INTERCONNECTION FACILITIES STUDY REPORT

GEN-2017-111

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By SPP Generator Interconnections Dept.

REVISION HISTORY

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION
04/14/2023	SPP	Initial draft report issued.

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SUMMARY

INTRODUCTION

This Interconnection Facilities Study (IFS) for Interconnection Request is for a 152 MW generating facility located in Bates County, MO. The Interconnection Request was studied in the DISIS-2017-002 Impact Study for ERIS. The Interconnection Customer's requested in-service date is December 31, 2024.

The interconnecting Transmission Owner, Evergy (KCPL), performed a detailed IFS at the request of SPP. The full report is included in Appendix A. SPP has determined that full Interconnection Service will be available after the assigned Transmission Owner Interconnection Facilities (TOIF), Non-Shared Network Upgrades, Shared Network Upgrades, Contingent Network Upgrades, and Affected System Upgrades that are required for full interconnection service are completed.

The primary objective of the IFS is to identify necessary Transmission Owner Interconnection Facilities, Network Upgrades, other direct assigned upgrades, cost estimates, and associated upgrade lead times needed to grant the requested Interconnection Service.

PHASE(S) OF INTERCONNECTION SERVICE

It is not expected that Interconnection Service will occur in phases. However, full Interconnection Service will not be available until all Interconnection Facilities and Network Upgrade(s) can be placed in service.

COMPENSATION FOR AMOUNTS ADVANCED FOR NETWORK UPGRADE(S)

FERC Order ER20-1687-000 eliminated the use of Attachment Z2 revenue crediting as an option for compensation. The Incremental Long Term Congestion Right (ILTCR) process will be the sole process to compensate upgrade sponsors as of July 1st, 2020.

INTERCONNECTION CUSTOMER INTERCONNECTION FACILITIES

The Generating Facility is proposed to consist of (49) Sungrow SG3600UD-MV inverters for a total generating nameplate capacity of 152 MW.

The Interconnection Customer's Interconnection Facilities to be designed, procured, constructed, installed, maintained, and owned by the Interconnection Customer at its sole expense include:

34.5 kV underground cable collection circuits;

34.5 kV to 161 kV transformation substation with associated 34.5 kV and 161 kV switchgear;

One 161/34.5/13.8 kV 108/133/167 MVA (ONAN/ONAF/ONAF) step-up transformer to be owned and maintained by the Interconnection Customer at the Interconnection Customer's substation;

Approx. 0.17 miles 161 kV line to connect the Interconnection Customer's substation to the Point of Interconnection ("POI") at the 161 kV bus at existing Transmission Owner substation ("Clinton – Stilwell 161 kV Line") that is owned and maintained by Transmission Owner;

All transmission facilities required to connect the Interconnection Customer's substation to the POI;

Equipment at the Interconnection Customer's substation necessary to maintain a composite power delivery at continuous rated power output at the high-side of the generator substation at a power factor within the range of 95% lagging and 95% leading in accordance with Federal Energy Regulatory Commission (FERC) Order 827. The Interconnection Customer may use inverter manufacturing options for providing reactive power under no/reduced generation conditions. The Interconnection Customer will be required to provide documentation and design specifications demonstrating how the requirements are met; and,

All necessary relay, protection, control and communication systems required to protect Interconnection Customer's Interconnection Facilities and Generating Facilities and coordinate with Transmission Owner's relay, protection, control and communication systems.

TRANSMISSION OWNER INTERCONNECTION FACILITIES AND NON-SHARED NETWORK UPGRADE(S)

To facilitate interconnection, the interconnecting Transmission Owner will perform work as shown below necessary for the acceptance of the Interconnection Customer's Interconnection Facilities.

Table 1 and **Table 2** lists the Interconnection Customer's estimated cost responsibility for Transmission Owner Interconnection Facilities (TOIF) and Non-Shared Network Upgrade(s) and provides an estimated lead time for completion of construction. The estimated lead time begins when the Generator Interconnection Agreement has been fully executed.

Table 1: Transmission Owner Interconnection Facilities (TOIF)

Transmission Owner Interconnection Facilities (TOIF)	Total Cost Estimate ($)	Allocated Percent (%)	Allocated Cost Estimate ($)	Estimated Lead Time
Clinton - Stilwell 161kV GEN-2017-111 Interconnection (TOIF) (KCPL) (143347): Interconnection upgrades and cost estimates needed to interconnect the following Interconnection Customer facility, GEN-2017-111 (152 MW/Solar), into the Point of Interconnection (POI) at Clinton - Stilwell 161kV	$631,240	100%	$631,240	36 Months
Total	**$631,240**		**$631,240**	

Table 2: Non-Shared Network Upgrade(s)

Non-Shared Network Upgrades Description	ILTCR	Total Cost Estimate ($)	Allocated Percent (%)	Allocated Cost Estimate ($)	Estimated Lead Time
Tap Clinton - Stilwell 161kV GEN-2017-111 Interconnection Costs (KCPL) (143346): Stillwell – Clinton 161kV New Three (3) Breaker Ring Bus Interconnection Substation (DISIS-2017-002)	Ineligible	$11,816,866	100%	11,816,866	36 Months
Total		**$11,816,866**		**$11,816,866**	

SHARED NETWORK UPGRADE(S)

The Interconnection Customer's share of costs for Shared Network Upgrades is estimated in **Table 3** below.

Table 3: Interconnection Customer Shared Network Upgrade(s)

Shared Network Upgrades Description	ILTCR	Total Cost Estimate ($)	Allocated Percent (%)	Allocated Cost Estimate ($)	Estimated Lead Time
Archie to G17-111 tap 161 kV Terminal Upgrades (KCPL) (156516): Upgrade terminal equipment at Archie to G17-108 tap 161 kV substations to achieve a min summer emergency rating of 356 MVA and a min Winter emergency rating of 407 MVA	Eligible	$1,455,931	22.43%	$326,632.34	36 Months
Archie to G17-108-TAP 161 kV Ckt 1 rebuild (KCPL) (156851): Rebuild Archie to G17-108-TAP 161 kV Ckt 1 28.73 mile line to achieve a min summer emergency rating of 356 MVA and a min Winter emergency rating of 407 MVA	Eligible	$41,157,960	22.43%	$9,233,624.95	36 Months
Truman 161 kV Terminal Equipment Upgrades (KCPL) (156852): Upgrade terminal equipment at Truman 161 kV to achieve a min rating of 286 MVA	Eligible	$500,000	22.40%	$111,979.16	36 Months
Total		**$43,113,891.00**		**$9,672,236.45**	

All studies have been conducted assuming that higher-queued Interconnection Request(s) and the associated Network Upgrade(s) will be placed into service. If higher-queued Interconnection Request(s) withdraw from the queue, suspend or terminate service, the Interconnection Customer's share of costs may be revised. Restudies, conducted at the customer's expense, will determine the Interconnection Customer's revised allocation of Shared Network Upgrades.

CONTINGENT NETWORK UPGRADE(S)

Certain Contingent Network Upgrades are **currently not the cost responsibility** of the Interconnection Customer but will be required for full Interconnection Service.

Table 4: Interconnection Customer Contingent Network Upgrade(s)

Contingent Network Upgrade(s) Description	Current Cost Assignment	Estimated In-Service Date
NA	NA	NA

Depending upon the status of higher- or equally-queued customers, the Interconnection Request's in-service date is at risk of being delayed or Interconnection Service is at risk of being reduced until the in-service date of these Contingent Network Upgrades.

AFFECTED SYSTEM UPGRADE(S)

To facilitate interconnection, the Affected System Transmission Owner will be required to perform the facilities study work as shown below necessary for the acceptance of the Interconnection Customer's Interconnection Facilities. **Table 5** displays the current impact study costs provided by either MISO or AECI as part of the Affected System Impact review. The Affected System facilities study could provide revised costs and will provide each Interconnection Customer's allocation responsibilities for the upgrades.

Table 5: Interconnection Customer Affected System Upgrade(s)

Affected System Upgrades Description	Total Cost Estimate ($)	Allocated Percent (%)	Allocated Cost Estimate ($)
AECI; Rebuild 26.49-mile-long Morgan to Brookline 161 kV line with 1192 ACSR rated at 100C	$34,450,000	6.53%	$2,248,659
AECI; Upgrade Sullivan 161/138 kV transformer #1 with 143S MVA Summer/167 MVA Winter transformer	$4,000,000	6.21%	$248,281
AECI; Rebuild 0.6-mile-long Thomas Hill to Thomas Hill Mine Tap 69 kV line with 795 ACSR at 100C **Upgrade bushing CTs at Thomas Hill on Thomas Hill Mine Tap line with 1200A bushing CTs** **Upgrade jumpers at Thomas Hill on Thomas Hill Mine Tap line with 795 ACSR**	$790,000	7.59%	$59,923
AECI; Rebuild 9.24-mile-long Cairo to Huntsville 69 kV line with 795 ACSR rated at 100C **Upgrade disconnect switches at Cario 69 kV on Huntsville line with 1200A switches**	$8,570,000	7.59%	$650,045
AECI; Rebuild 5.09-mile-long Cairo to Jacksonville 69 kV line with 795 ACSR rated at 100C **Upgrade bushing CTs at Cario 69 kV on Jacksonville line with 1200A bushing CTs**	$4,790,000	12.90%	$617,726
AECI; Rebuild 4.50-mile-long Huntsville to Thomas Hill Mine Tap 69 kV line with 795 ACSR rated at 100C	$4,050,000	7.59%	$307,198
AECI; Rebuild 9.10-mile-long Jacksonville to Macon 69 kV line with 336 ACSR rated at 100C	$8,190,000	12.90%	$1,056,196

AECI; Rebuild 5.91-mile-long Georgetown Tap 2 to Sedalia 69 kV line with 795 ACSR rated at 100C **Upgrade jumpers at Sedalia on Georgetown Tap 2 with 795 ACSR rated at 100C** **Upgrade bushing CTs, breaker switches, and disconnect switches at Sedalia on Georgetown Tap 2 with 1200A rated equipment**	$5,960,000	17.55%	$1,046,175
AECI; Rebuild 4.90-mile-long Enon Bus 2 to Ethlyn Bus 2 161 kV line with 795 ACSR rated at 100C	$6,370,000	7.24%	$461,435
AECI; Rebuild 17-mile-long Belltown to Palmyra 69 kV line with 336 ACSR rated at 100C **Upgrade bushing CTs at Belltown 69 kV on Palmyra line with 70 MVA Summer/85 MVA Winter rated bushing CTs**	$15,500,000	6.43%	$996,953
AECI; Rebuild 18.4-mile-long Cairo to Letner 69 kV line with 336 ACSR rated at 100C	$16,560,000	6.78%	$1,122,722
AECI; Rebuild 6.50-mile-long Coffman Bend to J-7 69 kV line with 366 ACSR rated at 100C	$5,850,000	13.74%	$803,804
AECI; Rebuild 4.40-mile-long Coffman Bend to Knobby 69 kV line with 336 ACSR rated at 100C	$3,960,000	13.74%	$544,113
AECI; Rebuild 2.4-mile-long Palmyra to Bross 69 kV line with 336 ACSR rated at 100C	$2,160,000	6.43%	$138,862
AECI; Rebuild 2.8-mile-long South River to Bross 3 69 kV line with 336 ACSR rated at 100C	$2,520,000	6.43%	$162,005
AECI; Uprate 12.4-mile-long Knobby to Turkey Creek 69 kV line from 75C rating to 100C	$3,700,000	13.74%	$508,389
AECI; Rebuild to 0.1-mile-long Bevier to Bevier 69 kV line with 1192 ACSR	$130,000	12.84%	$16,691
AECI; Rebuild to 1.2-mile-long Axtell to Macon Lake 69 kV line with 1192 ACSR	$1,560,000	6.92%	$107,966
AECI; Rebuild to 1.1-mile-long Axtell to Macon Tap 69 kV line with 1192 ACSR	$1,430,000	6.92%	$98,969
AECI; Rebuild to 4.3-mile-long Macon Lake to Bevier Tap 69 kV line with 1192 ACSR	$5,590,000	6.92%	$386,879
AECI; Rebuild to 12.2-mile-long Love Lake to Macon Tap 69 kV line with 795 ACSR	$15,860,000	15.63%	$2,479,463
Total	**$151,990,000**		**$14,062,454.00**

CONCLUSION

After all Interconnection Facilities and Network Upgrades have been placed into service, Interconnection Service for MW can be granted. Full Interconnection Service will be delayed until the TOIF, Non-Shared NU, Shared NU, Contingent NU, Affected System Upgrades that are required for full interconnection service are completed. The Interconnection Customer's estimated cost responsibility for full interconnection service is summarized in the table below.

Table 6: Cost Summary

Description	Allocated Cost Estimate
Transmission Owner Interconnection Facilities Upgrade(s)	$631,240
Non-Shared Network Upgrade(s)	$11,816,866
Shared Network Upgrade(s)	$9,672,236.45
Affected System Upgrade(s)	$14,062,454
Total	**$36,182,796.45**

Use the following link for Quarterly Updates on upgrades from this report: https://spp.org/spp-documents-filings/?id=18641

A draft Generator Interconnection Agreement will be provided to the Interconnection Customer consistent with the final results of this IFS report. The Transmission Owner and Interconnection Customer will have 60 days to negotiate the terms of the GIA consistent with the SPP Open Access Transmission Tariff (OATT).

APPENDICES

A: TRANSMISSION OWNER'S INTERCONNECTION FACILITIES STUDY REPORT AND NETWORK UPGRADES REPORT(S)

See next page for the Transmission Owner's Interconnection Facilities Study Report and Network Upgrades Report(s).

Interconnection Facilities Study

Network Upgrades associated with DISIS-2017-002

March 2023

Introduction

This report summarizes the scope of the Interconnection Facilities Analysis for Network Upgrade(s) to determine costs related to the addition of the SPP-GI DISIS-2017-002 Interconnection Request(s).

