Definitive Interconnection System Impact Study for Generation Interconnection Requests

(DISIS-2015-001)

(Excluding Group 2, 5, 6, and 7 Results)

July 2015

Generator Interconnection

Southwest Power Pool

Revision History

Date	Author	Change Description
07/30/2015	SPP	Report Issued (DISIS-2015-001). Group 2, 5, 6, and 7 Interconnection Request Results not included in this issue.

Executive Summary

Pursuant to the Generator Interconnection Procedures (GIP) of the Southwest Power Pool (SPP) Open Access Transmission Tariff (OATT), SPP has conducted this Definitive Interconnection System Impact Study (DISIS). The Interconnection Customers' requests have been clustered together for the following System Impact Cluster Study window which closed March 31, 2015. The Interconnection Customers will be referred to in this study as the DISIS-2015-001 Interconnection Customers. This System Impact Study analyzes the interconnecting of multiple generation interconnection requests associated with new generation totaling approximately 5,460.29 MW of new generation which would be located within the transmission systems of American Electric Power – Western (AEPW), Kansas City Power and Light Company – Greater Missouri Operations Company (KCPL-GMO), Grand River Dam Authority (GRDA), Kansas City Power and Light Company (KPCL), Midwest Energy, Inc. (MIDW), Nebraska Public Power District (NPPD), Oklahoma Gas and Electric (OKGE), Southwestern Public Service (SPS), Sunflower Electric Power Corporation\Mid-Kansas Electric Company, LLC (SUNC\MKEC), Westar Energy, Inc. (WERE), and Western Farmers Electric Cooperative (WFEC). The various generation interconnection requests have differing proposed in-service dates[1]. The generation interconnection requests included in this System Impact Cluster Study are listed in Appendix A by their queue number, amount, requested interconnection service, area, requested interconnection point, proposed interconnection point, and the requested in-service date. A separate analysis for each Interconnection Request for "Stand-Alone" operation has also been performed. The "Stand-Alone" analysis shows results for each Interconnection Request if no other Interconnection Requests in the cluster study move forward. This Stand Alone analysis also includes an analysis of Limited Operation that determines available Interconnection Service if constraints are identified in the "Stand-Alone" scenario.

Due to late stage withdrawals of higher queued Interconnection Requests, the DISIS-2015-001 study will be reposted including the results for Group 2, 5, 6, and 7 request results no later than August 31, 2015.

Power flow analysis has indicated that for the power flow cases studied, 5,460.29 MW of nameplate generation may be interconnected with transmission system reinforcements within the SPP transmission system. Dynamic stability and power factor analysis has determined the need for reactive compensation in accordance with SPP stability and voltage recovery requirements including FERC Order #661A for wind farm interconnection requests. Those reactive requirements are listed for each interconnection request within this report. Dynamic stability analysis has determined that the transmission system will remain stable with the assigned Network Upgrades and necessary reactive compensation requirements. Certain measures for mitigation of the

[1] The generation interconnection requests in-service dates may need to be deferred based on the required lead time for the Network Upgrades necessary. The Interconnection Customers that proceed to the Facility Study will be provided a new in-service date based on the Facility Study's time for completion of the Network Upgrades necessary or as otherwise provided for in the GIP.

Gentleman Stability Interface have yet to be determined as of the posting of this DISIS. These measures will be further analyzed in the Interconnection Facilities Study phase. A short circuit analysis has been performed with available short circuit values given in the stability study for each group in the appendices of this report. A short circuit analysis has been performed with available short circuit values given in the stability study for each group in the appendices of this report.

In no way does this study guarantee operation for all periods of time. This interconnection study identifies and assigns transmission reinforcements for Energy Resource Interconnection Service (ERIS) interconnection injection constraints (defined as a 20% or greater distribution factor impact for outage based constraints and 3% or greater distribution factor impact for system intact constraints) and Network Resource Interconnection Service (NRIS) constraints (defined as 3% or greater distribution factor impact), if requested by the Customer. These constraints are listed in Appendix G. This interconnection study does not assign transmission reinforcements for all potential transmission constraints. It should be noted that although this study analyzed many of the most probable contingencies, it is not an all-inclusive list and cannot account for every operational situation. Because of this, it is likely that the Interconnection Customer(s) may be required to reduce their generation output to 0 MW, also known as curtailment, under certain system conditions to allow system operators to maintain the reliability of the transmission network.

The total estimated minimum cost for interconnecting the DISIS-2015-001 Interconnection Customers is estimated at $229,843,633 (exclusive of Group 2, 5, 6, and 7 Interconnection Requests Costs) plus the costs associated with mitigating certain other constraints including the Gentleman Stability Interface. These costs determined at this time are shown in Appendix E and F. Interconnection Service to DISIS-2015-001 Interconnection Customers is also contingent upon higher queued customers paying for certain required network upgrades. **The in-service date for the DISIS customers will be deferred until the construction of these network upgrades can be completed.** These costs also do not include the Interconnection Customer Interconnection Facilities as defined by the SPP Open Access Transmission Tariff (OATT) or the additional SPP transmission network constraints identified through this study and shown in Appendix H.

Constraints listed in Appendix H do not require mitigation or transmission reinforcement for Interconnection Service, but could require Interconnection Customer to reduce generation in operational conditions. These transmission constraints are however, in the local area when this generation is dispatched into the SPP footprint for Energy Resource Interconnection Service (ERIS) or Network Resource Interconnection Service (NRIS).

It should be noted that the additional network constraints identified in Appendix H may also be identified by a Transmission Service Request (TSR) and may need to be verified by associated studies. With a defined source and sink in a TSR, the list of network constraints will be refined and expanded to account for all Network Upgrade requirements. The required interconnection costs listed in Appendix E and F do not include costs associated with the deliverability of the energy to load or other customers. These costs are determined by separate studies should the Customer decide to submit a Transmission Service Request through SPP's Open Access Same Time Information System (OASIS) as required by Attachment Z1 of the SPP OATT. Furthermore, this DISIS neither guarantees transmission service or deliverability of the requested resource.

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Introduction

Pursuant to the Southwest Power Pool (SPP) Open Access Transmission Tariff (OATT), SPP has conducted this Definitive Interconnection System Impact Study (DISIS) for certain generation interconnection requests in the SPP Generation Interconnection Queue. These interconnection requests have been clustered together for the following System Impact Study window which closed March 31, 2015. The customers will be referred to in this study as the DISIS-2015-001 Interconnection Customers. This DISIS analyzes the interconnecting of multiple generation interconnection requests associated with new generation totaling 5,460.29 MW of new generation which would be located within the transmission systems of American Electric Power – Western (AEPW), Kansas City Power and Light Company – Greater Missouri Operations Company (KCPL-GMO), Grand River Dam Authority (GRDA), Kansas City Power and Light Company (KPCL), Midwest Energy, Inc. (MIDW), Nebraska Public Power District (NPPD), Oklahoma Gas and Electric (OKGE), Southwestern Public Service (SPS), Sunflower Electric Power Corporation\Mid-Kansas Electric Company, LLC (SUNC\MKEC), Westar Energy, Inc. (WERE), and Western Farmers Electric Cooperative (WFEC). The various generation interconnection requests have differing proposed in-service dates[2]. The generation interconnection requests included in this System Impact Study are listed in Appendix A by their queue number, amount, requested interconnection service, area, requested interconnection point, proposed interconnection point, and the requested in-service date. A separate analysis for each Interconnection Request for “Stand-Alone” operation has also been performed. The “Stand-Alone” analysis shows results for each Interconnection Request if no other Interconnection Requests in the cluster study move forward. The “Stand-Alone” analysis also includes an analysis of Limited Operation that determines available Interconnection Service if constraints are identified in the “Stand-Alone” scenario.

The primary objective of this DISIS is to identify the system constraints, transient instabilities, and over-dutied equipment associated with connecting the generation to the area transmission system. The Impact Study and other subsequent Interconnection Studies are designed to identify required Transmission Owner Interconnection Facilities, Network Upgrades and other Direct Assignment Facilities needed to inject power into the grid at each specific point of interconnection.

[2] The generation interconnection requests in-service dates may need to be deferred based on the required lead time for the Network Upgrades necessary. The Interconnection Customers that proceed to the Facility Study will be provided a new in-service date based on the completion of the Facility Study or as otherwise provided for in the GIP.

Model Development

Interconnection Requests Included in the Cluster

SPP included all interconnection requests that submitted a Definitive Interconnection System Impact Study Agreement no later than March 31, 2015 and were subsequently accepted by Southwest Power Pool under the terms of the Generator Interconnection Procedures (GIP) that were in effect at the time this study commenced on April 1, 2015. The interconnection requests that are included in this study are listed in Appendix A.

Affected System Interconnection Request

Also included in this Definitive Interconnection System Impact Study are four (4) Affected System Studies. The Affected System Interconnection Requests have been given the designations with the "ASGI" prefix. These requests are listed in Appendix A. Affected System Interconnection Requests were only studied in "cluster" scenarios.

Previously Queued Interconnection Requests

The previous queued requests included in this study are listed in Appendix B. In addition to the Base Case Upgrades, the previous queued requests and associated upgrades were assumed to be in-service and added to the Base Case models. These projects were dispatched as Energy Resources Interconnection Service (ERIS) with equal distribution across the SPP footprint. Prior queued projects that requested Network Resource Interconnection Service (NRIS) were also dispatched in separate NRIS scenarios into the balancing authority of the interconnecting transmission owner.

Development of Base Cases

Power Flow

The 2014 series Integrated Transmission Planning models (used in the 2015 ITPNT) including the 2015 (spring and summer peak seasons), the 2020 (summer and winter peak seasons), and the 2025 (summer peak season) scenario 0 cases are used for this study. After the cases are developed, each of the control areas' resources are then re-dispatched to account for the new generation requests using current dispatch merit-orders. Planned High Priority Incremental Loads (HPILs) are also accounted for in these models.

Dynamic Stability

The 2014 series SPP Model Development Working Group (MDWG) Models 2014 winter, 2015 summer, and 2025 summer peak cases were used as starting points for this study. To account for HPILS upgrades expected in-service between 2016 and 2020, the 2020 summer and winter peak cases are also used for the Group 6 analysis.

Short Circuit

The 2025 summer peak stability case is used for this analysis.

Base Case Upgrades

The following facilities are part of the SPP Transmission Expansion Plan, the Balanced Portfolio or recently approved Priority Projects. These facilities have an approved Notification to Construct

(NTC) or are in construction stages and were assumed to be in-service at the time of dispatch and added to the base case models. The DISIS-2015-001 Interconnection Customers have not been assigned advancement costs for the below listed projects. The DISIS-2015-001 Interconnection Customers Generation Facilities in service dates may need to be delayed until the completion of the following upgrades. In some cases, the in-service date is beyond the allowable time a customer can delay. In this case, the Interconnection Customer may move forward with Limited Operation or remain in the DISIS Queue for additional study cycles. If for some reason, construction on these projects is discontinued, additional restudies will be needed to determine the interconnection needs of the DISIS Interconnection Customers.

- 2012 Integrated Transmission Plan (2012 ITP10) Projects
    - Woodward-Tatonga-Mathewson-Cimarron 345kV transmission line, scheduled for 2021 in-service[3]
    - Chisholm – Gracemont 345kV transmission line, and Chisholm 345/230kV transformer circuit #1, scheduled for 3/1/2018 in-service[4]
- 2015 Integrated Transmission Plan Near Term (2015 ITPNT) Projects
    - China Draw 115kV Reactive Power Support
        - 200Mvar Capacitive and 50Mvar Inductive Static Var Compensator (SVC)
    - Road Runner 115kV Reactive Power Support
        - 200Mvar Capacitive and 50Mvar Inductive Static Var Compensator (SVC)
    - Agave Hill 115kV reactive Power Support
        - 28.8Mvar Capacitor Bank(s)
    - Potash Junction – Intrepid – IMC #1 – Livingston Ridge 115kV rebuild
    - National Enrichment Plant – Targa – Cardinal 115kV circuit #1 rebuild
- Nebraska City – Mullin Creek – Sibley 345kV circuit #1 build, scheduled for 12/31/2016 in-service[5]
- Northwest 345/138/13.8 kV circuit #3 autotransformer, scheduled for 6/1/2015 in-service[6]
- Hoskins – Neligh East 345/115 kV Project[7]
    - Neligh East 345/115 kV substation and transformer
    - Neligh East Area 115 kV upgrades to support new station
    - Hoskins – Neligh East 345 kV circuit #1
- High Priority Incremental Loads (HPILs) Projects[8]:
    - TUCO Interchange – Yoakum – Hobbs Interchange 345/230 kV Project
        - TUCO Interchange – Yoakum – Hobbs Interchange 345 kV circuit #1 and associated terminal equipment upgrades
        - Hobbs 345/230/13 kV transformer circuit #1

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[3] SPP Notification to Construct (NTC) 200223
[4] SPP Notification to Construct (NTC) 200240 and 200255
[5] SPP Notification to Construct (NTC) 20097 and 20098
[6] SPP Transmission Service Project identified in SPP 2009-AG2-AFS6. Per SPP NTC 20137 & 200194
[7] SPP Regional Reliability 2012 ITP 10 Project Per SPP-NTC-200220
[8] Per Network Upgrades assigned in High Priority Incremental Loads (HPILs) study, Including Direct Assigned Upgrades, Projects in SPP-NTC-200256 and SPP-NTC-200283.

        - Yoakum 345/230/13 kV transformer circuit #1
    - Battle Axe – Road Runner 115 kV circuit #1
    - Chaves County – Price – CV Pines – Capitan 115 kV circuit #1
    - China Draw – Yeso Hills 115 kV circuit #1
    - Dollarhide – Toboso Flats 115 kV circuit #1
    - Hobbs Interchange – Kiowa 345 kV circuit #1
    - Kiowa – North Loving – China Draw 345/115 kV Projects
        - Kiowa – North Loving – China Draw circuit #1 and associated terminal equipment upgrades
        - China Draw 345/115/13 kV transformer circuit #1
        - North Loving 345/115/13 kV transformer circuit #1
    - Kiowa – Road Runner 345/230/115 kV Projects
        - Kiowa 345/230 kV transformer circuit #1
        - Road Runner 345/115/13 kV transformer circuit #1
    - Livingston Ridge – Sage Brush – Lagarto – Cardinal 115 kV circuit #1
    - North Loving – South Loving 115 kV circuit #1
    - Ponderosa – Ponderosa Tap 115 kV circuit #1
    - Potash 230/115/13kV Transformer circuit #1 replacement

Contingent Upgrades

The following facilities do not yet have approval. These facilities have been assigned to higher queued interconnection customers. These facilities have been included in the models for the DISIS-2015-001 study and are assumed to be in service. This list may not be all inclusive. <u>The DISIS-2015-001 Interconnection Customers, at this time, do not have responsibility for these facilities but may later be assigned the cost of these facilities if higher queued customers terminate their Generation Interconnection Agreement or withdraw from the interconnection queue. The DISIS-2015-001 Interconnection Customer Generation Facilities in-service dates may need to be delayed until the completion of the following upgrades.</u>

- Upgrades assigned to DISIS-2010-001 Interconnection Customers:
    - None at this time
- Upgrades assigned to DISIS-2010-002 Interconnection Customers:
    - Twin Church – Dixon County 230 kV circuit #1 rerate (320 MVA)
    - Buckner – Spearville 345 kV terminal equipment
- Upgrades assigned to DISIS-2011-001 Interconnection Customers:
    - Hoskins – Dixon County – Twin Church 230 kV circuit #1 conductor clearance increase
    - (NRIS only) Woodward – FPL Switch – Mooreland 138 kV circuit #1 rebuild
- Upgrades assigned to DISIS-2011-002 Interconnection Customers:
    - None at this time
- Upgrades assigned to DISIS-2012-001 Interconnection Customers:
    - None at this time
- Upgrades assigned to DISIS-2012-002 Interconnection Customers:
    - Associated Electric Cooperatives Inc. (AECI) Fairfax 138/69 kV transformer replacement
    - Lake Creek – Lone Wolf 69 kV circuit #1 reset CT

- Remington – Fairfax 138 kV circuit #1 conductor clearance increase
- (NRIS only) Arkansas City – Paris –Creswell – Oak – Rainbow – City of Winfield 69kV circuit #1 rebuild
- (NRIS only) Creswell 138/69/13kV Transformer circuit #1 and #2, replacements

- Upgrades assigned to DISIS-2013-001 Interconnection Customers:
  - None at this time
- Upgrades assigned to DISIS-2013-002 Interconnection Customers:
  - Battle Creek – County Line – Neligh East 115kV circuit #1 rebuild
- Upgrades assigned to DISIS-2014-001 Interconnection Customers:
  - None at this time
- Upgrades assigned to DISIS-2014-002 Interconnection Customers:
  - Arnold – Ransom 115kV circuit #1, terminal equipment replacement
  - Beaver County 345kV Reactive Power Support, build approximately 75Mvars of capacitive reactive power support
  - Carlisle 230/115/13kV Transformer circuit #1 replacement
  - Deaf Smith – Plant X 230kV circuit #1 replace wave trap
  - Harper Milan Tap – Clearwater 138kV rebuild
  - Knoll – Post Rock 230kV circuit #1 rebuild
  - Norton – Pleasant Hill 230kV circuit #1 rebuild for voltage conversion
  - Oklaunion 345kV Reactive Power Support, build approximately 110Mvars of Capacitor Bank(s) and +/- 50Mvar Static Var Compensator (SVC)
  - Tolk – Plant X 230kV circuit #3 build
  - TUCO 2 Substation 345/230kV
    - Build new 345/230kV substation along TUCO – Border 345kV and TUCO – Swisher 230kV. Tie in and Terminate TUCO 345kV, Border 345kV, TUCO 230kV, and Swisher 230kV at TUCO 2.
    - Build 345/230/13kV transformer
  - TUCO 2 – TUCO Interchange 230kV circuit #1 replace terminal equipment

Potential Upgrades Not in the Base Case

Any potential upgrades that do not have a Notification to Construct (NTC) and are not explicitly listed within this report have not been included in the base case. These upgrades include any identified in the SPP Extra-High Voltage (EHV) overlay plan, or any other SPP planning study other than the upgrades listed above in the previous section.

Regional Groupings

The interconnection requests listed in Appendix A are grouped together into eleven (11) active regional groups based on geographical and electrical impacts. These groupings are shown in Appendix C.

To determine interconnection impacts, eleven (11) different generation dispatch scenarios of the spring, summer, and winter base case models are developed to accommodate the regional groupings.

Power Flow

For Variable Energy Resources (VER) (solar/wind) in each power flow case, Energy Resource Interconnection Service (ERIS), is evaluated for the generating plants within a geographical area of the interconnection request(s) for the VERs dispatched at 100% nameplate of maximum generation. The VERs in the remote areas are dispatched at 20% nameplate of maximum generation. These projects are dispatched across the SPP footprint using load factor ratios.

Peaking units are not dispatched in the 2015 spring, or in the “High VER” summer and winter peaks. To study peaking units’ impacts, the 2015 summer and winter peaks, 2020 summer and winter peaks, and 2025 summer peak models are developed with peaking units dispatched at 100% of the nameplate rating and VERs dispatched at 20% of the nameplate rating. Each interconnection request is also modeled separately at 100% nameplate for certain analyses.

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

Dynamic Stability

For each group, all interconnection requests are dispatched at 100% nameplate output while the other groups are dispatched at 20% output for VERs and 100% output for thermal requests.

Short Circuit

The dynamic stability models (2025 SP) are used for this analysis.

Identification of Network Constraints

Network constraints are found by using PSS/E AC Contingency Calculation (ACCC) analysis with PSS/E MUST First Contingency Incremental Transfer Capability (FCITC) analysis on the entire cluster grouping dispatched at the various levels previously mentioned. The ERIS constraints are then screened to determine which of the generation interconnection requests have at least a 20% Distribution Factor (DF) upon outage based constraints (n-1) and 3% DF upon system intact constraints (n-0) or on non-convergences case solutions during outage based constraints (n-1). In addition, stability issues are also considered for transmission reinforcement under ERIS. Interconnection Requests that requested Network Resource Interconnection Service (NRIS) are also studied in the NRIS analysis to determine if any constraint measured greater than or equal to a 3% DF. If so, these constraints are also considered for mitigation under NRIS.

Constraints that are identified and require transmission reinforcement are listed in Appendix G. These constraints met the criteria for analysis for Energy Resource Interconnection Service and Network Resource Interconnection Service (if requested).

Other network constraints not requiring transmission reinforcements are shown in Appendix H. With a defined source and sink in a Transmission Service Request, this list of network constraints can be refined and expanded to account for all Network Upgrade requirements for firm transmission service. Additional constraints identified by multi-element contingencies are listed in Appendix I.

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

Determination of Cost Allocated Network Upgrades

Cost Allocated Network Upgrades of Variable Energy Resources (VER) (solar/wind)generation interconnection requests are determined using the 2015 spring model. Cost Allocated Network Upgrades of peaking units is determined using the 2020 summer peak model. A PSS/E and MUST sensitivity analysis is performed to determine the Distribution Factors (DF), a distribution factor with no contingency that each generation interconnection request has on each new upgrade. 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 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:

- Determine an Impact Factor on a given project for all responsible GI requests:

$$\text{Request X Impact Factor on Upgrade Project 1} = \text{PTDF(\%)(X)} * \text{MW(X)} = \text{X1}$$

$$\text{Request Y Impact Factor on Upgrade Project 1} = \text{PTDF(\%)(Y)} * \text{MW(Y)} = \text{Y1}$$

$$\text{Request Z Impact Factor on Upgrade Project 1} = \text{PTDF(\%)(Z)} * \text{MW(Z)} = \text{Z1}$$

- Determine each request's Allocation of Cost for that particular project:

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

- Repeat previous for each responsible GI request for each Project

The cost allocation of each needed Network Upgrade is determined by the size of each request and its impact on the given project. This allows for the most efficient and reasonable mechanism for sharing the costs of upgrades.

Credits/Compensation for Amounts Advanced for Network Upgrades

Interconnection Customer shall be entitled to either credits or potentially Long Term Congestion Rights (LTCR), otherwise known as compensation, in accordance with Attachment Z2 of the SPP Tariff for any Network Upgrades, including any tax gross-up or any other tax-related payments associated with the Network Upgrades, and not refunded to the Interconnection Customer.

Required Interconnection Facilities

The requirement to interconnect the 5,460.29 MW of generation into the existing and proposed transmission systems in the affected areas of the SPP transmission footprint consist of the necessary cost allocated shared facilities listed in Appendix F by upgrade. The interconnection requirements for the cluster total an estimated $229,843,633 (exclusive of Group 2, 5, 6, and 7 Interconnection Requests Costs). Interconnection Facilities specific to each generation interconnection request are listed in Appendix E. A preliminary one-line drawing for each generation interconnection request are listed in Appendix D.

For an explanation of how required Network Upgrades and Interconnection Facilities were determined, refer to the section on “Identification of Network Constraints.”

Facilities Analysis

The interconnecting Transmission Owner for each Interconnection Request has provided its preliminary analysis of required Transmission Owner Interconnection Facilities and the associated Network Upgrades, shown in Appendix D. This analysis was limited only to the expected facilities to be constructed by the Transmission Owner at the Point of Interconnection. These costs are included within one-line diagrams in Appendix D and also listed in Appendix E and F as combined “Interconnection Costs”. These costs will be further refined by the Transmission Owner as part of the Interconnection Facilities Study. Any additional Network Upgrades identified by this DISIS beyond the Point of Interconnection are defined and estimated by either the Transmission Owner or by SPP. These additional Network Upgrade costs will also be refined further by the Transmission Owner within the Interconnection Facilities Study.

Power Flow Analysis

Power Flow Analysis Methodology

The ACCC function of PSS/E is used to simulate single element and special (i.e., breaker-to-breaker, multi-element, etc) contingencies in portions or all of the modeled control areas of SPP, as well as, other control areas external to SPP and the resulting scenarios analyzed. Single element and multi-element contingencies are evaluated.

Power Flow Analysis

A power flow analysis is conducted for each Interconnection Customer's facility using modified versions of the 2015 spring, 2015 summer and winter peaks, the 2020 summer and winter peaks, and the 2025 summer peak models. The output of the Interconnection Customer's facility is offset in each model by a reduction in output of existing online SPP generation. This method allows the request to be studied as an Energy Resource Interconnection Service request (ERIS). Certain requests that are also pursuing Network Resource Interconnection Service (NRIS) have an additional analysis conducted for displacing resources in the interconnecting Transmission Owner's balancing area.

Power Flow Results

Cluster Group 1 (Woodward Area)

In addition to the 4,216.5 MW of previously queued generation in the area, 161.0 MW of new interconnection service was studied. The system intact thermal violation of FPL Switch – Mooreland 138kV will limit the Interconnection Service for the DISIS-2015-001 Interconnection Request. The FPL Switch – Mooreland 138kV rebuild upgrade is currently assigned to DISIS-2011-001 Interconnection Requests and will need to be advanced by the DISIS-2015-001 Group 1 Interconnection Customer if the Interconnection Request anticipates having full Interconnection Service with their current proposed in-service date.

Cluster ERIS Constraints			
MONITORED ELEMENT	Limiting Rate A/B (MVA)	TC%LOADING (% MVA)	CONTINGENCY
FPL Switch – Mooreland 138KV CKT 1	287	114.06	System intact

Cluster NRIS Constraints			
MONITORED ELEMENT	Limiting Rate A/B (MVA)	TC%LOADING (% MVA)	CONTINGENCY
No NRIS Interconnection Requests in Group 1			

Group 1 (Stand Alone)

The Interconnection Request was also studied as a Stand Alone Interconnection Request in addition to the Cluster Analysis. The FPL Switch - Mooreland 138kV transmission line is a constraint during system intact conditions for GEN-2015-029. An analysis for Limited operation indicates that Limited Operation for Group 1 Interconnection Requests will be limited to 0 MW prior to the in-service date of the upgrade(s) to alleviate this constraint. The FPL Switch – Mooreland 138kV rebuild upgrade is currently assigned to DISIS-2011-001 Interconnection Requests and will need to be advanced by the DISIS-2015-001 Group 1 Interconnection Customer if the Interconnection Request anticipates having full Interconnection Service with their current proposed in-service date.

Group 1 (Limited Operation)

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

Limited Operation Analysis		
Interconnection Request	**MW**	**Constraint that most limits LOIS**
GEN-2015-029	0	FPL SWITCH - MOORELAND 138KV CKT 1

Cluster Group 2 (Hitchland Area)

Due to late stage withdrawals of higher queued Interconnection Request(s), the Interconnection Request(s) in DISIS-2015-001 located in Group 2 (Hitchland Area) are not included within this posted study. The DISIS-2015-001 study will be reposted including the results of Group 2 Interconnection Request(s) no later than August 31, 2015.

Cluster Group 3 (Spearville Area)

In addition to the 3,909.3 MW of previously queued generation in the area, 39.4 MW of new interconnection service was studied. The addition of the Group 3 Interconnection Requests caused thermal ERIS constraints on Buckner – Holcomb 345kV circuit #1, Crooked Creek – Cudahy – Kismet 115kV circuit #1, FPL Switch – Mooreland 138kV circuit #1, and Greenburg – Shooting Star Tap 115kV circuit #1 during system intact and contingency system conditions. Mitigation for Buckner – Holcomb 345kV circuit #1 will require terminal equipment upgrades to achieve a higher emergency rating. Crooked Creek – Cudahy – Kismet 115kV and Greenburg – Shooting Start Tap 115kV will have to be rebuilt to mitigate the corresponding thermal overloads. The FPL Switch – Mooreland 138kV rebuild upgrade is currently assigned to DISIS-2011-001 Interconnection Requests and will need to be advanced by the DISIS-2015-001 Group 3 Interconnection Customers if the Interconnection Request anticipates having full Interconnection Service with their current proposed in-service date.

Cluster ERIS Constraints			
MONITORED ELEMENT	**Limiting Rate A/B (MVA)**	**TC%LOADING (% MVA)**	**CONTINGENCY**
Buckner – Holcomb 345kV CKT 1	726.6	100.00	G13-010T 345.00 - POST ROCK 345KV CKT 1
Crooked Creek – Cudahy 115kV CKT 1	148.2	114.80	BUCKNER7 345.00 - HOLCOMB 345KV CKT 1
Cudahy – Kismet 115kV CKT 1	148.2	118.18	BUCKNER7 345.00 - HOLCOMB 345KV CKT 1
FPL Switch – Mooreland 138kV CKT 1	287	100.21	System intact
Greenburg – Shooting Star Tap 115kV CKT1	115.1	120.00	System intact

Cluster NRIS Constraints

MONITORED ELEMENT	Limiting Rate A/B (MVA)	TC%LOADING (% MVA)	CONTINGENCY
Currently, No NRIS constraints for Group 3 Interconnection Requests			

Group 3 (Stand Alone)

The Interconnection Requests were studied as a Stand Alone Interconnection Request in addition to the Cluster Analysis. GEN-2015-021 currently does not have any ERIS or NRIS mitigation constraints for Stand Alone Analysis. The Buckner – Holcomb 345kV transmission line is a constraint for GEN-2015-026 Interconnection Request. An analysis for limited operation indicates that Limited Operation for GEN-2015-026 Interconnection Request will be limited to 0MW prior to the in-service date of the upgrade(s) to alleviate this constraint. The Crooked Creek – Cudahy – Kismet – Cimarron River Tap 115kV and Greenburg – Shooting Star Tap 115kV transmission lines are a constraint for GEN-2015-027 Interconnection Request. An analysis for limited operation indicates that Limited Operation for GEN-2015-027 Interconnection Request will be limited to 0MW prior to the in-service date of the upgrade(s) to alleviate these constraints. For Stand Alone Cost Allocation please refer to Appendix E1.

Group 3 (Limited Operation)

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

Limited Operation Analysis		
Interconnection Request	**MW**	**Constraint that most limits LOIS**
GEN-2015-021	20	None
GEN-2015-026	0	Buckner – Holcomb 345kV CKT 1
GEN-2015-027	0	Cimarron River Tap – Kismet 115kV CKT 1 Crooked Creek – Cudahy 115kV CKT 1 Cudahy – Kismet 115kV CKT 1 Greenburg – Shooting Star Tap 115kV CKT 1

Cluster Group 4 (Northwest Kansas Area)

In addition to the 1,762.6 MW of previously queued generation in the area, 242.0 MW of new interconnection service was studied. The second Mingo 345/115kV transformer network upgrade assigned in the 2015 SPP Integrated Transmission Plan 10-Year Assessment Study (ITP10), per SPP-NTC-200325, will mitigate the ERIS thermal constraint for Beach Station – GEN-2010-048 Tap 115kV. The NRIS thermal overload observed for Arnold – Ransom 115kV can be mitigated by the second Mingo transformer and/or possibly the Arnold – Ransom 115kV terminal equipment upgrade assigned to DISIS-2014-002 Interconnection Customer(s). Arnold – Ransom 115kV terminal equipment upgrade is currently being studied by the Transmission Owner (T.O.) in the Interconnection Facilities Study (IFS) stage based on DISIS-2014-002 study upgrade requirement. If terminal equipment upgrade minimum design standards met the required MVA needed to alleviate this study's overload, then the Arnold – Ransom 115k terminal equipment upgrade could mitigate the constraint on Arnold – Ransom 115kV.

Cluster ERIS Constraints

MONITORED ELEMENT	Limiting Rate A/B (MVA)	TC%LOADING (% MVA)	CONTINGENCY
Beach Station – GEN-2010-048 Tap 115kV CKT 1	88	107.15	Mingo 345/115/13.8KV Transformer CKT 1

Cluster NRIS Constraints			
MONITORED ELEMENT	Limiting Rate A/B (MVA)	TC%LOADING (% MVA)	CONTINGENCY
Arnold – Ransom 115kV CKT 1	79.7	111.72	Mingo 345/115/13.8KV Transformer CKT 1

Group 4 (Stand Alone)

The Interconnection Requests were studied as a Stand Alone Interconnection Request in addition to the Cluster Analysis. The Beach Station – GEN-2010-048 Tap 115kV transmission line is a constraint for GEN-2010-048 Interconnection Request. Analysis indicates that Limited Operation for GEN-2010-048 Interconnection Request will be limited to 55MW prior to the in-service date of the upgrade(s) to alleviate this constraint. The Arnold – Ransom 115kV transmission line is an ERIS and NRIS constraint for GEN-2015-017 Interconnection Request. An analysis for limited operation indicates that Limited Operation for GEN-2015-017 Interconnection Request will be limited to 82MW prior to the in-service date of the upgrade(s) to alleviate this constraint. For Stand Alone Cost Allocation please refer to Appendix E1.

