>LEPA</td></tr>
<tr><td>XEL</td></tr>
</table>

<table>
<tr><td>MP</td><td rowspan="4"></td><td rowspan="2"></td></tr>
<tr><td>SMMPA</td></tr>
<tr><td>GRE</td><td>0.90 – 1.10 pu</td></tr>
<tr><td>OTP</td><td>0.90 – 1.05 pu</td></tr>
<tr><td>OTP-H (115kV+)</td><td>0.97 – 1.05 pu</td><td>0.92 – 1.10 pu</td></tr>
<tr><td>ALTW</td><td rowspan="6">0.95 – 1.05 pu</td><td rowspan="3">0.90 – 1.05 pu</td></tr>
<tr><td>MEC</td></tr>
<tr><td>MDU</td></tr>
<tr><td>SPC</td><td>0.95 – 1.05 pu</td></tr>
<tr><td>DPC</td><td rowspan="2">0.90 – 1.05 pu</td></tr>
<tr><td>ALTE</td></tr>
</table>

The constraints identified through the voltage scan are then screened for the following for each interconnection request. 1) 3% DF on the contingent element and 2) 2% change in pu voltage.

RESULTS

ACCC with associated FCITC TDF results will be provided as part of the report for this Study.

The analysis will determine and verify the amount of generation that can be connected to the SPP transmission system without system constraints that require mitigation assuming only the upgrades that are expected to be in service at the expected time of interconnection Commercial Operation Date.

COST ALLOCATION

Calculation of Impact Factor for a particular request:

- 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:

- Request X's Project 1 Cost Allocation ($) = Network Upgrade Project 1 Cost($) * X1
- X1 + Y1 + Z1

If the current study interconnection request requires a network upgrade for full interconnection service, the study resource will determine the Limited Operation amount available to the request prior to all required network upgrades being in-service.

RESULTS

This impact analysis has determined that no network upgrades are required for ERIS or NRIS under the system conditions and study assumptions stated in this report. The interconnection service of GIA-68 may be subject to reevaluation upon completion of higher queued cluster studies.

The following constraints, while observed in the analysis, are not for mitigation. These constraints were observed in the 2017 ITPNT and were mitigated by UID 71928, thus the contingency is no longer valid. UID 71928 is considered in-service.

GROUP	SEASON	MONTCOMMON NAME	RATEA	RATEB	TDF	TC%LOADING	CONTNAME
00NR	17WP	'STILWEL7 - STLWL 22 - 22'	550	605	0.05057	106.7	''P55:345:KCPL:STILWELL_BUS_11''
12NR	18G	'STILWEL7 - STLWL 22 - 22'	550	605	0.04742	104	''P55:345:KCPL:STILWELL_BUS_11''

Please refer to Appendix H-T and H-V for the constraints captured by this analysis which do not meet SPP mitigation criteria. These constraints are listed for informational purposes only.

CONCLUSION

Southwest Power Pool (SPP) conducted an impact analysis on the AECI Interconnection Request GIA-68 in accordance with the Open Access Transmission Tariff (OATT) and Business Practice 7300 to determine the interim effects of interconnection into the system of Associated Electric Cooperative Inc. (AECI).

SPP has conducted this impact analysis restudy to evaluate potential impacts on an interim basis to the SPP Transmission System related to the interconnection of generators on the AECI Transmission System.

The impact analysis has determined that no network upgrades would be required for GIA-68 to interconnect on an interim basis all 200 MW of generation with Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS).

The results of this analysis are informational only. In the event GIA-68 would like to interconnect into the system at a time earlier than completion of the required higher queued studies, the customer may request an interim analysis. The interim analysis will determine the amount of available interconnection capacity available prior to a definitive analysis being performed.

It should be noted that although this impact analysis analyzed many of the most probable contingencies, it is not an all-inclusive list that can account for every operational situation. Additionally, the generator may not be able to inject any power onto the Transmission System due to constraints that fall below the threshold of mitigation for a Generator Interconnection request. 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.