Southwest Power Pool Generation Interconnection Request:

Per the SPP Generator Interconnection Procedures (GIP), SPP has requested that Evergy perform an Interconnection Facilities Study (IFS) for Network Upgrade(s) in accordance with the Scope of Interconnection Facilities Study GIP Section 8.10 and the Interconnection Facilities Study Procedures in accordance with GIP Section 8.11 for the following Interconnection Request(s):

Upgrade Type	UID	Upgrade Name	DISIS Cost	DISIS Lead Time
Network Upgrade	156516	Archie 161 kV Terminal Upgrades (DISIS-2017-002) (EMW)	$1,455,934	36 Months
Network Upgrade	156851	Archie – G17-108 Tap 161 kV Rebuild (DISIS-2017-002) (EMW	$41,157,960	36 Months
Network Upgrade	156461	Craig to Lenexa 161 kV Double Circuit Rebuild (DISIS-2017-002) (EM)	$8,294,859	36 Months
Network Upgrade	156457	Post Oak 69-35 kV Transformer Replacement (DISIS-2017-002) (EKC)	$2,470,058	36 Months
Network Upgrade	156471	Viola to G17-185 Tap 345 kV Line Rebuild (DISIS-2017-002) (EKC)	$47,418,635	36 Months

Archie 161 kV Terminal Upgrades 161

kV Substation

All terminal equipment to be replaced to meet a 2000 Amp rating. This will require a main bus rebuild to 4" aluminum pipe bus and includes bus side disconnects for the other three line terminals.

Total Cost

The total cost estimate for this Network Upgrade is:

$	0	161kV Transmission Line
$	1,451,579	161kV Substation
$	4,354	AFUDC
$	0	Contingency
$	1,455,934	Total

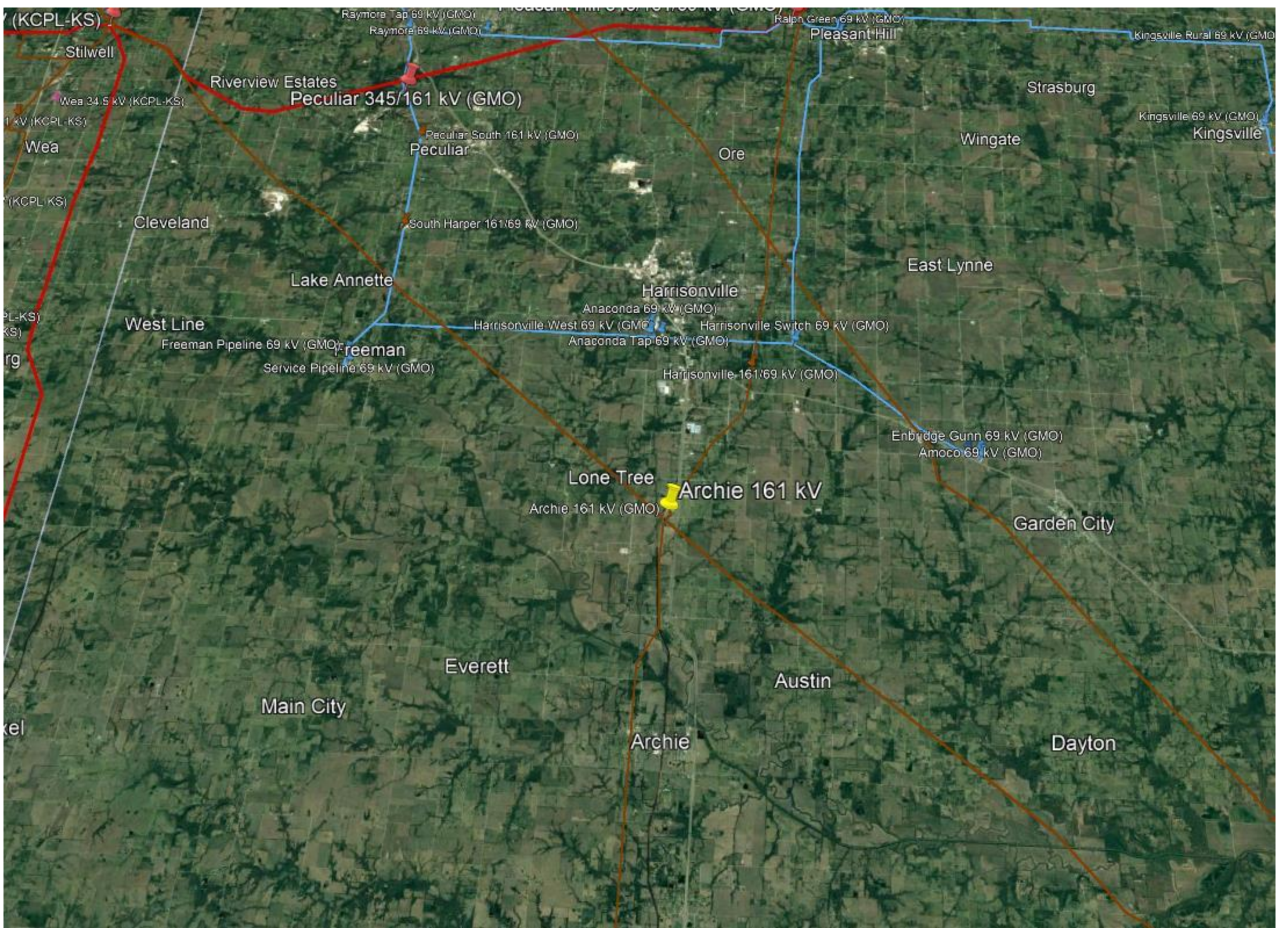
This estimate is accurate to +/- twenty (20) percent, based on current prices, in accordance with Attachment A of Appendix 4 of the Interconnection Facilities Study Agreement.
However, recent cost fluctuations in materials are very significant and the accuracy of this estimate at the time of actual settings cannot be assured.

Time Estimate

Time estimates are based on current version of the project schedule and some processes of each category run concurrently.

Engineering Time	12-18	Months
Procurement Time	12-18	Months
Construction Time	12	Months
Total Project Length	36-48	Months

Figure 1 – Archie 161 kV Sub



Archie – G17-108 Tap 161 kV Rebuild 161 kV Transmission Line

The estimated cost is for 28.73 miles of 161kV circuit. Line will be rebuilt using steel structures, with angles and dead-ends on drilled piers. Estimate assumes the conductor will be 1192 ACSS/TW and OPGW will be installed.

Total Cost

The total cost estimate for this Network Upgrade is:

$	39,783,750	161 kV Transmission Line
$	0	161 kV Substation
$	1,374,210	AFUDC
$	0	Contingency
$	41,157,960	Total

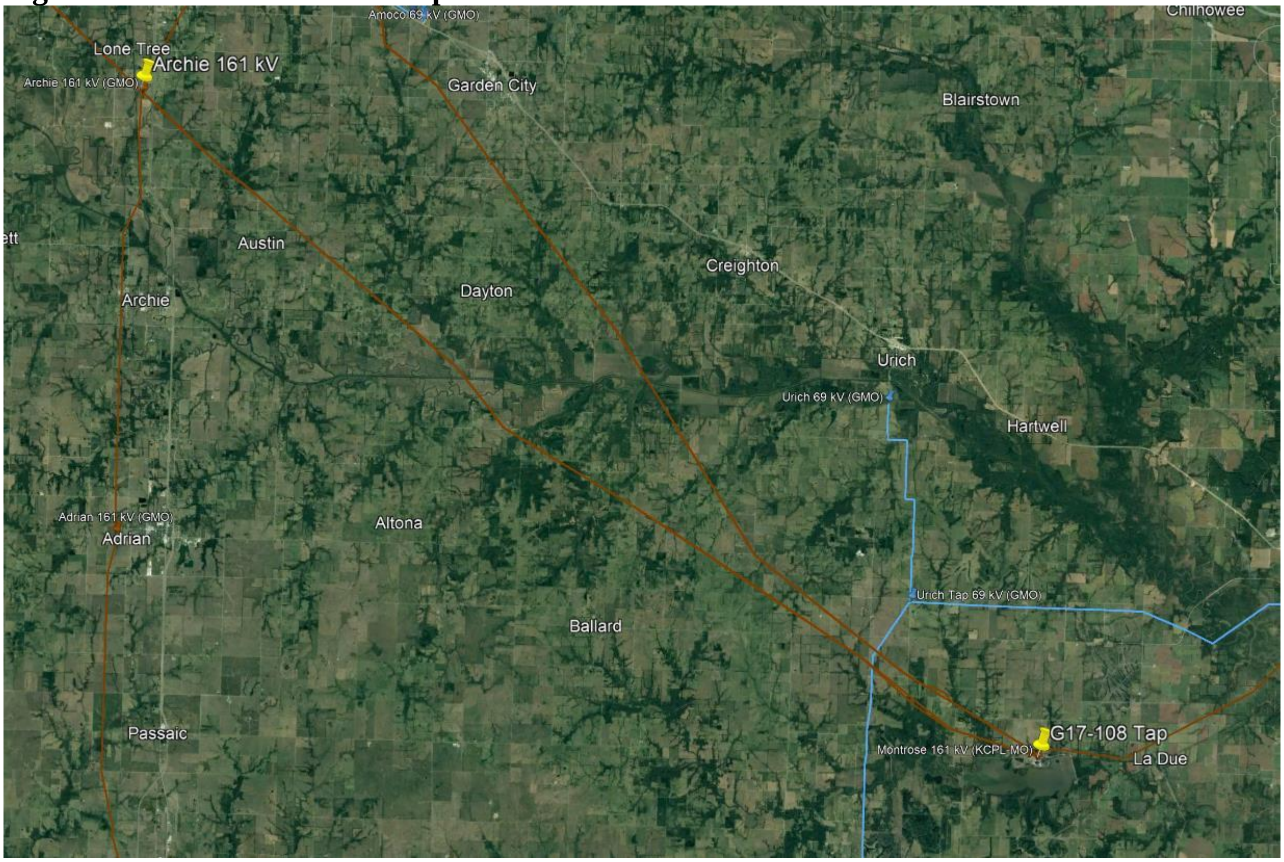
This estimate is accurate to +/- twenty (20) percent, based on current prices, in accordance with Attachment A of Appendix 4 of the Interconnection Facilities Study Agreement.
However, recent cost fluctuations in materials are very significant and the accuracy of this estimate at the time of actual settings cannot be assured.

Time Estimate

Time estimates are based on current version of the project schedule and some processes of each category run concurrently.

Engineering Time	12-18	Months
Procurement Time	12-18	Months
Construction Time	12	Months
Total Project Length	36-48	Months

Figure 2 – Archie – G17-108 Tap



Craig to Lenexa 161 kV Double Circuit Rebuild 161 kV

Transmission Line

The estimated cost is for 2.95 miles of 161kV double circuit. The lines will be rebuilt with steel structures, 1192 ACSS/TW conductor and two OPGW's designed to Evergy standards.

Total Cost

The total cost estimate for this Network Upgrade is:

$	7,763,088	161 kV Transmission Line
$	0	161 kV Substation
$	531,771	AFUDC
$	0	Contingency
$	8,294,859	Total

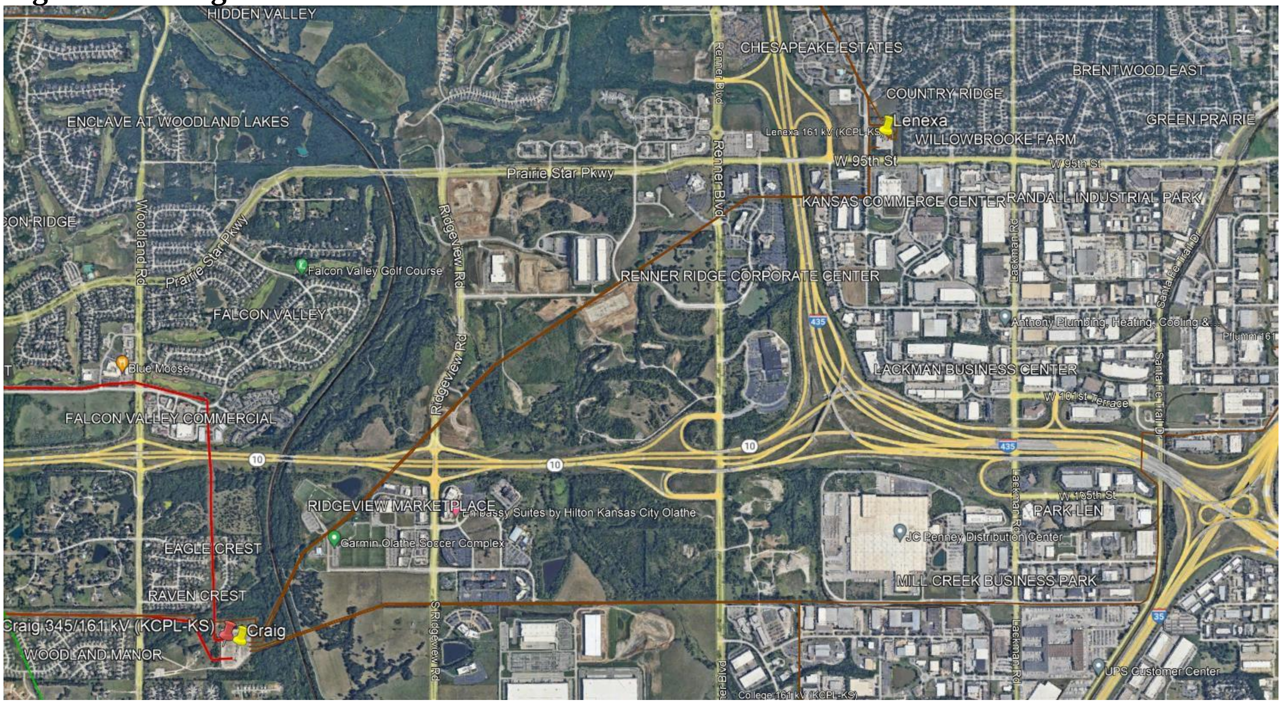
This estimate is accurate to +/- twenty (20) percent, based on current prices, in accordance with Attachment A of Appendix 4 of the Interconnection Facilities Study Agreement.
However, recent cost fluctuations in materials are very significant and the accuracy of this estimate at the time of actual settings cannot be assured.

Time Estimate

Time estimates are based on current version of the project schedule and some processes of each category run concurrently.

Engineering Time	12-18	Months
Procurement Time	12-18	Months
Construction Time	12	Months
Total Project Length	36-48	Months

Figure 3 – Craig – Lenexa 161kV Line



Post Oak 69-35 kV Transformer Replacement

69 kV Transformer

Replace Post Oak 69/35 kV Transformer with a 50MVA 69/34kV Transformer. This will also require a 34kV bank breaker, 34kV feeder breaker, box bay, RTU, control house and metering equipment.

