SPP DISIS-2020-001 AFS STUDY REPORT

INTRODUCTION

Associated Electric Cooperative Inc. (AECI), through coordination with the Southwest Power Pool (SPP), has performed the analysis for generator interconnection requests (GIRs) within the DISIS-2020-001 Study Cycle (the "Study Cycle") for an Affected System Study (AFS) evaluation on the AECI transmission system (the "Study"). This version of the report has been updated to consider the withdrawn projects listed in Table 1. The impacts of these withdrawn projects were determined by sensitivity analysis rather than a full power flow restudy.

Table 1: Withdrawn Study Cycle Requests

Project#	CA	Capacity (MW)	Fuel Type	POI
GEN-2020-073	KCPL	150	Solar	SE Ottawa to Pleasant Valley 161kV
GEN-2020-091	BEPC	150	Solar	Patent Gate Substation 345 kV

The full list of Study Cycle requests included in the Study are listed in Table 2 below.

Table 2: Study Cycle Requests Evaluated

Project#	CA	Capacity (MW)	Fuel Type	POI
ASGI-2020-001	KCPL	45	Solar	Waverly 69 kV Substation (Mt. Leonard)
ASGI-2020-003	KCPL	45	Solar	Coroltown 161 kV Substation (Bogard)
GEN-2020-002	OPPD	81	Solar	6846 Substation 69 kV
GEN-2020-007	KCPL	650	Solar	Evergy La Cygne to Wolf Creek 345kV Substation
GEN-2020-008	SPS	250	Solar	Corporation Carpenter 345kV Substation
GEN-2020-010	WFEC	140	Solar	Seiling-Taloga Substations 138kV
GEN-2020-011	NPPD	320	Solar	Axtell 345 kV Substation
GEN-2020-012	AEP	113	Solar	Snyder to Altus Jct. 138kV
GEN-2020-013	NPPD	215	Solar	Orleans-Holdrege Substation 115kV
GEN-2020-020	AEP	201.6	Solar	Northwest Texarkana - Valliant 345 kV line
GEN-2020-025	OPPD	255	Thermal	Substation 1363; 161kV Substation
GEN-2020-028	OPPD	255	Thermal	Substation 1363; 161kV Substation
GEN-2020-031	OPPD	303	Thermal	Substation 1363; 161kV Substation
GEN-2020-038	OPPD	303	Thermal	Substation 3740; 345kV
GEN-2020-054	AEP	298	Solar	Lydia 345 kV Station
GEN-2020-057	WERE	424.5	Battery/Storage	Atlantic 345 kV Substation
GEN-2020-058	WERE	424.5	Solar	Atlantic 345 kV Substation
GEN-2020-060	SPS	200	Battery/Storage	Lubbock East Substation 230 kV

Project#	CA	Capacity (MW)	Fuel Type	POI
GEN-2020-064	EDE	64	Thermal	4544 Stateline CC 161kV Substation
GEN-2020-065	SPS	1003	Thermal	Hobbs-Andrews 345 kV Line
GEN-2020-067	SPS	352.5	Wind	Tuco to Yoakum 345kV line
GEN-2020-072	GMO	150	Solar	Windsor to AEC Sedalia 161 kV line
GEN-2020-078	OPPD	100	Solar	Substation 1226 to Substation 1237, 161kV Tap
GEN-2020-079	EDE	225	Solar	Riverton-Neosho 161kV line
GEN-2020-081	AEP	200	Battery/Storage	Tenaska Switching Substation 345kV
GEN-2020-084	OPPD	350	Solar	Raun - Fort Calhoun 345 kV
GEN-2020-087	AEP	500	Solar	Cimmarron to Lawton 345 kV Line
GEN-2020-088	EDE	150	Solar	La Russell 161 kV Substation
GEN-2020-090	NEETSW	204.3	Battery/Storage	Wolf Creek - Blackberry 345 kV Substation
GEN-2020-092	AEP	100	Solar	Pryor Junction - Midwest Carbide 138kV line
GEN-2020-094	OPPD	250	Solar	Neb. City - 103rd & Rokeby 345 kV

Network upgrades from the following studies were added to models prior to the addition of the Study Cycle requests.