Any changes to these assumptions, for example, one or more of the previously queued requests not included within this study execute an interconnection agreement and commencing commercial operation, may require a re-study of this impact analysis at the expense of the Customer.

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

APPENDICES

APPENDIX A

Table 1: Current Study Interconnection Request(s)

Generation Interconnection Number	Point of Interconnection	Service	Group	Type	Status	Queue SP	Queue WP
GIA-68	Blackberry 345 kV	ER/NR	12 W-ARK[2]	Solar	GIA Negotiation	200	200

[2] While the current study request resides in Jasper County, MO, SPP may also study this request in Group 8 due to the electrical proximity of the request.

APPENDIX B

For the AECI GIA-68 interim analysis, SPP will consider all interconnection requests in the AECI, MISO, and SPP queue which are expected to be in-service by 10/1/2021 and are considered in-scope by SPP[3]

AECI INTERCONNECTION REQUESTS INCLUDED IN THE ANALYSIS

The following AECI interconnection requests have a proposed in-service date between 11/2012 and 10/1/2021. GIA-53, GIA-61, and GIA-81 are being excluded from this interim analysis as they are considered electrically distant enough not to significantly impact the study results. GIA-69, GIA-77, and GIA-78 are close enough to GIA-68 to significantly impact the study results. However, as SPP has not studied GIA-77 or GIA-78 nor identified the network upgrades required for interconnection service, these three projects will be excluded from the study models.

Table 2: AECI Higher Queued Interconnection Request(s) excluded from study

GI No.	Application Received	Location	State	Proposed In Service
GIA-53	12/19/2016	Nodaway County	MO	9/1/2020
GIA-61	5/3/2017	Nodaway County	MO	12/31/2019
GIA-77	1/18/2019	Mayes County	OK	9/28/2019
GIA-78	1/18/2019	Mayes County	OK	9/28/2020
GIA-81	3/6/2019	Dunklin County	MO	9/28/2019

MISO INTERCONNECTION REQEUSTS INCLUDED IN THE ANALYSIS

Per the MISO public queue, the following MISO projects have an application in-service date on or before 10/1/2021 and reside in either Arkansas or Kansas. The projects were evaluated individually on a geographic basis and it was determined that none were electrically close enough to include in the GIA-68 interim evaluation.

Table 3: MISO Higher Queued Interconnection Request(s) excluded from study

Project #	Appl In Service Date	County	State
J348	9/1/2017	Arkansas County	AR
J680	4/15/2018	Ashley County	AR
J620	1/30/2018	Chicot County	AR
J934	9/1/2021	Crittenden County	AR
J1007	9/1/2021	Crittenden County	AR
J1400	8/1/2021	Crittenden County	AR
J1125	7/31/2021	Cross County	AR
J1260	10/1/2021	Desha County	AR
J919	8/1/2021	Jackson County	AR
J1402	8/1/2021	Jackson County	AR
J328	8/4/2015	Jefferson County	AR
J1425	6/1/2020	Jefferson County	AR

[3] Interconnection requests are examined by SPP engineering staff on an individual basis and are determined to be in-scope based on electrical proximity to the SPP footprint, identification of network upgrades in previously conducted impact studies, and whether or not the request was included in a higher queued impact study conducted by SPP.

J552	10/15/2018	Lee County	AR
J586	11/1/2018	Mississippi County	AR
J1146	1/4/2019	Mississippi County	AR
J1155	6/1/2020	Mississippi County	AR
J1261	10/1/2021	Monroe County	AR
J663	10/1/2018	Phillips County	AR
J834	9/1/2020	Phillips County	AR
J376	5/27/2015	Union County	AR
J893	8/1/2021	White County	AR
J603	9/1/2018	Montrose, AR	AR
J476	7/1/2020	Atchison County	MO
J1026	9/30/2020	Audrain County, Ralls County	MO
J1145	4/1/2021	Callaway County	MO
J994	9/1/2021	Callaway County	MO
J1107	9/1/2021	Cape Girardeau County	MO
J1025	9/30/2020	Knox County	MO
J145	8/14/2012	Miller County	MO
J987	9/1/2021	Montgomery County	MO
J944	9/1/2021	New Madrid County	MO
J611	9/1/2020	Nodaway County	MO
J1024	9/30/2020	Nodaway County	MO
J956	9/15/2021	Ralls County	MO
J541	4/30/2020	Schuyler County	MO
J1087	1/2/2021	Scott County	MO
J817	9/1/2019	Warren County	MO