Total Cost

The total cost estimate for this Network Upgrade is:

$	2,462,670	69 kV Substation Transformer
$	7,388	AFUDC
$	0	Contingency
$	2,470,058	Total

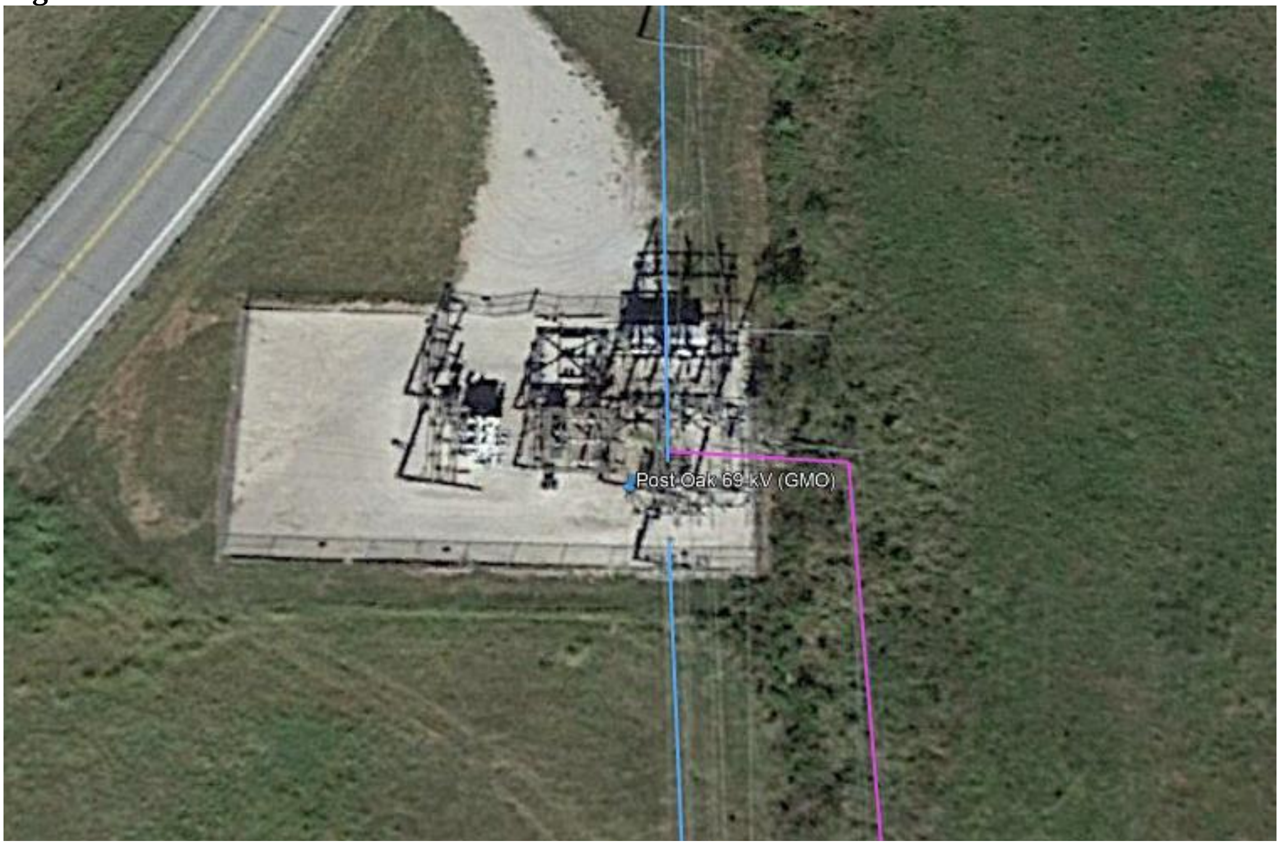
This estimate is accurate to +/- twenty (20) percent, based on current prices, in accordance with Attachment A of Appendix 4 of the Interconnection Facilities Study Agreement.
However, recent cost fluctuations in materials are very significant and the accuracy of this estimate at the time of actual settings cannot be assured.

Time Estimate

Time estimates are based on current version of the project schedule and some processes of each category run concurrently.

Engineering Time	12-18	Months
Procurement Time	12-18	Months
Construction Time	12	Months
Total Project Length	36-48	Months

Figure 4 – Post Oak – 69kV Transformer



Viola – Renfrow 345 kV Rebuild (Evergy Portion)

345 kV Transmission Line

The estimated cost is for the rebuild of the 23-mile Evergy portion of the Viola – Renfrow 345kV line to meet a 3000 Amp line rating. Line will be rebuilt using steel structures, with angles and dead-ends on drilled piers. Estimate assumes the conductor will be 1590 Lapwing ACSR and OPGW will be installed.

Total Cost

The total cost estimate for this Network Upgrade is:

$	47,276,805	345 kV Transmission Line
$	0	345 kV Substation
$	141,830	AFUDC
$	0	Contingency
$	47,418,635	Total

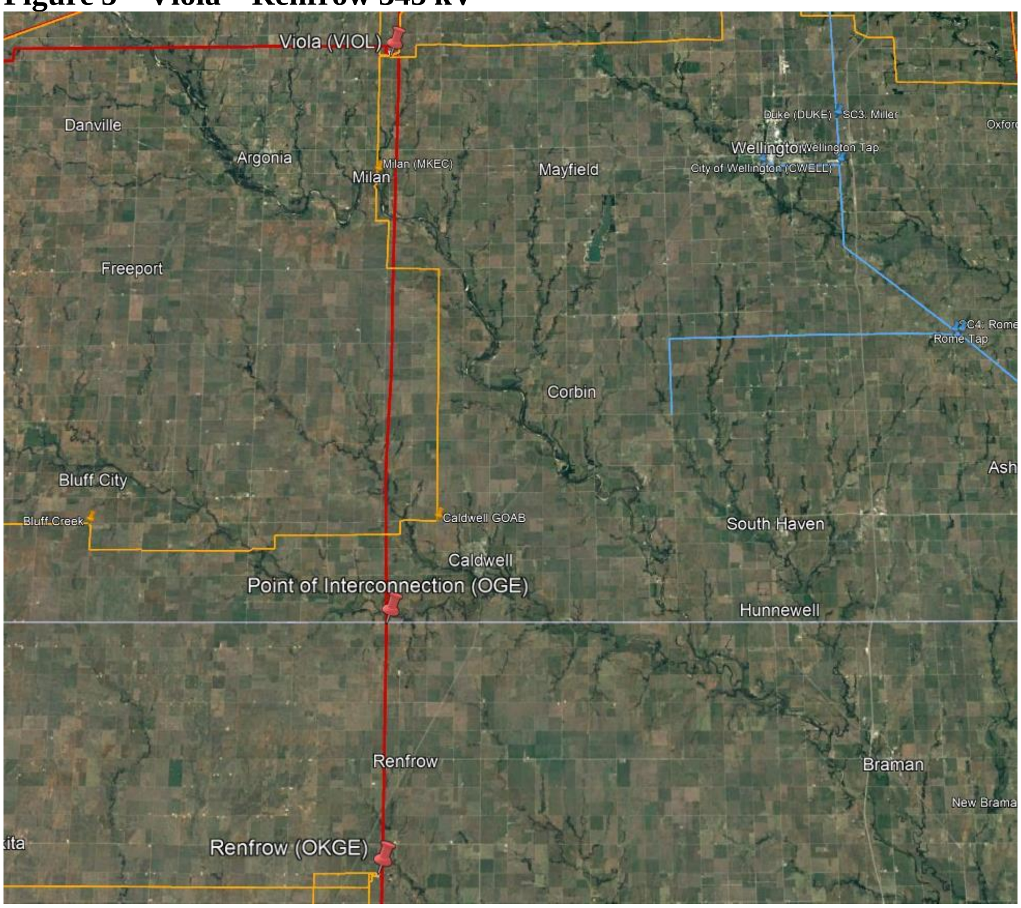
This estimate is accurate to +/- twenty (20) percent, based on current prices, in accordance with Attachment A of Appendix 4 of the Interconnection Facilities Study Agreement. However, recent cost fluctuations in materials are very significant and the accuracy of this estimate at the time of actual settings cannot be assured.

Time Estimate

Time estimates are based on current version of the project schedule and some processes of each category run concurrently.

Engineering Time	12-18	Months
Procurement Time	12-18	Months
Construction Time	12	Months
Total Project Length	36-48	Months

Figure 5 – Viola – Renfrow 345 kV



Associated Electric Cooperative, Inc.

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SPP DISIS-2017-002 AFS STUDY REPORT

INTRODUCTION

Associated Electric Cooperative Inc. (AECI), through coordination with the Southwest Power Pool (SPP), has identified generator interconnection requests (GIRs) within the DISIS-2017-002 Study Cycle (the "Study Cycle") for an Affected System Study (AFS) evaluation on the AECI transmission system (the "Study"). The full list of Study Cycle requests included in the Study is listed in Table 1.

Table 1: Study Cycle Requests Evaluated

Project #	CA	Capacity (MW)	Service Type	Fuel Type	POI	Cluster Group
GEN-2017-108	KCPL	400.0	ER/NR	Solar	Stillwell - Clinton 161kV Line	03 CENTRAL
GEN-2017-111	KCPL	152.0	ER	Solar	Clinton - Stilwell 161 kV Line Tap	03 CENTRAL
GEN-2017-115	KCPL	244.0	ER	Wind	Holt County 345 kV	03 CENTRAL
GEN-2017-119	SUNC	180.0	ER	Wind	Elm Creek 345kV substation	03 CENTRAL
GEN-2017-120	WERE	260.0	ER	Wind	Abilene Energy Center-Northview 115kV	03 CENTRAL
GEN-2017-121	WERE	200.0	ER/NR	Wind	Sumner 138kV	03 CENTRAL
GEN-2017-125	WERE	252.0	ER/NR	Wind	Swissvale 345kV	03 CENTRAL
GEN-2017-128	WERE	202.0	ER/NR	Wind	Swissvale 345kV	03 CENTRAL
GEN-2017-132	OKGE	400.0	ER/NR	Wind	Arcadia 345kV	04 SOUTHEAST
GEN-2017-133	OKGE	200.0	ER/NR	Wind	Arcadia 345kV	04 SOUTHEAST
GEN-2017-134	OKGE	250.0	ER/NR	Wind	Arcadia 345kV	04 SOUTHEAST
GEN-2017-137	OKGE	295.0	ER/NR	Wind	Arcadia 345kV	04 SOUTHEAST
GEN-2017-140	AEPW	160.0	ER/NR	Solar	Clarksville 345kV Switching Station	04 SOUTHEAST
GEN-2017-141	AEPW	241.7	ER/NR	Solar	Clarksville 345kV Switching Station	04 SOUTHEAST
GEN-2017-144	WAPA	200.0	ER	Wind	Holt County 345kV	02 NEBRASKA
GEN-2017-146	SWPS	151.8	ER	Wind	Deaf Smith-Plant X 230kV	05 SOUTHWEST
GEN-2017-148	EMDE	202.0	ER/NR	Wind	Joplin 161kV sub	03 CENTRAL
GEN-2017-149	OKGE	258.0	ER/NR	Wind	Johnson County 345kV Substation	04 SOUTHEAST
GEN-2017-150	OKGE	250.0	ER/NR	Solar	Minco 345kV	04 SOUTHEAST
GEN-2017-151	SWPS	300.0	ER	Wind	TUCO-Oklaunion 345kV	05 SOUTHWEST
GEN-2017-152	OKGE	252.0	ER/NR	Wind	McClain 138kV	04 SOUTHEAST
GEN-2017-154	OKGE	255.0	ER/NR	Wind	Johnson County 345kV Substation	04 SOUTHEAST
GEN-2017-155	OKGE	300.0	ER/NR	Wind	Muskogee 345kV Substation	04 SOUTHEAST
GEN-2017-158	SWPS	265.0	ER	Wind	Tolk 230kV Substation	05 SOUTHWEST
GEN-2017-164	OKGE	250.0	ER/NR	Solar	Woodring 345kV Substation	04 SOUTHEAST
GEN-2017-166	OKGE	250.0	ER/NR	Solar	Sunnyside 345kV	04 SOUTHEAST
GEN-2017-168	OKGE	250.0	ER/NR	Solar	McClain 138kV	04 SOUTHEAST
GEN-2017-171	AEPW	150.0	ER/NR	Solar	Lawton Eastside - Terry Road 345kV	04 SOUTHEAST

Project #	CA	Capacity (MW)	Service Type	Fuel Type	POI	Cluster Group
GEN-2017-175	WAPA	300.0	ER	Wind	Vfodnes-Utica Jct. 230kV	01 NORTH
GEN-2017-176	SWPS	300.0	ER/NR	Hybrid	Newhart 230kV Substation	05 SOUTHWEST
GEN-2017-179	WERE	222.0	ER/NR	Wind	Gordon Evans 138kV Substation	03 CENTRAL
GEN-2017-181	NPPD	300.0	ER/NR	Wind	Tobias 345kV Substation	02 NEBRASKA
GEN-2017-182	NPPD	128.0	ER/NR	Wind	Tobias 345kV Substation	02 NEBRASKA
GEN-2017-183	KCPL	400.0	ER/NR	Wind	Nashua-St. Joe 345kV	03 CENTRAL
GEN-2017-184	KCPL	400.0	ER/NR	Solar	Nashua-St. Joe 345kV	03 CENTRAL
GEN-2017-187	SWPS	150.0	ER	Solar	Sulphur Springs 115kV Substation	05 SOUTHWEST
GEN-2017-188	EMDE	130.0	ER	Solar	Asbury 161 kV	03 CENTRAL
GEN-2017-191	WERE	201.6	ER/NR	Solar	Swissvale 345kV	03 CENTRAL
GEN-2017-195	KCPL	500.4	ER/NR	Solar	West Gardner 345kV	03 CENTRAL
GEN-2017-196	KCPL	128.0	ER/NR	Battery/Storage	West Gardner 345kV	03 CENTRAL
GEN-2017-199	BEPC	202.0	ER/NR	Battery/Storage	Groton 345kV Substation	01 NORTH
GEN-2017-200	BEPC	302.0	ER/NR	Wind	Groton 345kV Substation	01 NORTH
GEN-2017-201	NPPD	250.0	ER/NR	Wind	Hoskins 345kV Substation	02 NEBRASKA
GEN-2017-202	SWPA	200.0	ER/NR	Solar	New Madrid - Sikeston 161kV	03 CENTRAL
GEN-2017-203	OKGE	210.0	ER	Hybrid	Renfrow 345kV Substation	04 SOUTHEAST
GEN-2017-209	KCPL	300.0	ER	Hybrid	LaCygne - Neosho 345kV	03 CENTRAL
GEN-2017-210	NPPD	310.0	ER	Hybrid	McCool 345kV Substation	02 NEBRASKA
GEN-2017-213	AEPW	300.0	ER	Hybrid	Clarksville 345kV Substation	04 SOUTHEAST
GEN-2017-220	WERE	201.6	ER/NR	Solar	Buffalo Flats 345kV Substation	03 CENTRAL
GEN-2017-221	WERE	152.0	ER/NR	Battery/Storage	Buffalo Flats 345kV Substation	03 CENTRAL
GEN-2017-222	WAPA	180.0	ER	Wind	Denison 230kV Substation	01 NORTH
GEN-2017-226	WERE	201.6	ER/NR	Solar	Gordon Evans 138kV Substation	03 CENTRAL
GEN-2017-227	WERE	201.6	ER/NR	Battery/Storage	Gordon Evans 138kV Substation	03 CENTRAL
GEN-2017-229	KCPL	76.0	ER/NR	Battery/Storage	Stilwell 345kV Substation	03 CENTRAL
GEN-2017-231	OKGE	72.5	ER/NR	Solar	Branch 161kV Substation	04 SOUTHEAST
GEN-2017-233	OKGE	215.0	ER/NR	Wind	Minco 345kV	04 SOUTHEAST
GEN-2017-234	NPPD	115.0	ER	Wind	Spalding to North Loup 115kV	02 NEBRASKA
GEN-2017-239	SWPS	300.0	ER	Solar	Mahoney 230kV Substation	05 SOUTHWEST
GEN-2017-240	OKGE	202.0	ER/NR	Solar	Bristow 138kV Substation	04 SOUTHEAST
GEN-2017-112[1]	KCPL	200.0	ER	Wind	Clinton - Stilwell 161 kV Line Tap	03 CENTRAL
GEN-2017-114[1]	BEPC	450.0	ER	Wind	Chappelle Creek - Leland Olds 345kV	01 NORTH
GEN-2017-116[1]	SWPS	192.5	ER	Solar	Oasis - Pleasant Hill 230kV	05 SOUTHWEST
GEN-2017-123[1]	WERE	180.0	ER/NR	Wind	Stranger Creek 345kV	03 CENTRAL