- Network Upgrades from AECI Expansion Plan
- Network Upgrades from AECI GI-083 request
- Network Upgrades from AECI GI-101/102 requests
- Network Upgrades from AECI GI-103 request
- Network Upgrades from AECI GI-104 request
- Network Upgrades from AECI's AFS of MISO DPP-2019-Cycle requests
- MISO Tranche 1 System Upgrades
- SPP 2024 Integrated Transmission Planning System Upgrades

The Network Upgrades included from these requests are detailed in Table 7. Should these upgrades no longer be tagged to the higher queued studies, AECI may 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. Modeling parameters from the SPP DISIS-2020-001 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-001-5 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.

AECI will perform an annual limited operations study which will indicate seasonal operating limits for SPP/MISO/AECI generation interconnection requests that will reach commercial operation in the 12-month horizon but whose AECI network upgrades have not yet been energized.

STEADY STATE ANALYSIS RESULTS

Steady state analysis results showed two (2) constraints reported on the AECI transmission system, as shown in Table 3, 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 6 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 3.

Table 3: 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	300520 2REFORM 69.000 300626 2CHAMOI 69.000 1	OPEN LINE FROM BUS 300060 [5BIGSPG 161.00] TO BUS 300067 [5CHAMOI 161.00] CKT 1	28W	105.8	111.4	62.8
				33W	106.8	112.5	63.5
NU02	P1	301370 5TURKEYCRK 161.00 301401 2TURKEYCRK 69.000 1	OPEN BRANCH FROM BUS 300034 [5EDMONS 161.00] TO BUS 301402 [5LOSTVALY 161.00] CKT 1	28W	88.1	101.9	96.3[1]
				33W	88.6	102.8	96.6[1]

Table 3 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).

[1] Upgrade loading reflects adjustment of transformer taps as mitigation.

CONTINGENT FACILITY RESULTS

Seven (7) facilities were reported as Contingent Facilities with the addition of the Study Cycle requests, as shown in Table 4. 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 may 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 7 were evaluated in order to mitigate the reported constraints as listed in Table 4 below.

Table 4: 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	P1	300772 2COFMAN 69.000 300779 2J&7 69.000 1	28S	86.5	100.3	33.8	CF MISO tranche 1
			28W	104.4	115.8	43.3	
			33W	104.4	115.4	42.9	
CF02	P1	300772 2COFMAN 69.000 300780 2KNOBBY 69.000 1	28S	93.6	107.4	36.3	CF MISO tranche 1
			28W	111.5	122.9	46.2	
			33S	94.6	107.0	36.6	
			33W	111.8	122.7	46.0	
CF03	P1	300780 2KNOBBY 69.000 301401 2TURKEYCRK 69.000 1	28S	107.5	120.8	40.9	CF MISO tranche 1
			28W	122.8	134.1	50.6	
			33S	108.1	121.5	41.1	
			33W	123.5	134.4	50.6	
CF04	P1	300541 2SEDALI 69.000 300545 2SYLVAN 69.000 1	28W	101.8	114.9	63.4	GI-091
			33W	105.5	118.5	65.4	

<table>
<tr><th>Constraint ID</th><th>Event</th><th>Monitored Facility</th><th>Season</th><th>Base Loading</th><th>Project loading</th><th>Upgrade loading</th><th>Contingent Generator(s)</th></tr>
<tr><td rowspan="2">CF05</td><td rowspan="2">P1</td><td rowspan="2">300530 2GEOGT2 69.000 300541 2SEDALI 69.000 1</td><td>28S</td><td>101.2</td><td>130.8</td><td>87.6</td><td rowspan="2">GI-091</td></tr>
<tr><td>33S</td><td>99.7</td><td>129.5</td><td>86.8</td></tr>
<tr><td rowspan="2">CF06</td><td>P1</td><td rowspan="2">300115 5STFRANB2 161.00 338202 5JIM HILL% 161.00 1</td><td>33S</td><td>103.6</td><td>107.0</td><td>48.4</td><td rowspan="2">MISO DPP-2019</td></tr>
<tr><td>P2EHV</td><td>33S</td><td>100.8</td><td>105.6</td><td>47.8</td></tr>
<tr><td rowspan="3">CF07</td><td rowspan="3">P1</td><td rowspan="3">300069 5CHOTEAU1 161.00 512648 MAID 5 161.00 1</td><td>28H</td><td>88.5</td><td>100.3</td><td>56.9</td><td rowspan="3">SPP DISIS-2017-002</td></tr>
<tr><td>28S</td><td>90.5</td><td>101.5</td><td>57.7</td></tr>
<tr><td>33S</td><td>90.6</td><td>101.6</td><td>57.8</td></tr>
</table>

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 may need to be coordinated with the appropriate transmission owner.

