MISO WEST AFFECTED SYSTEM IMPACT STUDIES
MISO DPP-2017-AUG-WEST

SOUTHWEST POWER POOL, INC.

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ELECTRIC POWER ENGINEERS

ENERGY ENGINEERING EXPERTS

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Document Revisions

NO.	Revision	Date	PRD	CHK	APV
1	Draft Report Issued for Review	12/18/2020	FO	TK	TK
2	Revision 1	01/05/2020	TK	TK	TK

Introduction

MISO requested a preliminary affected system impact study from SPP for the DPP-2017-AUG-West cluster for inclusion in Phase II of the DPP process. The purpose of this analysis was to determine the impact of the MISO generation interconnection requests on the SPP transmission system. Additionally, the analysis looked to identify the amount of Interconnection Service available to the projects resulting in no constraints requiring mitigation. This analysis evaluated twenty-seven MISO interconnection requests in SPP cluster groups 15 and 18 with a total generation capacity of 4,126.78 MW. While results from this analysis will be considered final, a restudy may be required should significant changes to the study assumptions occur[1].

The generation interconnection requests analyzed in this Affected System Impact Study are listed in **Appendix A** by queue number, amount, requested interconnection service type, area, and proposed interconnection point.

The Siemens Power Technologies International PSS/E Version 33.11.0 and PowerGem's TARA 2001 were used for this analysis. SPP provided following DISIS-2017-001 BASE case models:

- Year 2 (2020) Spring (20G)
- Year 5 (2024) Light (24L)
- Year 5 (2024) Summer Peak (24SP)
- Year 5 (2024) Winter Peak (24WP)

EPE updated power flow cases to reflect the groups under study and developed a total of thirty-two (32) cases, specifically 16 Base Cases (BC) and 16 Transfer Cases (TC). The power flow analysis was performed to determine if the transmission system can accommodate the injection from the current study cluster generation interconnection requests without violating SPP's transmission planning criteria outlined below in the Study Methodology Criteria Section.

The Affected System Impact Study (ASIS) has been conducted consistent with the Southwest Power Pool (SPP) Open Access Transmission Tariff (OATT), SPP-MISO Joint Operating Agreement (JOA) and SPP Business Practices to determine definitive impacts to the SPP transmission system.

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

Base Case Model Build and Dispatch

DC Scan

The DC Scan analysis was performed to determine which interconnection requests should be included in the analysis. The Distribution Factor (DF) cut-off criteria used (3%) for DC Scan is based on SPP's Transmission Distribution Factor (TDF) criteria used to identify constraints and mitigations.

The results of DC Scan analysis revealed that all projects from DPP-2017-AUG-West met the DC Screening criteria and hence they were included in the analysis. **Table 1** provides a summary of the DC Scan analysis. Distribution factors were calculated using each project as the "sending" system and the MISO Classic[2] region as the "sink" system. Detailed results for the DC scan can be found in **Table 2**.

Table 1: DC Scan Results by Queue Cluster

Queue Cycle	Region	3% DF Threshold	
		Include	Exclude
Aug-17	West	27	0

Table 2: Detailed DC Scan Results

Results	
DC Scan Detailed Results	DC_Screen_Details.xlsx

Base Case Model Review and Grouping

SPP provided following information to EPE:

1. List of interconnection requests for consideration in the analysis.
2. List of all higher queued interconnection requests.
3. DISIS-2017-001 BASE cases.
4. Latest MISO bench and study cases used for the DPP-2017-AUG-West.
5. Current study network upgrades previously identified by SPP for consideration in the analysis.

The DPP-2017-AUG-West affected system impact study included twenty-seven (27) generation interconnection requests ("GIRs") in the MISO footprint. **Appendix A** lists the current study cluster generation interconnection requests included in the study. The BASE cases are ITP cases that have topology added for all queue generators, but all queue generators are not necessarily dispatched. The MISO West study generators, including all available collector system data, were added, and kept offline in BASE models listed below:

- Year 2 (2020) Spring (20G)
- Year 5 (2024) Light (24L)
- Year 5 (2024) Summer Peak (24SP)
- Year 5 (2024) Winter Peak (24WP)

Higher queued projects were included in the models, including generators in the DISIS-2017-001 cluster or before and DPP Feb-17 and prior. The higher-queued requests included in this study are listed in **Appendix B**. These requests and associated upgrades were added to the BASE models. Note that DISIS-2016-002 Projects

[2] MISO Classic is defined as the PSSE areas of 207, 208, 210, 216, 217, 218, 219, 295, 296, 314, 333, 356, 357, 360, 361, 600, 608, 613, 615, 620, 627, 633, 635, 661, 680, 694, 696, 697, and 698

and Upgrades were already included in the BASE cases. DISIS-2017-001 and DPP Feb-17 upgrades added to the BASE cases are listed in **Appendix C**.

EPE also identified significant deviations[3] between the DISIS-2017-001 BASE cases and the MISO DPP reference cases used for MISO West study. To incorporate updated to the MISO footprint, the MISO shoulder case was used to update MISO representation in the spring and light load seasons. The MISO summer peak case was used to update the MISO representation in the summer and winter peak seasons. The identified topology upgrades in the MISO West area were added to the BASE models. The summary of the identified transmission topology changes that were incorporated is provided in **Appendix D**.

Grouping

The interconnection requests listed in **Appendix A** and **Appendix B** are grouped into sixteen (16) active regional groups. The SPP groupings are listed in **Table 3** below.

Table 3: All SPP Groupings

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

Development of Base Cases (BC Cases)

The number of base and transfer cases required for each impact study depends on the service requested and fuel type of the study units. **Table 4** outlines the number of cases required per seasonal case for each dispatch scenario. **Table 5** describes SPP Dispatch Criteria used for this analysis.