[1] GIR withdrew from SPP DISIS queue after the start of the analysis, the impact of the withdrawal will be captured in a future restudy.

Project #	CA	Capacity (MW)	Service Type	Fuel Type	POI	Cluster Group
GEN-2017-142[1]	WERE	170.0	ER/NR	Wind	Swissvale 345kV Station	03 CENTRAL
GEN-2017-147[1]	KCPL	252.0	ER/NR	Wind	Stilwell 345kV	03 CENTRAL
GEN-2017-153[1]	OKGE	253.0	ER/NR	Wind	McClain 138kV	04 SOUTHEAST
GEN-2017-156[1]	AEPW	234.0	ER/NR	Wind	Pittsburg 345kV Substation	04 SOUTHEAST
GEN-2017-157[1]	AEPW	202.0	ER/NR	Wind	Pittsburg 345kV Substation	04 SOUTHEAST
GEN-2017-185[1]	OKGE	200.0	ER/NR	Wind	Viola - Hunters 345kV	03 CENTRAL
GEN-2017-186[1]	KCPL	100.0	ER	Solar	KC South-N. Raymore 161 kV	03 CENTRAL
GEN-2017-193[1]	WERE	201.6	ER/NR	Solar	Tecumseh 230kV Substation	03 CENTRAL
GEN-2017-217[1]	SWPS	300.0	ER/NR	Solar	Plant X 230kV Substation	05 SOUTHWEST
GEN-2017-218[1]	SWPS	600.0	ER/NR	Solar	Tolk-Plant X 230kV Line	05 SOUTHWEST
GEN-2017-224[1]	KCPL	302.4	ER/NR	Solar	Craig 345kV Substation	03 CENTRAL
GEN-2017-228[1]	KCPL	302.4	ER/NR	Solar	Stilwell 345kV Substation	03 CENTRAL

The following key assumptions were included in the Study:

- Evergy System Upgrades identified by SPP for GEN-2017-108, GEN-2017-111, GEN-2017-112, and GEN-2017-186 in the SPP DISIS-2017-002 Phase 2 Study:
    - Rebuild the decommissioned 12.00 mile 161 kV line from G17-108-TAP to G17-111-TAP
    - Rebuild the decommissioned 19.94 mile 161 kV line from G17-108-TAP to G17-186-TAP
    - Rebuild the decommissioned 22.34 mile 161 kV line from G17-108-TAP to G17-186-TAP
    - Rebuild the decommissioned 16.73 mile 161 kV line from G17-11-TAP to Archie, upgrade the conductor

The listed network upgrades were included in the mitigation analysis to identify if these upgrades were able to resolve impacts seen on the AECI system in this area as a result of the Study Cycle. Should these upgrades no longer be tagged to the Study Cycle by SPP, AECI will have to restudy the Study Cycle.

INPUTS AND ASSUMPTIONS

Each of the SERC member transmission planners is responsible for submitting system modeling data to SERC for development of the power flow models. Power flow analysis utilized the latest Long-Term Working Group (LTWG) models as developed by SERC Reliability Corporation (SERC). Each of the power flow models for the steady state analysis was modified to include appropriate higher-queued generation interconnection requests at the level of dispatch consistent with requirements of the service type requested as defined in AECI's GI Study Guidelines document. Modeling parameters in the SPP DISIS 2017-002 steady state models were referenced for each of the Study Cycle requests.

Full details of the inputs and assumptions are provided in Appendix A.

METHODOLOGY

Steady state analysis was performed to confirm the reliability impacts on the AECI system under a variety of system conditions and outages. AECI's transmission system must be capable of operating within the applicable normal ratings, emergency ratings, and voltage limits of AECI planning criteria. AECI is a member of SERC, one of eight Electric Reliability Organizations under the North American Electric Reliability Corporation (NERC). As a member of SERC, AECI develops its planning criteria consistent with NERC Reliability Planning Standards and the SERC planning criteria. The NERC TPL-001-4 Planning Standard Table 1 requires that, for normal and contingency conditions, line and equipment loading shall be within applicable thermal limits, voltage levels shall be maintained within applicable limits, all customer demands shall be supplied (except as noted), and stability of the network shall be maintained.

In evaluating the impacts of the Study Cycle requests, the following thermal and voltage limits were applied to the analysis for P0 or normal system conditions:

- Thermal Limits within Applicable Rating – Applicable Rating shall be defined as the Normal Rating. The thermal limit shall be 100% of Rating A.
- Voltage Limits within Applicable Rating – Applicable Rating shall have the meaning of Nominal Voltage. Voltage limits shall be set at plus or minus five percent (+/- 5%), 0.95 p.u. - 1.05 p.u. for systems operating at 60 kV or above on load serving buses.

The following thermal and voltage limits were applied to the analysis for contingency conditions under P1 and P2EHV planning events:

- Thermal Limits within Applicable Rating – Applicable Rating shall be defined as the Emergency Rating. The thermal limit shall be 100% of Rating B.
- Voltage Limits within Applicable Rating – Applicable Rating shall have the meaning of Nominal Voltage. Voltage limits shall be set at plus five percent to minus ten percent (+5%/-10%), 0.90 p.u. – 1.05 p.u. for systems operating at 60 kV or above on load serving buses.

In order for the Study Cycle requests to have a negative impact (i.e. criteria violation) on the system, the Study Cycle must cause a three percent (3%) or greater increase in flow on an overloaded facility based upon the rating of the facility. In order for the Project to have a negative voltage impact on the system, the Project must cause a voltage violation and have a two percent (2%) or greater change in the voltage.

System upgrades are required for constraints resulting from the addition of the Study Cycle requests under P0, P1, P2.1, P2.2 (EHV only), and P2.3 (EHV only) system conditions. For the purpose of this study, P2.1 events are included as part of the P1 contingency file. As such, these events will be denoted as a P1 event in the results. All improvements were developed and studied in coordination with AECI.

STEADY STATE ANALYSIS RESULTS

Steady state analysis results showed forty-one (41) constraints reported on the AECI transmission system, as shown in Table 2, which are attributed to the Study Cycle requests. Transmission upgrades were evaluated to mitigate the impacts reported from the analysis as a result of the Study Cycle requests. Simulations were performed on each of the scenarios with the identified network upgrade and contingent network upgrades included.

The upgrades shown in Table 7 were evaluated in order to mitigate the reported steady state constraints for the Study Cycle requests; results from the simulations found that the network upgrades were able to mitigate the reported overload conditions as shown in Table 2.

Table 2: Steady State Constraints for the Study Cycle Requests with Upgrades

Constraint ID	Event	Monitored Facility	Contingency	Season	Base Loading	Project Loading	Upgrade Loading
NU01	P1	300087 5HICKCK 161.00 300094 5LOCUST 161.00 1	OPEN BRANCH FROM BUS 345435 [7MAYWOOD 345.00] TO BUS 345992 [7SPENCER 345.00] CKT 1	26S	115.8	135.1	64.6
NU02	P2EHV	300101 5MORGAN 161.00 549969 BROOKLINE 5161.00 1	OPEN BRANCH FROM BUS 300042 [7HUBEN 345.00] TO BUS 300045 [7MORGAN 345.00] CKT 1 OPEN BRANCH FROM BUS 300045 [7MORGAN 345.00] TO BUS 549984 [BROOKLINE 7345.00] CKT 1	26H	82.8	127.1	61.5
NU03	P1	300119 5SULLVN 161.00 300142 4SULVN 138.00 1	OPEN LINE FROM BUS 300040 [7FLETCH 345.00] TO BUS 300472 [7SALEMTP 345.00] CKT 1	26L	112.3	116.2	68.9
NU04	P1	300172 2TMHILLB1 69.000 301318 2THMINTP 69.000 1	OPEN LINE FROM BUS 300172 [2TMHILLB1 69.000] TO BUS 300387 [2BEVIER 69.000] CKT 1	26S	107.7	115.4	75.3
NU05	P2EHV	300382 2SFRKTP 69.000 300578 2SANTFE 69.000 1	OPEN BRANCH FROM BUS 345435 [7MAYWOOD 345.00] TO BUS 345992 [7SPENCER 345.00] CKT 1 OPEN BRANCH FROM BUS 40254 [J1025 POI 345.00] TO BUS 345435 [7MAYWOOD 345.00] CKT 1	26S	106.7	125.9	81.0
NU06	P1	300390 2CAIRO 69.000 300394 2HUNTSV 69.000 1	OPEN LINE FROM BUS 300172 [2TMHILLB1 69.000] TO BUS 300387 [2BEVIER 69.000] CKT 1	26S	106.5	114.1	95.8
NU07	P1	300390 2CAIRO 69.000 300395 2JCKSNV 69.000 1	OPEN LINE FROM BUS 300172 [2TMHILLB1 69.000] TO BUS 300387 [2BEVIER 69.000] CKT 1	31S	97.6	102.8	76.9
NU08	P1	300394 2HUNTSV 69.000 301318 2THMINTP 69.000 1	OPEN LINE FROM BUS 300172 [2TMHILLB1 69.000] TO BUS 300387 [2BEVIER 69.000] CKT 1	26S	107.7	115.4	75.1
NU09	P1	300395 2JCKSNV 69.000 300402 2MACON 69.000 1	OPEN LINE FROM BUS 300172 [2TMHILLB1 69.000] TO BUS 300387 [2BEVIER 69.000] CKT 1	31S	97.5	102.8	78.0
NU10	P1	300530 2GEOGT2 69.000 300541 2SEDALI 69.000 1	OPEN BRANCH FROM BUS 300117 [5SEDALA 161.00] TO BUS 541209 [SEDALIA5 161.00] CKT 1	26H	99.6	169.8	72.8
NU11	P1	300549 5ENONB2 161.00 301649 5ETHLYNB2 161.00 1	OPEN BRANCH FROM BUS 344102 [7BELLEAU 345.00] TO BUS 344536 [7ENON_TP 345.00] CKT 1	26H	103.9	107.7	80.6