One (1) facility was reported on the AECI ties with the addition of the Study Cycle requests. The most severe constraints are shown in Table 5.

Table 5: Steady State Affected Facilities for the Study Cycle Requests

Event	Event	Monitored Facility	Area	Season	Base Loading	Project Loading
AFS01	P1	300098 5MOCITYB2 161.00 541248 LBRTYST5 161.00 1	AECI/KCPL	28L	102.3	107.2
				28S	108.4	115.8
				28W	112.5	116.3
				33S	108.3	115.1
				33W	113.4	117.8

NETWORK UPGRADES

Transmission upgrades were evaluated to mitigate the impacts reported from the analyses as a result of the Study Cycle projects. The upgrades shown in Table 6 were evaluated in order to mitigate the reported steady state constraints for the Study Cycle as listed in Table 3.

Table 6: Network Upgrades for the Study Cycle Constraints

Constraint ID	Monitored Facility	Network Upgrade
NU00A	Sedalia 161 kV Substation Modifications	Modification to Sedalia 161 kV substation required for GEN-2020-072 to interconnect on Windsor-Sedalia 161 kV line
NU00B	Blackberry 345 kV Substation Modifications	Modification to Blackberry 345 kV substation required for GEN-2020-090 to interconnect on Wolf Creek-Blackberry 345 kV line
NU01	300520 2REFORM 69.000 300626 2CHAMOI 69.000 1	CT tap adjustments are able to mitigate overload; no upgrade evaluated.
NU02	301370 5TURKEYCRK 161.00 301401 2TURKEYCRK 69.000 1	Tap adjustments able to mitigate overload; no upgrade evaluated.

The upgrades shown in Table 7 were evaluated in order to mitigate the reported steady state contingent constraints for the Study Cycle requests as listed in Table 4.

Table 7: Network Upgrades for the Study Cycle Contingent Constraints

Constraint ID	Monitored Facility	Network Upgrade
-	300044 7MCCRED 345.00 41454 J1145 POI 345.00 1	**Contingent on MISO Tranche 1:** Build new 345 kV line from Orient 345 kV substation (Ameren) to Fairport 345 kV substation (Ameren/AECI). Build new 345 kV line from Fairport 345 kV substation to Zachary 345 kV substation (Ameren). Build new 345 kV line from Thomas Hill 345 kV substation (AECI) to Zachary 345 kV substation. Build new 345 kV line from Zachary 345 kV substation to Maywood 345 kV substation (Ameren). Build new 345 kV line from Meredosia 345 kV substation (Ameren) to Maywood 345 kV substation. Tap the existing 161 kV line from Adair 161 kV substation to Appanoose 161 kV substation with the Zachary 161 kV substation.
-	300505 2STURGN 69.000 300508 5STURGN 161.00 3	
-	300505 2STURGN 69.000 300508 5STURGN 161.00 4	
-	300045 7MORGAN 345.00 301622 5MORGANXF1 161.00 1	**Contingent on SPP ITP:** Tap the 345 kV line between Brookline and Flint Creek with a new Monett 345 kV station. Build a new 345 kV line between Monett 345 kV and Delaware 345 kV Build a new 345 kV line between Delaware 345 kV and Buffalo 345 kV Install a new 345/161 kV transformer at the Monett 345 kV station. Cut the Compton-Roark 161 kV in and out of the Monett 161 kV station. Cut the Branson-Reeds Spring 161 kV line in and out of the Monett 161 kV station. Cut the Cape Fair-Nixa 161 kV line in and out of the Monett 161 kV station. Install a reactor at on the new 345 kV Monett bus.
-	300101 5MORGAN 161.00 505498 STOCKTN5 161.00 1	
-	300042 7HUBEN 345.00 300088 5HUBEN 161.00 1	