SPP provided the four (4) dispatched seasonal power flow cases. The generation online in the BASE models should reflect the dispatch of the ITP study. The two SPP regional groups (Group 15 and Group 18) then had two types of dispatch for their local generation: High-Variable Energy Resource (HVER) and Network Resource Interconnection Service (NRIS). Additionally, NRIS and LVER dispatches were performed using the entire SPP footprint (Group 00). The groups and the dispatch resulted in 32 cases with unique dispatches, as shown in **Table 4**.

[3] Significant deviations would include additions/removals 161 kV+ facilities, changes to R, X, B, and L > 5% for 161 kV+ facilities, and generation differences > 10 MW for interconnection requests under consideration for inclusion in the analysis.

Table 4: SPP Seasons and Cases per Dispatch

Seasonal Case	ERIS HVER	NRIS HVER Cases (G, L)	NRIS HVER Cases (Peak)	ERIS LVER Cases (Peak)
+1 Spring (i.e., 20G)	1 per group	1 per group	--	--
+5 Light Load (i.e., 24L)	1 per group	1 per group	--	--
+5 Summer Peak (i.e., 24SP)	1 per group	--	1 per study	1 per study
+5 Winter Peak (i.e., 24WP)	1 per group	--	1 per study	1 per study
Total Cases	**8 Cases**	**4 Cases**	**2 Cases**	**2 Cases**
DPP-2017-AUG-West	**32 Cases (16 BC/16 TC)**			

All in-scope higher queued SPP and MISO generators listed in the **Appendix B** were added and dispatched per SPP's Generation Dispatch Procedure criteria[4].

Development of Analysis Cases (TC Cases)

All in-scope higher-queued and current study interconnection requests were dispatched as per criteria listed in **Table 5**. For existing SPP interconnection requests included in the scope, if the existing generation dispatch (P_{GEN}) was greater than the expected GI dispatch criteria, the generation was left as-is. If the existing generation dispatch (P_{GEN}) was less than the expected GI dispatch criteria, it was dispatched up to the defined amount.

Generation adjustments are dispatched against Legacy[5] conventional generation[6] in the host TO footprint. For the High Variable Energy Resource (HVER) dispatch scenario, all renewable generation facilities are dispatched to 100% within the studied group and at least 20% outside of the study group. Legacy resources and higher-queued conventional units are used to balance generation changes in the HVER scenarios. For the Light Load condition only, renewables are dispatched at or above 0% capacity outside of the study group. Out-group renewables may also be used to balance generation changes in addition to legacy and higher-queued conventional units for this scenario. The HVER dispatch scenario was used with all cases including Winter, Summer, Spring, and Light Load DISIS BASE cases.

For the Low Variable Energy Resource (LVER) dispatch scenario, all conventional generation facilities are dispatched to 100%. The code 00 for this scenario represents that the entire SPP footprint is included as being in-group. Legacy resources are used to balance generation changes. The LVER dispatch scenario is utilized in Winter and Summer DISIS BASE cases, but only used if there is a conventional resource in the current study.

For the Network Resource (NR) dispatch scenario, the dispatch levels for the renewable and conventional generation facilities are determined based upon the level of system integration being requested (ERIS and NRIS). For Spring and Light Load, dispatches are group based. For Winter and Summer, the entire SPP footprint is considered "in-group" for the study (like the LVER dispatch scenario). Legacy resources are used to balance generation changes.

[4] Please refer to SPP's Definitive Interconnection System Impact Study Manual

[5] Generators that are found in the SPP footprint in the DISIS BASE cases that do not map to the SPP generator mapping sheet are considered "Legacy" generators.

[6] Excluding non-adjustable generation such as hydro/run-of-river

Each current study interconnection request was included in the power flow analysis models as an equivalent generator dispatched at the applicable percentage of the requested service amount with 0.95 power factor capability. The facility modeling includes explicit representation of equivalent Generator Step-Up (GSU) and main project transformer(s) with impedance data provided in the interconnection request. All equivalent collector system branches and transmission tie-lines shorter than 20 miles in length are modeled as zero-impedance branches.

Table 5 : SPP Dispatch Criteria

Dispatch Type	Season	Service Type	Variable Energy Resource In Group	Variable Energy Resource Out Group	Conventional In Group	Conventional Out Group
ERIS HVER	All	All	100%	20%*	N/A	N/A
ERIS LVER	Peak	All	20%	20%	100%	100%
NRIS	Spring and Light Load	ERIS	80%	20%	N/A	N/A
		NRIS	100%	20%	100%	20%
	Peak	ERIS	20% (solar: 80% in SP)	20% (solar: 80% in SP)	80%	80%
		NRIS	100%	100%	100%	100%
* 0% for DISIS-2017-001 forward						

Study Methodology Criteria

Solve Parameters

The following solution parameters were used:

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

Thermal Overloads

Network constraints are found by using PowerGEM TARA AC Contingency Calculation (ACCC) analysis on the entire cluster grouping dispatched at the various levels.

For Energy Resource Interconnection Service (ERIS):

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

The overloads are then screened to determine which of generator interconnection requests have at least

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

Non-converged contingencies shall also be considered for limited operation service.

For Network Resource Interconnection Service (NRIS):

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

Contingencies

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

- All branches, ties, shunts, and generators within the following areas:
  - SPP Internal Areas for 60kV – 999kV facilities:
    - 515 – 546, 640, 641, 642, 645, 650, 652, 659. 998, 999
  - SPP External Areas for 100kV – 999kV facilities:
    - 327, 330, 351, 356, 502-504, 600, 615, 620, 627, 635, 672, 680
- NERC, SPP, and Tier 1 Permanent Contingent Flowgates
- SPP T.O. Specific P1, P2, P4, and P5 TPL-004-1 Contingencies
- SPP T.O. Specific Op Guide Implementation

Monitored Facilities

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

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

Voltage

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

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

SPP Areas (69kV+):