Constraint ID	Event	Monitored Facility	Contingency	Season	Base Loading	Project Loading	Upgrade Loading
NU12	P2EHV	300583 2VANDAL 69.000 300584 2VANDTP 69.000 1	OPEN BRANCH FROM BUS 345435 [7MAYWOOD 345.00] TO BUS 345992 [7SPENCER 345.00] CKT 1 OPEN BRANCH FROM BUS 40254 [J1025 POI 345.00] TO BUS 345435 [7MAYWOOD 345.00] CKT 1	26S	92.9	102.6	57.1
NU13	P1	301050 2CONWY 69.000 301071 2PBURG 69.000 1	OPEN BRANCH FROM BUS 300088 [5HUBEN 161.00] TO BUS 300102 [5MRSHFL 161.00] CKT 1	26S	75.3	103.9	52.0
NU14	P1	300184 2NORTHB 69.000 300189 2TARKIO 69.000 1	OPEN LINE FROM BUS 300186 [2ROCKPT 69.000] TO BUS 300241 [2ATCHISN 69.000] CKT 1	26S	101.9	105.6	84.9
NU15	P2EHV	300338 2BELLTN 69.000 300345 2PALMYR 69.000 1	OPEN BRANCH FROM BUS 345435 [7MAYWOOD 345.00] TO BUS 345992 [7SPENCER 345.00] CKT 1 OPEN BRANCH FROM BUS 40254 [J1025 POI 345.00] TO BUS 345435 [7MAYWOOD 345.00] CKT 1	26S	91.6	111.6	86.5
NU16	P2EHV	300380 2PERRYNE 69.000 300382 2SFRKTP 69.000 1	OPEN BRANCH FROM BUS 345435 [7MAYWOOD 345.00] TO BUS 345992 [7SPENCER 345.00] CKT 1 OPEN BRANCH FROM BUS 40254 [J1025 POI 345.00] TO BUS 345435 [7MAYWOOD 345.00] CKT 1	26S	78.4	109.4	78.6
NU17	P2EHV	300390 2CAIRO 69.000 300397 2LETNER 69.000 1	OPEN BRANCH FROM BUS 345435 [7MAYWOOD 345.00] TO BUS 345992 [7SPENCER 345.00] CKT 1 OPEN BRANCH FROM BUS 40254 [J1025 POI 345.00] TO BUS 345435 [7MAYWOOD 345.00] CKT 1	26S	96.3	105.0	85.8
NU18	P2EHV	300397 2LETNER 69.000 300407 2SHELBN 69.000 1	OPEN BRANCH FROM BUS 345435 [7MAYWOOD 345.00] TO BUS 345992 [7SPENCER 345.00] CKT 1 OPEN BRANCH FROM BUS 40254 [J1025 POI 345.00] TO BUS 345435 [7MAYWOOD 345.00] CKT 1	26S	91.6	111.0	82.4
NU19	P1	300398 2LOVELK 69.000 300412 2SUECITY 69.000 1	OPEN BRANCH FROM BUS 345435 [7MAYWOOD 345.00] TO BUS 345992 [7SPENCER 345.00] CKT 1	26S	74.0	103.2	78.5
NU20	P1	300398 2LOVELK 69.000 300420 2LAPLTP 69.000 1	OPEN LINE FROM BUS 631115 [OTTUMWA5 161.00] TO BUS 629075 [OTTUMW1G 24.000] CKT 1	31S	83.7	101.7	67.2
NU21	P2EHV	300399 2MACN3E 69.000 300401 2MACNTP 69.000 1	OPEN BRANCH FROM BUS 345435 [7MAYWOOD 345.00] TO BUS 345992 [7SPENCER 345.00] CKT 1 OPEN BRANCH FROM BUS 40254 [J1025 POI 345.00] TO BUS 345435 [7MAYWOOD 345.00] CKT 1	26S	87.7	109.0	75.5
NU22	P1	300402 2MACON 69.000 300405 2MCNPLT 69.000 1	OPEN LINE FROM BUS 300120 [5THMHILB1 161.00] TO BUS 300381 [5BEVIER 161.00] CKT 1	31S	92.0	113.2	74.3
NU23	P1	300412 2SUECITY 69.000 300457 2NOVELY_DST 69.000 1	OPEN BRANCH FROM BUS 345435 [7MAYWOOD 345.00] TO BUS 345992 [7SPENCER 345.00] CKT 1	26S	73.5	102.6	78.2
NU24	P1	300520 2REFORM 69.000 300626 2CHAMOI 69.000 1	OPEN LINE FROM BUS 41454 [J1145 POI 345.00] TO BUS 300044 [7MCCRED 345.00] CKT 1	26L	79.8	106.8	84.6
NU25	P1	300772 2COFMAN 69.000 300779 2J&7 69.000 1	OPEN BRANCH FROM BUS 300034 [5EDMONS 161.00] TO BUS 301402 [5LOSTVALY 161.00] CKT 1	26H	52.4	122.1	52.7
NU26	P1	300772 2COFMAN 69.000 300780 2KNOBBY 69.000 1	OPEN BRANCH FROM BUS 300034 [5EDMONS 161.00] TO BUS 301402 [5LOSTVALY 161.00] CKT 1	26H	58.4	127.8	55.7
NU27	P2EHV	300345 2PALMYR 69.000 301483 2BROSS1 69.000 1	OPEN BRANCH FROM BUS 345435 [7MAYWOOD 345.00] TO BUS 345992 [7SPENCER 345.00] CKT 1	26S	80.8	109.8	75.9

Constraint ID	Event	Monitored Facility	Contingency	Season	Base Loading	Project Loading	Upgrade Loading
			OPEN BRANCH FROM BUS 40254 [J1025 POI 345.00] TO BUS 345435 [7MAYWOOD 345.00] CKT 1				
NU28	P2EHV	300349 2SRIVER 69.000 301565 2BROSS3 69.000 1	OPEN BRANCH FROM BUS 345435 [7MAYWOOD 345.00] TO BUS 345992 [7SPENCER 345.00] CKT 1 OPEN BRANCH FROM BUS 40254 [J1025 POI 345.00] TO BUS 345435 [7MAYWOOD 345.00] CKT 1	26S	80.7	109.7	75.9
NU29	P1	300364 2NOVLTY_SW 69.000 300457 2NOVELY_DST 69.000 1	OPEN BRANCH FROM BUS 345435 [7MAYWOOD 345.00] TO BUS 345992 [7SPENCER 345.00] CKT 1	26S	70.6	115.8	75.5
NU30	P2EHV	300396 2LAKENN 69.000 300407 2SHELBN 69.000 1	OPEN BRANCH FROM BUS 345435 [7MAYWOOD 345.00] TO BUS 345992 [7SPENCER 345.00] CKT 1 OPEN BRANCH FROM BUS 40254 [J1025 POI 345.00] TO BUS 345435 [7MAYWOOD 345.00] CKT 1	26S	77.8	101.1	71.1
NU31	P2EHV	300338 2BELLTN 69.000 300396 2LAKENN 69.000 1	OPEN BRANCH FROM BUS 345435 [7MAYWOOD 345.00] TO BUS 345992 [7SPENCER 345.00] CKT 1 OPEN BRANCH FROM BUS 40254 [J1025 POI 345.00] TO BUS 345435 [7MAYWOOD 345.00] CKT 1	26S	76.8	101.7	70.2
NU32	P2EHV	300399 2MACN3E 69.000 300411 2TENMILETP 69.000 1	OPEN BRANCH FROM BUS 345435 [7MAYWOOD 345.00] TO BUS 345992 [7SPENCER 345.00] CKT 1 OPEN BRANCH FROM BUS 40254 [J1025 POI 345.00] TO BUS 345435 [7MAYWOOD 345.00] CKT 1	26S	72.3	100.0	65.1
NU33	P1	300780 2KNOBBY 69.000 301401 2TURKEYCRK 69.000 1	OPEN BRANCH FROM BUS 300034 [5EDMONS 161.00] TO BUS 301402 [5LOSTVALY 161.00] CKT 1	26H	69.5	138.4	93.1
NU34	P2EHV	300069 5CHOTEAU1 161.00 512648 MAID 5 161.00 1	OPEN BRANCH FROM BUS 300741 [5SPORTSMAN 161.00] TO BUS 300740 [7SPORTSMAN 345.00] CKT 2 OPEN BRANCH FROM BUS 300740 [7SPORTSMAN 345.00] TO BUS 512650 [GRDA1 7 345.00] CKT 1	26H	106.8	120.5	97.3
NU35	P1	300381 5BEVIER 161.00 300387 2BEVIER 69.000 1	OPEN LINE FROM BUS 300172 [2TMHILLB1 69.000] TO BUS 301318 [2THMINTP 69.000] CKT 1	26S	NB[2]	117.3	95.8
NU36	P1	300387 2BEVIER 69.000 301623 2BEVIERTP 69.000 1	OPEN BRANCH FROM BUS 345435 [7MAYWOOD 345.00] TO BUS 345992 [7SPENCER 345.00] CKT 1	31S	156.2	166.9	69.2
NU37	P1	300388 2AXTELL 69.000 300400 2MACNLK 69.000 1	OPEN BRANCH FROM BUS 345435 [7MAYWOOD 345.00] TO BUS 345992 [7SPENCER 345.00] CKT 1	31S	184.5	198.1	64.6
NU38	P1	300388 2AXTELL 69.000 300401 2MACNTP 69.000 1	OPEN BRANCH FROM BUS 345435 [7MAYWOOD 345.00] TO BUS 345992 [7SPENCER 345.00] CKT 1	31S	177.8	191.3	63.0
NU39	P1	300400 2MACNLK 69.000 301623 2BEVIERTP 69.000 1	OPEN BRANCH FROM BUS 345435 [7MAYWOOD 345.00] TO BUS 345992 [7SPENCER 345.00] CKT 1	31S	197.8	211.6	67.8
NU40	P1	300398 2LOVELK 69.000 300401 2MACNTP 69.000 1	OPEN LINE FROM BUS 300389 [2BYNUMV 69.000] TO BUS 301648 [2TMHILLB2 69.000] CKT 1	31S	99.4	107.2	69.0
NU41[3]	P1	300101 5MORGAN 161.00 300782 2MORGAN 69.000 1	OPEN LINE FROM BUS 300774 [2EUDORA 69.000] TO BUS 300788 [2SLAGLE 69.000] CKT 1	26H	90.9	100.0	80.3

[2] Monitored facility does not exist in base case, as such no loading reported for this scenario.
[3] Impact was able to be mitigated through the adjustment of transformer taps; as a result, no upgrade was evaluated for the reported constraint.

Table 2 shows stressed modeling conditions in which the Base Loading represents models built with higher queue generation requests in service, but without network upgrades tagged to those higher queue requests. Multiple iterations of solutions, which can include applicable higher queued network upgrades, were tested to alleviate both the Base Loading and the additional loading contributed by the Study Cycle (Project Loading). Table 2 lists facilities in which Project Loading cannot be mitigated by higher queue upgrades and in which a negative impact due to the Study Cycle was still present.

There were six (6) facilities in which the network upgrade assigned to higher queued generators were no longer sufficient to mitigate loadings observed with the addition of the Study Cycle. As a result, the below facilities are also included as Project impacts:

- Bevier 161/69 kV transformer # 1
- Bevier – Bevier Tap 69 kV line
- Bevier Tap – Macon Lake 69 kV line
- Macon Lake – Axtell 69 kV line
- Axtell – Macon Tap 69 kV line
- Love Lake – Macon Tap 69 kV line

CONTINGENT FACILITY RESULTS

Forty-seven (47) facilities were reported as Contingent Facilities with the addition of the Study Cycle requests, as shown in Table 3. Contingent Facilities are those facilities identified that are the responsibility of higher-queued generators or are included in the Transmission Provider's transmission expansion plan and that if not included in the Study would otherwise be the responsibility of the Study Cycle requests as necessary to interconnect to the transmission system.

The transmission upgrades for the Contingent Facilities were evaluated in order to confirm that the planned system adjustments were sufficient to mitigate the overload seen for the addition of the Study Cycle requests. Simulations were performed on each of the scenarios with the identified network upgrade and contingent network upgrades included. The upgrades shown in Table 5 were evaluated in order to mitigate the reported constraints as listed in Table 3 below.

Overloads seen on six (6) facilities were unable to be mitigated with the planned contingent upgrade; as a result, additional network upgrades have been assigned to the Study Cycle and are discussed in the Steady State Analysis Results section above. Results from the simulations found that the remaining planned contingent upgrades were able to mitigate the reported constraints as shown in Table 3.

Table 3: Steady State Contingent Constraints for the Study Cycle Requests with Upgrades

Constraint ID	Event	Monitored Facility	Season	Base Loading	Project Loading	Upgrade Loading	Contingent Generator(s)
CF01	P2EHV	300045 7MORGAN 345.00 301622 5MORGANXF1 161.00 1	26H	130.7	142.9	56.5	GI-094
CF02	P1	300057 5BARNET 161.00 45854 J1585 POI 161.00 1	31W	96.4	101.1	91.0	MISO DPP 2020
CF03	P1	300618 2BARNET 69.000 300633 2MTPLSTC 69.000 1	31W	92.1	103.9	97.7	MISO DPP 2020
CF04	P1	300115 5STFRANB2 161.00 338202 5JIM HILL% 161.00 1	31S	123.0	132.7	89.7	MISO DPP 2019
CF05	P1	300124 5HOLDENB2 161.00 300336 2HOLDEN 69.000 1	31S	116.5	143.7	93.9	MISO DPP 2019
CF06	P1	300172 2TMHILLB1 69.000 300387 2BEVIER 69.000 1	26S	130.2	139.0	NB[4]	GI-083
CF07	P1	301443 5THMHLB4 161.00 543062 SALSBRY5 161.00 1	31S	NB	102.1	91.1	GI-083
CF08	P1	300181 2LINDEN 69.000 300185 2PHELPS 69.000 1	26S	90.6	100.2	52.2	SPP DISIS 2016-002
CF09	P1	300184 2NORTHB 69.000 301662 2HAMBRGB2 69.000 1	26S	103.3	111.7	60.5	SPP DISIS 2016-002
CF10	P1	300185 2PHELPS 69.000 300186 2ROCKPT 69.000 1	26S	95.7	105.4	54.8	SPP DISIS 2016-002
CF11	P1	300327 2ELM 69.000 300336 2HOLDEN 69.000 1	31S	111.9	143.6	92.3	MISO DPP 2019
CF12	P1	300355 2SPALDNG 69.000 300373 2CENTER 69.000 1	26H	92.1	106.1	75.9	GI-092
CF13	P1	300373 2CENTER 69.000 300374 2CNTRSW 69.000 1	26H	94.7	108.8	77.9	GI-092
CF14	P1	300374 2CNTRSW 69.000 300380 2PERRYNE 69.000 1	26S	97.6	100.7	63.7	GI-092
CF15	P1	300505 2STURGN 69.000 300508 5STURGN 161.00 3	26H	104.5	110.0	93.2	GI-092
CF16	P1	300505 2STURGN 69.000 300508 5STURGN 161.00 4	26H	105.0	110.6	0.0	GI-092

[4] Monitored facility does not exist in upgrade case, as such no loading reported for this scenario.