Constraint ID	Monitored Facility	Network Upgrade
CF01	300772 2COFMAN 69.000 300779 2J&7 69.000 1	**Contingent on Tranche 1 Network Upgrades:** Rebuild 69 kV 6.31 mile long line from Coffman Bend to J-7 to 795 ACSR rated at 100C.
CF02	300772 2COFMAN 69.000 300780 2KNOBBY 69.000 1	**Contingent on Tranche 1 Network Upgrades:** Rebuild 69 kV 4.70 mile long line from Coffman Bend to Knobby to 795 ACSR rated at 100C.
CF03	300780 2KNOBBY 69.000 301401 2TURKEYCRK 69.000 1	**Contingent on Tranche 1 Network Upgrades:** Rebuild 69 kV 12.1 mile long line from Knobby to Turkey Creek to 795 ASCR rated at 100 C.
CF04	300541 2SEDALI 69.000 300545 2SYLVAN 69.000 1	**Contingent on GI-091:** Upgrade bushing CTs (via breaker upgrade), breaker switchers on Sylvan-Sedalia 69 kV line (at Sedalia) to 1200 amp rating.
CF05	300530 2GEOGT2 69.000 300541 2SEDALI 69.000 1	**Contingent on GI-091:** Upgrade bushing CTs (via breaker upgrade), breaker switchers on Georgetown-Sedalia 69 kV line (at Sedalia) to 1200 amp rating.
CF06	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 ACSS at 250C. Replace jumpers at St. Francis with 1192 ACSS at 250C. Replace disconnect switches at St. Francis 161 kV (1050, 1850) bus on Jim Hill line with 4000A switches.
CF07	300069 5CHOTEAU1 161.00 512648 MAID 5 161.00 1	**Contingent on SPP DISIS-2017-002:** Construct a new 161 kV switch yard (Patrol Road) on the Maid-Gerald 161 kV line ~1 mile from Maid. (GRDA SCOPE) Replace (4) 69 kV switches and associated jumpers/hardware at Afton Substation. (GRDA Scope) Construct a new 0.8 mile long 161 kV line from Chouteau-Patrol Road switch yard. Construct as double bundle 1590 ACSR at 100C. Assume series reactor installed on line to match impedance of reactor on existing Chouteau-Maid line. All terminal equipment/reactors rated for 4,000 amps. Add 4,000 amp breaker and associated equipment to the existing Chouteau-Maid line at Chouteau. Add a 161 kV terminal and associated equipment at Chouteau for the new 161 kV line to Patrol Road. Upgrade Chouteau West Yard E-W bus from 5" to 6" bus.

No upgrades were evaluated for the neighboring system constraints listed in Table 5. The upgrades for these impacts may need to be resolved through coordination with the transmission owner as listed in Table 8 below.

Table 8: Neighboring System Constraints

Constraint ID	Monitored Facility	Network Upgrade
AFS01	300098 5MOCITYB2 161.00 541248 LBRTYST5 161.00 1	KCPL Owned; no upgrade evaluated. Elements owned by AECI on this line are not overloaded.

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 9.

Table 9: Network Upgrade Costs

ID	Option/Description	Estimated Cost	Estimated Lead Time[2]
NU00A[3]	Modification to Sedalia 161 kV station required for GEN-2020-072 to interconnect on Windsor-Sedalia 161 kV line	$250,000	30 months
NU00B[3]	Modification to Blackberry 345 kV station required for GEN-2020-090 to interconnect on Wolf Creek-Blackberry 345 kV line	$350,000	30 months
NU01	CT tap adjustments are able to mitigate overload; no upgrade evaluated.	$0	-
NU02	Tap adjustments able to mitigate overload; no upgrade evaluated.	$0	-
	Total Cost:	$600,000	

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

[2] 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.
[3] The Study Cycle request connects on a transmission line that terminates at an AECI owned station. This request is responsible for all costs associated with the work required to ready the AECI station for the newly interconnected Study Cycle request.

COST ALLOCATION

Network upgrade costs are allocated to each of the Study Cycle projects based on the worst MW impact[4] 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 in the season it was reported:

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

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

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

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 10. Further breakdown of costs is provided in Appendix B.