Group 4 (Limited Operation)

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

Limited Operation Analysis		
Interconnection Request	MW	Constraint that most limits LOIS
GEN-2010-048	55	Beach Station – GEN-2010-048 Tap 115kV CKT 1
GEN-2015-017	82	Arnold – Ransom 115kV CKT 1

Cluster Group 5 (Amarillo Area)

Due to late stage withdrawals of higher queued Interconnection Request(s), the Interconnection Request(s) in DISIS-2015-001 located in Group 5 (Amarillo Area) are not included within this posted study. The DISIS-2015-001 study will be reposted including the results of Group 5 Interconnection Request(s) no later than August 31, 2015.

Cluster Group 6 (South Texas Panhandle/New Mexico Area)

Due to late stage withdrawals of higher queued Interconnection Request(s), the Interconnection Request(s) in DISIS-2015-001 located in Group 6 (South Texas Panhandle/New Mexico Area) are not included within this posted study. The DISIS-2015-001 study will be reposted including the results of Group 6 Interconnection Request(s) no later than August 31, 2015.

Cluster Group 7 (Southwestern Oklahoma Area)

Due to late stage withdrawals of higher queued Interconnection Request(s), the Interconnection Request(s) in DISIS-2015-001 located in Group 7 (Southwestern Oklahoma Area) are not included within this posted study. The DISIS-2015-001 study will be reposted including the results of Group 7 Interconnection Request(s) no later than August 31, 2015.

Cluster Group 8 (North Oklahoma/South Central Kansas Area)

In addition to the 4,188.20 MW of previously queued generation in the area, 1,454.1 MW of new interconnection service was studied. The analysis for ERIS observed thermal overloads on the Clearwater – Gill Energy Center West 138kV for system intact conditions and thermal overloads on the Benton – Wichita 345kV, Chikaskia – Kildare 138kV, and Viola 345/138/13kV transformer thermal constraints for single system contingencies (N-1) conditions. For mitigation of the system intact and N-1 constraints, Benton – Wichita 345kV terminal equipment upgrade, Viola 345/138/13 transformer circuit #2, and Viola 345/138kV Project assigned in the 2013 Integrated Transmission Plan Near Term Assessment (ITPNT), per SPP-NTC-200228 will be required. The analysis for NRIS indicates a need for the Viola 345/138 Project for mitigation for the overload on Clearwater – Gill Energy Center West 138kV.

Cluster ERIS Constraints			
MONITORED ELEMENT	Limiting Rate A/B (MVA)	TC%LOADING (% MVA)	CONTINGENCY
Benton – Wichita 345kV CKT 1	956	102.11	Wolf Creek Generating Station Unit #1
Chikaskia – Kildare 138kV CKT 1	143	106.45	Hunter – Woodring 345kV CKT 1
Clearwater – Gill Energy Center West 138kV CKT 1	143	108.21	System intact
Viola 345/138/13kV Transformer CKT 1	492.8	102.31	Viola – Wichita 345kV CKT 1

Cluster NRIS Constraints			
MONITORED ELEMENT	Limiting Rate A/B (MVA)	TC%LOADING (% MVA)	CONTINGENCY
Clearwater – Gill Energy Center West 138kV CKT 1	143	157.53	Gill Energy Center South – Viola 138kV CKT 1

Group 8 (Stand Alone)

The Interconnection Requests were studied as a Stand Alone Interconnection Request in addition to the cluster analysis. Currently, GEN-2015-001 does not have any ERIS or NRIS mitigation constraints for Stand Alone Analysis. The planned Viola 345/138/13kV transformer is a constraint for GEN-2015-003 Interconnection Request. An analysis for limited operation indicates that Limited Operation for GEN-2015-003 Interconnection Request will be limited to 195MW prior to the in-service date of the upgrade(s) to alleviate this constraint. After the in-service of the Viola 345/138kV Projects and if a delay exists in updating the Clearwater – Gill Energy Center West 138kV terminal equipment, there could potentially be an additional limited operation megawatt amount for GEN-2015-003. This particular scenario could limit GEN-2015-003 to 0 MW. Currently, GEN-2015-015 does not have ERIS mitigation constraints for Stand Alone Analysis. GEN-2015-015 will be limited to 0 MW for NRIS constraints on Clearwater – Gill Energy Center West 138kV before upgrade(s) to alleviate this overload are in-service. Currently, GEN-2015-016 does not have any ERIS or NRIS mitigation constraints for Stand Alone Analysis. Also Interconnection Requests GEN-2015-024, GEN-2015-025, GEN-2015-028, and GEN-2015-030 do not currently have any ERIS mitigation constraints for Stand Alone Analysis. For Stand Alone Cost Allocation please refer to Appendix E1.

Group 8 (Limited Operation)

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

Limited Operation Analysis		
Interconnection Request	MW	Constraint that most limits LOIS
GEN-2015-001	200	None
GEN-2015-003	195	Viola – Wichita 345kV CKT 1
GEN-2015-015	154.6 0 (NRIS)	None Clearwater – Gill Energy Center West 138kV CKT 1
GEN-2015-016	200	None
GEN-2015-024	220	None
GEN-2015-025	220	None
GEN-2015-028	3	None
GEN-2015-030	200.1	None

Cluster Group 9 (Nebraska Area)

In addition to the 2,492.7 MW of previously queued generation in the area, 976.8 MW of new interconnection service was studied. ERIS analysis identitified various thermal violations for the addition of the DISIS-2015-001 Group 09 Interconnection Requests during system intact and contingency conditions.

ERIS constraint for Gentleman Generating Station ("GGS") Flowgate will require the Gentleman – Cherry County/Thedford – Holt County 345kV Project ("R-Plan") previously assigned in SPP 2012 Integrated Transmission Plan 10 Year Assessment (ITP10), per SPP-NTC-200220, and also further Nebraska Public Power District (NPPD) review for GGS flowgate thermal and stability mitigation network upgrade(s) during the Interconnection Facilities Study (IFS). An additional sensitivity was also evaluated that includes three (3) Interconnection Requests in the Western Area Power Administration (WAPA) impact study queue. These three (3) WAPA Interconnection Requests are close in electrical configuration distance to the SPP transmission system and show extensive impacts on the GGS flowgate constraint.

ERIS constraints along the Fort Randall – Meadow Grove – Kelly (Columbus) corridor will require Albion – Petersburg – North Petersburg 115kV circuit #1 re-conductor, a new Meadow Grove 230/115/13kV transformer, and Meadow Grove – North Petersburg 115kV transmission circuit.

ERIS constraints in the Neligh area will require Albion – Petersburg – North Petersburg 115kV circuit #1 re-conductor, Battle Creek – Norfolk 115kV circuit #1 rebuild, Bloomfield – Gavins Point 115kV circuit #1 rebuild and, the Hoskins – Neligh 345/115kV Project assigned in 2014 SPP Integrated Transmission Plan Near Term Assessment (ITPNT) per SPP-NTC-200253. If the DISIS-2015-001 Interconnection Customer assigned the rebuild of Bloomfield – Gavins Point 115kV circuit #1 proceeds to the IFS, further review from WAPA will be needed for WAPA facilities associated with the transmission circuit.

ERIS constraints along the Fort Thompson – WAPA GI-0717/18 Tap – GEN-2015-023 Tap – Grand Island 345kV transmission corridor will also require the R-Plan for voltage and thermal mitigation. For details related to the voltage issues, please refer to the stability section of this report.

Various NRIS constraints across similar ERIS constraint corridors are observed. NRIS constraints unique to the previously mentioned ERIS constraints include the thermal violation for Victory Hill 230/115/13kV during single element contingency conditions. Mitigation for the Victory Hill transformer would require the previously assigned 2014 SPP ITPNT Stegall – Scotts Bluff 115kV transmission circuit and Stegall 345/115/13kV transformer Project per SPP-NTC-200253.

Cluster ERIS Constraints			
MONITORED ELEMENT	Limiting Rate A/B (MVA)	TC%LOADING (% MVA)	CONTINGENCY
Albion – Genoa 115kV CKT 1	137	109.75	County Line – Neligh East 115kV CKT 1
Albion – Petersburg 115kV CKT 1	137	154.87	LN-1163-2
Battle Creek – County Line 115kV CKT 1	240	121.25	Bloomfield – Gavins Point 115kV CKT 1
Battle Creek – North Norfolk 115kV CKT 1	193	147.1	Bloomfield – Gavins Point 115kV CKT 1
Bloomfield – Gavins Point 115kV CKT 1	120	188.36	County Line – Neligh East 115kV CKT 1
Columbus – Genoa 115kV CKT 1	137	104.23	County Line – Neligh East 115kV CKT 1
County Line – Neligh East 115kV CKT 1	240	121.55	Bloomfield – Gavins Point 115kV CKT 1
Fort Randall – GEN-2014-023 Tap 230kV CKT 1	320	123.63	Kelly – Meadow Grove 230kV CKT 1
GEN-2014-059 Tap – Ogallala 230kV CKT 1	320	125.03	Keystone – Sidney 345kV CKT 1
Gentleman Generation Station Flowgate	1635	104.99	System intact
Grand Island – Holt County 345kV CKT 1	N/A	N/A	Non-Convergence Contingency
Grand Island – Holt County 345kV CKT 1	720	105.62	Fort Thompson – WAPA GI-0717/18 Tap 345kV CKT 1
Kelly – Meadow Grove 230kV CKT 1	368	110.64	Fort Randall – GEN-2014-023 Tap 230kV CKT 1
Norfolk – North Norfolk 115kV CKT 1	120	136.84	Hoskins – North Norfolk 115kV CKT 1
North Petersburg – Petersburg 115kV CKT 1	137	155.50	LN-1163-2

Cluster NRIS Constraints			
MONITORED ELEMENT	Limiting Rate A/B (MVA)	TC%LOADING (% MVA)	CONTINGENCY
Albion – Petersburg 115kV CKT 1	137	130.74	LN-1163-2
Battle Creek – County Line 115kV CKT 1	240	104.17	Bloomfield – Gavins Point 115kV CKT 1
Battle Creek – North Norfolk 115kV CKT 1	193	125.86	Bloomfield – Gavins Point 115kV CKT 1
Bloomfield – Gavins Point 115kV CKT 1	120	156.06	County Line – Neligh East 115kV CKT 1
County Line – Neligh East 115kV CKT 1	240	104.47	Bloomfield – Gavins Point 115kV CKT 1
Fort Randall – GEN-2014-023 Tap 230kV CKT 1	320	109.69	Kelly – Meadow Grove 230kV CKT 1
GEN-2014-059 Tap – Ogallala 230kV CKT 1	320	126.06	Keystone – Sidney 345kV CKT 1
Gentleman Generation Station Flowgate	1635	105.44	System intact
Norfolk – North Norfolk 115kV CKT 1	120	116.19	Hoskins – North Norfolk 115kV CKT 1
North Petersburg – Petersburg 115kV CKT 1	137	131.40	LN-1163-2
Victory Hill 230/115/13kV Transformer CKT 1	187	105.31	Stegall – Wayside 230kV CKT 1

Group 9 (Stand Alone)

The Interconnection Requests were studied as a Stand Alone Interconnection Request in addition to the Cluster Analysis. Fort Randall – GEN-2014-023 Tap 230kV, Meadow Grove – Kelly (Columbus) 230kV, and Albion – Petersburg – North Petersburg 115kV are constraints for Stand Alone Analysis for GEN-2014-023. An analysis for limited operation indicates that Limited Operation for GEN-2014-023 Interconnection Request will be limited to 6 MW prior to the in-service date of the upgrade(s) to alleviate these constraints. The Gentleman Generating Station ("GGS") flowgate and GEN-2014-059 Tap – Ogallala 230kV transmission circuit are constraints. An analysis for limited operation indicates that Limited Operation for GEN-2014-059 Interconnection Request will be limited to 0MW prior to the in-service date of the upgrade(s) to alleviate these constraints. Currently, GEN-2014-060 does not have any ERIS or NRIS constraints in the Stand Alone Analysis. Currently, GEN-2015-007 does not have any ERIS constraints in the Stand Alone Analysis. Various ERIS and NRIS constraints in the Petersburg, Neligh, Battle Creek, and Bloomfield area were identified in the GEN-2015-008 Stand Alone Analysis. An analysis for limited operation indicates that Limited Operation for GEN-2015-008 Interconnection Request will be limited to 0MW prior to the in-service date of the upgrade(s) to alleviate these constraints. Holt County – Grand Island 345kV is a constraint for

GEN-2015-023 Stand Alone Analysis. An analysis for limited operation indicates that Limited Operation for GEN-2015-023 Interconnection Request will be limited to 0MW prior to the in-service date of the upgrade(s) to alleviate these constraints. For Stand Alone Cost Allocation please refer to Appendix E1.

Group 9 (Limited Operation)

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

Limited Operation Analysis		
Interconnection Request	**MW**	**Constraint that most limits LOIS**
GEN-2014-023	6	Fort Randall – GEN-2014-023 Tap 230kV CKT 1
GEN-2014-059	0	GEN-2014-059 Tap – Ogallala 230kV CKT Gentleman – Red Willow Flowgate Gentleman Stability Limitations
GEN-2014-060	125.8	None
GEN-2015-007	160	None
GEN-2015-008	0	Various Most Limiting Constraints
GEN-2015-023	0	Holt County – Grand Island 345kV

Cluster Group 10 (Southeast Oklahoma/Northeast Texas Area)

In addition to the 0.0 MW of previously queued generation in the area, 0.0 MW of new interconnection service was studied. No new constraints were found in this area.

Cluster Group 12 (Northwest Arkansas Area)

In addition to the 30.0 MW of previously queued generation in the area, 60.0 MW of new interconnection service was studied. No new constraints were found in this area.

Cluster ERIS Constraints			
MONITORED ELEMENT	**Limiting Rate A/B (MVA)**	**TC%LOADING (% MVA)**	**CONTINGENCY**
Currently, No ERIS Group 13 constraints			

Cluster NRIS Constraints			
MONITORED ELEMENT	**Limiting Rate A/B (MVA)**	**TC%LOADING (% MVA)**	**CONTINGENCY**
Currently, No NRIS Group 13 constraints			

Group 12 (Stand Alone)

The Interconnection Requests were studied as a Stand Alone Interconnection Request in addition to the cluster analysis. Currently, no ERIS or NRIS mitigation constraints for GEN-2015-019 are identified in the Stand Alone Analysis. For Stand Alone Cost Allocation please refer to Appendix E1.

Group 12 (Limited Operation)

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

Limited Operation Analysis		
Interconnection Request	**MW**	**Constraint that most limits LOIS**
GEN-2015-019	60	None

Cluster Group 13 (Northeast Kansas/Northwest Missouri Area)

In addition to the 608.6 MW of previously queued generation in the area, 200.1 MW of new interconnection service was studied. No new constraints were found in this area. SPP Interconnection Service for GEN-2015-005 would be dependent on the in-service of the Nebraska City – Mullins Creek - Sibley 345kV transmission circuit that is part of the SPP Priority Projects per SPP-NTC-20097 and SPP-NTC-20098, and the decommissioning of the GEN-2015-005 temporary Point of Interconnection (POI) at Associated Electric Cooperative, Inc.'s (AECI) Osborn 161kV.

Cluster ERIS Constraints			
MONITORED ELEMENT	**Limiting Rate A/B (MVA)**	**TC%LOADING (% MVA)**	**CONTINGENCY**
Currently, No ERIS Group 13 constraints			

Cluster NRIS Constraints			
MONITORED ELEMENT	**Limiting Rate A/B (MVA)**	**TC%LOADING (% MVA)**	**CONTINGENCY**
Currently, No NRIS Group 13 constraints			

Group 13 (Stand Alone)

The Interconnection Requests were studied as a Stand Alone Interconnection Request in addition to the cluster analysis. Currently, no ERIS or NRIS mitigation constraints for GEN-2015-005 are identified in the Stand Alone Analysis. For Stand Alone Cost Allocation please refer to Appendix E1.

Group 13 (Limited Operation)

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

Limited Operation Analysis		
Interconnection Request	**MW**	**Constraint that most limits LOIS**
GEN-2015-005	200.1	None

Cluster Group 14 (South Central Oklahoma Area)

In addition to the 612.50 MW of previously queued generation in the area, 0.0 MW of new interconnection service was studied. No current studies, DISIS-2015-001 Interconnection Customers, are located in this geographical group.

Curtailment and System Reliability

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

Stability & Short Circuit Analysis

A stability and short circuit analysis is conducted for each Interconnection Customer using modified versions of the 2014 series SPP Model Development Working Group (MDWG) Models 2015 winter, 2015 summer, and 2025 summer peak dynamic cases[9]. The stability analysis is conducted with all upgrades in service that are identified in the power flow analysis unless otherwise noted in the individual group stability study. For each group, the interconnection requests are studied at 100% nameplate output while the other groups are dispatched at 20% output for Variable Energy Resource (VER) requests and 100% output for other requests. The output of the Interconnection Customer's facility is offset in each model by a reduction in output of existing online SPP generation. Each Interconnection Request is studied in a Stand Alone scenario in addition to the cluster scenario. A synopsis is included for each group. The entire stability study for each group can be found in the Appendices.

Short-circuit analysis is performed but verification of over-dutied equipment is performed by the Transmission Owner within the Interconnection Facilities Study. Results of that analysis may require additional costs to replace circuit breakers and associated equipment.

Cluster Group 1 (Woodward Area)

The Group 1 stability analysis for this area was performed by ABB. Stability analysis has determined that with all previously assigned and currently assigned Network Upgrades placed in service the transmission system will remain stable and low voltage ride through requirements are satisfied for the contingencies studied. Power Factor requirements are listed in the table below. In addition, some Interconnection Requests may have requirements for reactors under low wind conditions as identified in the ABB Group 1 report.

Power Factor Requirements:

Request	Size (MW)	Generator Model	Point of Interconnection	Power Factor Requirement at POI*	
				Lagging (supplying)	Leading (absorbing)
GEN-2015-029**	161	G.E. 2.3MW	Tatonga 345kV	0.95	0.95

*As reactive power is required for all projects, the final requirement in the GIA will be the pro-forma 95% lagging to 95% leading at the point of interconnection.
** Requirement for reactors for low wind conditions

Cluster Group 2 (Hitchland Area)

Due to late stage withdrawals of previously queued Interconnection Requests, the Group 2 stability analysis is being delayed for planned posting no later than August 31, 2015.

[9] Short Circuit analysis performed only on the 2025 Summer Peak seasonal model. Group 6 Stability Analysis also includes 2020 Summer and Winter Peak seasons.

Cluster Group 3 (Spearville Area)

The Group 3 stability analysis for this area was performed by S&C Electric Company (S&C). Stability analysis has determined that with all previously assigned and currently assigned Network Upgrades placed in service the transmission system will remain stable and low voltage ride through requirements are satisfied for the probable contingencies studied. Certain instabilities were encountered for extreme events that will be mitigated through generation curtailment. GEN-2015-021 tripped offline due to an over frequency violation for a contingency near its POI. The vendor of the solar generator will need to be contacted to determine if an extended frequency protection option is available. Power Factor requirements are listed in the table below. In addition, some Interconnection Requests may have requirements for reactors under low wind conditions as identified in the S&C Group 3 report.

Power Factor Requirements:

Request	Size (MW)	Generator Model	Point of Interconnection	Power Factor Requirement at POI*	
				Lagging (supplying)	Leading (absorbing)
GEN-2015-021	20	AE	Johnson Corner 115kV	0.95	0.95
GEN-2015-026	8.3	Siemens	Buckner 345kV	0.95	0.95
GEN-2015-027	4.5	Siemens	Crooked Creek 115kV	0.95	0.95
ASGI-2015-001	4.27/ 6.13	GENSAL	Ninnescah 115kV	0.95	0.95

*As reactive power is required for all projects, the final requirement in the GIA will be the pro-forma 95% lagging to 95% leading at the point of interconnection.
** Requirement for reactors for low wind conditions

Cluster Group 4 (Northwest Kansas)

The Group 4 stability analysis for this area was performed by Power-tek Global Inc. (Power-tek). Stability analysis has determined that with all previously assigned and currently assigned Network Upgrades placed in service the transmission system will remain stable and low voltage ride through requirements are satisfied for the probable contingencies studied. Power Factor requirements are listed in the table below. In addition, some Interconnection Requests may have requirements for reactors under low wind conditions as identified in the Power-tek report.

Power Factor Requirements:

Request	Size (MW)	Generator Model	Point of Interconnection	Power Factor Requirement at POI*	
				Lagging (supplying)	Leading (absorbing)
GEN-2010-048	70	Nordex 2.5MW	Tap on Ross Beach – Redline 69kV	0.95	0.95
GEN-2015-017	155/ 172	GENROU	Mingo 115kV	0.95	0.95

*As reactive power is required for all projects, the final requirement in the GIA will be the pro-forma 95% lagging to 95% leading at the point of interconnection.

** Requirement for reactors for low wind conditions

Cluster Group 5 (Amarillo Area)

Due to late stage withdrawals of previously queued Interconnection Requests, the Group 2 stability analysis is being delayed for planned posting no later than August 31, 2015.

Cluster Group 6 (South Texas Panhandle/New Mexico)

Due to late stage withdrawals of previously queued Interconnection Requests, the Group 2 stability analysis is being delayed for planned posting no later than August 31, 2015.

Cluster Group 7 (Southwest Oklahoma)

Due to late stage withdrawals of previously queued Interconnection Requests, the Group 2 stability analysis is being delayed for planned posting no later than August 31, 2015.

Cluster Group 8 (South Central Kansas/North Oklahoma)

The Group 8 stability analysis for this area was performed by Mitsubishi Electric Power Products Inc. (MEPPI). Stability analysis has determined that with all previously assigned and currently assigned Network Upgrades placed in service the transmission system will remain stable and low voltage ride through requirements are satisfied for the probable contingencies studied. Power Factor requirements are listed in the table below. In addition, some Interconnection Requests may have requirements for reactors under low wind conditions as identified in the Group 8 report.

Power Factor Requirements:

Request	Size (MW)	Generator Model	Point of Interconnection	Power Factor Requirement at POI*	
				Lagging (supplying)	Leading (absorbing)
GEN-2015-001**	200	Vestas V110 2.0MW	Ranch Road 345kV	0.95	0.95
GEN-2015-003**	200	Vestas V110 2.0MW	Renfrow 345kV	0.95	0.95
GEN-2015-015	154.5	Siemens 2.3MW with PowerBoost (2.415MW)	Tap Medford – Coyote 138kV	0.95	0.95
GEN-2015-016	200	Vestas V110 2.0MW	Tap Centerville – Marmaton 161kV	0.95	0.95
GEN-2015-024**	220	G.E. 2.0MW	Tap Wichita – Thistle 345kV	0.95	0.95
GEN-2015-025**	220	G.E. 2.0MW	Tap Wichita – Thistle 345kV	0.95	0.95
GEN-2015-028	3	Uprate from Siemens 2.3 to 2.415MW	Nardins 69kV	0.95	0.95
GEN-2015-030**	200.1	G.E. 2.3MW	Sooner 345kV	0.95	0.95
ASGI-2015-004	54.3/ 56.3	GENSAL	Coffeyville 69kV	0.95	0.95

*As reactive power is required for all projects, the final requirement in the GIA will be the pro-forma 95% lagging to 95% leading at the point of interconnection.

** Requirement for reactors for low wind conditions

Cluster Group 9 (Nebraska)

The Group 9 stability analysis for this area was performed by S&C Electric (S&C). Stability analysis has determined, with the exception of faults around Gerald Gentleman Station (GGS), that with all previously assigned and currently assigned Network Upgrades placed in service the transmission system will remain stable and low voltage ride through requirements are satisfied for the contingencies studied. **Additional analysis is required to further evaluate the effects of GEN-2014-059 on the Gerald Gentleman stability interface. This analysis will take place during the Facility Study.** GEN-2015-023 exhibited instability for certain contingencies in the 2015 summer peak and the 2015 winter peak cases. If GEN-2015-023 requires service prior to the in-service date of the Gentleman – Cherry County/Thedford – Holt County 345kV Project ("R-Plan") previously assigned in SPP 2012 Integrated Transmission Plan 10 Year Assessment (ITP10), per SPP-NTC-200220, the Interconnection Customer will need to request an advancement of this upgrade. Power Factor requirements are listed in the table below. In addition, some Interconnection Requests may have requirements for reactors under low wind conditions as identified in the Group 9 report.

Power Factor Requirements:

Request	Size (MW)	Generator Model	Point of Interconnection	Power Factor Requirement at POI*	
				Lagging (supplying)	Leading (absorbing)
GEN-2014-023**	79.9	G.E. 1.7MW	Tap Fort Randall-Meadow Grove 230kV	0.95	0.95
GEN-2014-059**	160	G.E. 1.79MW	Tap Sidney-Ogallala 230kV	0.95	0.95
GEN-2014-060	125.8	G.E. 1.70MW	Tap Pauline-Hildreth 115kV	0.95	0.95
GEN-2015-007	160	G.E.	Hoskins 345kV	0.95	0.95
GEN-2015-008	150.4	G.E.	Antelope 115kV	0.95	0.95
GEN-2015-023	300.8	G.E.	Holt County 345kV	0.95	0.95

*As reactive power is required for all projects, the final requirement in the GIA will be the pro-forma 95% lagging to 95% leading at the point of interconnection.
** Requirement for reactors for low wind conditions

Cluster Group 10 (Southeast Oklahoma/Northeast Texas Area)

There were no customers requesting interconnection service in the southeast Oklahoma/northeast Texas area.

Cluster Group 12 (Northwest Arkansas Area)

The Group 12 stability analysis for this area was performed by ABB. Stability analysis has determined that with all previously assigned and currently assigned Network Upgrades placed in service the transmission system will remain stable and low voltage ride through requirements are satisfied for the probable contingencies studied. Power Factor requirements are listed in the table below.

Power Factor Requirements:

Request	Size (MW)	Generator Model	Point of Interconnection	Power Factor Requirement at POI*	
				Lagging (supplying)	Leading (absorbing)
GEN-2015-019	60	GENROU	Fitzhugh 161kV	0.95	0.95

*As reactive power is required for all projects, the final requirement in the GIA will be the pro-forma 95% lagging to 95% leading at the point of interconnection.
** Requirement for reactors for low wind conditions

Cluster Group 13 (Northwest Missouri Area)

The Group 13 stability analysis for this area was performed by Power-tek Global (Power-tek). Stability analysis has determined that with all previously assigned and currently assigned Network Upgrades placed in service the transmission system will remain stable and low voltage ride through requirements are satisfied for the probable contingencies studied. Power Factor requirements are listed in the table below. In addition, some Interconnection Requests may have requirements for reactors under low wind conditions as identified in the Power-tek report.

Power Factor Requirements:

Request	Size (MW)	Generator Model	Point of Interconnection	Power Factor Requirement at POI*	
				Lagging (supplying)	Leading (absorbing)
GEN-2015-005**	200	G.E. 1.79MW	Tap Nebraska City – Mullens Creek 345kV	0.95	0.95

*As reactive power is required for all projects, the final requirement in the GIA will be the pro-forma 95% lagging to 95% leading at the point of interconnection.
** Requirement for reactors for low wind conditions

Cluster Group 14 (South Central Oklahoma)

There were no customers requesting Interconnection Service in the south central Oklahoma area.

Conclusion

The minimum cost of interconnecting 5,460.29 MW of new generation interconnection requests included in this Definitive Interconnection System Impact Study is estimated at $229,843,633 (exclusive of Group 2, 5, 6, and 7 Interconnection Requests Costs) for the Allocated Network Upgrades and Transmission Owner Interconnection Facilities listed in Appendix E and F. These costs do not include the cost of upgrades of other transmission facilities listed in Appendix H which are Network Constraints. These interconnection costs do not include any cost of any Network Upgrades that are identified as required through the short circuit analysis. Potential over-dutied circuit breakers capability will be identified by the Transmission Owner in the Interconnection Facilities Study.

Further refinement of total estimated interconnection costs will be provided, should the Interconnection Customer meet the requirements for acceptance and choose to move into the Interconnection Facilities Study following the posting of this DISIS. The Interconnection Facilities Study may include additional study analysis, additional facility upgrades not yet identified by this DISIS, such as circuit breaker replacements and affected system facilities, and further refinement of existing cost estimates. Acceptance into the Interconnection Facilities Study requires execution of the Interconnection Facilities Study Agreement, additional security deposit of $3,000/MW of request, and other required data as requested by SPP. More information regarding the next steps as an Interconnection Customer may be found in Section 8.6 of the GIP. Requirements for acceptance into the Interconnection Facilities Study can be found in Section 8.9 of the GIP.

The required interconnection costs listed in Appendices E, and F, and other upgrades associated with Network Constraints do not include all costs associated with the deliverability of the energy to final customers. These costs are determined by separate studies if the Customer submits a Transmission Service Request (TSR) through SPP's Open Access Same Time Information System (OASIS) as required by Attachment Z1 of the SPP Open Access Transmission Tariff (OATT).

Appendices

A: Generation Interconnection Requests Considered for Impact Study

See next page.