Constraint ID	Event	Monitored Facility	Season	Base Loading	Project Loading	Upgrade Loading	Contingent Generator(s)
CF17	P1	300517 2KINGDM 69.000 301497 5KINGDMB2 161.00 2	31S	141.6	146.7	NB[4]	GI-083
CF18	P1	300517 2KINGDM 69.000 301497 5KINGDMB2 161.00 3	31S	141.5	146.6	73.8	GI-083
CF19	P1	300099 5MONTCT 161.00 300575 2MONTGY 69.000 2	31S	111.1	116.8	95.8	GI-083
CF20	P1	300512 2AUXVAS 69.000 300517 2KINGDM 69.000 1	31S	107.7	118.5	NB[4]	GI-083
CF21	P1	300512 2AUXVAS 69.000 300580 2SLTRVR 69.000 1	31S	93.2	103.5	NB[4]	GI-083
CF22	P2EHV	300525 5WRIGHTB2 161.00 300600 5NEWMELB1 161.00 1	31S	106.9	110.8	54.5	MISO DPP 2020
CF23	P2EHV	300525 5WRIGHTB2 161.00 300608 5WRIGHTB1 161.00 Z1	31S	106.6	110.3	84.3	MISO DPP 2020
CF24	P2EHV	300774 2EUDORA 69.000 300788 2SLAGLE 69.000 1	26H	131.9	141.0	54.1	GI-088
CF25	P2EHV	301207 2GRNFOR 69.000 301224 2TWNSHP 69.000 1	31S	98.9	105.3	54.5	MISO 2018 APR
CF26	P2EHV	300173 2GOBKNOB 69.000 301218 2PBSOUTH 69.000 1	26L	95.3	100.3	30.2	MISO DPP 2019
CF27	P2EHV	301209 2HARVEL 69.000 301218 2PBSOUTH 69.000 1	26L	91.9	101.6	77.3	MISO DPP 2019
CF28	P1	300133 5THMHLB3 161.00 344004 5ADAIR1 161.00 1	31S	133.2	143.3	96.4	MISO DPP 2019
CF29	P2EHV	300042 7HUBEN 345.00 300088 5HUBEN 161.00 1	31S	106.1	115.5	86.9	GI-085
CF30	P1	300381 5BEVIER 161.00 300387 2BEVIER 69.000 1	26S	NB[2]	117.3	95.8	GI-083
CF31	P1	300387 2BEVIER 69.000 301623 2BEVIERTP 69.000 1	31S	156.2	166.9	69.2	SPP DISIS 2016-002, GI-083, MISO DPP-2019
CF32	P1	300388 2AXTELL 69.000 300400 2MACNLK 69.000 1	31S	184.5	198.1	64.6	SPP DISIS 2016-002, GI-083, MISO DPP-2019
CF33	P1	300388 2AXTELL 69.000 300401 2MACNTP 69.000 1	31S	177.8	191.3	63.0	SPP DISIS 2016-002, GI-083, MISO DPP-2019
CF34	P1	300400 2MACNLK 69.000 301623 2BEVIERTP 69.000 1	31S	197.8	211.6	67.8	SPP DISIS 2016-002, GI-083, MISO DPP-2019
CF35	P1	300398 2LOVELK 69.000 300401 2MACNTP 69.000 1	31S	99.4	107.2	69.0	MISO DPP 2019
CF38	P1	300110 5PITTSV 161.00 300331 2PITTSV 69.000 1	31S	68.2	104.8	82.4	SPP DISIS-2017-002 Network Upgrades
CF39	P1	300323 2CENTRV 69.000 300334 2ROSEHL 69.000 1	26S	85.3	107.2	85.8	SPP DISIS-2017-002 Network Upgrades
CF40	P1	300323 2CENTRV 69.000 300336 2HOLDEN 69.000 1	26S	93.5	113.3	93.9	SPP DISIS-2017-002 Network Upgrades

Constraint ID	Event	Monitored Facility	Season	Base Loading	Project Loading	Upgrade Loading	Contingent Generator(s)
CF41	P1	300324 2CHAPHL 69.000 300325 2RT Z 69.000 1	31S	79.1	104.5	89.5	SPP DISIS-2017-002 Network Upgrades
CF42	P1	300325 2RT Z 69.000 300327 2ELM 69.000 1	31S	82.7	106.1	92.3	SPP DISIS-2017-002 Network Upgrades
CF43	P1	300688 2AUSTIN 69.000 300696 2CREIGH 69.000 1	26S	89.5	132.5	80.5	SPP DISIS-2017-002 Network Upgrades
CF44	P1	300688 2AUSTIN 69.000 300699 2ELYNTP 69.000 1	26S	77.9	121.2	69.0	SPP DISIS-2017-002 Network Upgrades
CF45	P1	300692 2CLINTN 69.000 300706 2PIPER 69.000 1	26S	98.9	103.1	98.8	SPP DISIS-2017-002 Network Upgrades
CF46	P1	300773 2ELKTON 69.000 300817 2OSCEOLA 69.000 1	26H	55.5	110.3	86.3	SPP DISIS-2017-002 Network Upgrades
CF36	P2EHV	300101 5MORGAN 161.00 301622 5MORGANXF1 161.00 1	26W	103.9	115.8	75.3	SPP DISIS-2017-002 Network Upgrades
CF37	P2EHV	300101 5MORGAN 161.00 505498 STOCKTN5 161.00 1	26H	39.4	104.4	83.7	SPP DISIS-2017-002 Network Upgrades
CF47	P2EHV	300831 2RGRSVL2 69.000 301165 2RGRSVL 69.000 1	31S	90.5	101.5	87.6	SPP DISIS-2017-002 Network Upgrades

NEIGHBORING SYSTEM RESULTS

The Study has identified impacts from the Study Cycle requests on the AECI ties with neighboring systems. The most limiting component of the AECI owned portion of the facility was evaluated and if found inadequate, a network upgrade for the AECI equipment was determined. Network upgrades for transmission facilities limited by non-AECI equipment are not captured and will need to be coordinated with the appropriate transmission owner.

Nine (9) facilities were reported on the AECI ties with the addition of the Study Cycle requests. The most severe constraints are shown in Table 4.

Table 4: Steady State Neighboring System Constraints for the Study Cycle Requests

Constraint ID	Event	Monitored Facility	Area	Season	Base Loading	Project Loading
AFS01	P2EHV	42684 J1268 POI 161.00 300590 5AUBURNTP 161.00 1	AMMO	26S	113.0	117.1

Constraint ID	Event	Monitored Facility	Area	Season	Base Loading	Project Loading
AFS02	P1	300071 5CLINTN 161.00 761278 G17-108-TAP 161.00 1	KCPL	31S	NB[2]	231.3
AFS03	P1	300097 5MARYVB2 161.00 652560 CRESTON5 161.00 1	WAPA	31S	149.2	163.7
AFS04	P2EHV	300101 5MORGAN 161.00 547478 DAD368 5 161.00 1	EMDE	31S	93.7	114.2
AFS05	P1	300179 2HAMBRGB1 69.000 635055 PERCIVAL 8 69.000 1	MEC	26S	145.2	166.0
AFS06	P2EHV	300590 5AUBURNTP 161.00 300595 5CYRENE 161.00 1	AMMO	26S	110.0	113.9
AFS07	P1	300740 7SPORTSMAN 345.00 512650 GRDA1 7 345.00 1	GRDA	26H	86.2	100.9
AFS09	P1	300694 5PALMYR_AI 161.00 347516 5MARBLE N 161.00 1	AMMO	26H	103.2	106.3

NETWORK UPGRADES

The upgrades shown in Table 5 were evaluated in order to mitigate the reported steady state contingent constraints for the Study Cycle requests as listed in Table 3.

Table 5: Network Upgrades for the Study Cycle Contingent Constraints

Constraint ID	Monitored Facility	Network Upgrade
CF01	300045 7MORGAN 345.00 301622 5MORGANXF1 161.00 1	**Contingent on GI-094** Replace Morgan 345/161 kV transformer with a 606 MVA Summer/690 MVA Winter unit
CF02	300057 5BARNET 161.00 45854 J1585 POI 161.00 1	**Contingent on MISO DPP 2020** Upgrade Wave Trap at Barnett 161 kV station
CF03	300618 2BARNET 69.000 300633 2MTPLSTC 69.000 1	
CF04	300115 5STFRANB2 161.00 338202 5JIM HILL% 161.00 1	**Contingent on MISO DPP 2019** Rebuild 9.9-mile-long St. Francis to Jim Hill 161 kV line to 1192 ACSR at 100C Replace jumpers at St. Francis with 1192 ACSR at 100C Replace disconnect switches at St. Francis 161 kV bus on Jim Hill line with 2,000A switches.
CF05	300124 5HOLDENB2 161.00 300336 2HOLDEN 69.000 1	**Contingent on MISO DPP 2019** Adjustment of transformer taps unable to mitigate overload Add second 161/69 kV transformer at Holden with rating of 84 MVA Summer/95 MVA Winter
CF06	300172 2TMHILLB1 69.000 300387 2BEVIER 69.000 1	**Contingent on GI-083** Thomas Hill – Bevier area upgrades: -Move Thomas Hill – Moberly 161 kV line to Thomas Hill Bus #2 -Move Thomas Hill – Meadville 161 kV line to Thomas Hill Bus #3 -Move Thomas Hill – Salisbury 161 kV line to Thomas Hill Bus #4 -Add Thomas Hill Bus #1 – Bevier 161 kV line -Add Bevier 161/69 kV transformer rated for 112/127 MVA -Remove Thomas Hill – Bevier 69 kV line
CF07	301443 5THMHLB4 161.00 543062 SALSBRY5 161.00 1	
CF08	300181 2LINDEN 69.000 300185 2PHELPS 69.000 1	**Contingent on SPP DISIS 2016-002** Rebuild the 11.4-mile-long Linden to Phelps 69 kV line to 336 ACSR.
CF09	300184 2NORTHB 69.000 301662 2HAMBRGB2 69.000 1	**Contingent on SPP DISIS 2016-002** Rebuild the 18-mile-long Hamburg to Northboro 69 kV line to 336 ACSR.
CF10	300185 2PHELPS 69.000 300186 2ROCKPT 69.000 1	**Contingent on SPP DISIS 2016-002** Rebuild the 4.4-mile-long Phelps to Rockport 69 kV line to 336 ACSR.
CF11	300327 2ELM 69.000 300336 2HOLDEN 69.000 1	**Contingent on MISO DPP 2019** Rebuild 3.1-mile-long 336 ACSR segment of Elm-Holden. Utilize 556 ACSR at 100C for 69 kV circuit
CF12	300355 2SPALDNG 69.000 300373 2CENTER 69.000 1	**Contingent on GI-092** Rebuild 6.5-mile-long 4/0 ACSR line segment of Spalding to Center 69 kV line to 336 ACSR at 100C
CF13	300373 2CENTER 69.000 300374 2CNTRSW 69.000 1	**Contingent on GI-092** Rebuild 6.4-mile-long Center to Center Switching 69 kV line to 336 ACSR at 100C
CF14	300374 2CNTRSW 69.000 300380 2PERRYNE 69.000 1	**Contingent on GI-092** Rebuild 3.9-mile-long Center Switching to Perry 69 kV line to 336 ACSR at 100C
CF15	300505 2STURGN 69.000 300508 5STURGN 161.00 3	**Contingent on GI-092** Replace Sturgeon #3 161/69 kV transformer with 84 MVA Summer/95 MVA Winter Unit Remove Sturgeon #4 161/69 kV transformer from service
CF16	300505 2STURGN 69.000 300508 5STURGN 161.00 4	
CF17	300517 2KINGDM 69.000 301497 5KINGDMB2 161.00 2	**Contingent on GI-083** Upgrade Kingdom City 161/69 kV transformer #3 to 84/96 MVA unit Remove Kingdom City 161/69 kV transformer #2 from service

<table>
<tr><th>Constraint ID</th><th>Monitored Facility</th><th>Network Upgrade</th></tr>
<tr><td>CF18</td><td>300517 2KINGDM 69.000
301497 5KINGDMB2 161.00 3</td><td rowspan="4">Salt River area upgrades:
- Add two new terminal positions to the Salt River 161 kV substation
- Add Salt River 161/69 kV transformer rated for 84/96 MVA
- Convert Auxvasse 69 kV substation to 161 kV operation
- Rebuild Kingdom City - Auxvasse 69 kV line, 8.00 miles, to 161 kV service, utilize 795 ACSR conductor to be designed for 100ºC and re-terminate line at the Kingdom City 161 kV bus 2
- Rebuild Auxvasse - Salt River Tap 69 kV line, 9 miles, to 161 kV service, utilize 795 ACSR conductor to be designed for 100ºC and re-terminate line at the Salt River 161 kV bus
- Rebuild 1 mile Salt River Tap-Salt River line to 161/69 kV D.C. 161 kV will be 795 ACSR at 100C. 69 kV will be 336 ACSR at 100C.
- Add one new terminal position to the Montgomery City 161 kV substation
- Build a new 161/69 kV double circuit from Salt River - Vandiver - Scotts Corner, ~17 miles
-- 161 kV line will be 795 ACSR at 100C. Terminated at Salt River and will continue to Montgomery City.
-- 69 kV line will be 336 ACSR at 100C. Terminated at Salt River, Vandiver, Lindell, and Scotts Corner.
---Upgrade jumpers at Lindell, Vandiver, Scotts Corner to 336 ACSR.
- Rebuild the 16.3 mile Scotts Corner-Montgomery City 69 kV line to 161 kV, 795 ACSR at 100C. Line section will be used as 161 kV path between Salt River and Montgomery City. The line will not terminate at Scotts Corner.
- Add two new breakers to Vandalia 69 kV substation
-- Construct a 69 kV line from Scotts Corner - Vandalia, 12.00 miles, utilize 336 ACSR conductor to be designed for 100ºC</td></tr>
<tr><td>CF19</td><td>300099 5MONTCT 161.00
300575 2MONTGY 69.000 2</td></tr>
<tr><td>CF20</td><td>300512 2AUXVAS 69.000
300517 2KINGDM 69.000 1</td></tr>
<tr><td>CF21</td><td>300512 2AUXVAS 69.000
300580 2SLTRVR 69.000 1</td></tr>
<tr><td>CF22</td><td>300525 5WRIGHTB2 161.00
300600 5NEWMELB1 161.00 1</td><td>Contingent on MISO DPP 2020
Reconductor 6.5-mile-long Wright City-New Melle 161 kV line with 795 ACSS at 250C
Replace Bushing CTs, Jumpers, Breaker Switchers, and Disconnect Switches at Wright City
Replace Disconnect Switches and Jumpers at New Melle</td></tr>
<tr><td>CF23</td><td>300525 5WRIGHTB2 161.00
300608 5WRIGHTB1 161.00 Z1</td><td>Contingent on MISO DPP 2020
Replace Jumpers and Disconnect Switches at Wright City 161 kV bus</td></tr>
<tr><td>CF24</td><td>300774 2EUDORA 69.000
300788 2SLAGLE 69.000 1</td><td>Contingent on GI-088
Rebuild 9.90-mile-long Eudora to Slagle 69 kV line with 795 ACSR rated at 100 C</td></tr>
<tr><td>CF25</td><td>301207 2GRNFOR 69.000
301224 2TWNSHP 69.000 1</td><td>Contingent on MISO 2018 APR
Reconductor the 2.44-mile-long Green Forest to Township 69 kV line to 336 ACSR</td></tr>
<tr><td>CF26</td><td>300173 2GOBKNOB 69.000
301218 2PBSOUTH 69.000 1</td><td>Contingent on MISO DPP 2019
Rebuild 3-mile-long section of Gobbler Knob to Poplar Bluff South 69 kV line to 795 ACSR at 100C</td></tr>
<tr><td>CF27</td><td>301209 2HARVEL 69.000
301218 2PBSOUTH 69.000 1</td><td>Contingent on MISO DPP 2019
Uprate 2.34-mile-long 4/0 portion of Harviell-Poplar Bluff South 69 kV from 75C to 100C</td></tr>
<tr><td>CF28</td><td>300133 5THMHLB3 161.00
344004 5ADAIR1 161.00 1</td><td>Contingent on MISO DPP 2019
Replace 161 kV disconnect switches on Thomas Hill-Adair line at Thomas Hill with 2000A switches
Upgrade jumpers on Thomas Hill-Adair line at Thomas Hill to 1590 ACSR at 100C
Replace Thomas Hill 161 kV breaker 1292 with 50 kA unit (3,000A continuous)</td></tr>
<tr><td>CF29</td><td>300042 7HUBEN 345.00
300088 5HUBEN 161.00 1</td><td>Contingent on GI-085
Reconfigure Morgan substation to a Breaker-and-a-Half configuration</td></tr>
<tr><td>CF30</td><td>300381 5BEVIER 161.00
300387 2BEVIER 69.000 1</td><td>Contingent on GI-083
Thomas Hill – Bevier area upgrades:
-Move Thomas Hill – Moberly 161 kV line to Thomas Hill Bus #2
-Move Thomas Hill – Meadville 161 kV line to Thomas Hill Bus #3
-Move Thomas Hill – Salisbury 161 kV line to Thomas Hill Bus #4
-Add Thomas Hill Bus #1 – Bevier 161 kV line
-Add Bevier 161/69 kV transformer rated for 112/127 MVA
-Remove Thomas Hill – Bevier 69 kV line</td></tr>
<tr><td>CF31</td><td>300387 2BEVIER 69.000
301623 2BEVIERTP 69.000 1</td><td>Contingent on SPP DISIS 2016-002, GI-083, MISO DPP 2019
Rebuild 0.1-mile-long Bevier to Bevier Tap 69 line to 795 ACSR at 100C</td></tr>
<tr><td>CF32</td><td>300388 2AXTELL 69.000
300400 2MACNLK 69.000 1</td><td>Contingent on SPP DISIS 2016-002, GI-083, MISO DPP 2019
Rebuild 1.15-mile-long Axtell to Macon Lake 69 line to 795 ACSR at 100C</td></tr>
<tr><td>CF33</td><td>300388 2AXTELL 69.000
300401 2MACNTP 69.000 1</td><td>Contingent on SPP DISIS 2016-002, GI-083, MISO DPP 2019
Rebuild 1.05-mile-long Axtell to Macon Tap 69 kV line to 795 ACSR at 100C</td></tr>
</table>