<table>
<tr><th>Transmission Owner</th><th>Voltage Criteria (System Intact)</th><th>Voltage Criteria (Contingency)</th></tr>
<tr><td>AEPW</td><td rowspan="17">0.95 – 1.05 pu</td><td>0.92 – 1.05 pu</td></tr>
<tr><td>GRDA</td><td rowspan="14">0.90 – 1.05 pu</td></tr>
<tr><td>KACY</td></tr>
<tr><td>SWPA</td></tr>
<tr><td>OKGE</td></tr>
<tr><td>OMPA</td></tr>
<tr><td>WFEC</td></tr>
<tr><td>SWPS</td></tr>
<tr><td>MIDW</td></tr>
<tr><td>SUNC</td></tr>
<tr><td>KCPL</td></tr>
<tr><td>INDN</td></tr>
<tr><td>SPRM</td></tr>
<tr><td>NPPD</td></tr>
<tr><td>WAPA</td></tr>
<tr><td>WERE L-V</td><td>0.93 – 1.05 pu</td></tr>
<tr><td>WERE H-V</td><td>0.95 – 1.05 pu</td></tr>
</table>

EMDE L-V		0.90 – 1.05 pu
EMDE H-V		0.92 – 1.05 pu
LES		0.90 – 1.05 pu
OPPD		

SPP Buses with more stringent voltage criteria:

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

Affected System Areas (115kV+):

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

ALTW	0.95 – 1.05 pu	0.90 – 1.05 pu
MEC		
MDU		
SPC		0.95 – 1.05 pu
DPC		0.90 – 1.05 pu
ALTE		

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

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

Identification of Network Constraints

ERIS Thermal Non-Converged Constraint Identification and Mitigation

ERIS non-converged constraints were observed for single contingency (N-1) conditions. **Table 6** below summarizes non-converged constraints and associated mitigations.

Table 6: Non-Converged ERIS Contingencies

Contingency	Mitigation
P12:345:OTP:AUTO-SINGLE:CENTER3:COYOTE3:1	MISO SPS at Coyote runs back generation for this outage
P21:345:OTP:AUTO-SINGLE:CENTER3:COYOTE3:1	
P13:41-115:OTP:AUTO-SINGLE:JAMESPK9:JAMESPK7:1	Adjust voltage schedules and shunts
P45:345:UMZW:# 1327 #: FT2 IN SD.	Reconfigure/add breakers at Ft. Thompson to protect against P4 loss of substation
601031 BRKNGCO3 345 620483 ASTORIA 3 345 1	New Astoria to Hazel Creek 345 kV Circuit

ERIS Thermal System Intact and Contingency Constraint Identification and Mitigation

Several ERIS thermal constraints were identified for single contingency (N-1) conditions. **Table 7** below summarizes ERIS thermal constraints and associated mitigations.

Table 7: ERIS Thermal Constraints

Monitored Facility	Mitigation
652437 GRNDFKS4 230 652443 GRNDFKS7 115 XFMR	Second 230/115 kV Transformer at GRNDFKS4/GRNDFKS7
652296 WARD 4 230 652426 BISMARK4 230 1	Rebuild WARD 4 to BISMARK 4 230 kV Circuit
601006 SPLT RK3 345 652864 SIOUXCY-LNX3 345 1	Upgrade Terminal Equipment at SPLT RK3 to SIOUXCY-LNX3 345 kV Circuit
652437 GRNDFKS4 230 657755 PRAIRIE4 230 1	Rebuild GRNDFKS4 to PRAIRIE4 230 kV Circuit
601006 SPLT RK3 345 652537 WHITE 3 345 1	Upgrade Terminal Equipment at SPLT RK3 to WHITE 3 345 kV Circuit
	New Astoria to Hazel Creek 345 kV Circuit

ERIS Voltage Constraint Identification and Mitigation

There were no voltage constraints identified for Group 15 or 18 ERIS interconnection requests.

NRIS Thermal Non-Converged Constraint Identification and Mitigation

NRIS non-converged constraints were observed for single contingency (N-1) conditions. **Table 8** below summarizes non-converged constraints and associated mitigations.

Table 8: Non-Converged NRIS Contingencies

Contingency	Mitigation
601044 BRIGGS RD 3 345 999044 BGG_SCAP 345 1	Add Var support at Briggs Road 345 kV
635580 ARBR HL 3 345 635590 FALLOW 3 345 1	Build 2nd MISO Colby - Killdeer - Quinn - J873 - Blackhawk - Hazlton 345 kV circuit
635580 ARBR HL 3 345 635622 RCCN TRL 3 345 1	
635740 DIAMOND TRL3 345 636399 HILLS-DT-RX3 345 1	
636399 HILLS-DT-RX3 345 636400 HILLS 3 345 Z	
88731 J873 POI 345 636199 BLACKHAWK 3 345 1	
P12:345:MEC:HILLS-MONTEZUMA + REACTOR	
P12:345:MEC:SYCAMORE-BONDURANT-GDMEC	
P23:345:AMMO::ZACHARY:2	
P23:345:MEC:HILLS 924	
P12:345:MPC:JAMESTOWN-BISON:JAMESTN3:BISON 3	Build Second Circuit CENTER 3 to JAMESTN3 to BUFFALO3 to BISON 3 345 kV
P12:345:OTP:AUTO-SINGLE:BUFFALO3:JAMESTN3:1	
P12:345:XEL-OTP:AUTO-SINGLE:BISON3:BUFFALO3:1	
P21:345:OTP:AUTO-SINGLE:BUFFALO3:JAMESTN3:1	
P21:345:XEL-OTP:AUTO-SINGLE:BISON3:BUFFALO3:1	
P23:345:MPC:BISON 3:6720	
P23:345:OTP:BUFFALO3:3615:V2016	
P23:345:OTP:BUFFALO3:3655:V2016	
P23:345:OTP:JAMESTN3:3135:V2020	
P23:345:OTP:JAMESTN3:3145:V2020	
P12:345:OTP:AUTO-SINGLE:CENTER3:COYOTE3:1	MISO SPS at Coyote runs back generation for this outage
P21:345:OTP:AUTO-SINGLE:CENTER3:COYOTE3:1	
601031 BRKNGCO3 345 620483 ASTORIA 3 345 1	New Astoria to Hazel Creek 345 kV Circuit
P45:345:UMZW:# 1327 #: FT2 IN SD.	Reconfigure/add breakers at Ft. Thompson to protect against P4 loss of substation

NRIS Thermal System Intact and Contingency Constraint Identification and Mitigation

Several NRIS thermal constraints were identified for single contingency (N-1) and multiple contingency conditions. The **Table 9** below summarizes NRIS thermal constraints and associated mitigations.