A: Generation Interconnection Requests Considered for Study

Request	Amount	Service	Area	Requested Point of Interconnection	Proposed Point of Interconnection	Requested In-Service Date	In Service Date Delayed Until no earlier than*
ASGI-2015-001	6.13	ER	SUNCMKEC	Ninnescah 115kV	Ninnescah 115kV		TBD
ASGI-2015-002	2.00	ER	SPS	SP-Yuma 69kV	SP-Yuma 69kV		TBD
ASGI-2015-003	30.00	ER	SPS	Tap San Jon Tap - Wheatland 115/69kV	Tap San Jon Tap - Wheatland 115/69kV		TBD
ASGI-2015-004	56.36	ER	GRDA	Coffeyville City 69kV	Coffeyville City 69kV		TBD
GEN-2010-048	70.00	ER	MIDW	Tap Beach Station - Redline 115kV	Tap Beach Station - Redline 115kV	12/30/2017	TBD
GEN-2014-023	79.90	ER/NR	NPPD	Tap Fort Randall - Meadow Grove 230kV	Tap Fort Randall - Meadow Grove 230kV	12/31/2015	TBD
GEN-2014-037	200.00	ER	SPS	Tap Hitchland - Beaver County Dbl Ckt (Optima) 345kV	Tap Hitchland - Beaver County Dbl Ckt (Optima) 345kV	9/30/2017	TBD
GEN-2014-038	200.00	ER	SPS	Tap Hitchland - Potter County 345kV	Tap Hitchland - Potter County 345kV	9/30/2017	TBD
GEN-2014-046	125.40	ER/NR	SPS	Chaves County 115kV	Chaves County 115kV	5/1/2016	TBD
GEN-2014-059	160.00	ER/NR	NPPD	Tap Sidney - Ogallala 230kV	Tap Sidney - Ogallala 230kV	9/1/2016	TBD
GEN-2014-060	125.80	ER/NR	NPPD	Tap Pauline - Hildreth (Rosemont) 115kV	Tap Pauline - Hildreth (Rosemont) 115kV	12/31/2015	TBD
GEN-2014-065	99.00	ER/NR	SPS	Whitten 115kV	Whitten 115kV	12/31/2016	TBD
GEN-2014-068	203.00	ER/NR	SPS	Tap Deaf Smith - Plant X 230kV	Tap Deaf Smith - Plant X 230kV	3/1/2019	TBD
GEN-2014-074	152.00	ER/NR	SPS	Tap TUCO Interchange - Oklaunion 345kV	Tap TUCO Interchange - Oklaunion 345kV	10/31/2017	TBD
GEN-2015-001	200.00	ER/NR	OKGE	Ranch Road 345kV	Ranch Road 345kV	12/31/2016	TBD
GEN-2015-003	200.00	ER	OKGE	Renfrow 345kV	Renfrow 345kV	12/31/2017	TBD
GEN-2015-004	52.90	ER	OKGE	Border 345kV	Border 345kV	5/15/2017	TBD
GEN-2015-005	200.10	ER	GMO	Tap Nebraska City - Sibley 345kV	Tap Nebraska City - Sibley 345kV	12/31/2017	TBD
GEN-2015-006	150.00	ER	OKGE	Beaver County 345kV	Beaver County 345kV	12/31/2017	TBD
GEN-2015-007	160.00	ER	NPPD	Hoskins 345kV	Hoskins 345kV	12/31/2016	TBD
GEN-2015-008	150.40	ER/NR	NPPD	Antelope 115kV	Antelope 115kV	12/1/2016	TBD
GEN-2015-009	300.00	ER/NR	SPS	Hobbs 230kV	Hobbs 230kV	9/1/2020	TBD
GEN-2015-010	250.70	ER	SPS	Curry County 115kV	Tap South Roosvelt - Tolk 230kV	12/1/2017	TBD
GEN-2015-013	120.00	ER/NR	WFEC	Synder 138kV	Synder 138kV	12/1/2016	TBD
GEN-2015-014	150.00	ER	SPS	Lehman 115kV	Tap Cochran - Lehman 115kV	12/1/2016	TBD
GEN-2015-015	154.60	ER/NR	OKGE	Tap Medford Tap - Coyote 138kV	Tap Medford Tap - Coyote 138kV	7/31/2016	TBD
GEN-2015-016	200.00	ER/NR	KCPL	Tap Marmaton - Centerville 161kV	Tap Marmaton - Centerville 161kV	12/31/2017	TBD
GEN-2015-017	172.00	ER/NR	SUNCMKEC	Mingo 115kV	Mingo 115kV	8/1/2018	TBD
GEN-2015-018	80.00	ER/NR	SPS	Tap Curry County - Bailey 115kV	Tap Curry County - Bailey 115kV	12/31/2016	TBD
GEN-2015-019	60.00	ER/NR	AEPW	Fitzhugh 161kV	Fitzhugh 161kV	1/1/2017	TBD
GEN-2015-020	99.96	ER/NR	SPS	Oasis 115kV	Oasis 115kV	12/1/2016	TBD
GEN-2015-021	20.00	ER/NR	SUNCMKEC	Johnson Corner 115kV	Johnson Corner 115kV	12/31/2016	TBD
GEN-2015-022	112.00	ER/NR	SPS	Swisher 115kV	Swisher 115kV	12/1/2016	TBD
GEN-2015-023	300.70	ER/NR	NPPD	Holt County 345kV	Holt County 345kV	12/31/2019	TBD
GEN-2015-024	220.00	ER	WERE	Wichita 345kV	Tap Thistle - Wichita 345kV Dbl CKT	12/31/2016	TBD
GEN-2015-025	220.00	ER	WERE	Wichita 345kV	Tap Thistle - Wichita 345kV Dbl CKT	12/31/2016	TBD
GEN-2015-026	8.30	ER	SUNCMKEC	Buckner 345kV	Buckner 345kV	3/1/2016	TBD
GEN-2015-027	4.94	ER	SUNCMKEC	Crooked Creek 115kV	Crooked Creek 115kV	3/1/2016	TBD
GEN-2015-028	3.00	ER	OKGE	Nardins 69kV	Nardins 69kV	3/1/2016	TBD
GEN-2015-029	161.00	ER	OKGE	Tatonga 345kV	Tatonga 345kV	12/1/2016	TBD

Request	Amount	Service	Area	Requested Point of Interconnection	Proposed Point of Interconnection	Requested In-Service Date	In Service Date Delayed Until no earlier than*
GEN-2015-030	200.10	ER	OKGE	Sooner 345kV	Sooner 345kV	12/1/2017	TBD
Total:	**5,460.29**						

*In-Service Date for each request is to be determined after the Interconnection Facility Study is completed.

B: Prior Queued Interconnection Requests

See next page.

B: Prior Queued Interconnection Requests

Request	Amount	Area	Requested/Proposed Point of Interconnection	Status or In-Service Date
ASGI-2010-006	150.00	AECI	Tap Fairfax (AECI) - Shilder (AEPW) 138kV	AECI queue Affected Study
ASGI-2010-010	42.20	SPS	Lovington 115kV	Lea County Affected Study
ASGI-2010-020	30.00	SPS	Tap LE-Tatum - LE-Crossroads 69kV	Lea County Affected Study
ASGI-2010-021	15.00	SPS	Tap LE-Saunders Tap - LE-Anderson 69kV	Lea County Affected Study
ASGI-2011-001	27.30	SPS	Lovington 115kV	On-Line
ASGI-2011-002	20.00	SPS	Herring 115kV	On-Line
ASGI-2011-003	10.00	SPS	Hendricks 115kV	On-Line
ASGI-2011-004	20.00	SPS	Pleasant Hill 69kV	Under Study (DISIS-2011-002)
ASGI-2012-002	18.15	SPS	FE-Clovis Interchange 115kV	Under Study (DISIS-2012-002)
ASGI-2012-006	22.50	SUNCMKEC	Tap Hugoton - Rolla 69kV	Under Study (DISIS-2012-001)
ASGI-2013-001	11.50	SPS	PanTex South 115kV	Under Study (DISIS-2013-001)
ASGI-2013-002	18.40	SPS	FE Tucumcari 115kV	Under Study (DISIS-2013-001)
ASGI-2013-003	18.40	SPS	FE Clovis 115kV	Under Study (DISIS-2013-001)
ASGI-2013-004	36.60	SUNCMKEC	Morris 115kV	Under Study (DISIS-2013-002)
ASGI-2013-005	1.65	SPS	FE Clovis 115kV	Under Study (DISIS-2013-002)
ASGI-2013-006	2.00	SPS	SP-Erskine 115kV	
ASGI-2014-001	2.50	SPS	SP-Erskine 115kV	Under Study (DISIS-2014-001)
ASGI-2014-002	49.60	SPS	Tap Tucumcari - Santa Rosa 115kV	Under Study (DISIS-2014-001)
ASGI-2014-005	10.00	SPS	Strata 69kV	Under Study (DISIS-2014-002)
ASGI-2014-008	10.00	SPS	South Loving 69kV	Under Study (DISIS-2014-002)
ASGI-2014-009	10.00	SPS	Wood Draw 115kV	Under Study (DISIS-2014-002)
ASGI-2014-010	10.00	SPS	Ochoa 115kV	Under Study (DISIS-2014-002)
ASGI-2014-012	10.00	SPS	Cooper Ranch 115kV	Under Study (DISIS-2014-002)
ASGI-2014-014	56.40	GRDA	Ferguson 69kV	Under Study (DISIS-2014-002)
GEN-2001-014	96.00	WFEC	Ft Supply 138kV	On-Line
GEN-2001-026	74.30	WFEC	Washita 138kV	On-Line
GEN-2001-033	180.00	SPS	San Juan Tap 230kV	On-Line at 120MW
GEN-2001-036	80.00	SPS	Norton 115kV	On-Line
GEN-2001-037	100.00	OKGE	FPL Moreland Tap 138kV	On-Line
GEN-2001-039A	105.00	SUNCMKEC	Shooting Star Tap 115kV	On-Line
GEN-2001-039M	100.00	SUNCMKEC	Central Plains Tap 115kV	On-Line
GEN-2002-004	200.00	WERE	Latham 345kV	On-Line at 150MW
GEN-2002-005	120.00	WFEC	Red Hills Tap 138kV	On-Line
GEN-2002-008	240.00	SPS	Hitchland 345kV	On-Line at 120MW
GEN-2002-009	80.00	SPS	Hansford 115kV	On-Line
GEN-2002-022	240.00	SPS	Bushland 230kV	On-Line
GEN-2002-023N	0.80	NPPD	Harmony 115kV	On-Line
GEN-2002-025A	150.00	SUNCMKEC	Spearville 230kV	On-Line
GEN-2003-004	100.00	WFEC	Washita 138kV	On-Line
GEN-2003-005	100.00	WFEC	Anadarko - Paradise (Blue Canyon) 138kV	On-Line
GEN-2003-006A	200.00	SUNCMKEC	Elm Creek 230kV	On-Line
GEN-2003-019	250.00	MIDW	Smoky Hills Tap 230kV	On-Line
GEN-2003-020	160.00	SPS	Martin 115kV	On-Line
GEN-2003-021N	75.00	NPPD	Ainsworth Wind Tap 115kV	On-Line
GEN-2003-022	120.00	AEPW	Washita 138kV	On-Line
GEN-2004-014	154.50	SUNCMKEC	Spearville 230kV	On-Line at 100MW
GEN-2004-020	27.00	AEPW	Washita 138kV	On-Line

Request	Amount	Area	Requested/Proposed Point of Interconnection	Status or In-Service Date
GEN-2004-023	20.60	WFEC	Washita 138kV	On-Line
GEN-2004-023N	75.00	NPPD	Columbus Co 115kV	On-Line
GEN-2005-003	30.60	WFEC	Washita 138kV	On-Line
GEN-2005-008	120.00	OKGE	Woodward 138kV	On-Line
GEN-2005-012	250.00	SUNCMKEC	Ironwood 345kV	On-Line at 160MW
GEN-2005-013	201.00	WERE	Caney River 345kV	On-Line
GEN-2006-002	101.00	AEPW	Sweetwater 230kV	On-Line
GEN-2006-006	205.50	SUNCMKEC	Spearville 345kV	On Suspension
GEN-2006-018	170.00	SPS	TUCO Interchange 230kV	On-Line
GEN-2006-020N	42.00	NPPD	Bloomfield 115kV	On-Line
GEN-2006-020S	18.90	SPS	DWS Frisco 115kV	On-Line
GEN-2006-021	101.00	SUNCMKEC	Flat Ridge Tap 138kV	On-Line
GEN-2006-024S	19.80	WFEC	Buffalo Bear Tap 69kV	On-Line
GEN-2006-026	502.00	SPS	Hobbs 230kV & Hobbs 115kV	On-Line
GEN-2006-031	75.00	MIDW	Knoll 115kV	On-Line
GEN-2006-035	225.00	AEPW	Sweetwater 230kV	On-Line at 132MW
GEN-2006-037N1	75.00	NPPD	Broken Bow 115kV	On-Line
GEN-2006-038N005	80.00	NPPD	Broken Bow 115kV	On-Line
GEN-2006-038N019	80.00	NPPD	Petersburg North 115kV	On-Line
GEN-2006-043	99.00	AEPW	Sweetwater 230kV	On-Line
GEN-2006-044	370.00	SPS	Hitchland 345kV	On-Line at 120MW
GEN-2006-044N	40.50	NPPD	North Petersburg 115kV	On-Line
GEN-2006-046	131.00	OKGE	Dewey 138kV	On-Line
GEN-2007-011N08	81.00	NPPD	Bloomfield 115kV	On-Line
GEN-2007-021	201.00	OKGE	Tatonga 345kV	On-Line
GEN-2007-025	300.00	WERE	Viola 345kV	On-Line
GEN-2007-032	150.00	WFEC	Tap Clinton Junction - Clinton 138kV	On Suspension
GEN-2007-040	200.00	SUNCMKEC	Buckner 345kV	On-Line at 132MW
GEN-2007-043	200.00	OKGE	Minco 345kV	On-Line
GEN-2007-044	300.00	OKGE	Tatonga 345kV	On-Line at 199MW
GEN-2007-046	200.00	SPS	Hitchland 115kV	On Schedule for 2015
GEN-2007-050	170.00	OKGE	Woodward EHV 138kV	On-Line at 150MW
GEN-2007-052	150.00	WFEC	Anadarko 138kV	On-Line
GEN-2007-062	765.00	OKGE	Woodward EHV 345kV	On Schedule for 2016 and 2017
GEN-2008-003	101.00	OKGE	Woodward EHV 138kV	On-Line
GEN-2008-013	300.00	OKGE	Hunter 345kV	On-Line at 235MW
GEN-2008-017	300.00	SUNCMKEC	Setab 345kV	On Schedule for 2017
GEN-2008-018	250.00	SPS	Finney 345kV	On-Line
GEN-2008-021	42.00	WERE	Wolf Creek 345kV	On-Line
GEN-2008-022	300.00	SPS	Tap Tolk - Eddy County (Crossroads) 345kV	On Schedule for 2015
GEN-2008-023	150.00	AEPW	Hobart Junction 138kV	On-Line
GEN-2008-037	101.00	WFEC	Tap Washita - Blue Canyon Wind 138kV	On-Line
GEN-2008-044	197.80	OKGE	Tatonga 345kV	On-Line
GEN-2008-047	300.00	OKGE	Beaver County 345kV	On-Line
GEN-2008-051	322.00	SPS	Potter County 345kV	On-Line at 161MW
GEN-2008-079	99.20	SUNCMKEC	Crooked Creek 115kV	On-Line
GEN-2008-086N02	201.00	NPPD	Meadow Grove 230kV	On-Line
GEN-2008-092	201.00	MIDW	Post Rock 230kV	On Schedule for 2015
GEN-2008-098	100.80	WERE	Waverly 345kV	On Schedule for 2015
GEN-2008-119O	60.00	OPPD	S1399 161kV	On-Line

Request	Amount	Area	Requested/Proposed Point of Interconnection	Status or In-Service Date
GEN-2008-123N	89.70	NPPD	Tap Pauline - Hildreth (Rosemont) 115kV	On Schedule for 2015
GEN-2008-124	200.10	SUNCMKEC	Ironwood 345kV	On Schedule for 2016
GEN-2008-129	80.00	GMO	Pleasant Hill 161kV	On-Line
GEN-2009-008	199.50	MIDW	South Hays 230kV	On Schedule for 2015
GEN-2009-020	48.30	MIDW	Tap Nekoma - Bazine (Walnut Creek) 69kV	On Schedule for 2015
GEN-2009-025	59.80	OKGE	Nardins 69kV	On-Line
GEN-2009-040	73.80	WERE	Marshall 115kV	On Schedule for 2016
GEN-2010-001	300.00	OKGE	Beaver County 345kV	On-Line at 204 MW, On Schedule for 2015 (96 MW)
GEN-2010-003	100.80	WERE	Waverly 345kV	On Schedule for 2015
GEN-2010-005	299.20	WERE	Viola 345kV	On-Line at 170MW
GEN-2010-006	205.00	SPS	Jones 230kV	On-Line
GEN-2010-009	165.60	SUNCMKEC	Buckner 345kV	On-Line
GEN-2010-011	29.70	OKGE	Tatonga 345kV	On-Line
GEN-2010-014	358.80	SPS	Hitchland 345kV	On Suspension
GEN-2010-036	4.60	WERE	6th Street 115kV	On-Line
GEN-2010-040	300.00	OKGE	Cimarron 345kV	On-Line
GEN-2010-041	10.50	OPPD	S1399 161kV	On Schedule for 2015
GEN-2010-045	197.80	SUNCMKEC	Buckner 345kV	On Schedule for 2017
GEN-2010-046	56.00	SPS	TUCO Interchange 230kV	On Schedule for 2016
GEN-2010-051	200.00	NPPD	Tap Twin Church - Hoskins 230kV	On Suspension
GEN-2010-055	4.50	AEPW	Wekiwa 138kV	On-Line
GEN-2010-057	201.00	MIDW	Rice County 230kV	On-Line
GEN-2011-008	600.00	SUNCMKEC	Clark County 345kV	On Schedule for 2016
GEN-2011-010	100.80	OKGE	Minco 345kV	On-Line
GEN-2011-011	50.00	KCPL	Iatan 345kV	On-Line
GEN-2011-014	201.00	OKGE	Tap Hitchland - Woodward Dbl Ckt (GEN-2011-014 Tap) 345kV	On Schedule for 2016
GEN-2011-016	200.10	SUNCMKEC	Spearville 345kV	Facility Study Stage
GEN-2011-017	299.00	SUNCMKEC	Tap Spearville - Post Rock (GEN-2011-017T) 345kV	On Schedule for 2018
GEN-2011-018	73.60	NPPD	Steele City 115kV	On-Line
GEN-2011-019	299.00	OKGE	Woodward 345kV	On Suspension
GEN-2011-020	299.00	OKGE	Woodward 345kV	On Suspension
GEN-2011-022	299.00	SPS	Hitchland 345kV	On Suspension
GEN-2011-025	80.00	SPS	Tap Floyd County - Crosby County 115kV	On Schedule for 2016
GEN-2011-027	120.00	NPPD	Hoskins 230kV	On Suspension
GEN-2011-037	7.00	WFEC	Blue Canyon 5 138kV	On-Line
GEN-2011-040	111.00	OKGE	Carter County 138kV	On-Line
GEN-2011-045	205.00	SPS	Jones 230kV	On-Line
GEN-2011-046	27.00	SPS	Lopez 115kV	On-Line
GEN-2011-048	175.00	SPS	Mustang 230kV	On-Line
GEN-2011-049	250.70	OKGE	Border 345kV	On Schedule for 2016
GEN-2011-050	109.80	AEPW	Santa Fe Tap 138kV	On Schedule for 2016
GEN-2011-051	104.40	OKGE	Tap Woodward - Tatonga 345kV (GEN-2011-051 Tap)	On Suspension
GEN-2011-054	300.00	OKGE	Cimarron 345kV	On Schedule for 2015
GEN-2011-056	3.60	NPPD	Jeffrey 115kV	On-Line
GEN-2011-056A	3.60	NPPD	John 1 115kV	On-Line
GEN-2011-056B	4.50	NPPD	John 2 115kV	On-Line
GEN-2011-057	150.40	WERE	Creswell 138kV	On Schedule for 2015
GEN-2012-001	61.20	SPS	Cirrus Tap 230kV	On-Line

Request	Amount	Area	Requested/Proposed Point of Interconnection	Status or In-Service Date
GEN-2012-004	41.40	OKGE	Carter County 138kV	On-Line
GEN-2012-007	120.00	SUNCMKEC	Rubart 115kV	On-Line
GEN-2012-009	15.00	SPS	Mustang 230kV	On-Line
GEN-2012-010	15.00	SPS	Mustang 230kV	On-Line
GEN-2012-020	478.00	SPS	TUCO 230kV	On Schedule for 2016
GEN-2012-021	4.80	LES	Terry Bundy Generating Station 115kV	On-Line
GEN-2012-024	180.00	SUNCMKEC	Clark County 345kV	On Schedule for 2016
GEN-2012-027	136.00	AEPW	Shidler 138kV	On Suspension
GEN-2012-028	74.80	WFEC	Gotebo 69kV	On Schedule for 2015
GEN-2012-032	300.00	OKGE	Open Sky 345kV	On Schedule for 2015
GEN-2012-033	98.80	OKGE	Tap and Tie South 4th - Bunch Creek & Enid Tap - Fairmont (GEN-2012-033T) 138kV	On Schedule for 2015
GEN-2012-034	7.00	SPS	Mustang 230kV	On-Line
GEN-2012-035	7.00	SPS	Mustang 230kV	On-Line
GEN-2012-036	7.00	SPS	Mustang 230kV	On-Line
GEN-2012-037	203.00	SPS	TUCO 345kV	On-Line
GEN-2012-040	76.50	WFEC	Chilocco 138kV	On Suspension
GEN-2012-041	121.50	OKGE	Ranch Road 345kV	On-Line
GEN-2013-002	50.60	LES	Tap Sheldon - Folsom & Pleasant Hill (GEN-2013-002 Tap) 115kV CKT 2	On Schedule for 2016
GEN-2013-007	100.30	OKGE	Tap Prices Falls - Carter 138kV	On Schedule for 2015
GEN-2013-008	1.20	NPPD	Steele City 115kV	On-Line
GEN-2013-010	99.00	SUNCMKEC	Tap Spearville - Post Rock (North of GEN-2011-017 Tap) 345kV	Facility Study
GEN-2013-011	30.00	AEPW	Turk 138kV	On-Line
GEN-2013-012	147.00	OKGE	Redbud 345kV	On-Line
GEN-2013-014	25.50	NPPD	Tap Guide Rock - Pauline (Rosemont) 115kV	On Suspension
GEN-2013-016	203.00	SPS	TUCO 345kV	IA Pending
GEN-2013-019	73.60	LES	Tap Sheldon - Folsom & Pleasant Hill (GEN-2013-002 Tap) 115kV CKT 2	On Schedule for 2016
GEN-2013-022	25.00	SPS	Norton 115kV	On Schedule for 2016
GEN-2013-027	150.00	SPS	Tap Tolk - Yoakum 230kV	Facility Study
GEN-2013-028	559.50	GRDA	Tap N Tulsa - GRDA 1 345kV	On Schedule for 2017
GEN-2013-029	300.00	OKGE	Renfrow 345kV	On Schedule for 2016 (150MW) and 2016 (150MW)
GEN-2013-030	300.00	OKGE	Beaver County 345kV	On Schedule for 2016 (200MW) and 2017 (100MW)
GEN-2013-032	204.00	NPPD	Antelope 115kV	On Schedule for 2017
GEN-2013-033	28.00	MIDW	Goodman Energy Center 115kV	On Schedule for 2016
GEN-2014-001	200.60	WERE	Tap Wichita - Emporia Energy Center 345kV	IA Pending
GEN-2014-002	10.50	OKGE	Tatonga 345kV (GEN-2007-021 POI)	Facility Study Stage
GEN-2014-003	15.84	OKGE	Tatonga 345kV (GEN-2007-044 POI)	Facility Study Stage
GEN-2014-004	4.00	NPPD	Steele City 115kV (GEN-2011-018 POI)	Facility Study Stage
GEN-2014-005	5.70	OKGE	Minco 345kV (GEN-2011-010 POI)	On-Line
GEN-2014-012	225.00	SPS	Tap Hobbs Interchange - Andrews 230kV	IA Pending
GEN-2014-013	73.50	NPPD	Meadow Grove (GEN-2008-086N2 Sub) 230kV	On Schedule for 2015
GEN-2014-020	100.00	AEPW	Tuttle 138kV	Facility Study
GEN-2014-021	300.00	GMO	Tap Nebraska City - Mullin Creek 345kV	Facility Study
GEN-2014-025	2.40	MIDW	Tap Nekoma - Bazine (Walnut Creek) 69kV	Facility Study
GEN-2014-026	150.00	OKGE	Beaver County 345kV	Facility Study
GEN-2014-028	35.00	EMDE	Riverton 161kV	Facility Study
GEN-2014-031	35.80	NPPD	Meadow Grove 230kV	Facility Study

Request	Amount	Area	Requested/Proposed Point of Interconnection	Status or In-Service Date
GEN-2014-032	10.20	NPPD	Meadow Grove 230kV	Facility Study
GEN-2014-033	70.00	SPS	Chaves County 115kV	Facility Study
GEN-2014-034	70.00	SPS	Chaves County 115kV	Facility Study
GEN-2014-035	30.00	SPS	Chaves County 115kV	Facility Study
GEN-2014-039	73.40	NPPD	Friend 115kV	Facility Study
GEN-2014-040	320.00	SPS	Castro 115kV	IA Pending
GEN-2014-041	120.80	SUNCMKEC	Arnold 115kV	Facility Study
GEN-2014-047	40.00	SPS	Tap Tolk - Eddy County (Crossroads) 345kV	Facility Study
GEN-2014-049	200.00	SUNCMKEC	Thistle 345kV	Facility Study
GEN-2014-051	174.00	WERE	Jeffrey Energy Center 345kV	Facility Study
GEN-2014-053	80.00	SPS	Carlisle 230kV	Facility Study
GEN-2014-054	120.00	SPS	Carlisle 230kV	Facility Study
GEN-2014-056	250.00	OKGE	Minco 345kV	Facility Study
GEN-2014-057	250.00	AEPW	Tap Lawton - Sunnyside 345kV	IA Pending
GEN-2014-064	248.40	OKGE	Otter 138kV	IA Pending
GEN-2014-066	30.00	SPS	Norton 115kV	Facility Study
Gray County Wind (Montezuma)	110.00	SUNCMKEC	Gray County Tap 115kV	On-Line
Llano Estacado (White Deer)	80.00	SPS	Llano Wind 115kV	On-Line
NPPD Distributed (Broken Bow)	8.30	NPPD	Broken Bow 115kV	On-Line
NPPD Distributed (Buffalo County Solar)	10.00	NPPD	Kearney Northeast	On-Line
NPPD Distributed (Burt County Wind)	12.00	NPPD	Tekamah & Oakland 115kV	On-Line
NPPD Distributed (Burwell)	3.00	NPPD	Ord 115kV	On-Line
NPPD Distributed (Columbus Hydro)	45.00	NPPD	Columbus 115kV	On-Line
NPPD Distributed (North Platte - Lexington)	54.00	NPPD	Multiple: Jeffrey 115kV, John_1 115kV, John_2 115kV	On-Line
NPPD Distributed (Ord)	11.90	NPPD	Ord 115kV	On-Line
NPPD Distributed (Stuart)	2.10	NPPD	Ainsworth 115kV	On-Line
SPS Distributed (Dumas 19th St)	20.00	SPS	Dumas 19th Street 115kV	On-Line
SPS Distributed (Etter)	20.00	SPS	Etter 115kV	On-Line
SPS Distributed (Hopi)	10.00	SPS	Hopi 115kV	On-Line
SPS Distributed (Jal)	10.00	SPS	S Jal 115kV	On-Line
SPS Distributed (Lea Road)	10.00	SPS	Lea Road 115kV	On-Line
SPS Distributed (Monument)	10.00	SPS	Monument 115kV	On-Line
SPS Distributed (Moore E)	25.00	SPS	Moore East 115kV	On-Line
SPS Distributed (Ocotillo)	10.00	SPS	S_Jal 115kV	On-Line
SPS Distributed (Sherman)	20.00	SPS	Sherman 115kV	On-Line
SPS Distributed (Spearman)	10.00	SPS	Spearman 69kV	On-Line
SPS Distributed (TC-Texas County)	20.00	SPS	Texas County 115kV	On-Line
SPS Distributed (Yuma)	2.57	SPS	SP-Yuma 69kV	On-Line
Total:	**27,581.4**			

C: Study Groupings

See next page

C. Study Groups

GROUP 1: WOODWARD AREA			
Request	Capacity	Area	Proposed Point of Interconnection
GEN-2001-014	96.00	WFEC	Ft Supply 138kV
GEN-2001-037	100.00	OKGE	FPL Moreland Tap 138kV
GEN-2005-008	120.00	OKGE	Woodward 138kV
GEN-2006-024S	19.80	WFEC	Buffalo Bear Tap 69kV
GEN-2006-046	131.00	OKGE	Dewey 138kV
GEN-2007-021	201.00	OKGE	Tatonga 345kV
GEN-2007-043	200.00	OKGE	Minco 345kV
GEN-2007-044	300.00	OKGE	Tatonga 345kV
GEN-2007-050	170.00	OKGE	Woodward EHV 138kV
GEN-2007-062	765.00	OKGE	Woodward EHV 345kV
GEN-2008-003	101.00	OKGE	Woodward EHV 138kV
GEN-2008-044	197.80	OKGE	Tatonga 345kV
GEN-2010-011	29.70	OKGE	Tatonga 345kV
GEN-2010-040	300.00	OKGE	Cimarron 345kV
GEN-2011-010	100.80	OKGE	Minco 345kV
GEN-2011-019	299.00	OKGE	Woodward 345kV
GEN-2011-020	299.00	OKGE	Woodward 345kV
GEN-2011-051	104.40	OKGE	Tap Woodward - Tatonga 345kV (GEN-2011-051 Tap)
GEN-2011-054	300.00	OKGE	Cimarron 345kV
GEN-2014-002	10.50	OKGE	Tatonga 345kV (GEN-2007-021 POI)
GEN-2014-003	15.84	OKGE	Tatonga 345kV (GEN-2007-044 POI)
GEN-2014-005	5.70	OKGE	Minco 345kV (GEN-2011-010 POI)
GEN-2014-020	100.00	AEPW	Tuttle 138kV
GEN-2014-056	250.00	OKGE	Minco 345kV
PRIOR QUEUED SUBTOTAL	**4,216.54**		
GEN-2015-029	161.00	OKGE	Tatonga 345kV
CURRENT CLUSTER SUBTOTAL	**161.00**		
AREA TOTAL	**4,377.54**		

GROUP 2: HITCHLAND AREA			
Request	**Capacity**	**Area**	**Proposed Point of Interconnection**
ASGI-2011-002	20.00	SPS	Herring 115kV
GEN-2002-008	240.00	SPS	Hitchland 345kV
GEN-2002-009	80.00	SPS	Hansford 115kV
GEN-2003-020	160.00	SPS	Martin 115kV
GEN-2006-020S	18.90	SPS	DWS Frisco 115kV
GEN-2006-044	370.00	SPS	Hitchland 345kV
GEN-2007-046	200.00	SPS	Hitchland 115kV
GEN-2008-047	300.00	OKGE	Beaver County 345kV
GEN-2010-001	300.00	OKGE	Beaver County 345kV
GEN-2010-014	358.80	SPS	Hitchland 345kV
GEN-2011-014	201.00	OKGE	Tap Hitchland - Woodward Dbl Ckt (GEN-2011-014 Tap) 345kV
GEN-2011-022	299.00	SPS	Hitchland 345kV
GEN-2013-030	300.00	OKGE	Beaver County 345kV
GEN-2014-026	150.00	OKGE	Beaver County 345kV
SPS Distributed (Dumas 19th St)	20.00	SPS	Dumas 19th Street 115kV
SPS Distributed (Etter)	20.00	SPS	Etter 115kV
SPS Distributed (Moore E)	25.00	SPS	Moore East 115kV
SPS Distributed (Sherman)	20.00	SPS	Sherman 115kV
SPS Distributed (Spearman)	10.00	SPS	Spearman 69kV
SPS Distributed (TC-Texas County)	20.00	SPS	Texas County 115kV
PRIOR QUEUED SUBTOTAL	**3,112.70**		
GEN-2014-037	200.00	SPS	Tap Hitchland - Beaver County Dbl Ckt (Optima) 345kV
GEN-2014-038	200.00	SPS	Tap Hitchland - Potter County 345kV
GEN-2015-006	150.00	OKGE	Beaver County 345kV
CURRENT CLUSTER SUBTOTAL	**550.00**		
AREA TOTAL	**3,662.70**		

GROUP 3: SPEARVILLE AREA			
Request	Capacity	Area	Proposed Point of Interconnection
ASGI-2012-006	22.50	SUNCMKEC	Tap Hugoton - Rolla 69kV
GEN-2001-039A	105.00	SUNCMKEC	Shooting Star Tap 115kV
GEN-2002-025A	150.00	SUNCMKEC	Spearville 230kV
GEN-2004-014	154.50	SUNCMKEC	Spearville 230kV
GEN-2005-012	250.00	SUNCMKEC	Ironwood 345kV
GEN-2006-006	205.50	SUNCMKEC	Spearville 345kV
GEN-2006-021	101.00	SUNCMKEC	Flat Ridge Tap 138kV
GEN-2007-040	200.00	SUNCMKEC	Buckner 345kV
GEN-2008-018	250.00	SPS	Finney 345kV
GEN-2008-079	99.20	SUNCMKEC	Crooked Creek 115kV
GEN-2008-124	200.10	SUNCMKEC	Ironwood 345kV
GEN-2010-009	165.60	SUNCMKEC	Buckner 345kV
GEN-2010-045	197.80	SUNCMKEC	Buckner 345kV
GEN-2011-008	600.00	SUNCMKEC	Clark County 345kV
GEN-2011-016	200.10	SUNCMKEC	Spearville 345kV
GEN-2011-017	299.00	SUNCMKEC	Tap Spearville - Post Rock (GEN-2011-017T) 345kV
GEN-2012-007	120.00	SUNCMKEC	Rubart 115kV
GEN-2012-024	180.00	SUNCMKEC	Clark County 345kV
GEN-2013-010	99.00	SUNCMKEC	Tap Spearville - Post Rock (North of GEN-2011-017 Tap) 345kV
GEN-2014-049	200.00	SUNCMKEC	Thistle 345kV
Gray County Wind (Montezuma)	110.00	SUNCMKEC	Gray County Tap 115kV
PRIOR QUEUED SUBTOTAL	**3,909.30**		
ASGI-2015-001	6.13	SUNCMKEC	Ninnescah 115kV
GEN-2015-021	20.00	SUNCMKEC	Johnson Corner 115kV
GEN-2015-026	8.30	SUNCMKEC	Buckner 345kV
GEN-2015-027	4.94	SUNCMKEC	Crooked Creek 115kV
CURRENT CLUSTER SUBTOTAL	**39.37**		
AREA TOTAL	**3,948.67**		