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

Table 10: Network Upgrade Cost Allocation

Project	Cluster Group	POI	MW	Estimated Cost
ASGI-2020-001	03 CENTRAL	Waverly 69 kV Substation (Mt. Leonard)	45	**$0**
ASGI-2020-003	03 CENTRAL	Coroltown 161 kV Substation (Bogard)	45	**$0**
GEN-2020-002	02 NEBRASKA	6846 Substation 69 kV	81	**$0**
GEN-2020-007	03 CENTRAL	Evergy La Cygne to Wolf Creek 345kV Substation	650	**$0**
GEN-2020-008	03 CENTRAL	Corporation Carpenter 345kV Substation	250	**$0**
GEN-2020-010	04 SOUTHEAST	Seiling-Taloga Substations 138kV	140	**$0**
GEN-2020-011	02 NEBRASKA	Axtell 345 kV Substation	320	**$0**
GEN-2020-012	04 SOUTHEAST	Snyder to Altus Jct. 138kV	113	**$0**
GEN-2020-013	02 NEBRASKA	Orleans-Holdrege Substation 115kV	215	**$0**
GEN-2020-020	04 SOUTHEAST	Tap the 345 kV Northwest Texarkana - Valliant line	201.6	**$0**
GEN-2020-025	02 NEBRASKA	Substation 1363; 161kV Substation	255	**$0**
GEN-2020-028	02 NEBRASKA	Substation 1363; 161kV Substation	255	**$0**
GEN-2020-031	02 NEBRASKA	Substation 1363; 161kV Substation	303	**$0**
GEN-2020-038	02 NEBRASKA	Substation 3740; 345kV	303	**$0**
GEN-2020-054	04 SOUTHEAST	Lydia 345 kV Station	298	**$0**
GEN-2020-057	03 CENTRAL	Atlantic 345 kV Substation	425	**$0**
GEN-2020-058	03 CENTRAL	Atlantic 345 kV Substation	425	**$0**
GEN-2020-060	05 SOUTHWEST	Lubbock East Substation 230 kV	200	**$0**
GEN-2020-064	03 CENTRAL	4544 Stateline CC 161kV Substation	64	**$0**
GEN-2020-065	05 SOUTHWEST	Hobbs-Andrews 345 kV Line	1003	**$0**
GEN-2020-067	05 SOUTHWEST	Tuco to Yoakum 345kV line	352.5	**$0**
GEN-2020-072	03 CENTRAL	Windsor to AEC Sedalia 161 kV line	150	**$250,000**
GEN-2020-078	02 NEBRASKA	Substation 1226 to Substation 1237, 161kV Tap	100	**$0**
GEN-2020-079	03 CENTRAL	Riverton-Neosho 161kV line	225	**$0**
GEN-2020-081	04 SOUTHEAST	Tenaska Switching Substation 345kV	200	**$0**
GEN-2020-084	02 NEBRASKA	Raun - Fort Calhoun 345 kV	350	**$0**
GEN-2020-087	04 SOUTHEAST	Cimmarron to Lawton 345 kV Line	500	**$0**
GEN-2020-088	03 CENTRAL	La Russell 161 kV Substation	150	**$0**
GEN-2020-090	03 CENTRAL	Wolf Creek - Blackberry 345 kV Substation	204.3	**$350,000**
GEN-2020-092	04 SOUTHEAST	Pryor Junction - Midwest Carbide 138kV line	100	**$0**
GEN-2020-094	02 NEBRASKA	Neb. City - 103rd & Rokeby 345 kV	250	**$0**
			Total	**$600,000**

VERSION HISTORY

Version Number and Date	Author	Change Description
V0 – 02/16/2024	AECI	Initial release
V1 – 08/15/2025	AECI	Re-study with the removal of 15 generators that withdrew from the SPP queue since the initial study.
V2 – 01/21/2026	AECI	Re-study with the removal of 4 generators that withdrew from the SPP queue since the V1 study.
V3 – 06/23/2026	AECI	Sensitivity study with the removal of 2 generators that withdrew from SPP queue since V2 study. This resulted in the removal of a network upgrade.