Constraint ID	Monitored Facility	Network Upgrade
CF34	300400 2MACNLK 69.000 301623 2BEVIERTP 69.000 1	**Contingent on SPP DISIS 2016-002, GI-083, MISO DPP 2019** Rebuild 4.25-mile-long Macon Lake to Bevier Tap 69 line to 795 ACSR at 100C
CF35	300398 2LOVELK 69.000 300401 2MACNTP 69.000 1	**Contingent on MISO DPP 2019** Rebuild 12.2-mile-long Lovelake-Macon Tap line to 336 ACSR at 100C Upgrade bushing CTs on CB 33 at Lovelake to 600A minimum base rating
CF36	300101 5MORGAN 161.00 301622 5MORGANXF1 161.00 1	**Contingent on SPP DISIS-2017-002 Network Upgrades** Rebuild the decommissioned 12.00 mile 161 kV line from G17-108-TAP to G17-111-TAP Rebuild the decommissioned 19.94 mile 161 kV line from G17-108-TAP to G17-186-TAP Rebuild the decommissioned 22.34 mile 161 kV line from G17-108-TAP to G17-186-TAP Rebuild the decommissioned 16.73 mile 161 kV line from G17-11-TAP to Archie, upgrade the conductor
CF37	300101 5MORGAN 161.00 505498 STOCKTN5 161.00 1	
CF38	300110 5PITTSV 161.00 300331 2PITTSV 69.000 1	
CF39	300323 2CENTRV 69.000 300334 2ROSEHL 69.000 1	
CF40	300323 2CENTRV 69.000 300336 2HOLDEN 69.000 1	
CF41	300324 2CHAPHL 69.000 300325 2RT Z 69.000 1	
CF42	300325 2RT Z 69.000 300327 2ELM 69.000 1	
CF43	300688 2AUSTIN 69.000 300696 2CREIGH 69.000 1	
CF44	300688 2AUSTIN 69.000 300699 2ELYNTP 69.000 1	
CF45	300692 2CLINTN 69.000 300706 2PIPER 69.000 1	
CF46	300773 2ELKTON 69.000 300817 2OSCEOLA 69.000 1	
CF47	300831 2RGRSVL2 69.000 301165 2RGRSVL 69.000 1	

No upgrades were evaluated for the neighboring system constraints listed in Table 4. The upgrades for these impacts will need to be resolved through coordination with the transmission owner as listed in Table 6 below.

Table 6: Neighboring System Constraints

Constraint ID	Monitored Facility	Network Upgrade
AFS01	42684 J1268 POI 161.00 300590 5AUBURNTP 161.00 1	AMMO owned; no upgrade evaluated
AFS02	300071 5CLINTN 161.00 761278 G17-108-TAP 161.00 1	KCPL owned; no upgrade evaluated
AFS03	300097 5MARYVB2 161.00 652560 CRESTON5 161.00 1	WAPA owned; no upgrade evaluated
AFS04	300101 5MORGAN 161.00 547478 DAD368 5 161.00 1	EMDE owned; no upgrade evaluated
AFS05	300179 2HAMBRGB1 69.000 635055 PERCIVAL 8 69.000 1	MEC owned; no upgrade evaluated
AFS06	300590 5AUBURNTP 161.00 300595 5CYRENE 161.00 1	AMMO owned; no upgrade evaluated
AFS07	300740 7SPORTSMAN 345.00 512650 GRDA1 7 345.00 1	GRDA owned; no upgrade evaluated
AFS09	300694 5PALMYR_AI 161.00 347516 5MARBLE N 161.00 1	AMMO owned; no upgrade evaluated

AECI developed non-binding, good faith estimates of the timing and cost estimates for upgrades needed as a result of the addition of the Study Cycle requests as shown in Table 7. Estimated Lead Time is the estimated time to place a network upgrade in service once AECI has received Provision of Security equal to the total Estimated Cost of the Network Upgrade.

Table 7: Network Upgrade Costs

ID	Option / Description	Estimated Cost (2022$)	Estimated Lead Time
NU01	Upgrade relay limits at Locust Creek 161 kV on Hickory Creek line with ratings of 203 MVA Summer/291 MVA Winter	$50,000	18 months
NU02	Rebuild 26.49-mile-long Morgan to Brookline 161 kV line with 1192 ACSR rated at 100C	$34,450,000	36 months
NU03	Upgrade Sullivan 161/138 kV transformer #1 with 143S MVA Summer/167 MVA Winter transformer	$4,000,000	48 months
NU04	Rebuild 0.6-mile-long Thomas Hill to Thomas Hill Mine Tap 69 kV line with 795 ACSR at 100C Upgrade bushing CTs at Thomas Hill on Thomas Hill Mine Tap line with 1200A bushing CTs Upgrade jumpers at Thomas Hill on Thomas Hill Mine Tap line with 795 ACSR	$790,000	24 months
NU05	Rebuild 7.09-mile-long Santa Fe to South Fork Tap 69 kV line with 336.4 ACSR rated at 100C	$6,390,000	36 months
NU06	Rebuild 9.24-mile-long Cairo to Huntsville 69 kV line with 795 ACSR rated at 100C Upgrade disconnect switches at Cario 69 kV on Huntsville line with 1200A switches	$8,570,000	36 months
NU07	Rebuild 5.09-mile-long Cairo to Jacksonville 69 kV line with 795 ACSR rated at 100C Upgrade bushing CTs at Cario 69 kV on Jacksonville line with 1200A bushing CTs	$4,790,000	36 months
NU08	Rebuild 4.50-mile-long Huntsville to Thomas Hill Mine Tap 69 kV line with 795 ACSR rated at 100C	$4,050,000	36 months
NU09	Rebuild 9.10-mile-long Jacksonville to Macon 69 kV line with 336 ACSR rated at 100C	$8,190,000	36 months
NU10	Rebuild 5.91-mile-long Georgetown Tap 2 to Sedalia 69 kV line with 795 ACSR rated at 100C Upgrade jumpers at Sedalia on Georgetown Tap 2 with 795 ACSR rated at 100C Upgrade bushing CTs, breaker switches, and disconnect switches at Sedalia on Georgetown Tap 2 with 1200A rated equipment	$5,960,000	36 months
NU11	Rebuild 4.90-mile-long Enon Bus 2 to Ethlyn Bus 2 161 kV line with 795 ACSR rated at 100C	$6,370,000	36 months
NU12	Rebuild 8.85-mile-long Vandalia to Vandalia Tap 69 kV with 336.4 ACSR rated at 100C	$8,010,000	36 months
NU13	Rebuild 5.58-mile-long Conway to Phillipsburg 69 kV line with 336.4 ACSR rated at 100C	$5,040,000	36 months
NU14	Rebuild 13.2-mile-long Northboro to Tarkio 69 kV line with 336 ACSR rated at 100C	$11,880,000	36 months
NU15	Rebuild 17-mile-long Belltown to Palmyra 69 kV line with 336 ACSR rated at 100C Upgrade bushing CTs at Belltown 69 kV on Palmyra line with 70 MVA Summer/85 MVA Winter rated bushing CTs	$15,500,000	48 months
NU16	Rebuild 8.77-mile-long Perry to South Fork Tap 69 kV line with 336 ACSR rated at 100C	$7,830,000	36 months
NU17	Rebuild 18.4-mile-long Cairo to Letner 69 kV line with 336 ACSR rated at 100C	$16,560,000	36 months
NU18	Rebuild 5.4-mile-long Letner to Shelbina 69 kV line with 336 ACSR rated at 100C	$4,860,000	36 months
NU19	Rebuild 8.8-mile-long Sue City to Lovelake 69 kV line with 336 ACSR rated at 100C Upgrade bushing CTs at Lovelace 69 kV on Sue City line with 70 MVA Summer/85 MVA Winter rated busing CTs	$8,120,000	36 months
NU20	Rebuild 5.3-mile-long Laplata Tap to Lovelake 69 kV line with 336 ACSR rated at 100C Upgrade bushing CTs at Lovelake 69 kV on Laplata Tap line with 70 MVA Summer/85 MVA Winter rated busing CTs	$4,970,000	36 months
NU21	Rebuild 3.6-mile-long Macon East 3 to Macon Tap 69 kV line with 336 ACSR rated at 100C	$3,240,000	36 months
NU22	Rebuild 0.58-mile-long Macon to Macon Plant 69 kV line with 366 ACSR rated at 100C	$540,000	18 months
NU23	Rebuild 9.8-mile-long Sue City to Novelty Dist 69 kV line with 336 ACSR rated at 100C	$8,820,000	36 months
NU24	Upgrade bushing CTs at Chamois 69 kV on Reform 69 kV line with 600A rated bushing CTs	$200,000	18 months
NU25	Rebuild 6.50-mile-long Coffman Bend to J-7 69 kV line with 366 ACSR rated at 100C	$5,850,000	36 months
NU26	Rebuild 4.40-mile-long Coffman Bend to Knobby 69 kV line with 336 ACSR rated at 100C	$3,960,000	36 months
NU27	Rebuild 2.4-mile-long Palmyra to Bross 69 kV line with 336 ACSR rated at 100C	$2,160,000	36 months
NU28	Rebuild 2.8-mile-long South River to Bross 3 69 kV line with 336 ACSR rated at 100C	$2,520,000	36 months
NU29	Rebuild 0.2-mile-long Novelty to Novelty Distribution 69 kV line with 336 ACSR rated at 100C	$380,000	24 months

ID	Option / Description	Estimated Cost (2022$)	Estimated Lead Time
	Upgrade bushing CTs at Novetly 69 kV on Novelty Distribution line with 600A rated bushing CTs		
NU30	Rebuild 2.3-mile-long Lakenan to Shelbina 69 kV line with 336 ACSR rated at 100C	$2,070,000	36 months
NU31	Rebuild 11.6-mile-long Belltown to Lakenan 69 kV line with 336 ACSR rated at 100C Upgrade bushing CTs at Belltown 69 kV on Lakenan line with 600A rated bushing CTs	$10,550,000	36 months
NU32	Rebuild 0.5-mile-long Macon East 3 to Ten Mile Tap 69 kV line 4/0 line section with 336 ACSR rated at 100C	$450,000	24 months
NU33	Uprate 12.4-mile-long Knobby to Turkey Creek 69 kV line from 75C rating to 100C	$3,700,000	36 months
NU34	Upgrade wave-traps and disconnect switches at Choteau 161 kV on Maid line with 873 MVA Summer/1071 MVA Winter rated equipment	$400,000	24 months
NU35	Add second 161/69 kV transformer at Bevier with ratings of 112 MVA Summer/128 MVA Winter	$5,000,000	48 months
NU36	Rebuild to 0.1-mile-long Bevier to Bevier 69 kV line with 1192 ACSR	$130,000	24 months
NU37	Rebuild to 1.2-mile-long Axtell to Macon Lake 69 kV line with 1192 ACSR	$1,560,000	36 months
NU38	Rebuild to 1.1-mile-long Axtell to Macon Tap 69 kV line with 1192 ACSR	$1,430,000	36 months
NU39	Rebuild to 4.3-mile-long Macon Lake to Bevier Tap 69 kV line with 1192 ACSR	$5,590,000	36 months
NU40	Rebuild to 12.2-mile-long Love Lake to Macon Tap 69 kV line with 795 ACSR	$15,860,000	36 months
	Total Cost:	$240,790,000	

Cost allocations for each of the impacted facilities are discussed in the Cost Allocation section below.

COST ALLOCATION

Network upgrade costs are allocated to each of the Study Cycle projects based on the worst MW impact[5] each project had on the constraint and as described in the steps below:

1. Determine the MW impact each Study Cycle project had on each constraint using the size of each request:

$$Project\ X\ MW\ Impact\ on\ Constraint\ 1 = DFAX\ (X) * MW\ (X) = X1$$

$$Project\ Y\ MW\ Impact\ on\ Constraint\ 1 = DFAX\ (Y) * MW\ (Y) = Y1$$

$$Project\ Z\ MW\ Impact\ on\ Constraint\ 1 = DFAX\ (Z) * MW\ (Z) = Z1$$

2. Determine the maximum MW% impact each generator has as a percentage of the total Study Cycle impact on a given constraint.

$$X2\ =\ Project\ X\ MW\ impact\ \% \ = \frac{X1}{Total\ MW\ Impact\ of\ Study\ Cycle\ on\ Constraint}$$

$$Y2\ =\ Project\ Y\ MW\ impact\ \% \ = \frac{Y1}{Total\ MW\ Impact\ of\ Study\ Cycle\ on\ Constraint}$$

$$Z2\ =\ Project\ Z\ MW\ impact\ \% \ = \frac{Z1}{Total\ MW\ Impact\ of\ Study\ Cycle\ on\ Constraint}$$

3. Apply three percent (3%) MW impact De Minimis Threshold: If a Study Cycle project MW% impact is less than 3% for a particular constraint then the project MW% impact is adjusted to 0 for that constraint and the Study Cycle project will not be allocated cost for that particular constraint.