GROUP 4: NORTHWEST KANSAS AREA

Request	Capacity	Area	Proposed Point of Interconnection
ASGI-2013-004	36.60	SUNCMKEC	Morris 115kV
GEN-2001-039M	100.00	SUNCMKEC	Central Plains Tap 115kV
GEN-2003-006A	200.00	SUNCMKEC	Elm Creek 230kV
GEN-2003-019	250.00	MIDW	Smoky Hills Tap 230kV
GEN-2006-031	75.00	MIDW	Knoll 115kV
GEN-2008-017	300.00	SUNCMKEC	Setab 345kV
GEN-2008-092	201.00	MIDW	Post Rock 230kV
GEN-2009-008	199.50	MIDW	South Hays 230kV
GEN-2009-020	48.30	MIDW	Tap Nekoma - Bazine (Walnut Creek) 69kV
GEN-2010-057	201.00	MIDW	Rice County 230kV
GEN-2013-033	28.00	MIDW	Goodman Energy Center 115kV
GEN-2014-025	2.40	MIDW	Tap Nekoma - Bazine (Walnut Creek) 69kV
GEN-2014-041	120.80	SUNCMKEC	Arnold 115kV
PRIOR QUEUED SUBTOTAL	**1,762.60**		
GEN-2010-048	70.00	MIDW	Tap Beach Station - Redline 115kV
GEN-2015-017	172.00	SUNCMKEC	Mingo 115kV
CURRENT CLUSTER SUBTOTAL	**242.00**		
AREA TOTAL	**2,004.60**		

GROUP 5: AMARILLO AREA

Request	Capacity	Area	Proposed Point of Interconnection
ASGI-2013-001	11.50	SPS	PanTex South 115kV
GEN-2002-022	240.00	SPS	Bushland 230kV
GEN-2008-051	322.00	SPS	Potter County 345kV
GEN-2014-040	320.00	SPS	Castro 115kV
Llano Estacado (White Deer)	80.00	SPS	Llano Wind 115kV
PRIOR QUEUED SUBTOTAL	**973.50**		
GEN-2014-068	203.00	SPS	Tap Deaf Smith - Plant X 230kV
CURRENT CLUSTER SUBTOTAL	**203.00**		
AREA TOTAL	**1,176.50**		

GROUP 6: SOUTH TEXAS PANHANDLE/NEW MEXICO AREA

Request	Capacity	Area	Proposed Point of Interconnection
ASGI-2010-010	42.20	SPS	Lovington 115kV
ASGI-2010-020	30.00	SPS	Tap LE-Tatum - LE-Crossroads 69kV
ASGI-2010-021	15.00	SPS	Tap LE-Saunders Tap - LE-Anderson 69kV
ASGI-2011-001	27.30	SPS	Lovington 115kV
ASGI-2011-003	10.00	SPS	Hendricks 115kV
ASGI-2011-004	20.00	SPS	Pleasant Hill 69kV
ASGI-2012-002	18.15	SPS	FE-Clovis Interchange 115kV
ASGI-2013-002	18.40	SPS	FE Tucumcari 115kV
ASGI-2013-003	18.40	SPS	FE Clovis 115kV
ASGI-2013-005	1.65	SPS	FE Clovis 115kV
ASGI-2013-006	2.00	SPS	SP-Erskine 115kV
ASGI-2014-001	2.50	SPS	SP-Erskine 115kV
ASGI-2014-002	49.60	SPS	Tap Tucumcari - Santa Rosa 115kV
ASGI-2014-005	10.00	SPS	Strata 69kV
ASGI-2014-008	10.00	SPS	South Loving 69kV
ASGI-2014-009	10.00	SPS	Wood Draw 115kV
ASGI-2014-010	10.00	SPS	Ochoa 115kV
ASGI-2014-012	10.00	SPS	Cooper Ranch 115kV
GEN-2001-033	180.00	SPS	San Juan Tap 230kV
GEN-2001-036	80.00	SPS	Norton 115kV
GEN-2006-018	170.00	SPS	TUCO Interchange 230kV
GEN-2006-026	502.00	SPS	Hobbs 230kV & Hobbs 115kV
GEN-2008-022	300.00	SPS	Tap Tolk - Eddy County (Crossroads) 345kV
GEN-2010-006	205.00	SPS	Jones 230kV
GEN-2010-046	56.00	SPS	TUCO Interchange 230kV
GEN-2011-025	80.00	SPS	Tap Floyd County - Crosby County 115kV
GEN-2011-045	205.00	SPS	Jones 230kV
GEN-2011-046	27.00	SPS	Lopez 115kV
GEN-2011-048	175.00	SPS	Mustang 230kV
GEN-2012-001	61.20	SPS	Cirrus Tap 230kV
GEN-2012-009	15.00	SPS	Mustang 230kV
GEN-2012-010	15.00	SPS	Mustang 230kV
GEN-2012-020	478.00	SPS	TUCO 230kV
GEN-2012-034	7.00	SPS	Mustang 230kV
GEN-2012-035	7.00	SPS	Mustang 230kV
GEN-2012-036	7.00	SPS	Mustang 230kV
GEN-2012-037	203.00	SPS	TUCO 345kV
GEN-2013-016	203.00	SPS	TUCO 345kV
GEN-2013-022	25.00	SPS	Norton 115kV
GEN-2013-027	150.00	SPS	Tap Tolk - Yoakum 230kV
GEN-2014-012	225.00	SPS	Tap Hobbs Interchange - Andrews 230kV
GEN-2014-033	70.00	SPS	Chaves County 115kV
GEN-2014-034	70.00	SPS	Chaves County 115kV
GEN-2014-035	30.00	SPS	Chaves County 115kV
GEN-2014-047	40.00	SPS	Tap Tolk - Eddy County (Crossroads) 345kV
GEN-2014-053	80.00	SPS	Carlisle 230kV
GEN-2014-054	120.00	SPS	Carlisle 230kV
GEN-2014-066	30.00	SPS	Norton 115kV
SPS Distributed (Hopi)	10.00	SPS	Hopi 115kV
SPS Distributed (Jal)	10.00	SPS	S Jal 115kV

SPS Distributed (Lea Road)	10.00	SPS	Lea Road 115kV
SPS Distributed (Monument)	10.00	SPS	Monument 115kV
SPS Distributed (Ocotillo)	10.00	SPS	S_Jal 115kV
SPS Distributed (Yuma)	2.57	SPS	SP-Yuma 69kV
PRIOR QUEUED SUBTOTAL	**4,173.97**		
ASGI-2015-002	2.00	SPS	SP-Yuma 69kV
ASGI-2015-003	30.00	SPS	Tap San Jon Tap - Wheatland 115/69kV
GEN-2014-046	125.40	SPS	Chaves County 115kV
GEN-2014-065	99.00	SPS	Whitten 115kV
GEN-2014-074	152.00	SPS	Tap TUCO Interchange - Oklaunion 345kV
GEN-2015-009	300.00	SPS	Hobbs 230kV
GEN-2015-010	250.70	SPS	Tap South Roosvelt - Tolk 230kV
GEN-2015-014	150.00	SPS	Tap Cochran - Lehman 115kV
GEN-2015-018	80.00	SPS	Tap Curry County - Bailey 115kV
GEN-2015-020	99.96	SPS	Oasis 115kV
GEN-2015-022	112.00	SPS	Swisher 115kV
CURRENT CLUSTER SUBTOTAL	**1,401.06**		
AREA TOTAL	**5,575.03**		

GROUP 7: SOUTHWEST OKLAHOMA AREA			
Request	Capacity	Area	Proposed Point of Interconnection
GEN-2001-026	74.30	WFEC	Washita 138kV
GEN-2002-005	120.00	WFEC	Red Hills Tap 138kV
GEN-2003-004	100.00	WFEC	Washita 138kV
GEN-2003-005	100.00	WFEC	Anadarko - Paradise (Blue Canyon) 138kV
GEN-2003-022	120.00	AEPW	Washita 138kV
GEN-2004-020	27.00	AEPW	Washita 138kV
GEN-2004-023	20.60	WFEC	Washita 138kV
GEN-2005-003	30.60	WFEC	Washita 138kV
GEN-2006-002	101.00	AEPW	Sweetwater 230kV
GEN-2006-035	225.00	AEPW	Sweetwater 230kV
GEN-2006-043	99.00	AEPW	Sweetwater 230kV
GEN-2007-032	150.00	WFEC	Tap Clinton Junction - Clinton 138kV
GEN-2007-052	150.00	WFEC	Anadarko 138kV
GEN-2008-023	150.00	AEPW	Hobart Junction 138kV
GEN-2008-037	101.00	WFEC	Tap Washita - Blue Canyon Wind 138kV
GEN-2011-037	7.00	WFEC	Blue Canyon 5 138kV
GEN-2011-049	250.70	OKGE	Border 345kV
GEN-2012-028	74.80	WFEC	Gotebo 69kV
PRIOR QUEUED SUBTOTAL	1,901.00		
GEN-2015-004	52.90	OKGE	Border 345kV
GEN-2015-013	120.00	WFEC	Synder 138kV
CURRENT CLUSTER SUBTOTAL	172.90		
AREA TOTAL	2,073.90		

GROUP 8: NORTH OKLAHOMA/SOUTH CENTRAL KANSAS AREA			
Request	Capacity	Area	Proposed Point of Interconnection
ASGI-2010-006	150.00	AECI	Tap Fairfax (AECI) - Shilder (AEPW) 138kV
ASGI-2014-014	56.40	GRDA	Ferguson 69kV
GEN-2002-004	200.00	WERE	Latham 345kV
GEN-2005-013	201.00	WERE	Caney River 345kV
GEN-2007-025	300.00	WERE	Viola 345kV
GEN-2008-013	300.00	OKGE	Hunter 345kV
GEN-2008-021	42.00	WERE	Wolf Creek 345kV
GEN-2008-098	100.80	WERE	Waverly 345kV
GEN-2009-025	59.80	OKGE	Nardins 69kV
GEN-2010-003	100.80	WERE	Waverly 345kV
GEN-2010-005	299.20	WERE	Viola 345kV
GEN-2010-055	4.50	AEPW	Wekiwa 138kV
GEN-2011-057	150.40	WERE	Creswell 138kV
GEN-2012-027	136.00	AEPW	Shidler 138kV
GEN-2012-032	300.00	OKGE	Open Sky 345kV
GEN-2012-033	98.80	OKGE	Tap and Tie South 4th - Bunch Creek & Enid Tap - Fairmont (GEN-2012-033T) 138kV
GEN-2012-040	76.50	WFEC	Chilocco 138kV
GEN-2012-041	121.50	OKGE	Ranch Road 345kV
GEN-2013-012	147.00	OKGE	Redbud 345kV
GEN-2013-028	559.50	GRDA	Tap N Tulsa - GRDA 1 345kV
GEN-2013-029	300.00	OKGE	Renfrow 345kV
GEN-2014-001	200.60	WERE	Tap Wichita - Emporia Energy Center 345kV
GEN-2014-028	35.00	EMDE	Riverton 161kV
GEN-2014-064	248.40	OKGE	Otter 138kV

PRIOR QUEUED SUBTOTAL	**4,188.20**		
ASGI-2015-004	56.36	GRDA	Coffeyville City 69kV
GEN-2015-001	200.00	OKGE	Ranch Road 345kV
GEN-2015-003	200.00	OKGE	Renfrow 345kV
GEN-2015-015	154.60	OKGE	Tap Medford Tap - Coyote 138kV
GEN-2015-016	200.00	KCPL	Tap Marmaton - Centerville 161kV
GEN-2015-024	220.00	WERE	Tap Thistle - Wichita 345kV Dbl CKT
GEN-2015-025	220.00	WERE	Tap Thistle - Wichita 345kV Dbl CKT
GEN-2015-028	3.00	OKGE	Nardins 69kV
GEN-2015-030	200.10	OKGE	Sooner 345kV
CURRENT CLUSTER SUBTOTAL	**1,454.06**		
AREA TOTAL	**5,642.26**		

GROUP 9: NEBRASKA AREA

Request	Capacity	Area	Proposed Point of Interconnection
GEN-2002-023N	0.80	NPPD	Harmony 115kV
GEN-2003-021N	75.00	NPPD	Ainsworth Wind Tap 115kV
GEN-2004-023N	75.00	NPPD	Columbus Co 115kV
GEN-2006-020N	42.00	NPPD	Bloomfield 115kV
GEN-2006-037N1	75.00	NPPD	Broken Bow 115kV
GEN-2006-038N005	80.00	NPPD	Broken Bow 115kV
GEN-2006-038N019	80.00	NPPD	Petersburg North 115kV
GEN-2006-044N	40.50	NPPD	North Petersburg 115kV
GEN-2007-011N08	81.00	NPPD	Bloomfield 115kV
GEN-2008-086N02	201.00	NPPD	Meadow Grove 230kV
GEN-2008-119O	60.00	OPPD	S1399 161kV
GEN-2008-123N	89.70	NPPD	Tap Pauline - Hildreth (Rosemont) 115kV
GEN-2009-040	73.80	WERE	Marshall 115kV
GEN-2010-041	10.50	OPPD	S1399 161kV
GEN-2010-051	200.00	NPPD	Tap Twin Church - Hoskins 230kV
GEN-2011-018	73.60	NPPD	Steele City 115kV
GEN-2011-027	120.00	NPPD	Hoskins 230kV
GEN-2011-056	3.60	NPPD	Jeffrey 115kV
GEN-2011-056A	3.60	NPPD	John 1 115kV
GEN-2011-056B	4.50	NPPD	John 2 115kV
GEN-2012-021	4.80	LES	Terry Bundy Generating Station 115kV
GEN-2013-002	50.60	LES	Tap Sheldon - Folsom & Pleasant Hill (GEN-2013-002 Tap) 115kV CKT 2
GEN-2013-008	1.20	NPPD	Steele City 115kV
GEN-2013-014	25.50	NPPD	Tap Guide Rock - Pauline (Rosemont) 115kV
GEN-2013-019	73.60	LES	Tap Sheldon - Folsom & Pleasant Hill (GEN-2013-002 Tap) 115kV CKT 2
GEN-2013-032	204.00	NPPD	Antelope 115kV
GEN-2014-004	4.00	NPPD	Steele City 115kV (GEN-2011-018 POI)
GEN-2014-013	73.50	NPPD	Meadow Grove (GEN-2008-086N2 Sub) 230kV
GEN-2014-031	35.80	NPPD	Meadow Grove 230kV
GEN-2014-032	10.20	NPPD	Meadow Grove 230kV
GEN-2014-039	73.40	NPPD	Friend 115kV
NPPD Distributed (Broken Bow)	8.30	NPPD	Broken Bow 115kV
NPPD Distributed (Buffalo County Solar)	10.00	NPPD	Kearney Northeast
NPPD Distributed (Burt County Wind)	12.00	NPPD	Tekamah & Oakland 115kV
NPPD Distributed (Burwell)	3.00	NPPD	Ord 115kV
NPPD Distributed (Columbus Hydro)	45.00	NPPD	Columbus 115kV
NPPD Distributed (North Platte - Lexington)	54.00	NPPD	Multiple: Jeffrey 115kV, John_1 115kV, John_2 115kV

NPPD Distributed (Ord)	11.90	NPPD	Ord 115kV
NPPD Distributed (Stuart)	2.10	NPPD	Ainsworth 115kV
PRIOR QUEUED SUBTOTAL	**2,092.50**		
GEN-2014-023	79.90	NPPD	Tap Fort Randall - Meadow Grove 230kV
GEN-2014-059	160.00	NPPD	Tap Sidney - Ogallala 230kV
GEN-2014-060	125.80	NPPD	Tap Pauline - Hildreth (Rosemont) 115kV
GEN-2015-007	160.00	NPPD	Hoskins 345kV
GEN-2015-008	150.40	NPPD	Antelope 115kV
GEN-2015-023	300.70	NPPD	Holt County 345kV
CURRENT CLUSTER SUBTOTAL	**976.80**		
AREA TOTAL	**3,069.30**		

GROUP 10: SOUTHEAST OKLAHOMA/NORTHEAST TEXAS AREA

Request	Capacity	Area	Proposed Point of Interconnection
AREA TOTAL	**0.00**		

GROUP 12: NORTHWEST ARKANSAS AREA

Request	Capacity	Area	Proposed Point of Interconnection
GEN-2013-011	30.00	AEPW	Turk 138kV
PRIOR QUEUED SUBTOTAL	**30.00**		
GEN-2015-019	60.00	AEPW	Fitzhugh 161kV
CURRENT CLUSTER SUBTOTAL	**60.00**		
AREA TOTAL	**90.00**		

GROUP 13: NORTHWEST MISSOURI AREA

Request	Capacity	Area	Proposed Point of Interconnection
GEN-2008-129	80.00	GMO	Pleasant Hill 161kV
GEN-2010-036	4.60	WERE	6th Street 115kV
GEN-2011-011	50.00	KCPL	Iatan 345kV
GEN-2014-021	300.00	GMO	Tap Nebraska City - Mullin Creek 345kV
GEN-2014-051	174.00	WERE	Jeffrey Energy Center 345kV
PRIOR QUEUED SUBTOTAL	**608.60**		
GEN-2015-005	200.10	GMO	Tap Nebraska City - Sibley 345kV
CURRENT CLUSTER SUBTOTAL	**200.10**		
AREA TOTAL	**808.70**		

GROUP 14: SOUTH CENTRAL OKLAHOMA AREA

Request	Capacity	Area	Proposed Point of Interconnection
GEN-2011-040	111.00	OKGE	Carter County 138kV
GEN-2011-050	109.80	AEPW	Santa Fe Tap 138kV
GEN-2012-004	41.40	OKGE	Carter County 138kV
GEN-2013-007	100.30	OKGE	Tap Prices Falls - Carter 138kV
GEN-2014-057	250.00	AEPW	Tap Lawton - Sunnyside 345kV
PRIOR QUEUED SUBTOTAL	**612.50**		
AREA TOTAL	**612.50**		

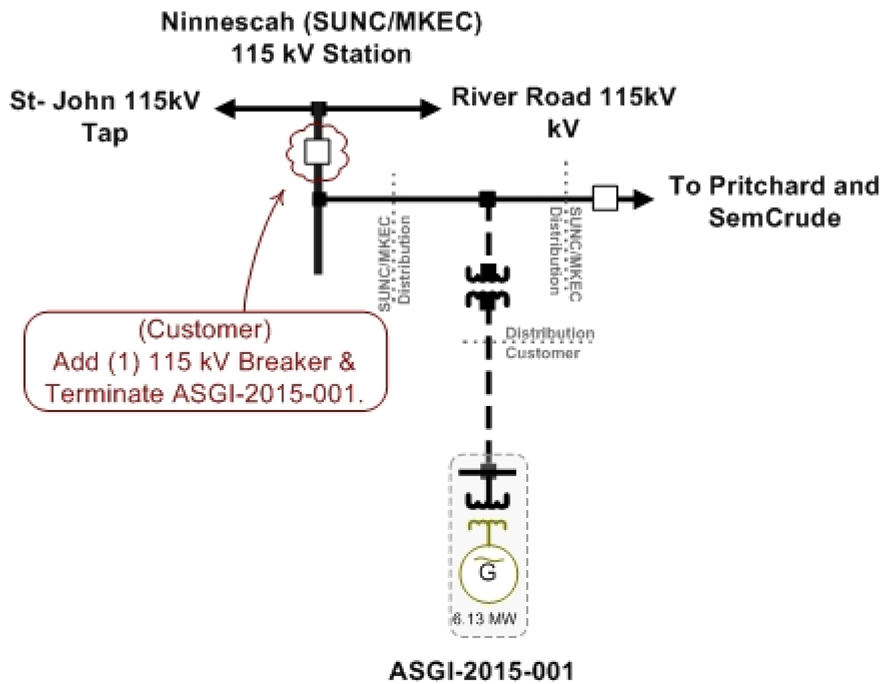
CLUSTER TOTAL (CURRENT STUDY)	**5,460.3**	MW
PQ TOTAL (PRIOR QUEUED)	**27,581.4**	MW
CLUSTER TOTAL (INCLUDING PRIOR QUEUED)	**33,041.7**	MW

D: Proposed Point of Interconnection One Line Diagrams

See next page

*Note: If not denoted otherwise for Affected System Generation Interconnection Requests (ASGI) interconnection cost estimate could include distribution system or third party system network upgrades and costs estimates.

ASGI-2015-001
Estimated Cluster Analysis Interconnection Cost: $3,188,259
Estimated Stand Alone Analysis Interconnection Cost: $3,188,259



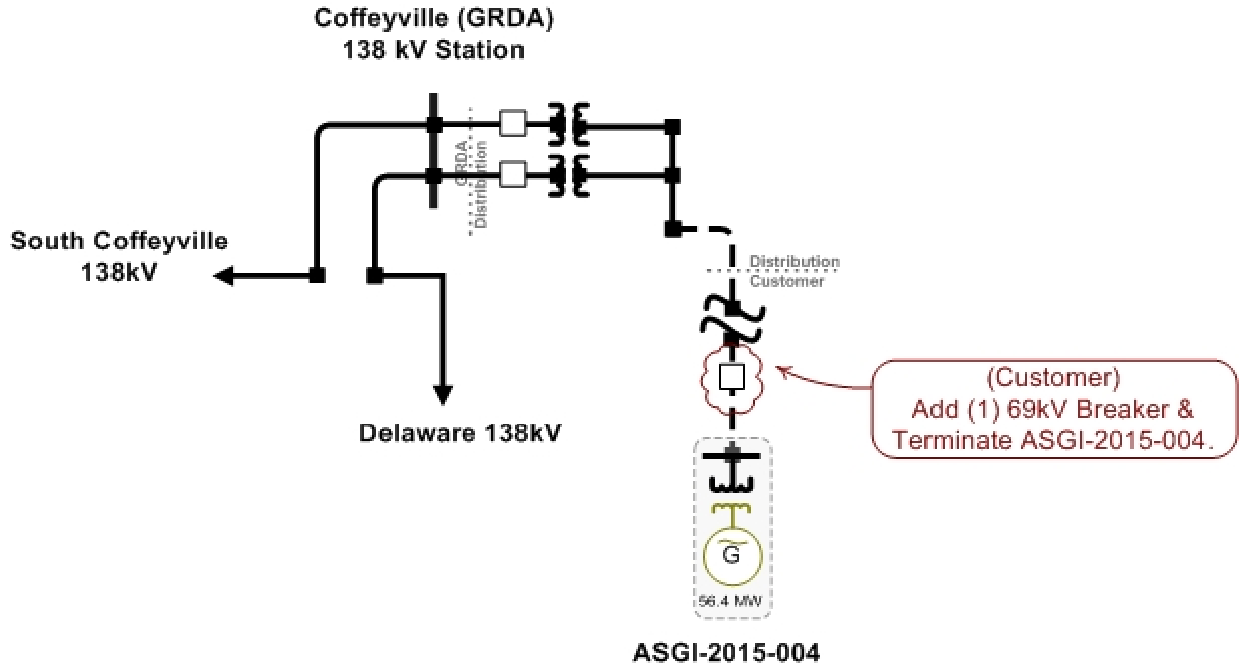
ASGI-2015-002
Estimated Cluster Analysis Interconnection Cost: $
Estimated Stand Alone Analysis Interconnection Cost: $

One-Line and Interconnection Cost Estimates will be inserted when Group 2,5,6 and 7 results are posted

ASGI-2015-003
Estimated Cluster Analysis Interconnection Cost: $
Estimated Stand Alone Analysis Interconnection Cost: $

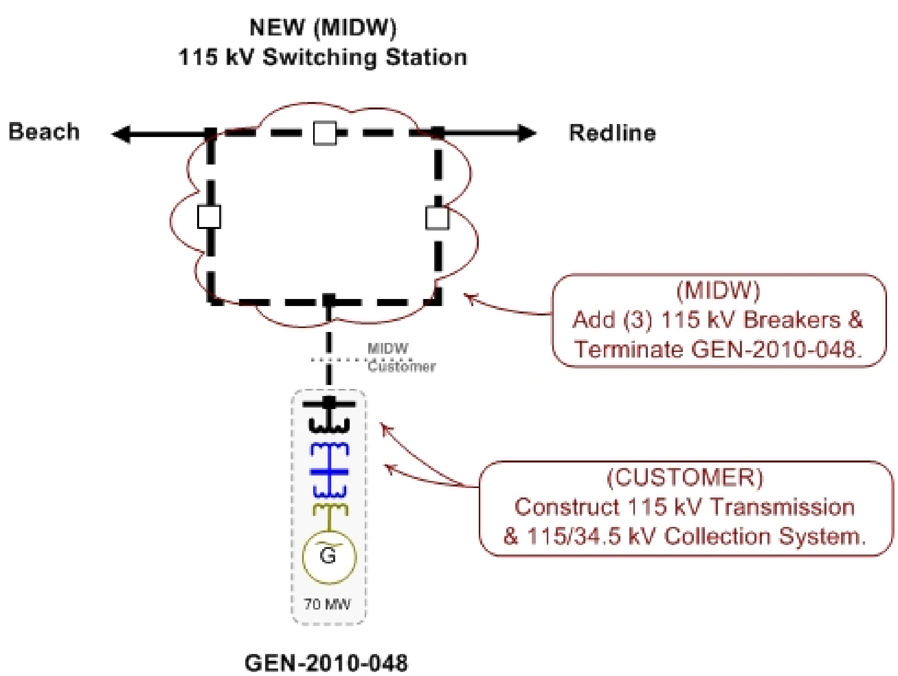
One-Line and Interconnection Cost Estimates will be inserted when Group 2,5,6 and 7 results are posted

ASGI-2015-004
Estimated Cluster Analysis Interconnection Cost: $ 0*
Estimated Stand Alone Analysis Interconnection Cost: $ 0*

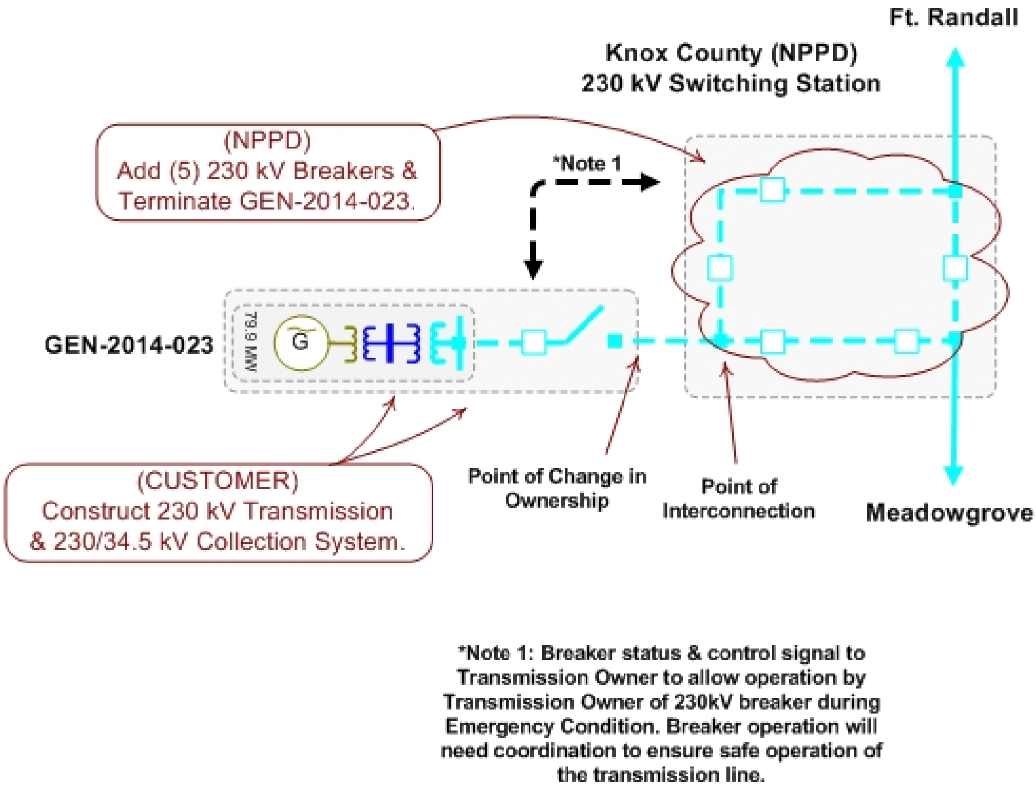


*** Interconnection Cost Estimate(s) only include Affected System Interconnection costs**

GEN-2010-048
Estimated Cluster Analysis Interconnection Cost: $4,000,000
Estimated Stand Alone Analysis Interconnection Cost: $4,000,000



GEN-2014-023
Estimated Cluster Analysis Interconnection Cost: $9,200,000
Estimated Stand Alone Analysis Interconnection Cost: $9,200,000



GEN-2014-037
Estimated Cluster Analysis Interconnection Cost: $
Estimated Stand Alone Analysis Interconnection Cost: $

One-Line and Interconnection Cost Estimates will be inserted when Group 2,5,6 and 7 results are posted

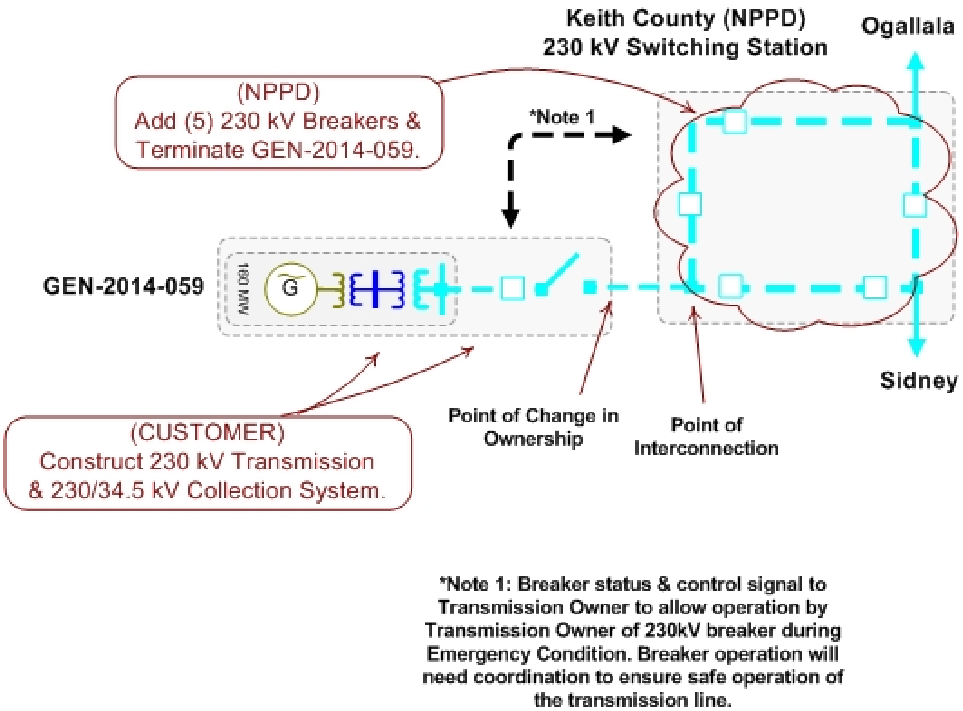
GEN-2014-038
Estimated Cluster Analysis Interconnection Cost: $
Estimated Stand Alone Analysis Interconnection Cost: $

One-Line and Interconnection Cost Estimates will be inserted when Group 2,5,6 and 7 results are posted