SPP INTERCONNECTION REQUESTS INCLUDED IN THE ANALYSIS

All SPP interconnection requests higher or equally queued to the DISIS-2016-001-2 are included in the SPP affected system GIA-68 interim study. The following interconnection requests are listed in the scope as they may significantly impact the current study request:

SPP requests not already present in the 17ITP models will be added and dispatched according to SPP dispatch methodology. Requests already present will be redispatched according to SPP dispatch methodology[4].

Generation Interconnection Number	Nearest Town or County	State	In-Service Date
GEN-2016-013	Joplin	MO	4/25/2003
GEN-2016-014	Joplin	MO	4/25/2003

The following SPP interconnection requests have requested interim service and will be included in the analysis.

[4] Existing interconnection requests with Pgen greater than the new GI Study Proposed Pgen will not be redispatched; these requests will be left as-is with the exception of conventional generation, which may be scaled down to accommodate renewable generation.

Generation Interconnection Number	Nearest Town or County	In-Service Date
GEN-2017-009	Neosho County	10/31/2020
GEN-2017-060	Barton County	9/1/2020
GEN-2017-082	Barton/Jasper Counties	7/1/2020

APPENDIX C

Unless noted otherwise below, all 17ITP projects are assumed to be in-service according to their proposed in-service date. Also, unless noted otherwise below, all network upgrades assigned to the DISIS-2016-001 (for all groups) are included in this analysis.

The following projects are not expected to be in-service by 10/1/2021 and are therefore excluded from the analysis:

- Gentleman – Thedford – Holt 345 kV Ckt 1 (R-Plan) excluded from 21L – 26SP
- Wolf Creek – Neosho 345 kV Ckt 1 (not expected to be in-service by 10/1/2021)

The following network upgrades have been identified in an SPP DISIS and were included in all seasonal BASE-DIS1601 study models (unless otherwise specified).

- 13.DIS-14-2_ERIS_REBUILD_TOLKWEST-PLANTX-230kV-CKT1&2[17WP-18G].IDV
- 13.DIS-14-2_ERIS_REBUILD_TUCO_345-230kV_XFMR_CKT1[17WP-18G].IDV
- 14.DIS-15-2_ERIS_RERATE_CLEO CORNER-CLEOPLT4-138kV-CKT1.IDV
- 14.DIS-15-2_ERIS_RERATE_CLEVELAND-SILVERCITY-138kV-CKT1[SPRING LIGHT SUMMER].IDV
- 14.DIS-15-2_ERIS_RERATE_MATHEWSON-GEN-2015-063TAP-345kV-CKT1.IDV
- 14.DIS1501_NRIS_RERATE_RENFROW-RENFROW-138kV-CKT1.IDV
- 15.DIS-15-2_ERIS_G09_REBUILD_BEATRICE-HARBINE-115kV-CKT1.IDV
- 15.DIS-15-2_ERIS_G09_REBUILD_GAVINS-YANKTON-115kV-CKT1.IDV
- 15.DIS-15-2_ERIS_G16_BUILD_DICKSINSON-TRANSFORMER-230-115-13kV-CKT2.IDV
- 16.DIS16011_ERIS_G09_BUILD_KEYSTONE-GGS-345kV-CKT2.IDV
- 16.DIS16011_NRIS_G16_REPLACE_CT_GLENHAM-CAMBELL-230kV-CKT1.IDV
- 16.DIS16012_ERIS_G08_TERMINAL_EQUIPMENT_RANCHROAD-SOONER-345kV-CKT1.idv
- 16.DIS16013_ERIS_G09_BUILD_SIDNEY-KEYSTONE-345kV-CKT2.IDV
- 16.DIS16014_G09_REROUTE_LRS-STEGALL-345KV-CKT1.IDV
- 16.DIS1601PQ_NRIS_REPLACE_CARLISLE-TRANSFORMER-230-115kV-CKT1.IDV