Table 9: NRIS Thermal Constraints

Monitored Facility	Mitigation
530583 POSTROCK7 345 530584 POSTROCK6 230 1	Replace 345/230 kV Transformer at Postrock
660000 ABDNJCT7 115 661027 ELLENDL7 115 1	Rebuild ABDNJCT7 to ELLENDL7 115 kV Rebuild ABDNJCT7 to ABDNSBT7 115 kV

Monitored Facility	Mitigation
652443 GRNDFKS7 115 657706 FALCONR7 115 1	Rebuild GRNDFKS7 to FALCONR7 115 kV
655487 SULLYBT-ER4 230 655510 SB.LS-WK-ER4 230 Z 655510 SB.LS-WK-ER4 230 655765 WHITLOCK_-RM 230 1	Rebuild SULLYBT-ER4 - SB.LS-WK-ER4 230 kV Rebuild SB.LS-WK-ER4 to WHITLOCK_-RM 230 kV
620263 FORMN 7 115 652438 FORMAN 7 115 1	Rebuild FORMN 7 - FORMAN 7 115 kV
640540 MEADOWGROVE4 230 652509 FTRANDL4 230 1	Rebuild MEADOWGROVE4 - FTRANDL4 230 kV
640377 TEKAMAH5 161 646226 S1226 5 161 1 640377 TEKAMAH5 161 991050 G17-105-TAP 161 1 652499 CAMPBELL 4 230 661038 GLENHAM4 230 1 652519 OAHE 4 230 655487 SULLYBT-ER4 230 1 652552 SIOUXCY2 230 652565 SIOUXCY4 230 Z 652552 SIOUXCY2 230 652565 SIOUXCY4 230 Z2 655765 WHITLOCK_-RM 230 661038 GLENHAM4 230 1	Build Second Circuit from RAUN 3 - S3451 3 345 kV Upgrade Terminal Equipment S345 1 to S3454 345 kV Circuit
631048 EMERY 5 161 656201 SHEFFLD5 161 1 636200 BLACKHAWK 5 161 656087 BREMER CO5 161 1 636230 FRANKLN5 161 656207 HAMPTONTAP5 161 1 636300 FLOYD 5 161 656087 BREMER CO5 161 1 656051 NEWHAMPM G 69.0 680317 WAPSI 69.0 1 656201 SHEFFLD5 161 656207 HAMPTONTAP5 161 1	Build Second Circuit from COLBY3 to KILLDEER3 to QUINN3 345 kV to J873 POI to BLACKHAWK 3 to HAZLTON3 345 kV
659101 ANTELOPE-BE3 345 659420 AV.LS-BD-BE3 345 Z 659120 BROADLND-BE3 345 659421 BD.LS-AV-BE3 345 Z 659420 AV.LS-BD-BE3 345 659421 BD.LS-AV-BE3 345 1	Upgrade Terminal Equipment ANTELOPE-BE3 to AV.LS-BD-BE3 to BD.LS-AV-BE3 to to BROADLND-BE3 345 kV Circuit
602006 SHEYNNE4 230 652435 FARGO 4 230 1 652435 FARGO 4 230 652444 JAMESTN4 230 1 652435 FARGO 4 230 652444 JAMESTN4 230 2	Build Second Circuit CENTER 3 to JAMESTN3 to BUFFALO3 to BISON 3 345 kV
589024 G17-064-TAP 230 652484 NUNDRWD4 230 1 601006 SPLT RK3 345 652864 SIOUXCY-LNX3 345 1 602004 SPLT RK4 230 652523 SIOUXFL4 230 1 631183 CAYLER5 161 656570 WISDOM5 161 1 635223 PLYMOTH5 161 652566 SIOUXCY5 161 1 652506 FTTHOMP3 - 652507 FTTHOMP4 345/230 kV XFMR 652509 FTRANDL4 230 652526 UTICAJC4 230 1 652523 SIOUXFL4 230 659311 PAHOJA__-BE4 230 1 659311 PAHOJA__-BE4 230 659900 EAGLE___-NI4 230 1	Build Second Circuit from SPLT RK3 to SIOUXCY-LNX3 to SIOUXCY3 345 kV Build Second Circuit from HOLT to GRPRAIRIE 345 kV Build Second Circuit from RAUN to SIOUXCY 3 345 kV
652474 AURORA 7 115 652504 BROOKNG7 115 1	Rebuild FLANDRU7 to AURORA 7 to BROOKNG7 115 kV Circuit
602009 MNVLTAP4 230 652550 GRANITF4 230 1	Rebuild MINVALT4 to GRANITF4 230 kV Circuit
603030 MINVALY7 115 652551 GRANITF7 115 1	Rebuild MINVALY7 to GRANITF7 115 kV Circuit

Monitored Facility	Mitigation
619975 GRE-WILLMAR4 230 652550 GRANITF4 230 1	Rebuild GRE-WILLMAR4 to GRANITF4 230 kV Circuit
602008 MINVALT4 230 652550 GRANITF4 230 1 620314 BIGSTON4 230 655465 BLAIR-ER4 230 1 652550 GRANITF4 230 655465 BLAIR-ER4 230 1	Build Second Circuit BSSOUTH to DEUEL CO 3 345 kV Build Second Circuit from ASTORIA to HAZEL CREEK 345 kV
652427 BISMARK7 115 661029 ESTBMRK7 115 1	Rebuild BISMARK7 to ESTBMRK7 115 kV Circuit
345408 7OVERTON 345 541201 SIBLEY 7 345 1	Rebuild OVERTON to SIBLEY 345 kV Circuit

NRIS Voltage Constraint Identification and Mitigation

There were no voltage constraints identified for Group 15 or 18 NRIS interconnection requests after accounting for network upgrades associated with non-convergence and thermal issues.