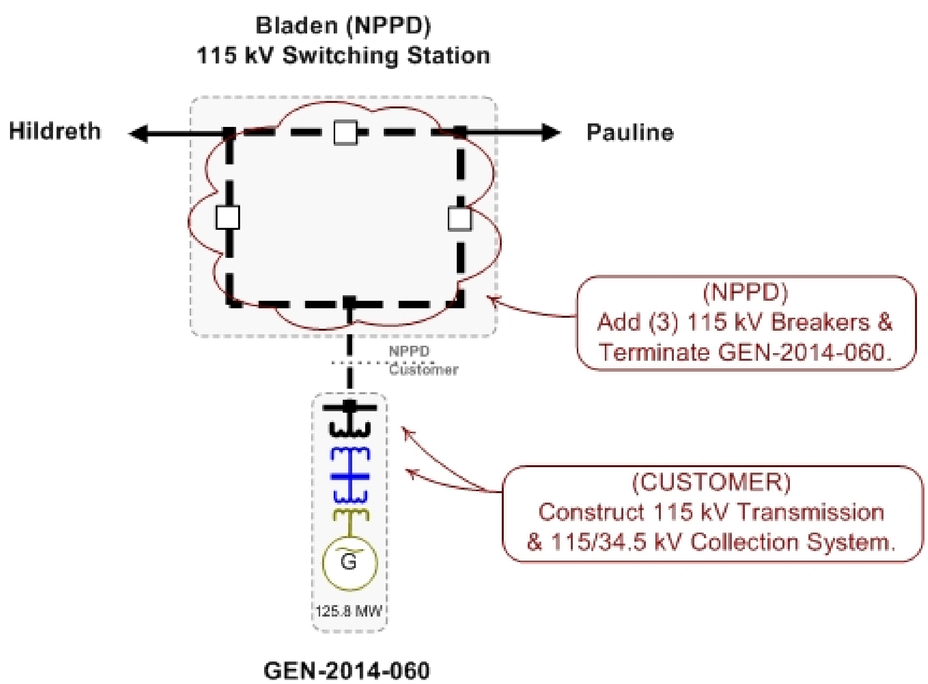
GEN-2014-046
Estimated Cluster Analysis Interconnection Cost: $
Estimated Stand Alone Analysis Interconnection Cost: $

One-Line and Interconnection Cost Estimates will be inserted when Group 2,5,6 and 7 results are posted

GEN-2014-059
Estimated Cluster Analysis Interconnection Cost: $9,200,000
Estimated Stand Alone Analysis Interconnection Cost: $9,200,000



GEN-2014-060
Estimated Cluster Analysis Interconnection Cost: $6,300,000
Estimated Stand Alone Analysis Interconnection Cost: $6,300,000



GEN-2014-065
Estimated Cluster Analysis Interconnection Cost: $
Estimated Stand Alone Analysis Interconnection Cost: $

One-Line and Interconnection Cost Estimates will be inserted when Group 2,5,6 and 7 results are posted

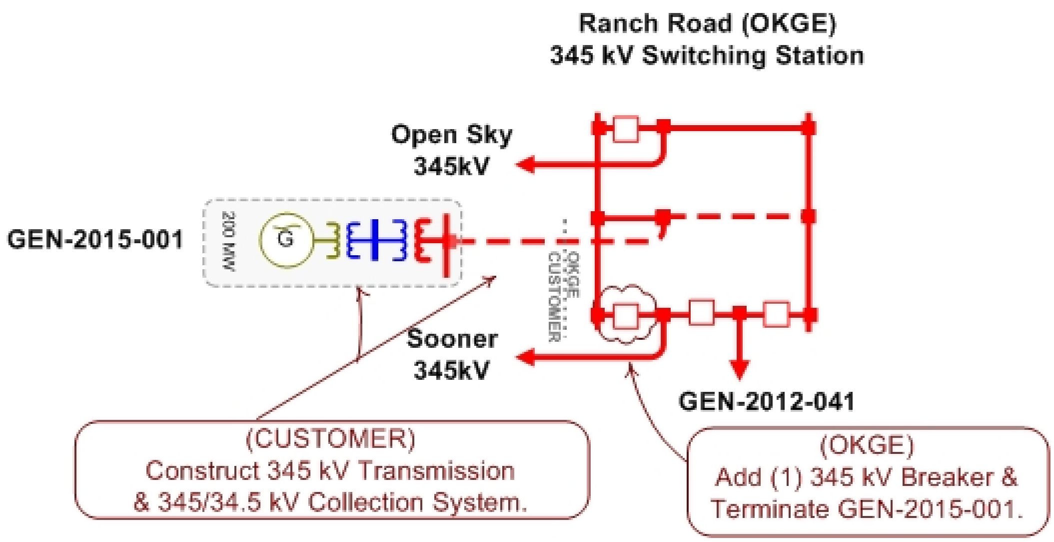
GEN-2014-068
Estimated Cluster Analysis Interconnection Cost: $
Estimated Stand Alone Analysis Interconnection Cost: $

One-Line and Interconnection Cost Estimates will be inserted when Group 2,5,6 and 7 results are posted

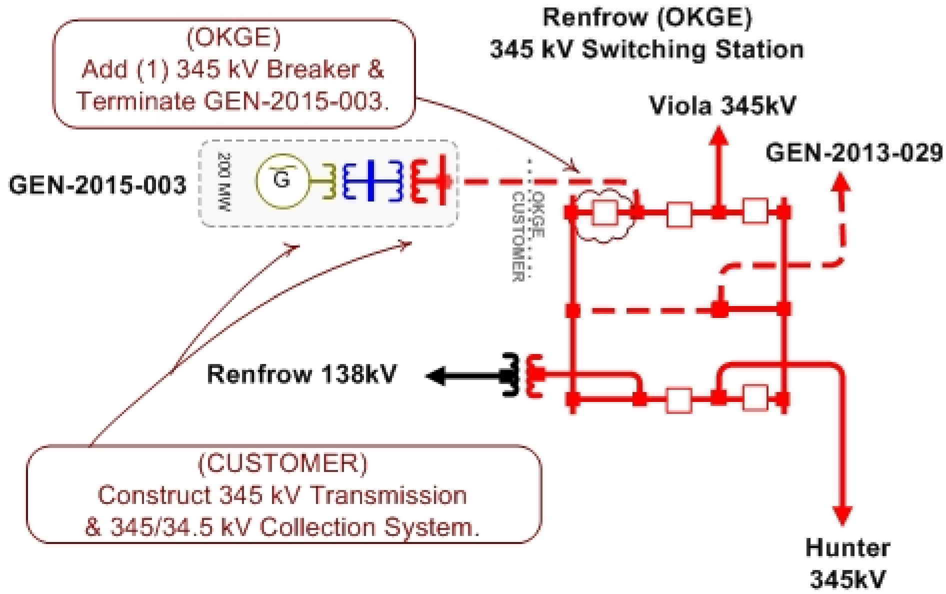
GEN-2014-074
Estimated Cluster Analysis Interconnection Cost: $
Estimated Stand Alone Analysis Interconnection Cost: $

One-Line and Interconnection Cost Estimates will be inserted when Group 2,5,6 and 7 results are posted

GEN-2015-001
Estimated Cluster Analysis Interconnection Cost: $2,250,100
Estimated Stand Alone Analysis Interconnection Cost: $2,250,100



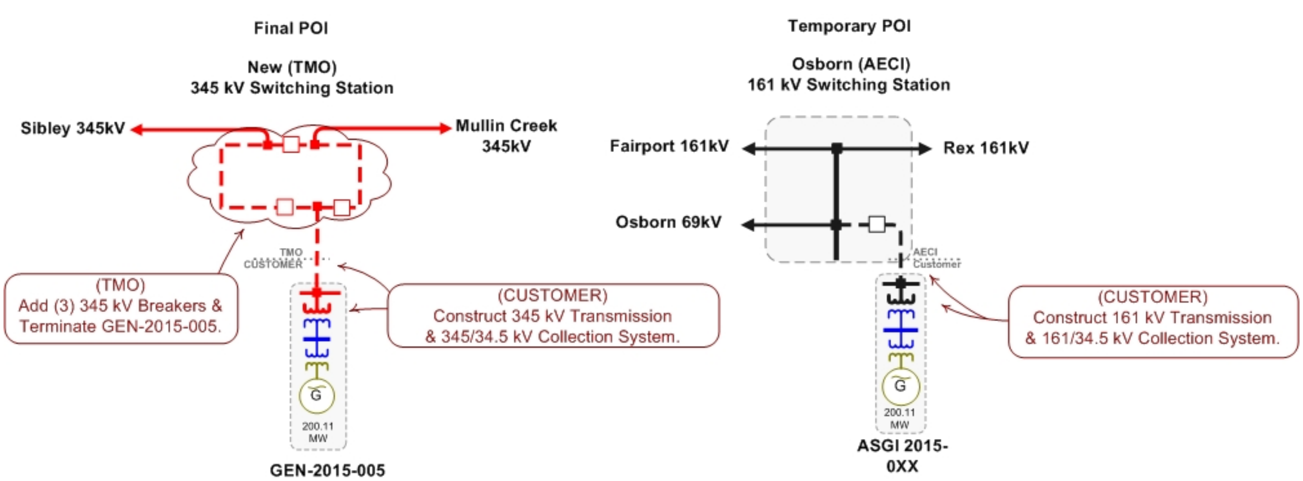
GEN-2015-003
Estimated Cluster Analysis Interconnection Cost: $2,250,100
Estimated Stand Alone Analysis Interconnection Cost: $2,250,100



GEN-2015-004
Estimated Cluster Analysis Interconnection Cost: $
Estimated Stand Alone Analysis Interconnection Cost: $

One-Line and Interconnection Cost Estimates will be inserted when Group 2,5,6 and 7 results are posted

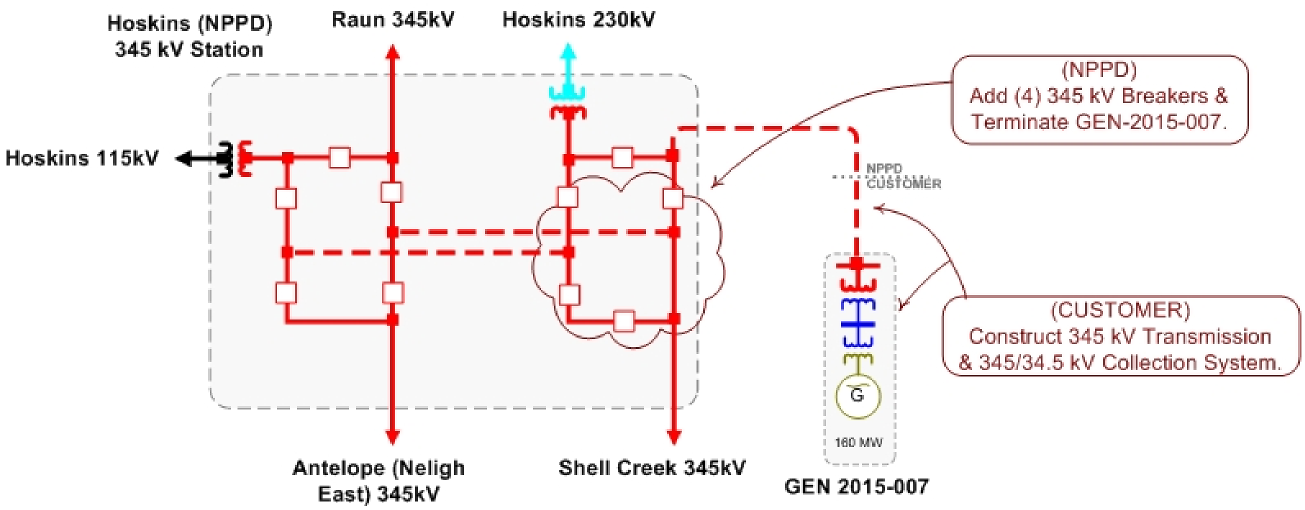
GEN-2015-005
Estimated Cluster Analysis Interconnection Cost: $18,262,000
Estimated Stand Alone Analysis Interconnection Cost: $18,262,000



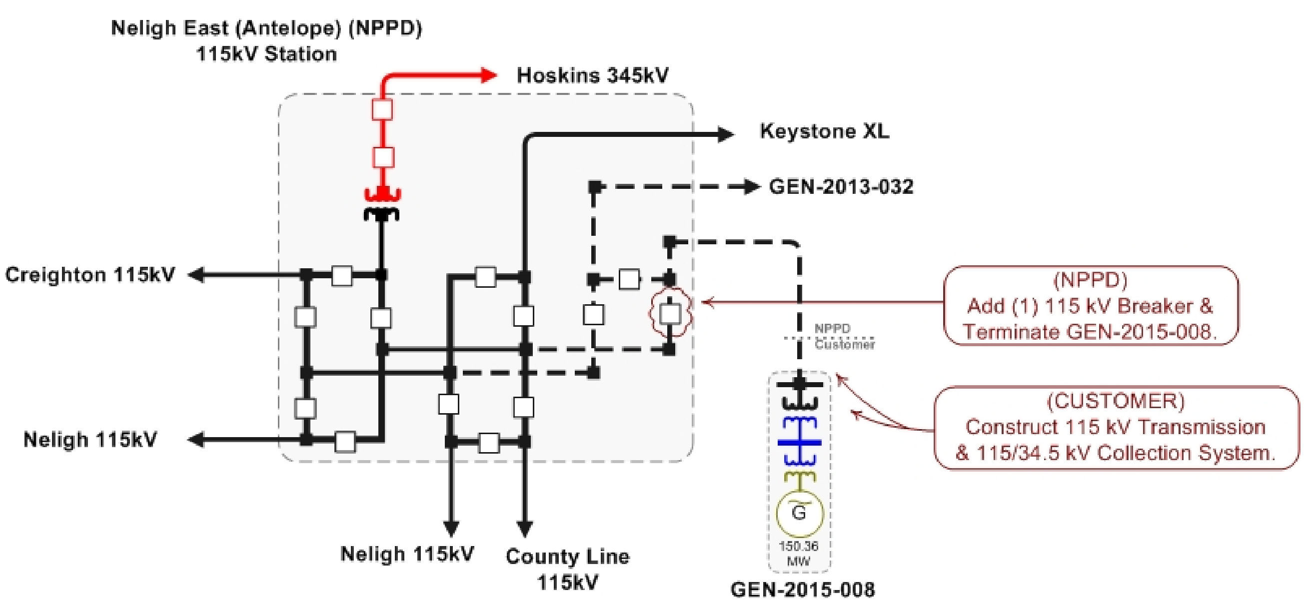
GEN-2015-006
Estimated Cluster Analysis Interconnection Cost: $
Estimated Stand Alone Analysis Interconnection Cost: $

One-Line and Interconnection Cost Estimates will be inserted when Group 2,5,6 and 7 results are posted

GEN-2015-007
Estimated Cluster Analysis Interconnection Cost: $5,300,000
Estimated Stand Alone Analysis Interconnection Cost: $5,300,000



GEN-2015-008
Estimated Cluster Analysis Interconnection Cost: $1,000,000
Estimated Stand Alone Analysis Interconnection Cost: $1,000,000



GEN-2015-009
Estimated Cluster Analysis Interconnection Cost: $
Estimated Stand Alone Analysis Interconnection Cost: $

One-Line and Interconnection Cost Estimates will be inserted when Group 2,5,6 and 7 results are posted

GEN-2015-010
Estimated Cluster Analysis Interconnection Cost: $
Estimated Stand Alone Analysis Interconnection Cost: $

One-Line and Interconnection Cost Estimates will be inserted when Group 2,5,6 and 7 results are posted

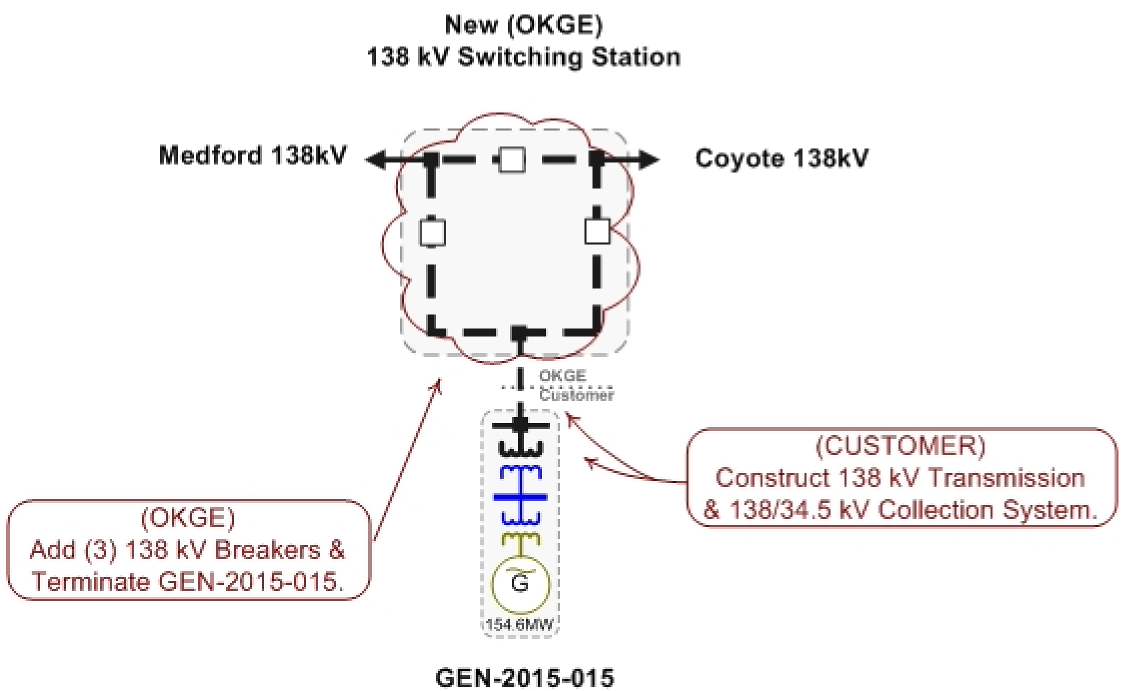
GEN-2015-013
Estimated Cluster Analysis Interconnection Cost: $
Estimated Stand Alone Analysis Interconnection Cost: $

One-Line and Interconnection Cost Estimates will be inserted when Group 2,5,6 and 7 results are posted

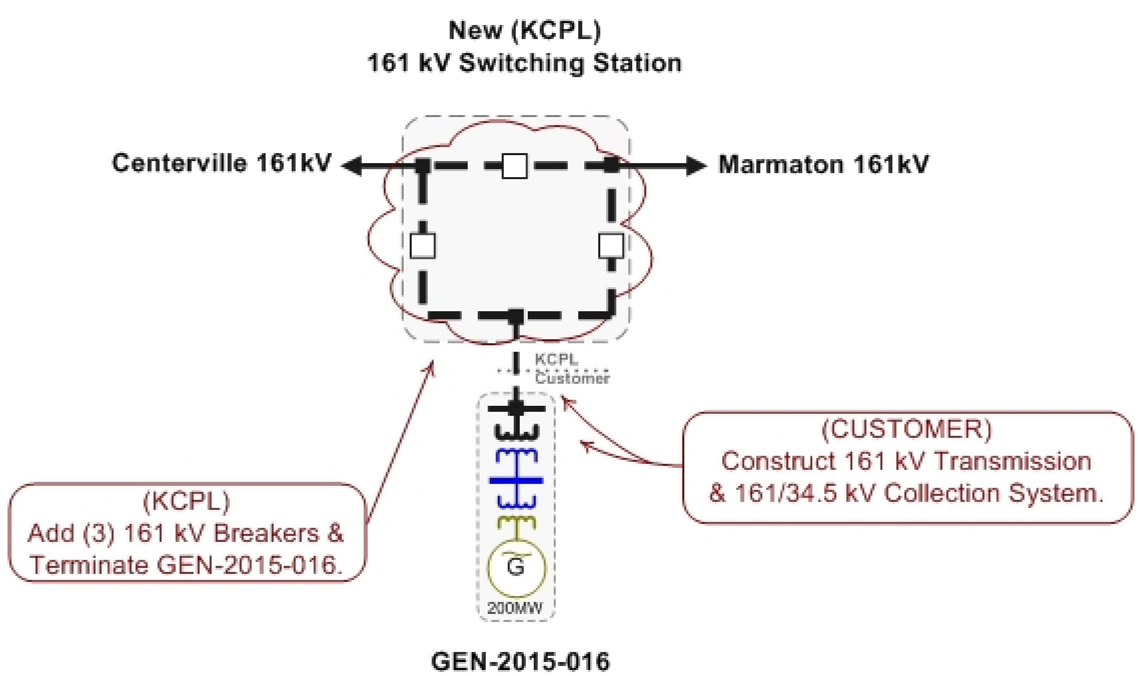
GEN-2015-014
Estimated Cluster Analysis Interconnection Cost: $
Estimated Stand Alone Analysis Interconnection Cost: $

One-Line and Interconnection Cost Estimates will be inserted when Group 2,5,6 and 7 results are posted

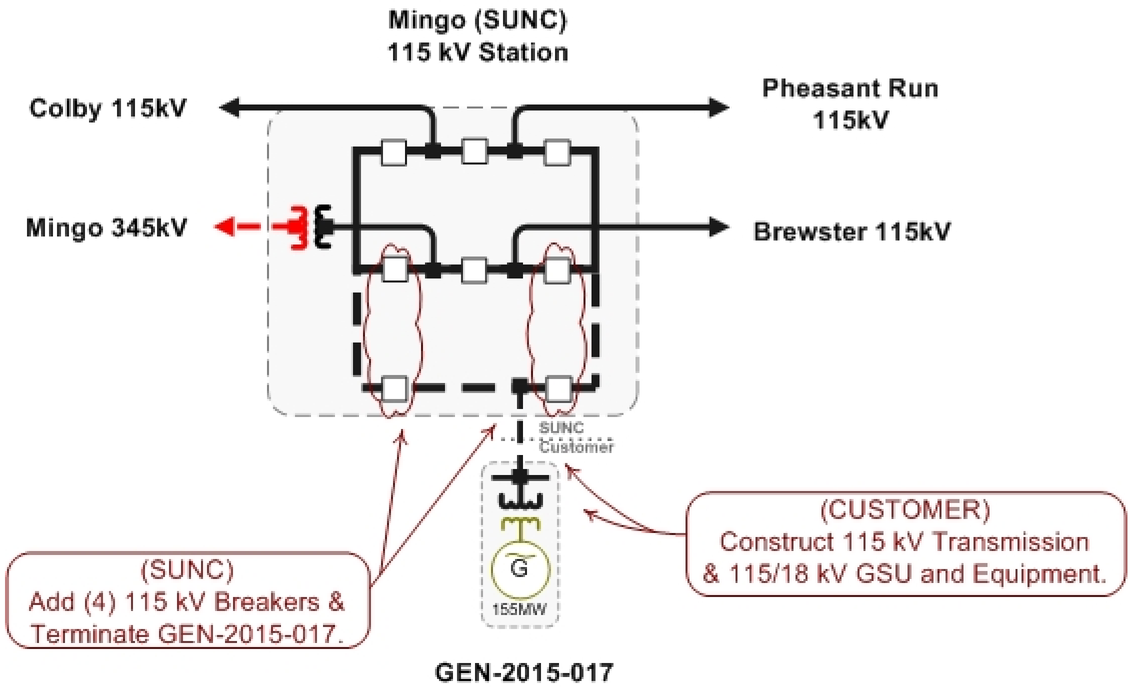
GEN-2015-015
Estimated Cluster Analysis Interconnection Cost: $3,041,661
Estimated Stand Alone Analysis Interconnection Cost: $3,041,661



GEN-2015-016
Estimated Cluster Analysis Interconnection Cost: $8,110,000
Estimated Stand Alone Analysis Interconnection Cost: $8,110,000



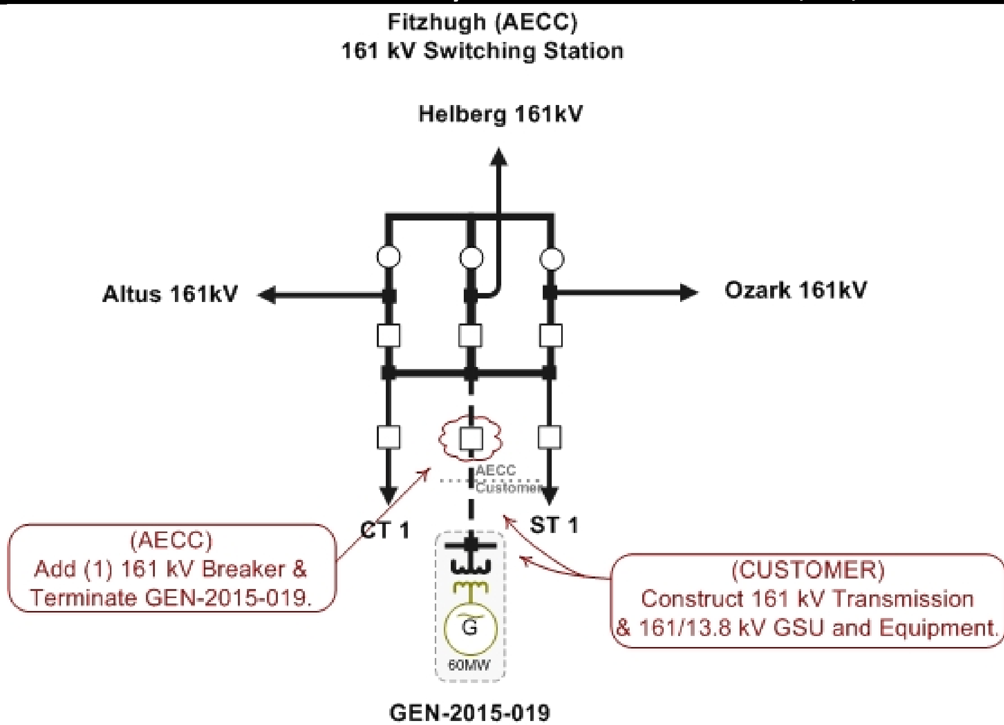
GEN-2015-017
Estimated Cluster Analysis Interconnection Cost: $3,459,098
Estimated Stand Alone Analysis Interconnection Cost: $3,459,098



GEN-2015-018
Estimated Cluster Analysis Interconnection Cost: $
Estimated Stand Alone Analysis Interconnection Cost: $

One-Line and Interconnection Cost Estimates will be inserted when Group 2,5,6 and 7 results are posted

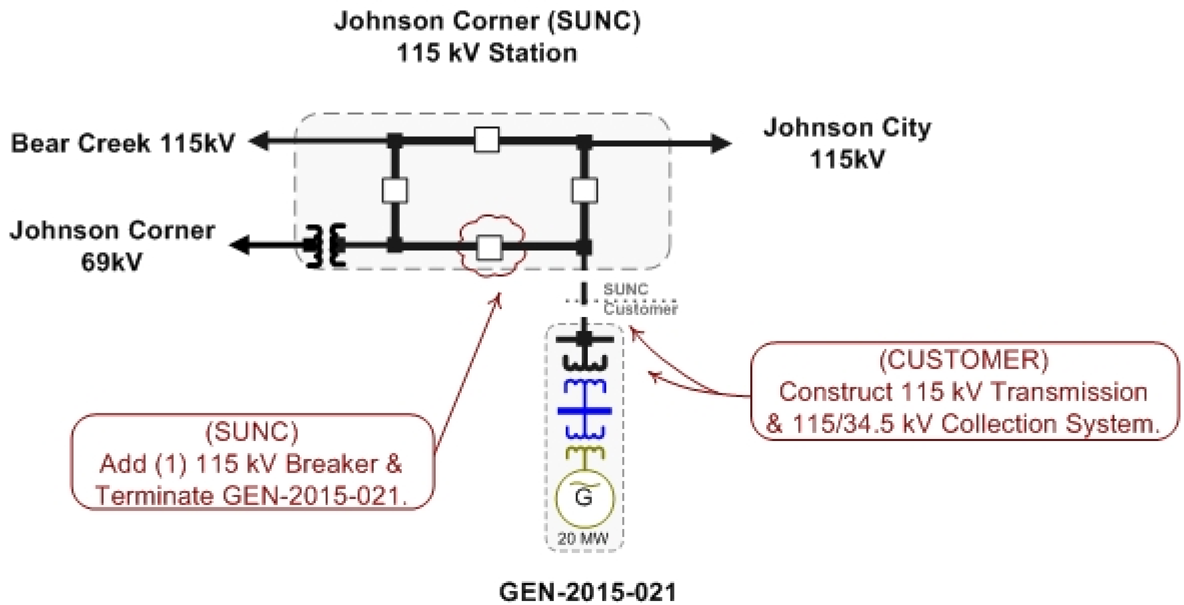
GEN-2015-019
Estimated Cluster Analysis Interconnection Cost: $1,250,000
Estimated Stand Alone Analysis Interconnection Cost: $1,250,000



GEN-2015-020
Estimated Cluster Analysis Interconnection Cost: $
Estimated Stand Alone Analysis Interconnection Cost: $

One-Line and Interconnection Cost Estimates will be inserted when Group 2,5,6 and 7 results are posted

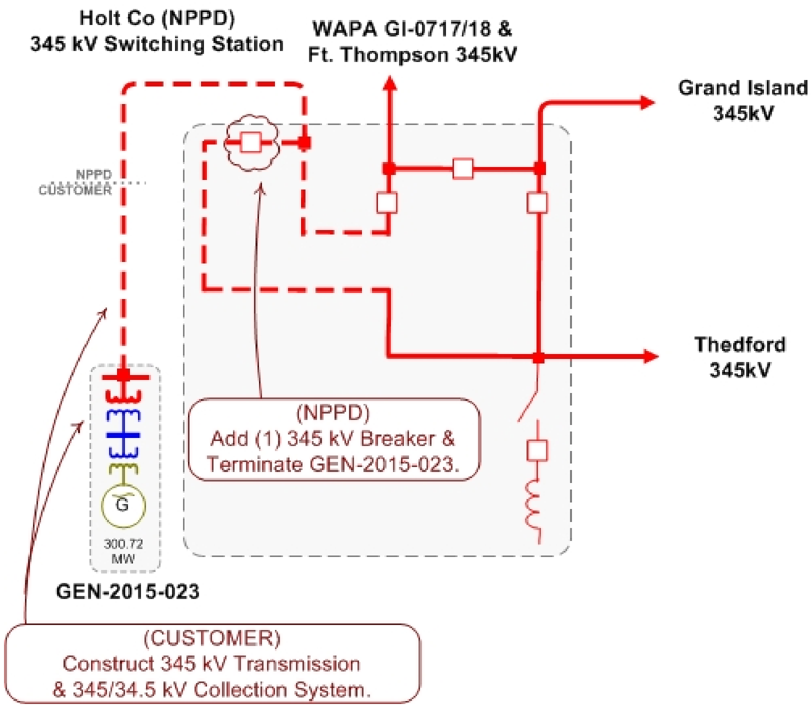
GEN-2015-021
Estimated Cluster Analysis Interconnection Cost: $1,438,309
Estimated Stand Alone Analysis Interconnection Cost: $1,438,309



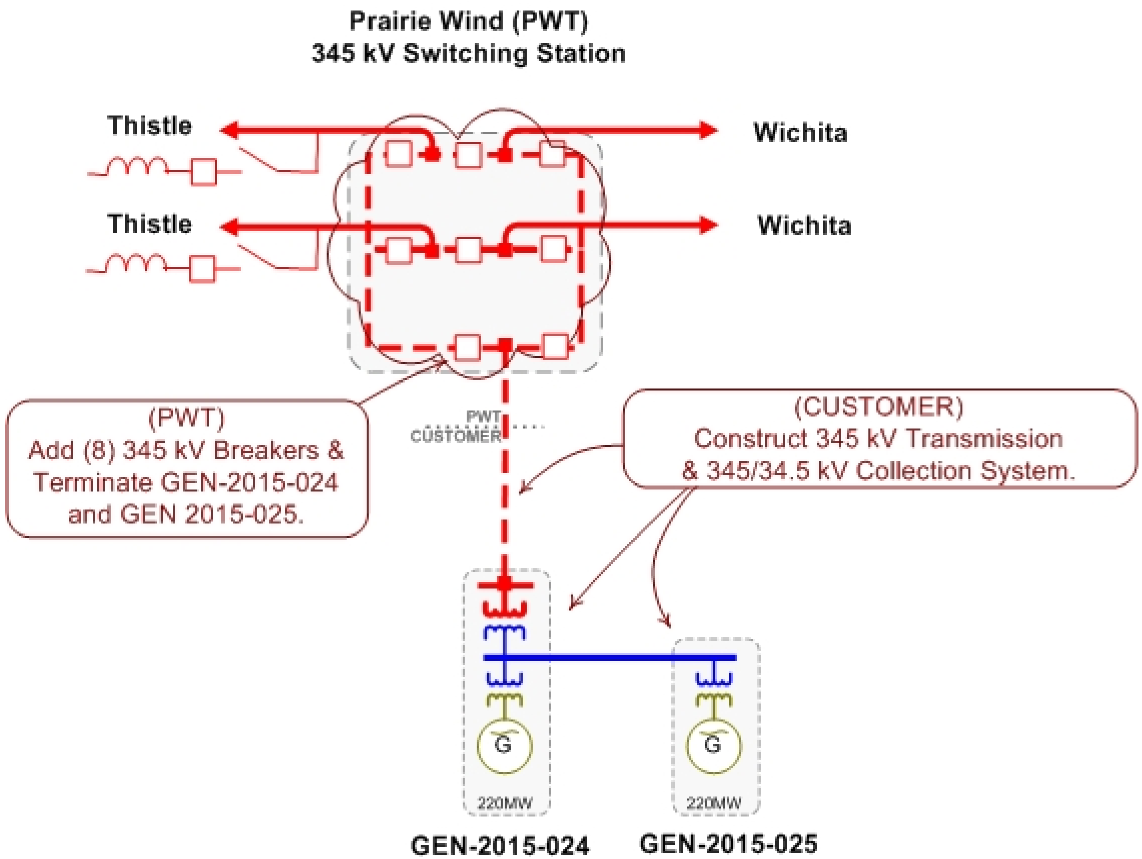
GEN-2015-022
Estimated Cluster Analysis Interconnection Cost: $
Estimated Stand Alone Analysis Interconnection Cost: $