APPENDIX D

GIA-68 will be dispatched against the AECI conventional generation (listed below) for both the ERIS and NRIS dispatch scenarios. This bus list will also be used to calculate the transfer distribution factor (TDF) of the request for each constraint identified in the analysis.

300001
300002
300003
300006
300007
300010
300011
300012
300013
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SOLUTION	GROUP	SCENARIO	SEASON	SOURCE	DIRECTION	MONITORED ELEMENT	FROM AREA NAME	TO AREA NAME	RATE A (MVA)	RATE B (MVA)	TDF	TC% LOADING (% MVA)	CONTINGENCY
FDNS	12ALL	0	18SP	GIA_68	'FROM -> TO'	'5LAMAR - 2LAMR - 1'	AECI	AECI	84	84	0.03191	107.8	'5CLARK - 5LAMAR - 1'
FDNS	12ALL	0	21SP	GIA_68	'FROM -> TO'	'8GPDELL - 1SGPDEL - 1'	AECI	AECI	330	330	0.07163	105.2	'8GPDELL - 8DELL% - Z1'
FDNS	12ALL	0	18SP	GIA_68	'FROM -> TO'	'8GPDELL - 1SGPDEL - 1'	AECI	AECI	330	330	0.07473	103.2	'8GPDELL - 8DELL% - Z1'
FDNS	12ALL	0	26SP	GIA_68	'FROM -> TO'	'8GPDELL - 1SGPDEL - 1'	AECI	AECI	330	330	0.06536	102.9	'8GPDELL - 8DELL% - Z1'
FDNS	00NR	0	17WP	GIA_68	'TO -> FROM'	'STILWEL5 - STLWL 22 - 22'	KCPL	KCPL	550	605	0.05057	106.2	''P55:345:KCPL:STILWELL_BUS_11''
FDNS	12NR	0	18G	GIA_68	'TO -> FROM'	'STILWEL5 - STLWL 22 - 22'	KCPL	KCPL	550	605	0.04742	104.5	''P55:345:KCPL:STILWELL_BUS_11''
FDNS	00NR	0	21WP	GIA_68	'TO -> FROM'	'STILWEL5 - STLWL 22 - 22'	KCPL	KCPL	550	605	0.05275	101.2	''P55:345:KCPL:STILWELL_BUS_11''
FDNS	00NR	0	18SP	GIA_68	'TO -> FROM'	'STILWEL5 - STLWL 22 - 22'	KCPL	KCPL	550	605	0.05577	101	''P55:345:KCPL:STILWELL_BUS_11''
FDNS	00NR	0	17WP	GIA_68	'FROM -> TO'	'STILWEL7 - STLWL 22 - 22'	KCPL	KCPL	550	605	0.05057	107.1	''P55:345:KCPL:STILWELL_BUS_11''
FDNS	12NR	0	18G	GIA_68	'FROM -> TO'	'STILWEL7 - STLWL 22 - 22'	KCPL	KCPL	550	605	0.04742	104.9	''P55:345:KCPL:STILWELL_BUS_11''
FDNS	00NR	0	18SP	GIA_68	'FROM -> TO'	'STILWEL7 - STLWL 22 - 22'	KCPL	KCPL	550	605	0.05577	102.7	''P55:345:KCPL:STILWELL_BUS_11''
FDNS	00NR	0	21WP	GIA_68	'FROM -> TO'	'STILWEL7 - STLWL 22 - 22'	KCPL	KCPL	550	605	0.05275	102	''P55:345:KCPL:STILWELL_BUS_11''