Network Upgrade Cost Estimates, Alternative Solutions, and Limited Operation Availability

Network Upgrade Cost Estimates

Preliminary cost estimates provided in this analysis are subject to change.

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

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

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

Allocation of Cost for a particular project:

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

Repeat previous for each responsible GI request for each Project.

If the current study interconnection request requires a network upgrade for full interconnection service, the study resource will determine the Limited Operation amount available to the request prior to all required network upgrades being in-service. **Table 10** lists the allocated costs for Network Upgrades assigned to current study projects.

It should be noted that network upgrades associated with higher-queued projects are also considered as contingent upgrades. These facilities have been included in the models for this study and are assumed to be in service. This list may not be all-inclusive. The interconnection customers, at this time, do not have cost responsibility for these facilities but may later be assigned cost if higher-queued customers terminate their generation

Table 10: Network Upgrade Cost Estimates

Interconnection Request	Project Size (MW)	ERIS	NRIS	Total	ERIS Total	NRIS Total	Total
J545	110	$6,390,845	$32,469,863	$38,860,708	$144,521,188	$1,426,243,782	$1,570,764,970
J580	298	$19,446,106	$0	$19,446,106			
J628	400	$14,790,414	$148,236,421	$163,026,835			
J705	100	$4,435,188	$70,059,305	$74,494,493			
J706	100	$4,435,188	$70,059,305	$74,494,493			
J713	300	$13,305,564	$210,177,914	$223,483,478			
J720	200	$0	$48,699,911	$48,699,911			
J722	200	$23,624,496	$92,441,809	$116,066,305			
J785	105	$0	$26,623,038	$26,623,038			
J801	74	$10,821	$9,504,535	$9,515,356			
J803	32.5	$1,710,190	$0	$1,710,190			
J816	60	$1,258,861	$41,154,512	$42,413,373			
J836	200	$0	$0	$0			
J840	150	$0	$34,212,765	$34,212,765			
J873	200	$0	$94,244,425	$94,244,425			
J874	150	$3,569,462	$45,564,314	$49,133,775			
J877	250	$0	$60,459,128	$60,459,128			
J885	64	$0	$14,624,732	$14,624,732			
J897	190	$7,008,189	$73,226,568	$80,234,757			
J898	100	$0	$10,917,460	$10,917,460			
J901	200	$445,030	$48,894,553	$49,339,583			
J905	40	$2,323,944	$11,807,223	$14,131,166			
J916	2	$0	$503,292	$503,292			
J926	101.28	$15,627	$13,300,115	$13,315,742			
J927	100	$0	$22,543,972	$22,543,972			
J933	200	$37,992,071	$123,672,178	$161,664,249			
J946	200	$3,759,194	$122,846,445	$126,605,640			

Alternative Solutions

To identify the final network upgrades, numerous combinations and options were tested for effectiveness. Reasons for not opting for the alternative solutions include higher cost and limited ability to mitigate identified constraints.

Table 11: Alternative Solutions

Type	Constraint(s)	Mitigation	Alternative
Nconv	601031 BRKNGCO3 345 620483 ASTORIA 3 345 1	New Astoria to Hazel Creek 345 kV Circuit	Rebuild Split Rock - White 345 kV Add a 2nd Astoria - Brookings County 345 kV
ERIS	601006 SPLT RK3 345 652537 WHITE 3 345 1		
Nconv	635580 ARBR HL 3 345 635590 FALLOW 3 345 1	Build 2nd MISO Colby - Killdeer - Quinn - J873 - Blackhawk - Hazlton 345 kV	Loss of any part of the 345 kV path from Colby to Hazleton pushes significant power onto the 161 kV system in the Northern part of Iowa and South Minnesota, resulting in severe overloads and a non-converging system. A majority of the 161 kV paths in this area would require double circuits or more to support the area. Line mileage well exceeded double the length of adding a 2nd Colby - Hazleton line. Additional alternatives included segments of the proposed mitigation in addition to 345 kV segments from Colby to Adams or Webster to J873 POI
	635580 ARBR HL 3 345 635622 RCCN TRL 3 345 1		
	635740 DIAMOND TRL3 345 636399 HILLS-DT-RX3 345 1		
	636399 HILLS-DT-RX3 345 636400 HILLS 3 345 Z		
	88731 J873 POI 345 636199 BLACKHAWK 3 345 1		
	P12:345:MEC:HILLS-MONTEZUMA + REACTOR		
	P12:345:MEC:SYCAMORE-BONDURANT-GDMEC		
	P23:345:AMMO::ZACHARY:2		
	P23:345:MEC:HILLS 924		
NRIS	631048 EMERY 5 161 656201 SHEFFLD5 161 1 636200 BLACKHAWK 5 161 656087 BREMER CO5 161 1 636230 FRANKLN5 161 656207 HAMPTONTAP5 161 1 636300 FLOYD 5 161 656087 BREMER CO5 161 1 656051 NEWHAMPM G 69.0 680317 WAPSI 69.0 1 656201 SHEFFLD5 161 656207 HAMPTONTAP5 161 1		