One-Line and Interconnection Cost Estimates will be inserted when Group 2,5,6 and 7 results are posted

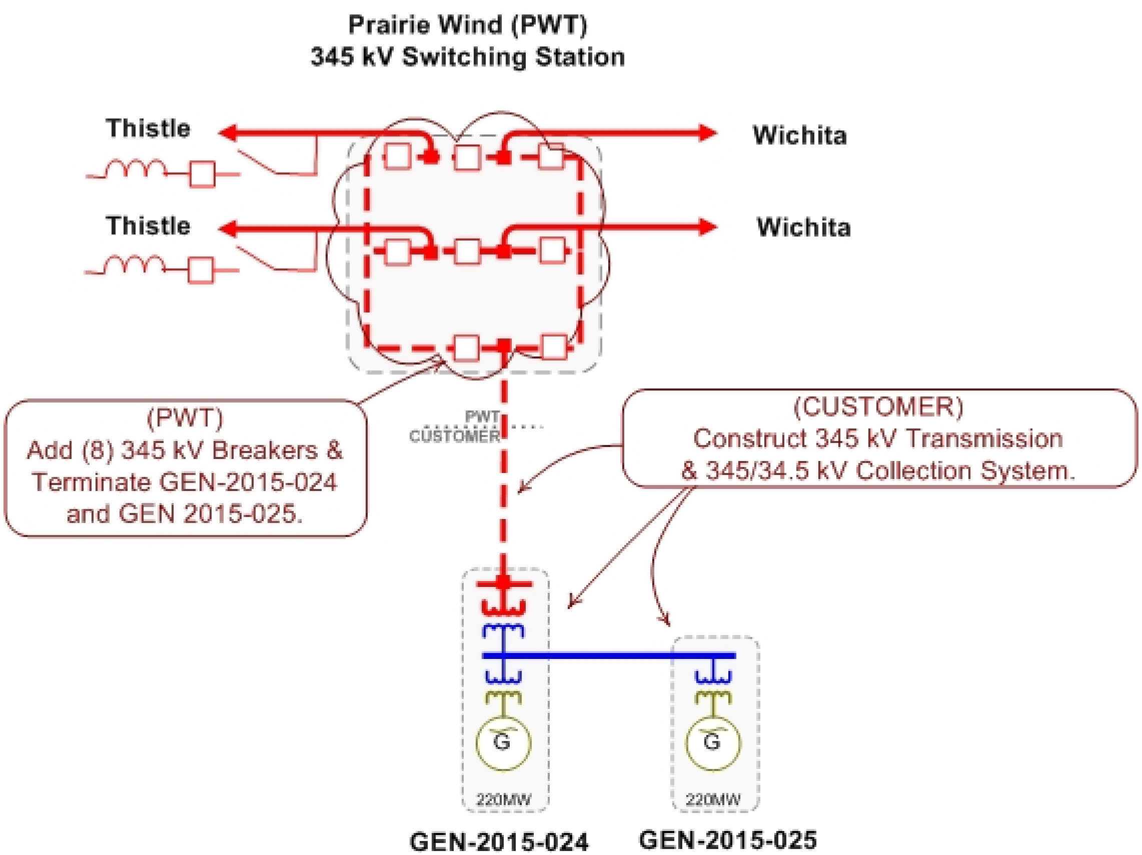
GEN-2015-023
Estimated Cluster Analysis Interconnection Cost: $4,800,000
Estimated Stand Alone Analysis Interconnection Cost: $4,800,000



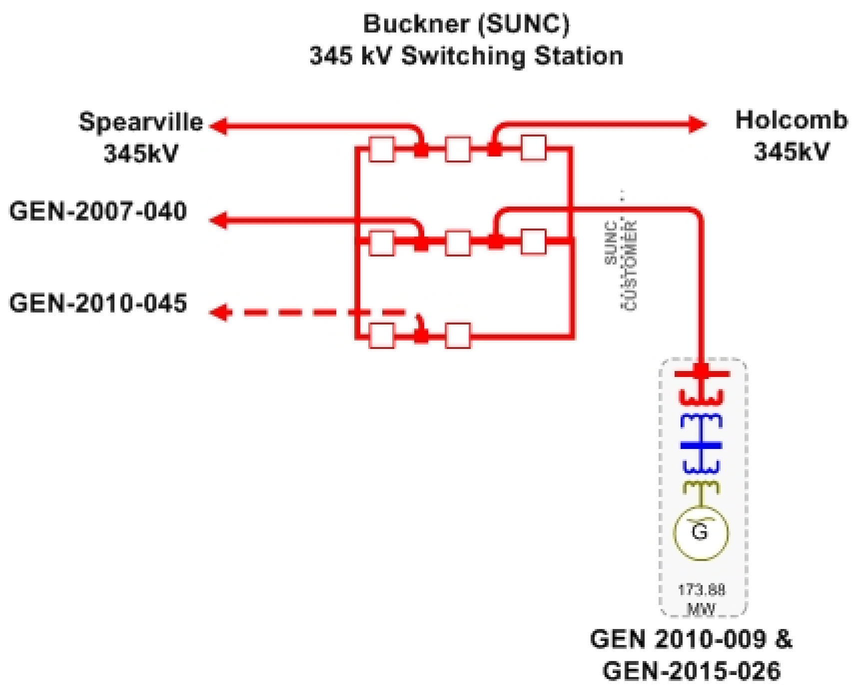
GEN-2015-024
Estimated Cluster Analysis Interconnection Cost: $32,704,640
Estimated Stand Alone Analysis Interconnection Cost: $32,704,640



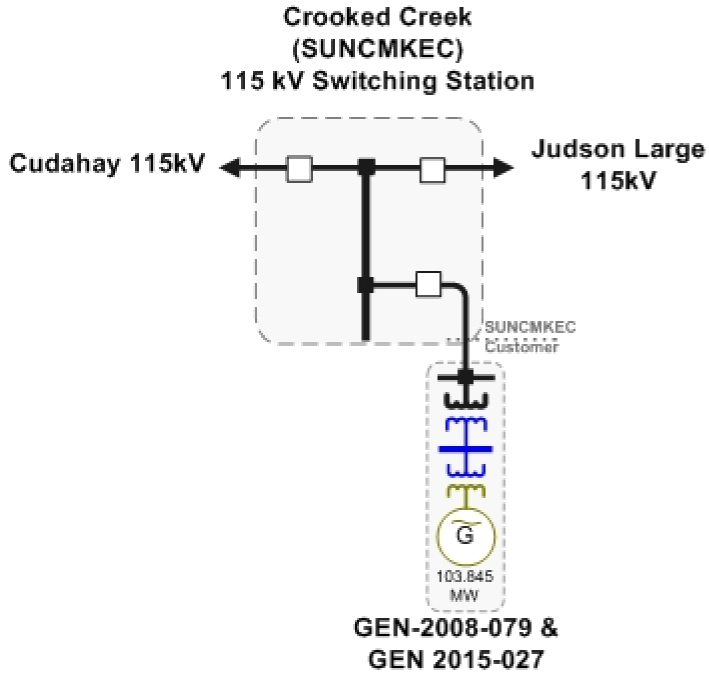
GEN-2015-025
Estimated Cluster Analysis Interconnection Cost: $0
Estimated Stand Alone Analysis Interconnection Cost: $32,704,640



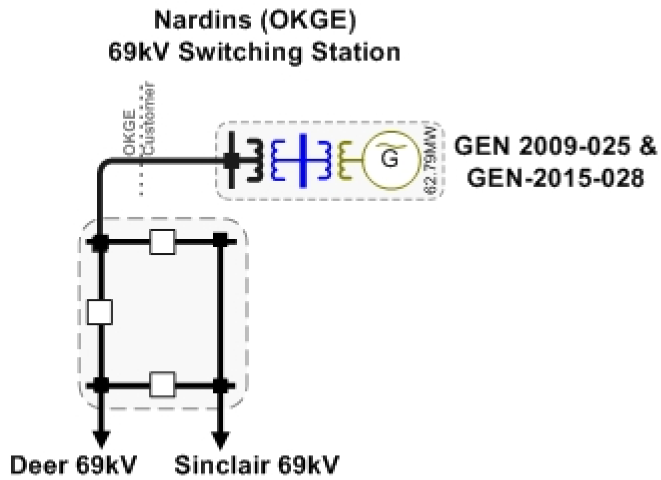
GEN-2015-026
Estimated Cluster Analysis Interconnection Cost: $150,000
Estimated Stand Alone Analysis Interconnection Cost: $150,000



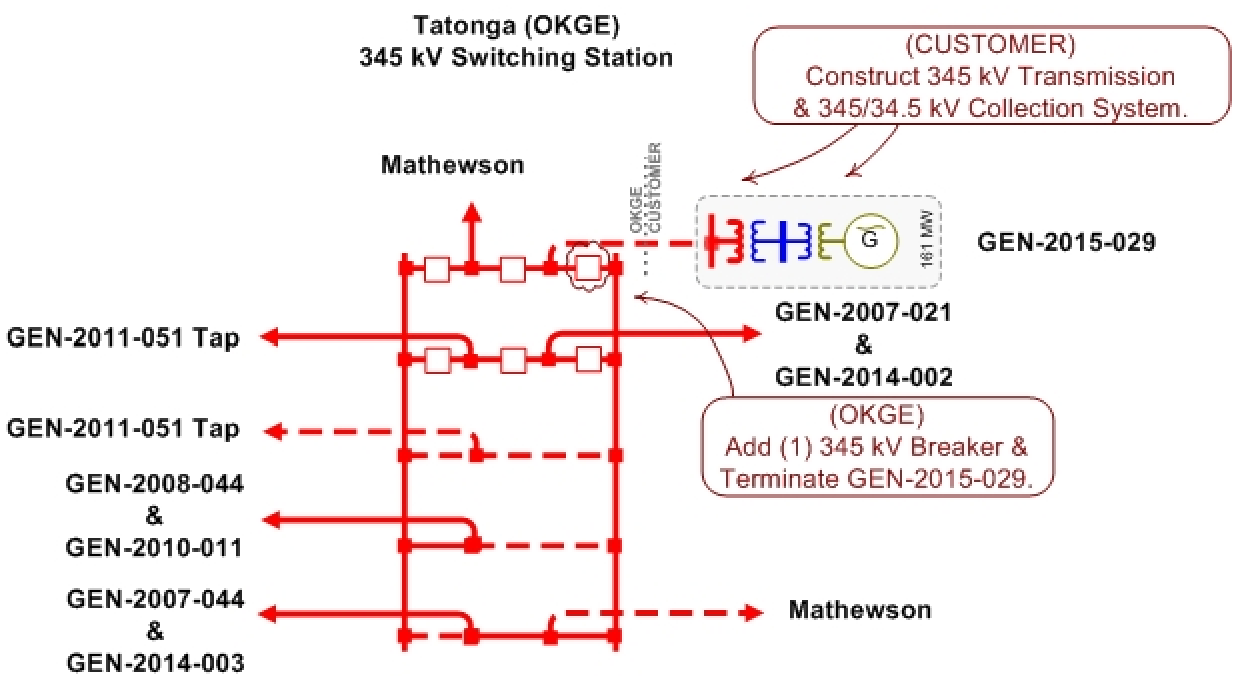
GEN-2015-027
Estimated Cluster Analysis Interconnection Cost: $150,000
Estimated Stand Alone Analysis Interconnection Cost: $150,000



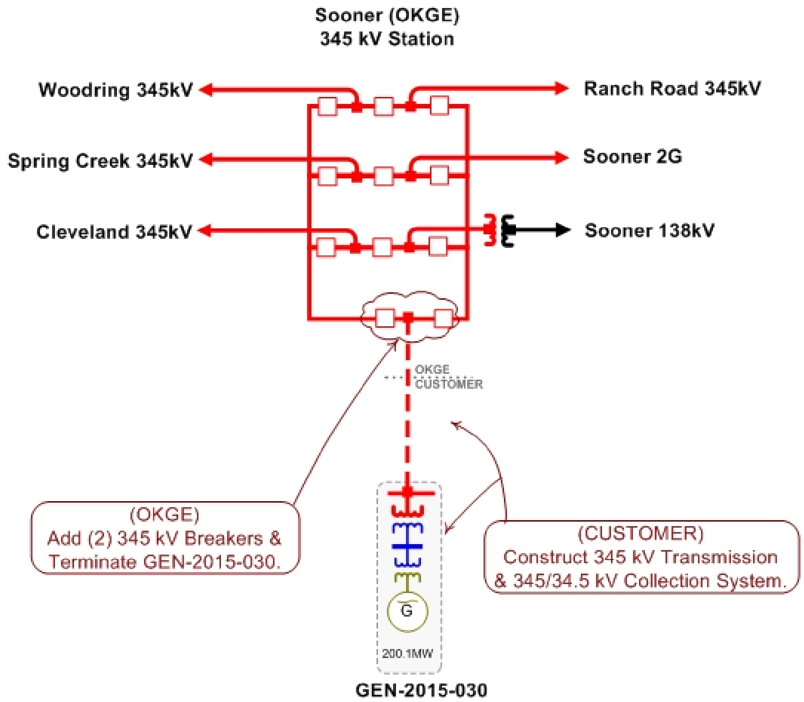
GEN-2015-028
Estimated Cluster Analysis Interconnection Cost: $0
Estimated Stand Alone Analysis Interconnection Cost: $0



GEN-2015-029
Estimated Cluster Analysis Interconnection Cost: $2,270,100
Estimated Stand Alone Analysis Interconnection Cost: $2,270,100



GEN-2015-030
Estimated Cluster Analysis Interconnection Cost: $3,369,366
Estimated Stand Alone Analysis Interconnection Cost: $3,369,366



E: Cost Allocation per Interconnection Request (Including Prior Queued Upgrades)

Important Note:

****WITHDRAWAL OF HIGHER QUEUED PROJECTS WILL CAUSE A RESTUDY AND MAY RESULT IN HIGHER INTERCONNECTION COSTS****

This section shows each Generation Interconnection Request Customer, their current study impacted Network Upgrades, and the previously allocated upgrades upon which they rely to accommodate their interconnection to the transmission system.

The costs associated with the current study Network Upgrades are allocated to the Customers shown in this report.

In addition should a higher queued request, defined as one this study includes as a prior queued request, withdraw, the Network Upgrades assigned to the withdrawn request may be reallocated to the remaining requests that have an impact on the Network Upgrade under a restudy. Also, should an Interconnection Request choose to go into service prior to the operation date of any necessary Network Upgrades, the costs associated with those upgrades may be reallocated to the impacted Interconnection Request. The actual costs allocated to each Generation Interconnection Request Customer will be determined at the time of a restudy.

The required interconnection costs listed do not include all costs associated with the deliverability of the energy to final customers. These costs are determined by separate studies if the Customer submits a Transmission Service Request through SPP's Open Access Same Time Information System (OASIS) as required by Attachment Z1 of the SPP OATT. In addition, costs associated with a short circuit analysis will be allocated should the Interconnection Request Customer choose to execute a Facility Study Agreement.

There may be additional costs allocated to each Customer. See Appendix F for more details.

Appendix E. Cost Allocation Per Request

(Including Previously Allocated Network Upgrades*)

Interconnection Request and Upgrades	Upgrade Type	Allocated Cost	Upgrade Cost
ASGI-2015-001			
ASGI-2015-001 Interconnection Costs See One-Line Diagram.	Current Study	$3,188,259	$3,188,259
Clark County Reactive Power Support Install 100Mvar SVC at Clark County Substation.	Previously Allocated		$24,303,536
FPL Switch - Mooreland 138kV CKT 1 Rebuild approximately 0.2 miles of 138kV line	Previously Allocated		$820,000
FPL Switch - Woodward 138kV CKT 1 Rebuild approximately 12 miles of 138kV line	Previously Allocated		$8,499,000
Harper - Milan Tap 138kV CKT 1 Rebuild approximately 22 miles of 138kV line	Previously Allocated		$9,613,332
Knoll - Postrock 230kV CKT 1 Rebuild approximately 1 mile of 230kV from Knoll - Post Rock.	Previously Allocated		$500,000
Milan Tap - Clearwater 138kV CKT 1 Rebuild approximately 12 miles of 138kV line	Previously Allocated		$18,000,000
Walkemeyer Tap - Walkemeyer 345/115kV Project Per SPP-NTC-200343 (Total Project E&C Cost Shown).	Previously Allocated		$17,838,846
	Current Study Total	$3,188,259	
ASGI-2015-004			
ASGI-2015-004 Interconnection Costs See One-Line Diagram.	Current Study	$0	$0
Fairfax 138/69kV CKT 1 Per AECI Affected System Study for DISIS-2012-002	Previously Allocated		$2,200,000
Remington - Fairfax 138KV CKT 1 Increase conductor clearance	Previously Allocated		$400,000
	Current Study Total	$0	
GEN-2010-048			
GEN-2010-048 Interconnection Costs See One-Line Diagram.	Current Study	$4,000,000	$4,000,000

* Withdrawal of higher queued projects will cause a restudy and may result in higher costs

Interconnection Request and Upgrades	Upgrade Type	Allocated Cost	Upgrade Cost
Arnold - Ransom 115kV CKT 1 Replace terminal equipment to achieve at least a 600 amp rating.	Previously Allocated		$3,000,000
Bucker - Spearville 345V CKT 1 Replace Terminal equipment	Previously Allocated		$1,480,238
Mingo 345/115kV Transformer CKT 2 Build second 345/115/13.8kV transformer at Mingo per 2015 ITP10 SPP-NTC-200325.	Previously Allocated		$9,842,317
	Current Study Total	$4,000,000	
GEN-2014-023			
Albion - Petersburg - North Petersburg 115kV CKT 1 Reconductor 115kV lines and replace all terminal equipment for at least a 193MVA rate.	Current Study	$860,684	$3,500,000
GEN-2014-023 Interconnection Costs See One-Line Diagram.	Current Study	$9,200,000	$9,200,000
GEN-2014-059 Tap - Ogallala 230kV CKT 1 Replace terminal equipment and increase line clearance. ERIS upgrade for GEN-2014-059. NRIS upgrade for GEN-2014-023.	Current Study	$13,347	$3,000,000
Meadow Grove - North Petersburg 115kV CKT 1 Build approx. 25 miles of new 115kV circuit from Meadow Grove - N. Petersburg, expand N. Petersburg 115kV Sub and replace equip. at Neligh 115kV Sub.	Current Study	$16,200,000	$16,200,000
Meadow Grove 230/115/13.8kV Transformer CKT 1 Build Meadow Grove 230/115/13.8kV Transformer and Substation Expansion.	Current Study	$11,300,000	$11,300,000
Battle Creek-County Line 115kV CKT 1 Rebuild approximately 11 miles of 115kV from Battle Creek to County Line.	Previously Allocated		$4,000,000
County Line-Neligh East 115kV CKT 1 Rebuild approximately 12 miles of 115kV from County Line to Neligh East.	Previously Allocated		$8,050,000
Gentleman - Thedford 345kV CKT 1 Build approximately 76 Miles of 345kV from Gentleman to Thedford. (Total Project E&C Cost Shown).	Previously Allocated		$313,376,623
Hoskins - Neligh 345/115kV Projects Per SPP 2014 ITP NT and NTC 200253 for 6/1/2016 in-service.	Previously Allocated		$98,697,720
Thedford - Holt County 345kV CKT 1 Build approximately 146 Miles of 345kV from Thedford to Holt County. (Total Project E&C Cost Shown).	Previously Allocated		$313,376,623
	Current Study Total	$37,574,031	
GEN-2014-059			
GEN-2014-059 Interconnection Costs See One-Line Diagram.	Current Study	$9,200,000	$9,200,000

* Withdrawal of higher queued projects will cause a restudy and may result in higher costs

Interconnection Request and Upgrades	Upgrade Type	Allocated Cost	Upgrade Cost
GEN-2014-059 Tap - Ogallala 230kV CKT 1 Replace terminal equipment and increase line clearance. ERIS upgrade for GEN-2014-059. NRIS upgrade for GEN-2014-023.	Current Study	$2,968,726	$3,000,000
Gerald Gentleman Station Flowgate Stability Limit Mitigation Mitigation for GGS Flowgate Stability Limit. TBD in the Facilities Study with NPPD.	Current Study	$TBD	$TBD
Battle Creek-County Line 115kV CKT 1 Rebuild approximately 11 miles of 115kV from Battle Creek to County Line.	Previously Allocated		$4,000,000
County Line-Neligh East 115kV CKT 1 Rebuild approximately 12 miles of 115kV from County Line to Neligh East.	Previously Allocated		$8,050,000
Hoskins - Neligh 345/115kV Projects Per SPP 2014 ITP NT and NTC 200253 for 6/1/2016 in-service.	Previously Allocated		$98,697,720
Stegall - Scottsbluff 115kV CKT 1 NRIS only required upgrade: Install Stegall 345/115kV transformer and build a new 22 mile 115kV line from Stegall - Scottsbluff. SPP-NTC-200253.	Previously Allocated		$35,000,000
Thedford 345/115kV Transformer CKT 1 Install Thedford 345/115kV transformer (Total Project E&C Cost Shown). SPP-NTC-200277.	Previously Allocated		$10,236,800
	Current Study Total	$12,168,726*	
GEN-2014-060			
GEN-2014-060 Interconnection Costs See One-Line Diagram.	Current Study	$6,300,000	$6,300,000
Battle Creek-County Line 115kV CKT 1 Rebuild approximately 11 miles of 115kV from Battle Creek to County Line.	Previously Allocated		$4,000,000
County Line-Neligh East 115kV CKT 1 Rebuild approximately 12 miles of 115kV from County Line to Neligh East.	Previously Allocated		$8,050,000
Hoskins - Neligh 345/115kV Projects Per SPP 2014 ITP NT and NTC 200253 for 6/1/2016 in-service.	Previously Allocated		$98,697,720
Thedford 345/115kV Transformer CKT 1 Install Thedford 345/115kV transformer (Total Project E&C Cost Shown). SPP-NTC-200277.	Previously Allocated		$10,236,800
	Current Study Total	$6,300,000	
GEN-2015-001			
GEN-2015-001 Interconnection Costs See One-Line Diagram.	Current Study	$2,250,100	$2,250,100
Fairfax 138/69kV CKT 1 Per AECI Affected System Study for DISIS-2012-002	Previously Allocated		$2,200,000

* Withdrawal of higher queued projects will cause a restudy and may result in higher costs

Interconnection Request and Upgrades	Upgrade Type	Allocated Cost	Upgrade Cost
Remington - Fairfax 138KV CKT 1 Increase conductor clearance	Previously Allocated		$400,000
	Current Study Total	$2,250,100	
GEN-2015-003			
GEN-2015-003 Interconnection Costs See One-Line Diagram.	Current Study	$2,250,100	$2,250,100
Viola 345/138kV Transformer CKT 2 Build second 345/138/13.8kV transformer at Viola.	Current Study	$15,000,000	$15,000,000
Clearwater - Viola 138kV CKT 1 Per SPP 2013 ITP NT and SPP-NTC-200213 for 6/1/2018 in-service.	Previously Allocated		$40,525,225
Fairfax 138/69kV CKT 1 Per AECI Affected System Study for DISIS-2012-002	Previously Allocated		$2,200,000
Remington - Fairfax 138KV CKT 1 Increase conductor clearance	Previously Allocated		$400,000
Viola - Sumner County 138kV CKT 1 Per SPP 2014 ITP NT and SPP-NTC-200296 for 6/1/2019 in-service.	Previously Allocated		$51,513,963
Viola 345/138 kV Transformer CKT 1 Per SPP 2013 ITP NT and SPP-NTC-200213 for 6/1/2018 in-service.	Previously Allocated		$15,402,744
	Current Study Total	$17,250,100	
GEN-2015-005			
GEN-2015-005 Interconnection Costs See One-Line Diagram.	Current Study	$18,262,000	$18,262,000
Nebraska City - Sibley 345kV CKT 1 Priority Project: Nebraska City - Mullin Creek - Sibley 345kV circuit 1 per NTC (SPP-NTC-20097 and SPP-NTC-20098. (Total Project E&C Cost Shown).	Previously Allocated		$407,764,364
	Current Study Total	$18,262,000	
GEN-2015-007			
GEN-2015-007 Interconnection Costs See One-Line Diagram.	Current Study	$5,300,000	$5,300,000
Gentleman - Thedford 345kV CKT 1 Build approximately 76 Miles of 345kV from Gentleman to Thedford. (Total Project E&C Cost Shown).	Previously Allocated		$313,376,623
Thedford - Holt County 345kV CKT 1 Build approximately 146 Miles of 345kV from Thedford to Holt County. (Total Project E&C Cost Shown).	Previously Allocated		$313,376,623

* Withdrawal of higher queued projects will cause a restudy and may result in higher costs

Interconnection Request and Upgrades	Upgrade Type	Allocated Cost	Upgrade Cost
Twin Church - Dixon County 230kV Increase conductor clearances to accommodate 320MVA facility rating	Previously Allocated		$100,000
	Current Study Total	$5,300,000	

GEN-2015-008

Interconnection Request and Upgrades	Upgrade Type	Allocated Cost	Upgrade Cost
Albion - Petersburg - North Petersburg 115kV CKT 1 Reconductor 115kV lines and replace all terminal equipment for at least a 193MVA rate.	Current Study	$2,639,316	$3,500,000
Battle Creek - Norfolk 115kV CKT 1 Rebuild approximately 10 miles of 115kV from Norfolk - Battle Creek.	Current Study	$4,000,000	$4,000,000
Bloomfield - Gavins 115kV CKT 1 Rebuild approximately 17 miles of 115kV from Gavins - Bloomfield.	Current Study	$20,000,000	$20,000,000
GEN-2014-059 Tap - Ogallala 230kV CKT 1 Replace terminal equipment and increase line clearance. ERIS upgrade for GEN-2014-059. NRIS upgrade for GEN-2014-023.	Current Study	$13,158	$3,000,000
GEN-2015-008 Interconnection Costs See One-Line Diagram.	Current Study	$1,000,000	$1,000,000
Battle Creek-County Line 115kV CKT 1 Rebuild approximately 11 miles of 115kV from Battle Creek to County Line.	Previously Allocated		$4,000,000
County Line-Neligh East 115kV CKT 1 Rebuild approximately 12 miles of 115kV from County Line to Neligh East.	Previously Allocated		$8,050,000
Gentleman - Thedford 345kV CKT 1 Build approximately 76 Miles of 345kV from Gentleman to Thedford. (Total Project E&C Cost Shown).	Previously Allocated		$313,376,623
Hoskins - Neligh 345/115kV Projects Per SPP 2014 ITP NT and NTC 200253 for 6/1/2016 in-service.	Previously Allocated		$98,697,720
Thedford - Holt County 345kV CKT 1 Build approximately 146 Miles of 345kV from Thedford to Holt County. (Total Project E&C Cost Shown).	Previously Allocated		$313,376,623
Twin Church - Dixon County 230kV Increase conductor clearances to accommodate 320MVA facility rating	Previously Allocated		$100,000
	Current Study Total	$27,652,474	

GEN-2015-015

Interconnection Request and Upgrades	Upgrade Type	Allocated Cost	Upgrade Cost
GEN-2015-015 Interconnection Costs See One-Line Diagram.	Current Study	$3,041,661	$3,041,661
Clearwater - Viola 138kV CKT 1 Per SPP 2013 ITP NT and SPP-NTC-200213 for 6/1/2018 in-service.	Previously Allocated		$40,525,225

* Withdrawal of higher queued projects will cause a restudy and may result in higher costs

Interconnection Request and Upgrades	Upgrade Type	Allocated Cost	Upgrade Cost
Fairfax 138/69kV CKT 1 Per AECI Affected System Study for DISIS-2012-002	Previously Allocated		$2,200,000
Remington - Fairfax 138KV CKT 1 Increase conductor clearance	Previously Allocated		$400,000
Viola - Sumner County 138kV CKT 1 Per SPP 2014 ITP NT and SPP-NTC-200296 for 6/1/2019 in-service.	Previously Allocated		$51,513,963
Viola 345/138 kV Transformer CKT 1 Per SPP 2013 ITP NT and SPP-NTC-200213 for 6/1/2018 in-service.	Previously Allocated		$15,402,744
	Current Study Total	$3,041,661	
GEN-2015-016			
GEN-2015-016 Interconnection Costs See One-Line Diagram.	Current Study	$8,110,000	$8,110,000
Remington - Fairfax 138KV CKT 1 Increase conductor clearance	Previously Allocated		$400,000
	Current Study Total	$8,110,000	
GEN-2015-017			
GEN-2015-017 Interconnection Costs See One-Line Diagram.	Current Study	$3,459,098	$3,459,098
Arnold - Ransom 115kV CKT 1 Replace terminal equipment to achieve at least a 600 amp rating.	Previously Allocated		$3,000,000
Bucker - Spearville 345V CKT 1 Replace Terminal equipment	Previously Allocated		$1,480,238
Mingo 345/115kV Transformer CKT 2 NRIS only required upgrade: Build second 345/115/13.8kV transformer at Mingo per 2015 ITP10 SPP-NTC-200325.	Previously Allocated		$9,842,317
	Current Study Total	$3,459,098	
GEN-2015-019			
GEN-2015-019 Interconnection Costs See One-Line Diagram.	Current Study	$1,250,000	$1,250,000
	Current Study Total	$1,250,000	
GEN-2015-021			
GEN-2015-021 Interconnection Costs See One-Line Diagram.	Current Study	$1,438,309	$1,438,309

* Withdrawal of higher queued projects will cause a restudy and may result in higher costs

Interconnection Request and Upgrades	Upgrade Type	Allocated Cost	Upgrade Cost
Bucker - Spearville 345V CKT 1 Replace Terminal equipment	Previously Allocated		$1,480,238
Clark County Reactive Power Support Install 100Mvar SVC at Clark County Substation.	Previously Allocated		$24,303,536
FPL Switch - Mooreland 138kV CKT 1 Rebuild approximately 0.2 miles of 138kV line	Previously Allocated		$820,000
FPL Switch - Woodward 138kV CKT 1 Rebuild approximately 12 miles of 138kV line	Previously Allocated		$8,499,000
Harper - Milan Tap 138kV CKT 1 Rebuild approximately 22 miles of 138kV line	Previously Allocated		$9,613,332
Knoll - Postrock 230kV CKT 1 Rebuild approximately 1 mile of 230kV from Knoll - Post Rock.	Previously Allocated		$500,000
Milan Tap - Clearwater 138kV CKT 1 Rebuild approximately 12 miles of 138kV line	Previously Allocated		$18,000,000
	Current Study Total	$1,438,309	