4. Determine the cost allocated to each remaining Study Cycle project for each upgrade using the total cost of a given upgrade:

$$Project\ X\ Upgrade\ 1\ Cost\ Allocation\ (\$) = \frac{Network\ Upgrade\ 1\ Cost\ (\$) * X2}{X2 + Y2 + Z2}$$

The associated cost allocation of the network upgrades to each of the Study Cycle projects is shown below in Table 8. Further breakdown of costs is provided in Appendix B.

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[5] All negative MW impacts (helpers) were set to 0 MW impact.

Table 8: Network Upgrade Cost Allocation

Project	Cluster Group	POI	MW	Total Cost
GEN-2017-108	03 CENTRAL	Stillwell - Clinton 161kV Line	400.0	**$63,821,910**
GEN-2017-111	03 CENTRAL	Clinton - Stilwell 161 kV Line Tap	152.0	**$14,062,455**
GEN-2017-112	03 CENTRAL	Clinton - Stilwell 161 kV Line Tap	200.0	**$25,428,962**
GEN-2017-114	01 NORTH	Chappelle Creek - Leland Olds 345kV	450.0	**$2,376,907**
GEN-2017-115	03 CENTRAL	Holt County 345 kV	244.0	**$272,068**
GEN-2017-116	05 SOUTHWEST	Oasis - Pleasant Hill 230kV	192.5	**$0**
GEN-2017-119	03 CENTRAL	Elm Creek 345kV substation	180.0	**$0**
GEN-2017-120	03 CENTRAL	Abilene Energy Center-Northview 115kV	260.0	**$0**
GEN-2017-121	03 CENTRAL	Sumner 138kV	200.0	**$0**
GEN-2017-123	03 CENTRAL	Stranger Creek 345kV	180.0	**$12,745**
GEN-2017-125	03 CENTRAL	Swissvale 345kV	252.0	**$1,969,028**
GEN-2017-128	03 CENTRAL	Swissvale 345kV	202.0	**$2,114**
GEN-2017-132	04 SOUTHEAST	Arcadia 345kV	400.0	**$1,079,058**
GEN-2017-133	04 SOUTHEAST	Arcadia 345kV	200.0	**$0**
GEN-2017-134	04 SOUTHEAST	Arcadia 345kV	250.0	**$0**
GEN-2017-137	04 SOUTHEAST	Arcadia 345kV	295.0	**$0**
GEN-2017-140	04 SOUTHEAST	Clarksville 345kV Switching Station	160.0	**$0**
GEN-2017-141	04 SOUTHEAST	Clarksville 345kV Switching Station	241.7	**$0**
GEN-2017-142	03 CENTRAL	Swissvale 345kV Station	170.0	**$0**
GEN-2017-144	02 NEBRASKA	Holt County 345kV	200.0	**$0**
GEN-2017-146	05 SOUTHWEST	Deaf Smith-Plant X 230kV	151.8	**$0**
GEN-2017-147	03 CENTRAL	Stilwell 345kV	252.0	**$11,043,954**
GEN-2017-148	03 CENTRAL	Joplin 161kV sub	202.0	**$965,294**
GEN-2017-149	04 SOUTHEAST	Johnson County 345kV Substation	258.0	**$0**
GEN-2017-233	04 SOUTHEAST	Minco 345kV	215.0	**$0**
GEN-2017-150	04 SOUTHEAST	Minco 345kV	250.0	**$0**
GEN-2017-151	05 SOUTHWEST	TUCO-Oklaunion 345kV	300.0	**$0**
GEN-2017-152	04 SOUTHEAST	McClain 138kV	252.0	**$0**
GEN-2017-153	04 SOUTHEAST	McClain 138kV	253.0	**$0**
GEN-2017-154	04 SOUTHEAST	Johnson County 345kV Substation	255.0	**$0**
GEN-2017-155	04 SOUTHEAST	Muskogee 345kV Substation	300.0	**$1,005,836**
GEN-2017-156	04 SOUTHEAST	Pittsburg 345kV Substation	234.0	**$0**
GEN-2017-157	04 SOUTHEAST	Pittsburg 345kV Substation	202.0	**$0**
GEN-2017-158	05 SOUTHWEST	Tolk 230kV Substation	265.0	**$0**
GEN-2017-164	04 SOUTHEAST	Woodring 345kV Substation	250.0	**$0**
GEN-2017-166	04 SOUTHEAST	Sunnyside 345kV	250.0	**$0**
GEN-2017-168	04 SOUTHEAST	McClain 138kV	250.0	**$0**
GEN-2017-171	04 SOUTHEAST	Lawton Eastside - Terry Road 345kV	150.0	**$0**
GEN-2017-175	01 NORTH	Vfodnes-Utica Jct. 230kV	300.0	**$365,775**

GEN-2017-176	05 SOUTHWEST	Newhart 230kV Substation	300.0	**$0**
GEN-2017-179	03 CENTRAL	Gordon Evans 138kV Substation	222.0	**$0**
GEN-2017-181	02 NEBRASKA	Tobias 345kV Substation	300.0	**$296,738**
GEN-2017-182	02 NEBRASKA	Tobias 345kV Substation	128.0	**$0**
GEN-2017-183	03 CENTRAL	Nashua-St. Joe 345kV	400.0	**$17,018,182**
GEN-2017-184	03 CENTRAL	Nashua-St. Joe 345kV	400.0	**$17,018,182**
GEN-2017-185	03 CENTRAL	Viola - Hunters 345kV	200.0	**$0**
GEN-2017-186	03 CENTRAL	KC South-N. Raymore 161 kV	100.0	**$0**
GEN-2017-187	05 SOUTHWEST	Sulphur Springs 115kV Substation	150.0	**$0**
GEN-2017-188	03 CENTRAL	Asbury 161 kV	130.0	**$0**
GEN-2017-191	03 CENTRAL	Swissvale 345kV	201.6	**$0**
GEN-2017-193	03 CENTRAL	Tecumseh 230kV Substation	201.6	**$2,215**
GEN-2017-195	03 CENTRAL	West Gardner 345kV	500.4	**$33,881,350**
GEN-2017-196	03 CENTRAL	West Gardner 345kV	128.0	**$0**
GEN-2017-199	01 NORTH	Groton 345kV Substation	202.0	**$258,522**
GEN-2017-200	01 NORTH	Groton 345kV Substation	302.0	**$386,503**
GEN-2017-201	02 NEBRASKA	Hoskins 345kV Substation	250.0	**$287,655**
GEN-2017-202	03 CENTRAL	New Madrid - Sikeston 161kV	200.0	**$1,429,419**
GEN-2017-203	04 SOUTHEAST	Renfrow 345kV Substation	210.0	**$0**
GEN-2017-209	03 CENTRAL	LaCygne - Neosho 345kV	300.0	**$11,909,548**
GEN-2017-210	02 NEBRASKA	McCool 345kV Substation	310.0	**$303,236**
GEN-2017-213	04 SOUTHEAST	Clarksville 345kV Substation	300.0	**$1,052,081**
GEN-2017-217	05 SOUTHWEST	Plant X 230kV Substation	300.0	**$0**
GEN-2017-218	05 SOUTHWEST	Tolk-Plant X 230kV Line	600.0	**$1,109,888**
GEN-2017-220	03 CENTRAL	Buffalo Flats 345kV Substation	201.6	**$0**
GEN-2017-221	03 CENTRAL	Buffalo Flats 345kV Substation	152.0	**$0**
GEN-2017-222	01 NORTH	Denison 230kV Substation	180.0	**$224,552**
GEN-2017-224	03 CENTRAL	Craig 345kV Substation	302.4	**$13,882,179**
GEN-2017-226	03 CENTRAL	Gordon Evans 138kV Substation	201.6	**$0**
GEN-2017-227	03 CENTRAL	Gordon Evans 138kV Substation	201.6	**$0**
GEN-2017-228	03 CENTRAL	Stilwell 345kV Substation	302.4	**$19,323,644**
GEN-2017-229	03 CENTRAL	Stilwell 345kV Substation	76.0	**$0**
GEN-2017-231	04 SOUTHEAST	Branch 161kV Substation	72.5	**$0**
GEN-2017-234	02 NEBRASKA	Spalding to North Loup 115kV	115.0	**$0**
GEN-2017-239	05 SOUTHWEST	Mahoney 230kV Substation	300.0	**$0**
GEN-2017-240	04 SOUTHEAST	Bristow 138kV Substation	202.0	**$0**
			Total Cost	**$240,790,000**

VERSION HISTORY

Version Number and Date	Author	Change Description
V0 – 11/18/2022	AECI	Initial release

Facility Study
for UID 156852

Terminal Equipment Upgrade

Truman Bay 52 and 68

on 161kV Line Truman – Lost Valley

May 11, 2023

Summary

At the request of Southwest Power Pool (SPP), Southwestern Power Administration (SWPA) performed the following Facility Study. This Facility Study is in regard to SPP Upgrade Request UID 156852, Truman 161kV Terminal Equipment Upgrade (DISIS-2017-002). From SPP's DISIS_Results_Workbook_DIS1702-1-PowerFlow_Final workbook, the request consists of upgrading the U.S. Army Corps of Engineers' (COE) Truman powerhouse switchyard bay 52 terminal equipment for uprating the Truman – Lost Valley 161kV transmission line to 286 MVA (1025 amps).

1. <u>Introduction</u>
The SPP has requested a Facility Study for the purpose of uprating the Truman – Lost Valley 161kV transmission line to a facility rating of at least 286 MVA (1025 amps). The upgrade request will require upgrade of COE's Truman Substation of the following equipment:

    1. vertical line bay conductor in bay 52

The estimated upgrade cost is $187,000.

2. <u>Existing Interconnection Facilities Review</u>
The existing facility thermal ratings and circuit breaker interrupting capabilities will establish the necessary facility upgrades to accommodate the interconnection request as described in Sections 2.1 and 2.2 below.

2.1. <u>Power Flow Constraints</u>
COE's Truman Substation bays 52 and 68 have the following seasonal thermal ratings.

Season	**Summer Normal**	**Summer Emergency**	**Spring/Fall Normal**	**Spring/Fall Emergency**	**Winter Normal**	**Winter Emergency**
Line Rating (Amps)	1000	1000	1000	1000	1000	1000
Line Rating (MVA)	278	278	278	278	278	278

The request is for facility line rating upgrade of COE's Truman Substation bay 52 for the Truman – Lost Valley 161kV transmission line equipment to a rating of 286 MVA (1026 amps) or higher.

COE's Truman Substation bay 52, Truman – Lost Valley, has the following summer emergency facility ratings limited by the elements shown in the table below.

Equipment	**Circuit Breaker**	**Disconnect Switches**	**Metering CTs**	**Bus/ Jumpers**	**Vert. Line Bay Cond.**	**Relay Settings**
Summer Emergency Rating (Amps)	1200	1200	1200	1582	1000	1411
Summer Emergency Rating (MVA)	334	334	334	441	278	393

As shown in the tables above, COE's Truman Substation bay 52 will require upgrade of the following:

  1. Vertical Line Bay Conductor

2.2. <u>Short-Circuit Constraints</u>
COE's circuit breakers 52 at COE's Truman Substation have interrupting capability of greater than 30kA. The highest fault current for the subject line is approximately 7kA and the subject Upgrade

ID does not mention increase in nearby generation or increase in fault current capability, therefore no need for upgrade of circuit breakers due to interrupting capability.

3. Required Interconnection Facility Upgrades
In order to accommodate the facility line rating of 286 MVA for the Truman – Lost Valley 161kV transmission line, COE's Truman Powerhouse switchyard bay 52 will require upgrade of its vertical bay conductor. Below is a summary of estimated costs for the requested upgrade.

UID 156852, Truman 161kV Terminal Equipment Upgrade (DISIS-2017-002)	$187,000	36 months

Due to Truman Powerhouse switchyard and all equipment within the switchyard being owned by COE, COE's review and approval will be necessary if the subject project is approved. SWPA is the transmission planner and Power Marketing Authority for COE, therefore SWPA will coordinate interagency agreements between COE and SWPA and SWPA will coordinate project efforts between the requesting party and COE. If the subject project is approved, the agreement from the requesting party and/or SPP will be in accordance with SPP's Tariff Attachment AD as stated below. This agreement will be between SWPA, on behalf of COE, and either the requesting party or SPP.

Southwestern originally had within its notes that UID 156852, Truman 161kV Terminal Equipment Upgrade (DISIS-2017-002) was for uprating the Truman – Lost Valley 161kV transmission line to a facility rating of 356.5 MVA (1278 amps), therefore the cost estimate has been reduced due to the upgrade request is for a facility rating of 286 MVA (1025 amps). The cost estimate and SPP SCERT have been corrected and updated.

Interconnection requests with Southwestern shall be in accordance with SPP's Tariff Attachment AD, Article I, Section 14, (c) and (d), as shown below. In addition, Southwestern's deadline of 36 months does not begin with SPP's approval, but upon the interconnecting party's signed construction agreement with Southwestern. As stated in Southwestern's Interconnection Request Procedures, Southwestern's Interconnection Request Procedures is a two-step process. First, a Facility Study Agreement between the interconnecting party and Southwestern begins the process. Second, a Construction Agreement between the interconnecting party and Southwestern starts the second phase of the project. The anticipated lead time/deadline will be established in the construction agreement and will not start until all construction funds are received by Southwestern.

> ***"(c) Southwestern agrees to coordinate transmission planning and construction activities with SPP, but reserves the right to plan and construct modifications or additions to Southwestern's transmission facilities without the approval of SPP, and to approve or disapprove the requests by others to plan and construct such modifications or additions.***
>
> ***(d) No interconnections to Southwestern's transmission facilities shall be made without written contractual agreements between Southwestern and the interconnecting party which satisfy Southwestern's NEPA requirements and which establish the terms and conditions of the interconnection. Such agreements shall be made pursuant to Southwestern's then-current Interconnection Request Procedure as posted on Southwestern's web site."***