Type	Constraint(s)	Mitigation	Alternative
Nconv	P12:345:MPC:JAMESTOWN-BISON:JAMESTN3:BISON 3 P12:345:OTP:AUTO-SINGLE:BUFFALO3:JAMESTN3:1 P12:345:XEL-OTP:AUTO-SINGLE:BISON3:BUFFALO3:1 P21:345:OTP:AUTO-SINGLE:BUFFALO3:JAMESTN3:1 P21:345:XEL-OTP:AUTO-SINGLE:BISON3:BUFFALO3:1 P23:345:MPC:BISON 3:6720 P23:345:OTP:BUFFALO3:3615:V2016 P23:345:OTP:BUFFALO3:3655:V2016 P23:345:OTP:JAMESTN3:3135:V2020 P23:345:OTP:JAMESTN3:3145:V2020	Build 2nd CENTER 3 to JAMESTN3 to BUFFALO3 to BISON 3 345 kV	Rebuild entire double circuit 230 kV path from Center to Bison
NRIS	602006 SHEYNNE4 230 652435 FARGO 4 230 1 652435 FARGO 4 230 652444 JAMESTN4 230 1 652435 FARGO 4 230 652444 JAMESTN4 230 2		
NRIS	640377 TEKAMAH5 161 646226 S1226 5 161 1 640377 TEKAMAH5 161 991050 G17-105-TAP 161 1 652499 CAMPBELL 4 230 661038 GLENHAM4 230 1 652519 OAHE 4 230 655487 SULLYBT-ER4 230 1 652552 SIOUXCY2 230 652565 SIOUXCY4 230 Z 652552 SIOUXCY2 230 652565 SIOUXCY4 230 Z2 655765 WHITLOCK_-RM 230 661038 GLENHAM4 230 1	Build 2nd Circuit from RAUN 3 - S3451 3 345 kV Upgrade Terminal Equipment S3451 to S3454 345 kV	Build 2nd high-capacity S1226 - Tekamah - Raun 161 kV Rebuild/2nd Campbell - Glenham 230 kV Rebuild/2nd Oahe - Sully Butte 230 kV Rebuild/2nd Whitlock - Glenham 230 kV Upgrade Sioux City 230 kV substation design

Type	Constraint(s)	Mitigation	Alternative
NRIS	589024 G17-064-TAP 230 652484 NUNDRWD4 230 1 601006 SPLT RK3 345 652864 SIOUXCY-LNX3 345 1 602004 SPLT RK4 230 652523 SIOUXFL4 230 1 631183 CAYLER5 161 656570 WISDOM5 161 1 635223 PLYMOTH5 161 652566 SIOUXCY5 161 1 652506 FTTHOMP3 - 652507 FTTHOMP4 345/230 kV XFMR 652509 FTRANDL4 230 652526 UTICAJC4 230 1 652523 SIOUXFL4 230 659311 PAHOJA__-BE4 230 1 659311 PAHOJA__-BE4 230 659900 EAGLE___-NI4 230 1	Build 2nd SPLT RK3 to SIOUXCY-LNX3 345 kV Build 2nd SIOUXCY-LNX3 to SIOUXCY3 345 kV Build 2nd HOLT to GRPRAIRIE 345 kV Build 2nd RAUN to SIOUXCY 3 345 kV	Numerous combinations of the following: Rebuild/New Pahoja - Eagle 230 kV Rebuild/New Sioux Falls - Pahoja 230 kV New Utica - Meadow Grove 230 kV New Hoskins - S3451 345 kV New Hoskins - Broadland 345 kV New Ft. Thompson - Watertown 345 kV New Ft. Thompson - Raun 345 kV New Ft. Thompson - Split Rock 345 kV New 345/230 kV substation at Ft. Randall
NRIS	602008 MINVALT4 230 652550 GRANITF4 230 1 620314 BIGSTON4 230 655465 BLAIR-ER4 230 1 652550 GRANITF4 230 655465 BLAIR-ER4 230 1	Build 2nd BSSOUTH to DEUEL CO 3 345 kV Build 2nd ASTORIA to HAZEL CREEK 345 kV	New Big Stone - Hazel Creek 345 kV or New Big Stone - Granite Falls 230 kV
NRIS	345408 7OVERTON 345 541201 SIBLEY 7 345 1	Rebuild OVERTON to SIBLEY 345 kV Circuit	Build a new circuit from Fairport to Thomas Hill or Build a 2nd Overton - Sibley 345 kV circuit

Limited Operation Availability

The results of the Power Flow identified the system constraints that require mitigation. The Limited Operation Analysis evaluated the most limiting of these constraints for each current study request and identifies an amount of available interconnection service.

Power Flow Analysis results included the thermal overload amount, circuit rating, size and TDF of each current study request. An initial Limited Operation amount is calculated by identifying the impact of each request on each constraint and identifying a reduced size of each request proportional to the thermal constraint that would result in a circuit loading within the applicable rating. The Limited Operation amount is calculated according to the following equation:

$$\text{Limited Operation amount} = \text{Request MW} - \frac{\text{MVA Rating} * (\text{Overload PU} - 1)}{\text{Request TDF}}$$

With the initial Limited Operation amount request sizes applied to the study cases, ACCC is repeated to verify that the thermal constraints are not observed, or the calculation and verification is repeated until all thermal constraints are mitigated.

Power Flow Analysis results for voltage violations are then further mitigated by identifying the contribution of each request and determination of the required impact reduction is conducted and verified through ACCC to determine the Power Flow Analysis Limited Operation amount for each request.

Limited Operation Results are listed below in **Table 12**. While these results are based on the criteria listed in GIP 8.4.3, the Interconnection Customers may request additional scenarios for Limited Operation based on higher-queued Interconnection Requests not being placed in service.