GEN-2015-023

Interconnection Request and Upgrades	Upgrade Type	Allocated Cost	Upgrade Cost
GEN-2014-059 Tap - Ogallala 230kV CKT 1 Replace terminal equipment and increase line clearance. ERIS upgrade for GEN-2014-059. NRIS upgrade for GEN-2014-023.	Current Study	$4,769	$3,000,000
GEN-2015-023 Interconnection Costs See One-Line Diagram.	Current Study	$4,800,000	$4,800,000
Battle Creek-County Line 115kV CKT 1 Rebuild approximately 11 miles of 115kV from Battle Creek to County Line.	Previously Allocated		$4,000,000
County Line-Neligh East 115kV CKT 1 Rebuild approximately 12 miles of 115kV from County Line to Neligh East.	Previously Allocated		$8,050,000
Gentleman - Thedford 345kV CKT 1 Build approximately 76 Miles of 345kV from Gentleman to Thedford. (Total Project E&C Cost Shown).	Previously Allocated		$313,376,623
Hoskins - Neligh 345/115kV Projects Per SPP 2014 ITP NT and NTC 200253 for 6/1/2016 in-service.	Previously Allocated		$98,697,720
Thedford - Holt County 345kV CKT 1 Build approximately 146 Miles of 345kV from Thedford to Holt County. (Total Project E&C Cost Shown).	Previously Allocated		$313,376,623
Thedford 345/115kV Transformer CKT 1 Install Thedford 345/115kV transformer (Total Project E&C Cost Shown). SPP-NTC-200277.	Previously Allocated		$10,236,800

* Withdrawal of higher queued projects will cause a restudy and may result in higher costs

Interconnection Request and Upgrades	Upgrade Type	Allocated Cost	Upgrade Cost
Twin Church - Dixon County 230kV Increase conductor clearances to accommodate 320MVA facility rating	Previously Allocated		$100,000
	Current Study Total	$4,804,769	
GEN-2015-024			
Benton - Wichita 345kV Replace terminal equipment.	Current Study	$125,000	$250,000
GEN-2015-024 Interconnection Costs See One-Line Diagram.	Current Study	$32,704,640	$32,704,640
	Current Study Total	$32,829,640	
GEN-2015-025			
Benton - Wichita 345kV Replace terminal equipment.	Current Study	$125,000	$250,000
GEN-2015-025 Interconnection Costs See One-Line Diagram.	Current Study	$0	$0
	Current Study Total	$125,000	
GEN-2015-026			
Buckner - Holcomb 345kV Replace terminal equipment.	Current Study	$600,000	$600,000
GEN-2015-026 Interconnection Costs See One-Line Diagram.	Current Study	$150,000	$150,000
Bucker - Spearville 345V CKT 1 Replace Terminal equipment	Previously Allocated		$1,480,238
Clark County Reactive Power Support Install 100Mvar SVC at Clark County Substation.	Previously Allocated		$24,303,536
FPL Switch - Mooreland 138kV CKT 1 Rebuild approximately 0.2 miles of 138kV line	Previously Allocated		$820,000
FPL Switch - Woodward 138kV CKT 1 Rebuild approximately 12 miles of 138kV line	Previously Allocated		$8,499,000
Harper - Milan Tap 138kV CKT 1 Rebuild approximately 22 miles of 138kV line	Previously Allocated		$9,613,332
Knoll - Postrock 230kV CKT 1 Rebuild approximately 1 mile of 230kV from Knoll - Post Rock.	Previously Allocated		$500,000

* Withdrawal of higher queued projects will cause a restudy and may result in higher costs

Interconnection Request and Upgrades	Upgrade Type	Allocated Cost	Upgrade Cost
Milan Tap - Clearwater 138kV CKT 1 Rebuild approximately 12 miles of 138kV line	Previously Allocated		$18,000,000
	Current Study Total	$750,000	
GEN-2015-027			
Crooked Creek - Cudahy 115kV CKT 1 Rebuild approximately 10 miles of 115kV from Crooked Creek - Cudahy.	Current Study	$6,650,000	$6,650,000
Cudahy - Kismet 115kV CKT 1 Rebuild approximately 32 miles of 115kV from Cudahy - Kismet.	Current Study	$22,400,000	$22,400,000
GEN-2015-027 Interconnection Costs See One-Line Diagram.	Current Study	$150,000	$150,000
Greenburg - Shooting Star 115kV CKT 1 Rebuild approximately 8 miles of 115kV from Greenburg - Shooting Star.	Current Study	$5,250,000	$5,250,000
Clark County Reactive Power Support Install 100Mvar SVC at Clark County Substation.	Previously Allocated		$24,303,536
FPL Switch - Mooreland 138kV CKT 1 Rebuild approximately 0.2 miles of 138kV line	Previously Allocated		$820,000
FPL Switch - Woodward 138kV CKT 1 Rebuild approximately 12 miles of 138kV line	Previously Allocated		$8,499,000
Harper - Milan Tap 138kV CKT 1 Rebuild approximately 22 miles of 138kV line	Previously Allocated		$9,613,332
Knoll - Postrock 230kV CKT 1 Rebuild approximately 1 mile of 230kV from Knoll - Post Rock.	Previously Allocated		$500,000
Milan Tap - Clearwater 138kV CKT 1 Rebuild approximately 12 miles of 138kV line	Previously Allocated		$18,000,000
	Current Study Total	$34,450,000	
GEN-2015-028			
GEN-2015-028 Interconnection Costs See One-Line Diagram.	Current Study	$0	$0
Clearwater - Viola 138kV CKT 1 Per SPP 2013 ITP NT and SPP-NTC-200213 for 6/1/2018 in-service.	Previously Allocated		$40,525,225
Fairfax 138/69kV CKT 1 Per AECI Affected System Study for DISIS-2012-002	Previously Allocated		$2,200,000

* Withdrawal of higher queued projects will cause a restudy and may result in higher costs

Interconnection Request and Upgrades	Upgrade Type	Allocated Cost	Upgrade Cost
Remington - Fairfax 138KV CKT 1 Increase conductor clearance	Previously Allocated		$400,000
Viola - Sumner County 138kV CKT 1 Per SPP 2014 ITP NT and SPP-NTC-200296 for 6/1/2019 in-service.	Previously Allocated		$51,513,963
Viola 345/138 kV Transformer CKT 1 Per SPP 2013 ITP NT and SPP-NTC-200213 for 6/1/2018 in-service.	Previously Allocated		$15,402,744
	Current Study Total	$0	
GEN-2015-029			
GEN-2015-029 Interconnection Costs See One-Line Diagram.	Current Study	$2,270,100	$2,270,100
FPL Switch - Mooreland 138kV CKT 1 Rebuild approximately 0.2 miles of 138kV line	Previously Allocated		$820,000
FPL Switch - Woodward 138kV CKT 1 Rebuild approximately 12 miles of 138kV line	Previously Allocated		$8,499,000
	Current Study Total	$2,270,100	
GEN-2015-030			
GEN-2015-030 Interconnection Costs See One-Line Diagram.	Current Study	$3,369,366	$3,369,366
Fairfax 138/69kV CKT 1 Per AECI Affected System Study for DISIS-2012-002	Previously Allocated		$2,200,000
Remington - Fairfax 138KV CKT 1 Increase conductor clearance	Previously Allocated		$400,000
	Current Study Total	$3,369,366	
	TOTAL CURRENT STUDY COSTS:	**$229,843,633***	

* Does not include cost to mitigate GGS Flowgate Limitations.

* Withdrawal of higher queued projects will cause a restudy and may result in higher costs

E1: Stand Alone Cost Allocation per Interconnection Request (Including Prior Queued Upgrades)

Important Note:

****WITHDRAWAL OF HIGHER QUEUED PROJECTS WILL CAUSE A RESTUDY AND MAY RESULT IN HIGHER INTERCONNECTION COSTS****

This section shows each Generation Interconnection Request Customer, their current study impacted Network Upgrades, and the previously allocated upgrades upon which they rely to accommodate their interconnection to the transmission system UNDER A STAND ALONE SCENARIO ONLY.

The costs associated with the current study Network Upgrades are allocated to the Customers shown in this report.

In addition should a higher queued request, defined as one this study includes as a prior queued request, withdraw, the Network Upgrades assigned to the withdrawn request may be reallocated to the remaining requests that have an impact on the Network Upgrade under a restudy. Also, should a Interconnection Request choose to go into service prior to the operation date of any necessary Network Upgrades, the costs associated with those upgrades may be reallocated to the impacted Interconnection Request. The actual costs allocated to each Generation Interconnection Request Customer will be determined at the time of a restudy.

The required interconnection costs listed do not include all costs associated with the deliverability of the energy to final customers. These costs are determined by separate studies if the Customer submits a Transmission Service Request through SPP's Open Access Same Time Information System (OASIS) as required by Attachment Z1 of the SPP OATT. In addition, costs associated with a short circuit analysis will be allocated should the Interconnection Request Customer choose to execute a Facility Study Agreement.

Appendix E1. Cost Allocation Per Stand-Alone Request

(Including Previously Allocated Network Upgrades*)

Interconnection Request and Upgrades	Upgrade Type	Allocated Cost	Upgrade Cost
ASGI-2015-001			
ASGI-2015-001 Interconnection Costs See One-Line Diagram.	Current Study	$3,188,259	$3,188,259
Clark County Reactive Power Support Install 100Mvar SVC at Clark County Substation.	Previously Allocated		$24,303,536
FPL Switch - Mooreland 138kV CKT 1 Rebuild approximately 0.2 miles of 138kV line	Previously Allocated		$820,000
FPL Switch - Woodward 138kV CKT 1 Rebuild approximately 12 miles of 138kV line	Previously Allocated		$8,499,000
Harper - Milan Tap 138kV CKT 1 Rebuild approximately 22 miles of 138kV line	Previously Allocated		$9,613,332
Knoll - Postrock 230kV CKT 1 Rebuild approximately 1 mile of 230kV from Knoll - Post Rock.	Previously Allocated		$500,000
Milan Tap - Clearwater 138kV CKT 1 Rebuild approximately 12 miles of 138kV line	Previously Allocated		$18,000,000
Walkemeyer Tap - Walkemeyer 345/115kV Project Per SPP-NTC-200343 (Total Project E&C Cost Shown).	Previously Allocated		$17,838,846
	Current Study Total	$3,188,259	
ASGI-2015-004			
ASGI-2015-004 Interconnection Costs See One-Line Diagram.	Current Study	$0	$0
Fairfax 138/69kV CKT 1 Per AECI Affected System Study for DISIS-2012-002	Previously Allocated		$2,200,000
Remington - Fairfax 138KV CKT 1 Increase conductor clearance	Previously Allocated		$400,000
	Current Study Total	$0	
GEN-2010-048			
GEN-2010-048 Interconnection Costs See One-Line Diagram.	Current Study	$4,000,000	$4,000,000

* Withdrawal of higher queued projects will cause a restudy and may result in higher costs

Interconnection Request and Upgrades	Upgrade Type	Allocated Cost	Upgrade Cost
Arnold - Ransom 115kV CKT 1 Replace terminal equipment to achieve at least a 600 amp rating.	Previously Allocated		$3,000,000
Bucker - Spearville 345V CKT 1 Replace Terminal equipment	Previously Allocated		$1,480,238
Mingo 345/115kV Transformer CKT 2 Build second 345/115/13.8kV transformer at Mingo per 2015 ITP10 SPP-NTC-200325.	Previously Allocated		$9,842,317
	Current Study Total	$4,000,000	
GEN-2014-023			
Albion - Petersburg - North Petersburg 115kV CKT 1 Reconductor 115kV lines and replace all terminal equipment for at least a 193MVA rate.	Current Study	$3,500,000	$3,500,000
GEN-2014-023 Interconnection Costs See One-Line Diagram.	Current Study	$9,200,000	$9,200,000
Meadow Grove - North Petersburg 115kV CKT 1 Build approx. 25 miles of new 115kV circuit from Meadow Grove - N. Petersburg, expand N. Petersburg 115kV Sub and replace equip. at Neligh 115kV Sub.	Current Study	$16,200,000	$16,200,000
Meadow Grove 230/115/13.8kV Transformer CKT 1 Build Meadow Grove 230/115/13.8kV Transformer and Substation Expansion.	Current Study	$11,300,000	$11,300,000
Battle Creek-County Line 115kV CKT 1 Rebuild approximately 11 miles of 115kV from Battle Creek to County Line.	Previously Allocated		$4,000,000
County Line-Neligh East 115kV CKT 1 Rebuild approximately 12 miles of 115kV from County Line to Neligh East.	Previously Allocated		$8,050,000
Hoskins - Dixon County - Twin Church 230kV Rerate per NPPD Facility Study	Previously Allocated		$500,000
Hoskins - Neligh 345/115kV Projects Per SPP 2014 ITP NT and NTC 200253 for 6/1/2016 in-service.	Previously Allocated		$98,697,720
	Current Study Total	$40,200,000	
GEN-2014-059			
GEN-2014-059 Interconnection Costs See One-Line Diagram.	Current Study	$9,200,000	$9,200,000
GEN-2014-059 Tap - Ogallala 230kV CKT 1 Replace terminal equipment and increase line clearance. ERIS upgrade for GEN-2014-059. NRIS upgrade for GEN-2014-023.	Current Study	$3,000,000	$3,000,000
Gerald Gentleman Station Flowgate Stability Limit Mitigation Mitigation for GGS Flowgate Stability Limit. TBD in the Facilities Study with NPPD.	Current Study	$TBD	$TBD

* Withdrawal of higher queued projects will cause a restudy and may result in higher costs

Interconnection Request and Upgrades	Upgrade Type	Allocated Cost	Upgrade Cost
Battle Creek-County Line 115kV CKT 1 Rebuild approximately 11 miles of 115kV from Battle Creek to County Line.	Previously Allocated		$4,000,000
County Line-Neligh East 115kV CKT 1 Rebuild approximately 12 miles of 115kV from County Line to Neligh East.	Previously Allocated		$8,050,000
Gentleman - Thedford 345kV CKT 1 Build approximately 76 Miles of 345kV from Gentleman to Thedford. (Total Project E&C Cost Shown).	Previously Allocated		$313,376,623
Hoskins - Neligh 345/115kV Projects Per SPP 2014 ITP NT and NTC 200253 for 6/1/2016 in-service.	Previously Allocated		$98,697,720
Stegall - Scottsbluff 115kV CKT 1 NRIS only required upgrade: Install Stegall 345/115kV transformer and build a new 22 mile 115kV line from Stegall - Scottsbluff. SPP-NTC-200253.	Previously Allocated		$35,000,000
Thedford - Holt County 345kV CKT 1 Build approximately 146 Miles of 345kV from Thedford to Holt County. (Total Project E&C Cost Shown).	Previously Allocated		$313,376,623
Thedford 345/115kV Transformer CKT 1 Install Thedford 345/115kV transformer (Total Project E&C Cost Shown). SPP-NTC-200277.	Previously Allocated		$10,236,800
	Current Study Total	$12,200,000*	

GEN-2014-060

Interconnection Request and Upgrades	Upgrade Type	Allocated Cost	Upgrade Cost
GEN-2014-060 Interconnection Costs See One-Line Diagram.	Current Study	$6,300,000	$6,300,000
Battle Creek-County Line 115kV CKT 1 Rebuild approximately 11 miles of 115kV from Battle Creek to County Line.	Previously Allocated		$4,000,000
County Line-Neligh East 115kV CKT 1 Rebuild approximately 12 miles of 115kV from County Line to Neligh East.	Previously Allocated		$8,050,000
Hoskins - Neligh 345/115kV Projects Per SPP 2014 ITP NT and NTC 200253 for 6/1/2016 in-service.	Previously Allocated		$98,697,720
	Current Study Total	$6,300,000	

GEN-2015-001

Interconnection Request and Upgrades	Upgrade Type	Allocated Cost	Upgrade Cost
GEN-2015-001 Interconnection Costs See One-Line Diagram.	Current Study	$2,250,100	$2,250,100
Fairfax 138/69kV CKT 1 Per AECI Affected System Study for DISIS-2012-002	Previously Allocated		$2,200,000
Remington - Fairfax 138KV CKT 1 Increase conductor clearance	Previously Allocated		$400,000

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Interconnection Request and Upgrades	Upgrade Type	Allocated Cost	Upgrade Cost
	Current Study Total	$2,250,100	
GEN-2015-003			
GEN-2015-003 Interconnection Costs See One-Line Diagram.	Current Study	$2,250,100	$2,250,100
Viola 345/138kV Transformer CKT 2 Build second 345/138/13.8kV transformer at Viola.	Current Study	$15,000,000	$15,000,000
Clearwater - Viola 138kV CKT 1 Per SPP 2013 ITP NT and SPP-NTC-200213 for 6/1/2018 in-service.	Previously Allocated		$40,525,225
Fairfax 138/69kV CKT 1 Per AECI Affected System Study for DISIS-2012-002	Previously Allocated		$2,200,000
Remington - Fairfax 138KV CKT 1 Increase conductor clearance	Previously Allocated		$400,000
Viola - Sumner County 138kV CKT 1 Per SPP 2014 ITP NT and SPP-NTC-200296 for 6/1/2019 in-service.	Previously Allocated		$51,513,963
Viola 345/138 kV Transformer CKT 1 Per SPP 2013 ITP NT and SPP-NTC-200213 for 6/1/2018 in-service.	Previously Allocated		$15,402,744
	Current Study Total	$17,250,100	
GEN-2015-005			
GEN-2015-005 Interconnection Costs See One-Line Diagram.	Current Study	$18,262,000	$18,262,000
Nebraska City - Sibley 345kV CKT 1 Priority Project: Nebraska City - Mullin Creek - Sibley 345kV circuit 1 per NTC (SPP-NTC-20097 and SPP-NTC-20098. (Total Project E&C Cost Shown).	Previously Allocated		$407,764,364
	Current Study Total	$18,262,000	
GEN-2015-007			
GEN-2015-007 Interconnection Costs See One-Line Diagram.	Current Study	$5,300,000	$5,300,000
Twin Church - Dixon County 230kV Increase conductor clearances to accommodate 320MVA facility rating	Previously Allocated		$100,000
	Current Study Total	$5,300,000	
GEN-2015-008			
Albion - Petersburg - North Petersburg 115kV CKT 1 Reconductor 115kV lines and replace all terminal equipment for at least a 193MVA rate.	Current Study	$3,500,000	$3,500,000

* Withdrawal of higher queued projects will cause a restudy and may result in higher costs

Interconnection Request and Upgrades	Upgrade Type	Allocated Cost	Upgrade Cost
Battle Creek - Norfolk 115kV CKT 1 Rebuild approximately 10 miles of 115kV from Norfolk - Battle Creek.	Current Study	$4,000,000	$4,000,000
Bloomfield - Gavins 115kV CKT 1 Rebuild approximately 17 miles of 115kV from Gavins - Bloomfield.	Current Study	$20,000,000	$20,000,000
GEN-2015-008 Interconnection Costs See One-Line Diagram.	Current Study	$1,000,000	$1,000,000
Battle Creek-County Line 115kV CKT 1 Rebuild approximately 11 miles of 115kV from Battle Creek to County Line.	Previously Allocated		$4,000,000
County Line-Neligh East 115kV CKT 1 Rebuild approximately 12 miles of 115kV from County Line to Neligh East.	Previously Allocated		$8,050,000
Hoskins - Neligh 345/115kV Projects Per SPP 2014 ITP NT and NTC 200253 for 6/1/2016 in-service.	Previously Allocated		$98,697,720
Twin Church - Dixon County 230kV Increase conductor clearances to accommodate 320MVA facility rating	Previously Allocated		$100,000
	Current Study Total	$28,500,000	

GEN-2015-015

Interconnection Request and Upgrades	Upgrade Type	Allocated Cost	Upgrade Cost
GEN-2015-015 Interconnection Costs See One-Line Diagram.	Current Study	$3,041,661	$3,041,661
Clearwater - Viola 138kV CKT 1 Per SPP 2013 ITP NT and SPP-NTC-200213 for 6/1/2018 in-service.	Previously Allocated		$40,525,225
Fairfax 138/69kV CKT 1 Per AECI Affected System Study for DISIS-2012-002	Previously Allocated		$2,200,000
Remington - Fairfax 138KV CKT 1 Increase conductor clearance	Previously Allocated		$400,000
Viola - Sumner County 138kV CKT 1 Per SPP 2014 ITP NT and SPP-NTC-200296 for 6/1/2019 in-service.	Previously Allocated		$51,513,963
Viola 345/138 kV Transformer CKT 1 Per SPP 2013 ITP NT and SPP-NTC-200213 for 6/1/2018 in-service.	Previously Allocated		$15,402,744
	Current Study Total	$3,041,661	

GEN-2015-016

Interconnection Request and Upgrades	Upgrade Type	Allocated Cost	Upgrade Cost
GEN-2015-016 Interconnection Costs See One-Line Diagram.	Current Study	$8,110,000	$8,110,000

* Withdrawal of higher queued projects will cause a restudy and may result in higher costs

Interconnection Request and Upgrades	Upgrade Type	Allocated Cost	Upgrade Cost
Remington - Fairfax 138KV CKT 1 Increase conductor clearance	Previously Allocated		$400,000
	Current Study Total	$8,110,000	
GEN-2015-017			
GEN-2015-017 Interconnection Costs See One-Line Diagram.	Current Study	$3,459,098	$3,459,098
Arnold - Ransom 115kV CKT 1 Replace terminal equipment to achieve at least a 600 amp rating.	Previously Allocated		$3,000,000
Bucker - Spearville 345V CKT 1 Replace Terminal equipment	Previously Allocated		$1,480,238
Mingo 345/115kV Transformer CKT 2 Build second 345/115/13.8kV transformer at Mingo per 2015 ITP10 SPP-NTC-200325.	Previously Allocated		$9,842,317
	Current Study Total	$3,459,098	
GEN-2015-019			
GEN-2015-019 Interconnection Costs See One-Line Diagram.	Current Study	$1,250,000	$1,250,000
	Current Study Total	$1,250,000	
GEN-2015-021			
GEN-2015-021 Interconnection Costs See One-Line Diagram.	Current Study	$1,438,309	$1,438,309
Bucker - Spearville 345V CKT 1 Replace Terminal equipment	Previously Allocated		$1,480,238
Clark County Reactive Power Support Install 100Mvar SVC at Clark County Substation.	Previously Allocated		$24,303,536
Harper - Milan Tap 138kV CKT 1 Rebuild approximately 22 miles of 138kV line	Previously Allocated		$9,613,332
Knoll - Postrock 230kV CKT 1 Rebuild approximately 1 mile of 230kV from Knoll - Post Rock.	Previously Allocated		$500,000
Milan Tap - Clearwater 138kV CKT 1 Rebuild approximately 12 miles of 138kV line	Previously Allocated		$18,000,000
Walkemeyer Tap - Walkemeyer 345/115kV Project Per SPP-NTC-200343 (Total Project E&C Cost Shown).	Previously Allocated		$17,838,846

* Withdrawal of higher queued projects will cause a restudy and may result in higher costs

	Current Study Total	$1,438,309	

GEN-2015-023

Interconnection Request and Upgrades	Upgrade Type	Allocated Cost	Upgrade Cost
GEN-2015-023 Interconnection Costs See One-Line Diagram.	Current Study	$4,800,000	$4,800,000
Battle Creek-County Line 115kV CKT 1 Rebuild approximately 11 miles of 115kV from Battle Creek to County Line.	Previously Allocated		$4,000,000
County Line-Neligh East 115kV CKT 1 Rebuild approximately 12 miles of 115kV from County Line to Neligh East.	Previously Allocated		$8,050,000
Gentleman - Thedford 345kV CKT 1 Build approximately 76 Miles of 345kV from Gentleman to Thedford. (Total Project E&C Cost Shown).	Previously Allocated		$313,376,623
Hoskins - Neligh 345/115kV Projects Per SPP 2014 ITP NT and NTC 200253 for 6/1/2016 in-service.	Previously Allocated		$98,697,720
Thedford - Holt County 345kV CKT 1 Build approximately 146 Miles of 345kV from Thedford to Holt County. (Total Project E&C Cost Shown).	Previously Allocated		$313,376,623
Thedford 345/115kV Transformer CKT 1 Install Thedford 345/115kV transformer (Total Project E&C Cost Shown). SPP-NTC-200277.	Previously Allocated		$10,236,800
Twin Church - Dixon County 230kV Increase conductor clearances to accommodate 320MVA facility rating	Previously Allocated		$100,000
	Current Study Total	$4,800,000	

GEN-2015-024

Interconnection Request and Upgrades	Upgrade Type	Allocated Cost	Upgrade Cost
GEN-2015-024 Interconnection Costs See One-Line Diagram.	Current Study	$32,704,640	$32,704,640
	Current Study Total	$32,704,640	

GEN-2015-025

Interconnection Request and Upgrades	Upgrade Type	Allocated Cost	Upgrade Cost
GEN-2015-025 Interconnection Costs See One-Line Diagram.	Current Study	$32,704,640	$32,704,640
	Current Study Total	$32,704,640	

GEN-2015-026

Interconnection Request and Upgrades	Upgrade Type	Allocated Cost	Upgrade Cost
Buckner - Holcomb 345kV Replace terminal equipment.	Current Study	$600,000	$600,000
GEN-2015-026 Interconnection Costs See One-Line Diagram.	Current Study	$150,000	$150,000

* Withdrawal of higher queued projects will cause a restudy and may result in higher costs

Interconnection Request and Upgrades	Upgrade Type	Allocated Cost	Upgrade Cost
Bucker - Spearville 345V CKT 1 Replace Terminal equipment	Previously Allocated		$1,480,238
Clark County Reactive Power Support Install 100Mvar SVC at Clark County Substation.	Previously Allocated		$24,303,536
FPL Switch - Mooreland 138kV CKT 1 Rebuild approximately 0.2 miles of 138kV line	Previously Allocated		$820,000
FPL Switch - Woodward 138kV CKT 1 Rebuild approximately 12 miles of 138kV line	Previously Allocated		$8,499,000
Harper - Milan Tap 138kV CKT 1 Rebuild approximately 22 miles of 138kV line	Previously Allocated		$9,613,332
Knoll - Postrock 230kV CKT 1 Rebuild approximately 1 mile of 230kV from Knoll - Post Rock.	Previously Allocated		$500,000
Milan Tap - Clearwater 138kV CKT 1 Rebuild approximately 12 miles of 138kV line	Previously Allocated		$18,000,000
Walkemeyer Tap - Walkemeyer 345/115kV Project Per SPP-NTC-200343 (Total Project E&C Cost Shown).	Previously Allocated		$17,838,846
	Current Study Total	$750,000	

GEN-2015-027

Interconnection Request and Upgrades	Upgrade Type	Allocated Cost	Upgrade Cost
Crooked Creek - Cudahy 115kV CKT 1 Rebuild approximately 10 miles of 115kV from Crooked Creek - Cudahy.	Current Study	$6,650,000	$6,650,000
Cudahy - Kismet 115kV CKT 1 Rebuild approximately 32 miles of 115kV from Cudahy - Kismet.	Current Study	$22,400,000	$22,400,000
GEN-2015-027 Interconnection Costs See One-Line Diagram.	Current Study	$150,000	$150,000
Greenburg - Shooting Star 115kV CKT 1 Rebuild approximately 8 miles of 115kV from Greenburg - Shooting Star.	Current Study	$5,250,000	$5,250,000
Clark County Reactive Power Support Install 100Mvar SVC at Clark County Substation.	Previously Allocated		$24,303,536
FPL Switch - Mooreland 138kV CKT 1 Rebuild approximately 0.2 miles of 138kV line	Previously Allocated		$820,000
FPL Switch - Woodward 138kV CKT 1 Rebuild approximately 12 miles of 138kV line	Previously Allocated		$8,499,000

* Withdrawal of higher queued projects will cause a restudy and may result in higher costs

Interconnection Request and Upgrades	Upgrade Type	Allocated Cost	Upgrade Cost
Harper - Milan Tap 138kV CKT 1 Rebuild approximately 22 miles of 138kV line	Previously Allocated		$9,613,332
Knoll - Postrock 230kV CKT 1 Rebuild approximately 1 mile of 230kV from Knoll - Post Rock.	Previously Allocated		$500,000
Milan Tap - Clearwater 138kV CKT 1 Rebuild approximately 12 miles of 138kV line	Previously Allocated		$18,000,000
Walkemeyer Tap - Walkemeyer 345/115kV Project Per SPP-NTC-200343 (Total Project E&C Cost Shown).	Previously Allocated		$17,838,846
	Current Study Total	$34,450,000	
GEN-2015-028			
GEN-2015-028 Interconnection Costs See One-Line Diagram.	Current Study	$0	$0
Fairfax 138/69kV CKT 1 Per AECI Affected System Study for DISIS-2012-002	Previously Allocated		$2,200,000
Remington - Fairfax 138KV CKT 1 Increase conductor clearance	Previously Allocated		$400,000
	Current Study Total	$0	
GEN-2015-029			
GEN-2015-029 Interconnection Costs See One-Line Diagram.	Current Study	$2,270,100	$2,270,100
FPL Switch - Mooreland 138kV CKT 1 Rebuild approximately 0.2 miles of 138kV line	Previously Allocated		$820,000
FPL Switch - Woodward 138kV CKT 1 Rebuild approximately 12 miles of 138kV line	Previously Allocated		$8,499,000
	Current Study Total	$2,270,100	
GEN-2015-030			
GEN-2015-030 Interconnection Costs See One-Line Diagram.	Current Study	$3,369,366	$3,369,366
Fairfax 138/69kV CKT 1 Per AECI Affected System Study for DISIS-2012-002	Previously Allocated		$2,200,000
Remington - Fairfax 138KV CKT 1 Increase conductor clearance	Previously Allocated		$400,000

* Withdrawal of higher queued projects will cause a restudy and may result in higher costs

Interconnection Request and Upgrades	Upgrade Type	Allocated Cost	Upgrade Cost
	Current Study Total	$3,369,366	

TOTAL CURRENT STUDY COSTS: $265,798,273*

* Does not include cost to mitigate GGS Flowgate Limitation.

* Withdrawal of higher queued projects will cause a restudy and may result in higher costs

F: Cost Allocation per Proposed Study Network Upgrade

Important Note:

****WITHDRAWAL OF HIGHER QUEUED PROJECTS WILL CAUSE A RESTUDY AND MAY RESULT IN HIGHER INTERCONNECTION COSTS****

This section shows each Direct Assigned Facility and Network Upgrade and the Generation Interconnection Request Customer(s) which have an impact in this study assuming all higher queued projects remain in the queue and achieve commercial operation.

The required interconnection costs listed do not include all costs associated with the deliverability of the energy to final customers. These costs are determined by separate studies if the Customer submits a Transmission Service Request through SPP's Open Access Same Time Information System (OASIS) as required by Attachment Z1 of the SPP OATT. In addition, costs associated with a short circuit analysis will be allocated should the Interconnection Request Customer choose to execute a Facility Study Agreement.

There may be additional costs allocated to each Customer. See Appendix E for more details.