Table 12: Limited Operation Results

Interconnection Request	Group	Service Type	Available MW Before Mitigation	Most Limiting Constraint
J545	15 E-SD	ERIS	0	NonConv, Split Rock - White 345 kV
		NRIS	0	Iowa NonConv
J580	18 E-ND	ERIS	0	NonConv, Split Rock - White 345 kV
J628	18 E-ND	ERIS	0	NonConv, Split Rock - White 345 kV
		NRIS	0	Iowa NonConv, ND NonConv
J705	18 E-ND	ERIS	0	NonConv, Split Rock - White 345 kV
		NRIS	0	Iowa NonConv, ND NonConv
J706	18 E-ND	ERIS	0	NonConv, Split Rock - White 345 kV
		NRIS	0	Iowa NonConv, ND NonConv
J713	18 E-ND	ERIS	0	NonConv, Split Rock - White 345 kV
		NRIS	0	Iowa NonConv, ND NonConv
J720	15 E-SD	ERIS	200	None
		NRIS	0	Iowa NonConv
J722	15 E-SD	ERIS	0	NonConv, Split Rock - White 345 kV
		NRIS	0	Iowa NonConv, ND NonConv
J785	15 E-SD	ERIS	105	None
		NRIS	0	Iowa NonConv
J801	15 E-SD	ERIS	0	Split Rock - White 345 kV
		NRIS	0	Iowa NonConv
J803	15 E-SD	ERIS	0	NonConv, Split Rock - White 345 kV

Interconnection Request	Group	Service Type	Available MW Before Mitigation	Most Limiting Constraint
J816	18 E-ND	ERIS	0	NonConv, Split Rock - White 345 kV
		NRIS	0	Iowa NonConv, ND NonConv
J836	15 E-SD	ERIS	200	None
J840	15 E-SD	ERIS	150	None
		NRIS	0	Iowa NonConv
J873	15 E-SD	ERIS	200	None
		NRIS	0	Iowa NonConv
J874	15 E-SD	ERIS	0	NonConv, Split Rock - Sioux City 345 kV
		NRIS	0	Iowa NonConv
J877	15 E-SD	ERIS	250	None
		NRIS	0	Iowa NonConv
J885	15 E-SD	ERIS	64	None
		NRIS	0	Iowa NonConv
J897	18 E-ND	ERIS	0	NonConv, Split Rock - White 345 kV
		NRIS	0	Iowa NonConv, ND NonConv
J898	15 E-SD	ERIS	100	None
		NRIS	0	Iowa NonConv
J901	15 E-SD	ERIS	0	NonConv, Split Rock - White 345 kV
		NRIS	0	Iowa NonConv
J905	15 E-SD	ERIS	0	NonConv, Split Rock - White 345 kV
		NRIS	0	Iowa NonConv
J916	15 E-SD	NRIS	0	Iowa NonConv
J926	15 E-SD	ERIS	0	Split Rock - White 345 kV
		NRIS	0	Iowa NonConv
J927	15 E-SD	ERIS	100	None
		NRIS	0	Iowa NonConv
J933	15 E-SD	ERIS	0	NonConv, Split Rock - White 345 kV
		NRIS	0	Iowa NonConv
J946	18 E-ND	ERIS	0	NonConv, Split Rock - White 345 kV
		NRIS	0	Iowa NonConv, ND NonConv

Power Flow Analysis

The results of the power flow analysis for interconnection requests under study are embedded in **Table 12**.

Table 13: Power Flow Analysis Results

Results	
Non-Convergence	AUG17_Non_Convergence.xlsx
Thermal Constraints	AUG17 Thermal Constraints.xlsx
Network Upgrades and Cost Allocation Calculations	AUG17_Network_Upgrades_Cost_Alloc

Conclusion

A power flow analysis was performed to determine the impact of twenty-seven (27) MISO GIRs on the SPP transmission system. The results of the Power Flow analysis identified the system constraints that require mitigation. The Limited Operation Analysis evaluated the most limiting of these constraints for each current study request and identified an amount of available interconnection service. The minimum cost of interconnecting all new generation interconnection requests included in this analysis is estimated at $1.574 billion. Allocated costs for Network Upgrades are listed in **Table 10**.

The study results identified several ERIS constraints. Full ERIS interconnection service capacity is available for projects J720, J785, J836, J840, J873, J877, J885, J898, and J927 as they do not have identified ERIS constraints/upgrades. All other Aug-17 projects require ERIS upgrades to be in service before interconnection service is available. No Aug-17 generator projects have any NRIS Service capacity available until identified upgrades are in service.

Appendix A: Current Study Interconnection Requests

Generation Interconnection Number	Study	Group	Type	G PMAX	SP PMAX	WP PMAX	Service	GEN Area	Point of Interconnection
J873	DIS-17-2-PQ	15 E-SD	Wind	200	200	200	ER/NR	MEC	QUINN3
J898	DIS-17-2-PQ	15 E-SD	Wind	100	100	100	ER/NR	DPC	RICE 5
J840	DIS-17-2-PQ	15 E-SD	Wind	150	150	150	ER/NR	MEC	WEBSTER3
J836	DIS-17-2-PQ	15 E-SD	Wind	200	200	200	ER	ALTW	LEDYARD3
J877	DIS-17-2-PQ	15 E-SD	Solar	250	250	250	ER/NR	MEC	PALO ALTO 3
J885	DIS-17-2-PQ	15 E-SD	Wind	64	64	64	ER/NR	ALTW	FREEBRN WF 5
J916	DIS-17-2-PQ	15 E-SD	Diesel	2	2	2	ER/NR	ALTW	GRE-MNTN LK8
J927	DIS-17-2-PQ	15 E-SD	Wind	100	100	100	ER/NR	ALTW	WALTERS8
J720	DIS-17-2-PQ	15 E-SD	Wind	200	200	200	ER/NR	ALTW	LAKEFLD3
J785	DIS-17-2-PQ	15 E-SD	Wind	105	105	105	ER/NR	ALTW	LAKEFLD3
J545	DIS-17-2-PQ	15 E-SD	Wind	110	110	110	ER/NR	XEL	BUFFRID7
J803	DIS-17-2-PQ	15 E-SD	Solar	32.5	32.5	32.5	ER	XEL	TRACYSW8
J874	DIS-17-2-PQ	15 E-SD	Solar	150	150	150	ER/NR	XEL	FENTON 7
J905	DIS-17-2-PQ	15 E-SD	Solar	40	40	40	ER/NR	XEL	BUFFRID7
J901	DIS-17-2-PQ	15 E-SD	Wind	200	200	200	ER/NR	XEL	GRE-CEDRMT23
J722	DIS-17-2-PQ	15 E-SD	Wind	200	200	200	ER/NR	OTP	BSSOUTH4
J933	DIS-17-2-PQ	15 E-SD	Wind	200	200	200	ER/NR	OTP	BSSESHUNT3
J801	DIS-17-2-PQ	15 E-SD	Solar	74	74	74	ER/NR	DPC	CRYSTAL5
J926	DIS-17-2-PQ	15 E-SD	Wind	101.28	101.28	101.28	ER/NR	XEL	J926 POI
J580	DIS-17-2-PQ	18 E-ND	Wind	298	298	298	ER	MDU	HESKETT4
J946	DIS-17-2-PQ	18 E-ND	Solar	200	200	200	ER/NR	XEL	BISON 3
J816	DIS-17-2-PQ	18 E-ND	Solar	60	60	60	ER/NR	OTP	BUFFALO7

Generation Interconnection Number	Study	Group	Type	G P_{MAX}	SP P_{MAX}	WP P_{MAX}	Service	GEN Area	Point of Interconnection
J897	DIS-17-2-PQ	18 E-ND	Wind	190	190	190	ER/NR	GRE	PRAIRIE4
J628	DIS-17-2-PQ	18 E-ND	Wind	400	400	400	ER/NR	GRE	PRAIRIE4
J705	DIS-17-2-PQ	18 E-ND	Wind	100	100	100	ER/NR	MP	TRICNTY4
J706	DIS-17-2-PQ	18 E-ND	Wind	100	100	100	ER/NR	MP	TRICNTY4
J713	DIS-17-2-PQ	18 E-ND	Wind	300	300	300	ER/NR	MP	SQBEAST4

Appendix B: Higher Queued Interconnection Requests

Higher Queued
Projects.xlsx

Appendix C: DISIS-2017-001 and DPP Feb-17 Network Upgrades

Higher Queued
Network Upgrades.x

Appendix D: MISO Topology Updates included in this Analysis

Description	Area Number	kV
Add 2nd 345-161 kV transformer at Sub 39	635	345/161
New Beehive 345/138 kV Substation	356	345/138
Rebuild Messenger - Carbide 69 kV to double circuit	356	69
New Cardinal - Hickory Creek 345 kV	600	138
Rebuild Triboji - Orleans Tap 69kV line	635	69
New Elisha 115/34.5 kV substation using Hubbard transformer	608	115/34.5
Build 115 kV line from Potato Lake tap to Arago distribution substation.	608	115
Construct a new substation in the Hills area.	627	345/69
Construct a new 3 terminal switch station near Lyon	652	69
New 69 kV line to add the new Marion South sub.	627	69
Install 345/138 kV transformer at Gateway	357	345/138
Replace161 kV circuit breaker at Bondurant Substation	635	161
New 115 kV substation yard adjacent to the Boswell 230 kV yard. A new 230/115 kV transformer will connect both yards.	608	230/115
New +/-75 MVAR STATCOM	608	115
Build a new 115 kV line from the MP Big Rock substation to the GRE Waldo substation	608	115
Extend existing Forbes - Laskin 115 kV Line (38 Line) up to Hoyt Lakes, removing connection to Laskin	608	115
New 115 Tioga Substation	608	115/23
Construct a second 161 kV line from Sub A to Sub 39.	635	161
Reconfigure the 115 kV near Indiana	600	115
Expansion of the existing Hollydale substation to accommodate serving load at Hollydale at 69 kV on a permanent basis.	600, 615	69/13.8
New 115 kV from WAPA's Miles City #2 substation to MDU's new Miles City SW 115 kV substation.	652, 661	115
New 161 kV Bondurant substation	635	161/13
Upgrade Red Rock TR 9 and associated bus work and equipment to higher rating	600	345/115
Rebuild/replace the existing Glenwood 69-13 kV Substation to improve reliability.	680	69/13
Adds 10MVAR cap bank at Turtle Lake	680	69
Rebuild 2 69kV line feeders into new Clear Lake Substation across the street from existing Clear Lake Substation. Install new 69kV breakers and buswork.	600	69
Rebuild and upgrade 14 miles of 69 kV line to 138 kV design (Altoona - Pierson)	635	138
Replace bus tie 3-4 OCB, and pos S OCB at Maline substation	356	138
Upgrade Hazel Creek TR9 to accommodate the interconnection of J460 - Blazing Star 1.	600	345/230

Description	Area Number	kV
New 345 kV and 230 kV facilities at Big Stone South, Brookings County, and Whapeton to accommodate multiple Generation Interconnection Requests	620	345
Add new 69 kV Path (Maquoketa - Delmar)	627	69
Add new 69 kV path (Taft & Brinsdale - Prairie)	620	69
Add parallel branch and transformer at Zachary	356	345/161
Add parallel transformer at Sub 18	635	161/69
Add series capacitor at Briggs Road	600	345
Add series capacitor at Pillsbury	620	230
Reconfigure 69 kV at Court Tap	627	69
Add new 69 kV path at Blomkest	600	69
Reconfigure Adams 161 kV substation	627	161
Add new 69 kV path at Hector Tap	600	69
Add new transformer at Frontier	620	230/115
Add new Raccoon 345 kV station	635	345
Reconfigure 69 kV at Bryantsburg	627	69
Reconfigure 69 kV at Slakes	627	69
Reconfigure 69 kV at Morrell and Cliff Ave	600	69
Reconfigure 69 kV at IPL Tiffin	627	69
Remove transformer at Poplar Lake	680	69
Add new 69 kV path from Ryan to Machester	627	69
Reconfigure 69 kV at Huntley	627	69
Reconfigure 118.1 kV at Fort Frances	103	118.1
Remove duplicate modeling of transformers at Hancock	627	69
Add Walters 161 tap and 161/69 transformer	627	161
Remove parallel transformer at Henry County	330	161/69
Reconfigure Hall transformer connections	356	138/34.5
Transformer parameter modifications, including all impedance changes >5%	Multiple	Multiple
Branch parameter modifications, including all impedance changes >5%	Multiple	Multiple
Add, remove, and modify various switched shunts	Multiple	Multiple