Appendix F. Cost Allocation by Upgrade

ASGI-2015-001 Interconnection Costs			**$3,188,259**
See One-Line Diagram.			
	ASGI-2015-001	$3,188,259	
	Total Allocated Costs	**$3,188,259**	
ASGI-2015-004 Interconnection Costs			**$0**
See One-Line Diagram.			
	ASGI-2015-004	$0	
	Total Allocated Costs	**$0**	
Battle Creek - Norfolk 115kV CKT 1			**$4,000,000**
Rebuild approximately 10 miles of 115kV from Norfolk - Battle Creek.			
	GEN-2015-008	$4,000,000	
	Total Allocated Costs	**$4,000,000**	
Benton - Wichita 345kV			**$250,000**
Replace terminal equipment.			
	GEN-2015-024	$125,000	
	GEN-2015-025	$125,000	
	Total Allocated Costs	**$250,000**	
Bloomfield - Gavins 115kV CKT 1			**$20,000,000**
Rebuild approximately 17 miles of 115kV from Gavins - Bloomfield.			
	GEN-2015-008	$20,000,000	
	Total Allocated Costs	**$20,000,000**	
Buckner - Holcomb 345kV			**$600,000**
Replace terminal equipment.			
	GEN-2015-026	$600,000	
	Total Allocated Costs	**$600,000**	
Crooked Creek - Cudahy 115kV CKT 1			**$6,650,000**
Rebuild approximately 10 miles of 115kV from Crooked Creek - Cudahy.			
	GEN-2015-027	$6,650,000	
	Total Allocated Costs	**$6,650,000**	

* Withdrawal of higher queued projects will cause a restudy and may result in higher costs

Cudahy - Kismet 115kV CKT 1			**$22,400,000**
Rebuild approximately 32 miles of 115kV from Cudahy - Kismet.			
	GEN-2015-027	$22,400,000	
	Total Allocated Costs	**$22,400,000**	
GEN-2014-059 Tap - Ogallala 230kV CKT 1			**$3,000,000**
Replace terminal equipment and increase line clearance. ERIS upgrade for GEN-2014-059. NRIS upgrade for GEN-2014-023.			
	GEN-2014-023	$13,347	
	GEN-2014-059	$2,968,726	
	GEN-2015-008	$13,158	
	GEN-2015-023	$4,769	
	Total Allocated Costs	**$3,000,000**	
GEN-2010-048 Interconnection Costs			**$4,000,000**
See One-Line Diagram.			
	GEN-2010-048	$4,000,000	
	Total Allocated Costs	**$4,000,000**	
GEN-2014-023 Interconnection Costs			**$9,200,000**
See One-Line Diagram.			
	GEN-2014-023	$9,200,000	
	Total Allocated Costs	**$9,200,000**	
GEN-2014-059 Interconnection Costs			**$9,200,000**
See One-Line Diagram.			
	GEN-2014-059	$9,200,000	
	Total Allocated Costs	**$9,200,000**	
GEN-2014-060 Interconnection Costs			**$6,300,000**
See One-Line Diagram.			
	GEN-2014-060	$6,300,000	
	Total Allocated Costs	**$6,300,000**	
GEN-2015-001 Interconnection Costs			**$2,250,100**
See One-Line Diagram.			
	GEN-2015-001	$2,250,100	
	Total Allocated Costs	**$2,250,100**	

* Withdrawal of higher queued projects will cause a restudy and may result in higher costs

GEN-2015-003 Interconnection Costs		**$2,250,100**
See One-Line Diagram.		
GEN-2015-003	$2,250,100	
Total Allocated Costs	**$2,250,100**	
GEN-2015-005 Interconnection Costs		**$18,262,000**
See One-Line Diagram.		
GEN-2015-005	$18,262,000	
Total Allocated Costs	**$18,262,000**	
GEN-2015-007 Interconnection Costs		**$5,300,000**
See One-Line Diagram.		
GEN-2015-007	$5,300,000	
Total Allocated Costs	**$5,300,000**	
GEN-2015-008 Interconnection Costs		**$1,000,000**
See One-Line Diagram.		
GEN-2015-008	$1,000,000	
Total Allocated Costs	**$1,000,000**	
GEN-2015-015 Interconnection Costs		**$3,041,661**
See One-Line Diagram.		
GEN-2015-015	$3,041,661	
Total Allocated Costs	**$3,041,661**	
GEN-2015-016 Interconnection Costs		**$8,110,000**
See One-Line Diagram.		
GEN-2015-016	$8,110,000	
Total Allocated Costs	**$8,110,000**	
GEN-2015-017 Interconnection Costs		**$3,459,098**
See One-Line Diagram.		
GEN-2015-017	$3,459,098	
Total Allocated Costs	**$3,459,098**	
GEN-2015-019 Interconnection Costs		**$1,250,000**
See One-Line Diagram.		
GEN-2015-019	$1,250,000	
Total Allocated Costs	**$1,250,000**	

* Withdrawal of higher queued projects will cause a restudy and may result in higher costs

GEN-2015-021 Interconnection Costs			**$1,438,309**
See One-Line Diagram.			
	GEN-2015-021	$1,438,309	
	Total Allocated Costs	**$1,438,309**	
GEN-2015-023 Interconnection Costs			**$4,800,000**
See One-Line Diagram.			
	GEN-2015-023	$4,800,000	
	Total Allocated Costs	**$4,800,000**	
GEN-2015-024 Interconnection Costs			**$32,704,640**
See One-Line Diagram.			
	GEN-2015-024	$32,704,640	
	Total Allocated Costs	**$32,704,640**	
GEN-2015-025 Interconnection Costs			**$0**
See One-Line Diagram.			
	GEN-2015-025	$0	
	Total Allocated Costs	**$0**	
GEN-2015-026 Interconnection Costs			**$150,000**
See One-Line Diagram.			
	GEN-2015-026	$150,000	
	Total Allocated Costs	**$150,000**	
GEN-2015-027 Interconnection Costs			**$150,000**
See One-Line Diagram.			
	GEN-2015-027	$150,000	
	Total Allocated Costs	**$150,000**	
GEN-2015-028 Interconnection Costs			**$0**
See One-Line Diagram.			
	GEN-2015-028	$0	
	Total Allocated Costs	**$0**	
GEN-2015-029 Interconnection Costs			**$2,270,100**
See One-Line Diagram.			
	GEN-2015-029	$2,270,100	
	Total Allocated Costs	**$2,270,100**	

* Withdrawal of higher queued projects will cause a restudy and may result in higher costs

GEN-2015-030 Interconnection Costs			**$3,369,366**
See One-Line Diagram.			
	GEN-2015-030	$3,369,366	
	Total Allocated Costs	**$3,369,366**	
Gerald Gentleman Station Flowgate Stability Limit Mitigation			**$TBD**
Mitigation for GGS Flowgate Stability Limit. TBD in the Facilities Study with NPPD.			
	GEN-2014-059	$TBD	
	Total Allocated Costs	**$TBD**	
Greenburg - Shooting Star 115kV CKT 1			**$5,250,000**
Rebuild approximately 8 miles of 115kV from Greenburg - Shooting Star.			
	GEN-2015-027	$5,250,000	
	Total Allocated Costs	**$5,250,000**	
Meadow Grove - North Petersburg 115kV CKT 1			**$16,200,000**
Build approx. 25 miles of new 115kV circuit from Meadow Grove - N. Petersburg, expand N. Petersburg 115kV Sub and replace equip. at Neligh 115kV Sub.			
	GEN-2014-023	$16,200,000	
	Total Allocated Costs	**$16,200,000**	
Meadow Grove 230/115/13.8kV Transformer CKT 1			**$11,300,000**
Build Meadow Grove 230/115/13.8kV Transformer and Substation Expansion.			
	GEN-2014-023	$11,300,000	
	Total Allocated Costs	**$11,300,000**	
Albion - Petersburg - North Petersburg 115kV CKT 1			**$3,500,000**
Reconductor 115kV lines and replace all terminal equipment for at least a 193MVA rate.			
	GEN-2014-023	$860,684	
	GEN-2015-008	$2,639,316	
	Total Allocated Costs	**$3,500,000**	
Viola 345/138kV Transformer CKT 2			**$15,000,000**
Build second 345/138/13.8kV transformer at Viola.			
	GEN-2015-003	$15,000,000	
	Total Allocated Costs	**$15,000,000**	

* Withdrawal of higher queued projects will cause a restudy and may result in higher costs

G: Power Flow Analysis (Constraints Used For Mitigation)

See next page.

SOLUTION	GROUP	SCENARIO	SEASON	SOURCE	DIRECTION	MONITORED ELEMENT	RATEA (MVA)	RATEB(MVA)	TDF	TC%LOADING (% MVA)	CONTINGENCY
FDNS	04ALL	0	25SP	G10_048	TO->FROM	BEACH STATION - G10-48T 115.00 115KV CKT 1	80	88	0.41103	107.1480	MINGO (MINGO) 345/115/13.8KV TRANSFORMER CKT 1
FDNS	04ALL	0	20SP	G10_048	TO->FROM	BEACH STATION - G10-48T 115.00 115KV CKT 1	80	88	0.41103	101.6866	MINGO (MINGO) 345/115/13.8KV TRANSFORMER CKT 1
FDNSLock-Blown up	09ALL	0	15SP	G14_023		Non-Converged Contingency	720	720	0.08131	-	GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1
FDNSLock-Blown up	09ALL	0	15G	G14_023		Non-Converged Contingency	720	720	0.08136	-	GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1
FDNSLock-Blown up	09ALL	0	15WP	G14_023		Non-Converged Contingency	720	720	0.0804	-	GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1
FDNSLock-Blown up	09ALL	2	15SP	G14_023		Non-Converged Contingency	720	720	0.08187	-	GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1
FDNSLock-Blown up	09ALL	2	15G	G14_023		Non-Converged Contingency	720	720	0.08125	-	GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1
FDNSLock-Blown up	09ALL	2	15WP	G14_023		Non-Converged Contingency	720	720	0.08059	-	GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1
FDNS	09ALL	0	15G	G14_023	TO->FROM	FT RANDAL - G14_023T 230.00 230KV CKT 1	320	320	1	123.6343	KELLY - MEADOWGROVE4230.00 230KV CKT 1
FDNS	09ALL	0	15SP	G14_023	TO->FROM	FT RANDAL - G14_023T 230.00 230KV CKT 1	320	320	1	122.8962	KELLY - MEADOWGROVE4230.00 230KV CKT 1
FDNS	09ALL	0	25SP	G14_023	TO->FROM	FT RANDAL - G14_023T 230.00 230KV CKT 1	320	320	1	122.7810	KELLY - MEADOWGROVE4230.00 230KV CKT 1
FDNS	09ALL	0	20WP	G14_023	TO->FROM	FT RANDAL - G14_023T 230.00 230KV CKT 1	320	320	1	122.7258	KELLY - MEADOWGROVE4230.00 230KV CKT 1
FDNS	09ALL	0	15WP	G14_023	TO->FROM	FT RANDAL - G14_023T 230.00 230KV CKT 1	320	320	1	122.7181	KELLY - MEADOWGROVE4230.00 230KV CKT 1
FDNS	09ALL	0	20SP	G14_023	TO->FROM	FT RANDAL - G14_023T 230.00 230KV CKT 1	320	320	1	122.6494	KELLY - MEADOWGROVE4230.00 230KV CKT 1
FDNS	09NR	0	15G	G14_023	TO->FROM	FT RANDAL - G14_023T 230.00 230KV CKT 1	320	320	1	109.6911	KELLY - MEADOWGROVE4230.00 230KV CKT 1
FDNS	09NR	0	15G	G14_023	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.04256	125.8320	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	00NR	0	15SP	G14_023	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.04129	124.5109	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	00NR	0	25SP	G14_023	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.03532	116.3340	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	00NR	0	15WP	G14_023	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.03926	115.6280	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	00NR	0	20SP	G14_023	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.03601	115.3019	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	00NR	0	20WP	G14_023	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.03448	112.8683	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	09ALL	0	15G	G14_023	TO->FROM	KELLY - MEADOWGROVE4230.00 230KV CKT 1	368	368	1	110.6376	FT RANDAL - G14_023T 230.00 230KV CKT 1
FDNS	09ALL	0	20WP	G14_023	TO->FROM	KELLY - MEADOWGROVE4230.00 230KV CKT 1	368	368	1	109.0458	FT RANDAL - G14_023T 230.00 230KV CKT 1
FDNS	09ALL	0	15WP	G14_023	TO->FROM	KELLY - MEADOWGROVE4230.00 230KV CKT 1	368	368	1	108.8899	FT RANDAL - G14_023T 230.00 230KV CKT 1
FDNS	09ALL	0	25SP	G14_023	TO->FROM	KELLY - MEADOWGROVE4230.00 230KV CKT 1	368	368	1	108.7906	FT RANDAL - G14_023T 230.00 230KV CKT 1
FDNS	09ALL	0	15SP	G14_023	TO->FROM	KELLY - MEADOWGROVE4230.00 230KV CKT 1	368	368	1	108.4508	FT RANDAL - G14_023T 230.00 230KV CKT 1
FDNS	09ALL	0	20SP	G14_023	TO->FROM	KELLY - MEADOWGROVE4230.00 230KV CKT 1	368	368	1	108.3702	FT RANDAL - G14_023T 230.00 230KV CKT 1
FDNS	09ALL	2	15G	G14_023	TO->FROM	FT RANDAL - G14_023T 230.00 230KV CKT 1	320	320	1	123.2484	KELLY - MEADOWGROVE4230.00 230KV CKT 1
FDNS	09ALL	2	15SP	G14_023	TO->FROM	FT RANDAL - G14_023T 230.00 230KV CKT 1	320	320	1	122.8419	KELLY - MEADOWGROVE4230.00 230KV CKT 1
FDNS	09ALL	2	15WP	G14_023	TO->FROM	FT RANDAL - G14_023T 230.00 230KV CKT 1	320	320	1	122.6410	KELLY - MEADOWGROVE4230.00 230KV CKT 1
FDNS	09NR	2	15G	G14_023	TO->FROM	FT RANDAL - G14_023T 230.00 230KV CKT 1	320	320	1	109.6312	KELLY - MEADOWGROVE4230.00 230KV CKT 1
FDNS	09NR	2	15G	G14_023	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.04251	125.5977	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	00NR	2	15SP	G14_023	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.04124	124.5047	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	00NR	2	15WP	G14_023	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.0392	115.5316	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	09ALL	2	15G	G14_023	TO->FROM	KELLY - MEADOWGROVE4230.00 230KV CKT 1	368	368	1	110.1577	FT RANDAL - G14_023T 230.00 230KV CKT 1
FDNS	09ALL	2	15SP	G14_023	TO->FROM	KELLY - MEADOWGROVE4230.00 230KV CKT 1	368	368	1	108.3764	FT RANDAL - G14_023T 230.00 230KV CKT 1
FDNS	09ALL	2	15WP	G14_023	TO->FROM	KELLY - MEADOWGROVE4230.00 230KV CKT 1	368	368	1	108.3556	FT RANDAL - G14_023T 230.00 230KV CKT 1
FDNS	09ALL	3	15G	G14_023	TO->FROM	FT RANDAL - G14_023T 230.00 230KV CKT 1	320	320	1	123.2375	KELLY - MEADOWGROVE4230.00 230KV CKT 1
FDNS	09ALL	3	15SP	G14_023	TO->FROM	FT RANDAL - G14_023T 230.00 230KV CKT 1	320	320	1	122.8292	KELLY - MEADOWGROVE4230.00 230KV CKT 1
FDNS	09ALL	3	15WP	G14_023	TO->FROM	FT RANDAL - G14_023T 230.00 230KV CKT 1	320	320	1	122.6376	KELLY - MEADOWGROVE4230.00 230KV CKT 1
FDNS	09NR	3	15G	G14_023	TO->FROM	FT RANDAL - G14_023T 230.00 230KV CKT 1	320	320	1	109.6286	KELLY - MEADOWGROVE4230.00 230KV CKT 1
FDNS	00NR	3	15SP	G14_023	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.03618	126.0617	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	09NR	3	15G	G14_023	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.03716	125.5611	KEYSTONE - SIDNEY 345KV CKT 1
FDNSLock	00NR	3	15WP	G14_023	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.03442	119.7142	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	09ALL	3	15G	G14_023	TO->FROM	KELLY - MEADOWGROVE4230.00 230KV CKT 1	368	368	1	110.0463	FT RANDAL - G14_023T 230.00 230KV CKT 1
FDNS	09ALL	3	15WP	G14_023	TO->FROM	KELLY - MEADOWGROVE4230.00 230KV CKT 1	368	368	1	108.3238	FT RANDAL - G14_023T 230.00 230KV CKT 1
FDNS	09ALL	3	15SP	G14_023	TO->FROM	KELLY - MEADOWGROVE4230.00 230KV CKT 1	368	368	1	108.2727	FT RANDAL - G14_023T 230.00 230KV CKT 1
FDNS	09ALL	4	15SP	G14_023	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.04573	100.0000	BASE CASE
FDNS	00NR	4	15SP	G14_023	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.03564	125.8998	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	09NR	4	15G	G14_023	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.03662	125.5394	KEYSTONE - SIDNEY 345KV CKT 1
FDNSLock	00NR	4	15WP	G14_023	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.03389	119.6486	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	00NR	4	25SP	G14_023	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.0347	116.1383	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	00NR	4	20SP	G14_023	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.03538	115.1176	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	00NR	4	20WP	G14_023	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.03386	112.7372	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	09ALL	4	15SP	G14_023	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.04573	103.5479	BASE CASE
FDNS	09NR	0	15G	G14_059	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.83953	125.8320	KEYSTONE - SIDNEY 345KV CKT 1
FDNSLock	09ALL	0	15G	G14_059	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.81748	125.0226	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	00NR	0	15SP	G14_059	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.83828	124.5109	KEYSTONE - SIDNEY 345KV CKT 1
FDNSLock	09ALL	0	15SP	G14_059	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.81763	122.8945	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	09ALL	0	15WP	G14_059	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.81718	117.0122	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	00NR	0	25SP	G14_059	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.8375	116.3340	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	00NR	0	15WP	G14_059	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.83623	115.6280	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	09ALL	0	25SP	G14_059	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.8198	115.3575	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	00NR	0	20SP	G14_059	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.83816	115.3019	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	09ALL	0	20SP	G14_059	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.81974	114.7674	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	00NR	0	20WP	G14_059	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.83661	112.8683	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	09ALL	0	20WP	G14_059	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.81946	110.9595	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	09NR	0	15G	G14_059	FROM->TO	GGS	1635	1635	0.08822	105.4338	BASE CASE
FDNS	09ALL	0	15G	G14_059	FROM->TO	GGS	1635	1635	0.7494	104.9857	BASE CASE
FDNS	09ALL	0	15WP	G14_059	FROM->TO	GGS	1635	1635	0.75335	102.7627	BASE CASE
FDNS	00NR	0	15WP	G14_059	FROM->TO	GGS	1635	1635	0.37011	102.2452	BASE CASE
FDNS	09ALL	0	15G	G14_059	FROM->TO	REDWILLMINGO	468	468	0.24627	101.0842	BASE CASE
FDNS	00NR	0	15WP	G14_059	FROM->TO	VICTORY HILL (VICTORYHL T1) 230/115/13.8KV TRANSFORMER CKT 1	187	187	0.03485	105.3110	STEGALL - WAYSIDE 230KV CKT 1
FDNS	00NR	0	15WP	G14_059	FROM->TO	VICTORY HILL (VICTORYHL T1) 230/115/13.8KV TRANSFORMER CKT 1	187	187	0.03485	104.7769	STEGALL - WAYSIDE 230KV CKT 1
FDNS	09NR	2	15G	G14_059	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.8395	125.5977	KEYSTONE - SIDNEY 345KV CKT 1

SOLUTION	GROUP	SCENARIO	SEASON	SOURCE	DIRECTION	MONITORED ELEMENT	RATEA (MVA)	RATEB(MVA)	TDF	TC%LOADING (% MVA)	CONTINGENCY
FDNSLock	09ALL	2	15G	G14_059	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.81777	124.7843	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	00NR	2	15SP	G14_059	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.83825	124.5047	KEYSTONE - SIDNEY 345KV CKT 1
FDNSLock	09ALL	2	15SP	G14_059	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.81859	122.7529	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	09ALL	2	15WP	G14_059	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.81779	116.8049	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	00NR	2	15WP	G14_059	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.8362	115.5316	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	00NR	2	15WP	G14_059	FROM->TO	VICTORY HILL (VICTORYHL T1) 230/115/13.8KV TRANSFORMER CKT 1	187	187	0.03487	105.5943	STEGALL - WAYSIDE 230KV CKT 1
FDNS	00NR	2	15WP	G14_059	FROM->TO	VICTORY HILL (VICTORYHL T1) 230/115/13.8KV TRANSFORMER CKT 1	187	187	0.03487	105.1342	STEGALL - WAYSIDE 230KV CKT 1
FDNS	00NR	3	15SP	G14_059	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.8409	126.0617	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	09NR	3	15G	G14_059	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.84186	125.5611	KEYSTONE - SIDNEY 345KV CKT 1
FDNSLock	09ALL	3	15G	G14_059	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.8231	124.4385	KEYSTONE - SIDNEY 345KV CKT 1
FDNSLock	09ALL	3	15SP	G14_059	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.82379	122.4590	KEYSTONE - SIDNEY 345KV CKT 1
FDNSLock	00NR	3	15WP	G14_059	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.83912	119.7142	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	09ALL	3	15WP	G14_059	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.82311	116.8160	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	00NR	3	15WP	G14_059	FROM->TO	VICTORY HILL (VICTORYHL T1) 230/115/13.8KV TRANSFORMER CKT 1	187	187	0.03175	101.0614	STEGALL - WAYSIDE 230KV CKT 1
FDNS	00NR	3	15WP	G14_059	FROM->TO	VICTORY HILL (VICTORYHL T1) 230/115/13.8KV TRANSFORMER CKT 1	187	187	0.03175	100.6369	STEGALL - WAYSIDE 230KV CKT 1
FDNS	00NR	4	15SP	G14_059	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.8409	125.8998	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	09NR	4	15G	G14_059	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.84186	125.5394	KEYSTONE - SIDNEY 345KV CKT 1
FDNSLock	09ALL	4	15G	G14_059	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.82311	124.4290	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	09ALL	4	15SP	G14_059	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.8238	121.6178	KEYSTONE - SIDNEY 345KV CKT 1
FDNSLock	00NR	4	15WP	G14_059	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.83911	119.6486	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	09ALL	4	15WP	G14_059	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.82312	116.7808	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	00NR	4	25SP	G14_059	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.8375	116.1383	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	09ALL	4	25SP	G14_059	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.82063	115.2171	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	00NR	4	20SP	G14_059	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.83816	115.1176	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	09ALL	4	20SP	G14_059	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.82059	114.6469	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	00NR	4	20WP	G14_059	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.83661	112.7372	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	09ALL	4	20WP	G14_059	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.82062	110.9362	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	00NR	4	15WP	G14_059	FROM->TO	VICTORY HILL (VICTORYHL T1) 230/115/13.8KV TRANSFORMER CKT 1	187	187	0.03175	101.1351	STEGALL - WAYSIDE 230KV CKT 1
FDNS	00NR	4	15WP	G14_059	FROM->TO	VICTORY HILL (VICTORYHL T1) 230/115/13.8KV TRANSFORMER CKT 1	187	187	0.03175	100.7147	STEGALL - WAYSIDE 230KV CKT 1
FDNS	08ALL	0	20SP	G15_003	FROM->TO	VIOLA 7 345.00 (VIOLA 1X) 345/138/13.8KV TRANSFORMER CKT 1	448	492.8	0.26865	102.3131	VIOLA 7 345.00 - WICHITA 345KV CKT 1
FDNS	08ALL	0	20SP	G15_003	FROM->TO	VIOLA 7 345.00 (VIOLA 1X) 345/138/13.8KV TRANSFORMER CKT 1	448	492.8	0.26865	101.3791	VIOLA 7 345.00 - WICHITA 345KV CKT 1
FDNS	08ALL	2	15SP	G15_003	FROM->TO	VIOLA 7 345.00 (VIOLA 1X) 345/138/13.8KV TRANSFORMER CKT 1	448	492.8	0.26807	101.8523	VIOLA 7 345.00 - WICHITA 345KV CKT 1
FDNS	08ALL	2	15SP	G15_003	FROM->TO	VIOLA 7 345.00 (VIOLA 1X) 345/138/13.8KV TRANSFORMER CKT 1	448	492.8	0.26807	101.0406	VIOLA 7 345.00 - WICHITA 345KV CKT 1
FDNS	08ALL	2	15G	G15_003	FROM->TO	VIOLA 7 345.00 (VIOLA 1X) 345/138/13.8KV TRANSFORMER CKT 1	448	492.8	0.26519	99.8000	VIOLA 7 345.00 - WICHITA 345KV CKT 1
FDNS	08ALL	3	15G	G15_003	FROM->TO	CLEARWATER - GILL ENERGY CENTER WEST 138KV CKT 1	143	143	0.03976	108.2121	BASE CASE
FDNSLock-Blown up	09ALL	0	15SP	G15_008		Non-Converged Contingency	720	720	0.03767	-	GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1
FDNSLock-Blown up	09ALL	0	15G	G15_008		Non-Converged Contingency	720	720	0.03769	-	GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1
FDNSLock-Blown up	09ALL	0	15WP	G15_008		Non-Converged Contingency	720	720	0.03687	-	GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	ALBION - GENOA 115KV CKT 1	137	137	0.25175	109.7479	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	ALBION - GENOA 115KV CKT 1	137	137	0.25175	109.7003	LN-1163-2
FDNS	09ALL	0	15G	G15_008	FROM->TO	ALBION - GENOA 115KV CKT 1	137	137	0.25175	109.5768	BATTLE CREEK - COUNTY LINE 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	ALBION - GENOA 115KV CKT 1	137	137	0.25175	107.9803	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.37876	154.8701	LN-1163-2
FDNS	09ALL	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.37876	154.8480	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.37876	154.5864	BATTLE CREEK - COUNTY LINE 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.37869	153.2615	LN-1163-2
FDNS	09ALL	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.37869	153.1926	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.37869	153.0361	BATTLE CREEK - COUNTY LINE 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.37876	152.2926	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1
FDNS	09ALL	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.37877	149.2833	LN-1163-2
FDNS	09ALL	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.37877	149.1657	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.37869	148.4734	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1
FDNS	09ALL	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.37877	147.4188	BATTLE CREEK - COUNTY LINE 115KV CKT 1
FDNS	09ALL	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.37877	138.6036	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1
FDNS	09NR	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.38313	130.7394	LN-1163-2
FDNS	09NR	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.38313	130.6700	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09NR	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.38313	130.5191	BATTLE CREEK - COUNTY LINE 115KV CKT 1
FDNS	09NR	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.38313	128.5785	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.27079	126.1127	BLOOMFIELD - GAVINS POINT 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.27083	125.5575	BLOOMFIELD - GAVINS POINT 115KV CKT 1
FDNS	09ALL	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.27087	124.2243	BLOOMFIELD - GAVINS POINT 115KV CKT 1
FDNS	09ALL	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.27441	116.7655	LN-1164
FDNS	09ALL	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.27441	116.6701	CLEARWATER - NELIGH 115KV CKT 1
FDNS	09ALL	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22272	116.5193	KELLY - MEADOWGROVE4230.00 230KV CKT 1
FDNS	09ALL	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.27087	116.3462	CREIGHTON - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09ALL	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.21621	114.5525	BROKEN BOW - LOUP CITY 115KV CKT 1
FDNS	09ALL	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.27441	114.2061	CLEARWATER - ONEILL 115KV CKT 1
FDNS	09ALL	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22321	112.9939	GRPRAR1-LNX3345.00 - HOLT.CO3 345.00 345KV CKT 1
FDNS	09ALL	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22321	112.9892	GRPRAR1-LNX3345.00 - YANKTON 345KV CKT Z
FDNS	09ALL	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.27079	112.4778	CREIGHTON - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.27431	111.4071	LN-1164
FDNS	09ALL	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.27431	111.3925	CLEARWATER - NELIGH 115KV CKT 1
FDNS	09ALL	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22203	111.2176	GEN640010 1-GERALD GENTLEMAN STATION UNIT 1
FDNS	09ALL	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22203	111.1392	GEN640011 2-GERALD GENTLEMAN STATION UNIT 2
FDNS	09ALL	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.27431	110.8700	CLEARWATER - ONEILL 115KV CKT 1

SOLUTION	GROUP	SCENARIO	SEASON	SOURCE	DIRECTION	MONITORED ELEMENT	RATEA (MVA)	RATEB(MVA)	TDF	TC%LOADING (% MVA)	CONTINGENCY
FDNS	09ALL	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22203	110.7609	GEN640428 1-BRKNBW.GEN1W0.6900
FDNS	09ALL	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.2308	110.7553	GAVINS POINT - YANKON JCT 115KV CKT 1
FDNS	09ALL	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22391	110.7505	NEB02WAPAB2
FDNS	09ALL	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22203	110.5701	GEN640449 W-BRKNBW.GEN2W0.6900
FDNS	09ALL	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22487	110.1134	COLUMEAST - SHELL CREEK 345KV CKT 1
FDNS	09ALL	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22391	110.0869	GAVINS POINT - HARTINGTON 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.27083	110.0651	CREIGHTON - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09ALL	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22387	109.9675	GAVINS POINT - SPIRIT MOUND 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.21614	109.6634	BROKEN BOW - LOUP CITY 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22261	109.4695	KELLY - MEADOWGROVE4230.00 230KV CKT 1
FDNS	09ALL	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.27436	108.6045	LN-1164
FDNS	09ALL	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.27436	108.5913	CLEARWATER - NELIGH 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.27079	108.2435	BLOOMFIELD - CREIGHTON 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.27436	108.1803	CLEARWATER - ONEILL 115KV CKT 1
FDNS	09ALL	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22203	107.7181	BASE CASE
FDNS	09ALL	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22203	107.5418	NUCOR-1
FDNS	09ALL	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.27083	107.0769	BLOOMFIELD - CREIGHTON 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.2307	106.6417	GAVINS POINT - YANKON JCT 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22268	106.2506	KELLY - MEADOWGROVE4230.00 230KV CKT 1
FDNS	09ALL	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.2162	105.8650	BROKEN BOW - LOUP CITY 115KV CKT 1
FDNS	09NR	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.27609	105.6912	BLOOMFIELD - GAVINS POINT 115KV CKT 1
FDNS	09ALL	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22272	105.5977	FT RANDAL - G14_023T 230.00 230KV CKT 1
FDNS	09ALL	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22165	105.5537	MCCOOL - MOORE 345KV CKT 1
FDNS	09ALL	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22173	105.2836	GRAND ISLAND - MCCOOL 345KV CKT 1
FDNS	09ALL	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22203	105.0942	GEN659111 2-LELAND OLDS UNIT2
FDNS	09ALL	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.21087	105.0563	NELIGH - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.24567	104.9952	LN-WAPA6
FDNS	09ALL	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.24567	104.9952	NEB001NPPB2
FDNS	09ALL	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.24567	104.9119	ONEILL - SPENCER 115KV CKT 1
FDNS	09ALL	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22203	104.8750	GEN640421 1-CROFTON HILLS WIND
FDNS	09ALL	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22203	104.8484	GEN659103 1-ANTELOPE VALLEY UNIT1
FDNS	09ALL	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22203	104.8484	GEN659107 2-ANTELOPE VALLEY UNIT2
FDNS	09ALL	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22321	104.8149	FTTHOM2-LNX3345.00 - GRPRAR2-LNX3345.00 345KV CKT 1
FDNS	09ALL	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22321	104.6756	GRPRAR2-LNX3345.00 - YANKTON 345KV CKT Z
FDNS	09ALL	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22193	104.6577	GEN640428 1-BRKNBW.GEN1W0.6900
FDNS	09ALL	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22321	104.6517	FT THOMPSON - FTTHOM2-LNX3345.00 345KV CKT Z
FDNS	09ALL	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22193	104.4580	GEN640449 W-BRKNBW.GEN2W0.6900
FDNS	09ALL	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22193	104.4418	GEN640010 1-GERALD GENTLEMAN STATION UNIT 1
FDNS	09ALL	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22783	104.3884	UTICA - YANKON JCT 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22381	104.3875	NEB02WAPAB2
FDNS	09ALL	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22203	104.3828	SPALDING 115KV SWITCHED SHUNT
FDNS	09ALL	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22378	104.3739	GAVINS POINT - SPIRIT MOUND 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.24572	104.3721	LN-WAPA6
FDNS	09ALL	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.24572	104.3721	NEB001NPPB2
FDNS	09ALL	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22309	104.3474	GRPRAR1-LNX3345.00 - YANKTON 345KV CKT Z
FDNS	09ALL	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22309	104.3466	GRPRAR1-LNX3345.00 - HOLT.CO3 345.00 345KV CKT 1
FDNS	09ALL	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.24572	104.3393	ONEILL - SPENCER 115KV CKT 1
FDNSLock	09ALL	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22203	104.3303	SPALDING 115KV SWITCHED SHUNT
FDNS	09ALL	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.24572	103.9692	FT RANDAL - SPENCER 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.24567	103.9359	FT RANDAL - SPENCER 115KV CKT 1
FDNS	09ALL	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.20607	103.8927	NELIGH - NELIGH.EAST7115.00 115KV CKT 2
FDNS	09ALL	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22381	103.8149	GAVINS POINT - HARTINGTON 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.2335	103.7886	HOSKINS - NORTH NORFOLK 115KV CKT 1
FDNS	09ALL	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.24575	103.6458	LN-WAPA6
FDNS	09ALL	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.24575	103.6458	NEB001NPPB2
FDNS	09ALL	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.24575	103.5657	ONEILL - SPENCER 115KV CKT 1
FDNS	09ALL	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22203	103.5033	ALBION 115KV SWITCHED SHUNT
FDNSLock	09ALL	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22203	103.4861	ALBION 115KV SWITCHED SHUNT
FDNS	09ALL	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.23076	102.9979	GAVINS POINT - YANKON JCT 115KV CKT 1
FDNS	09ALL	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.24575	102.7416	FT RANDAL - SPENCER 115KV CKT 1
FDNS	09ALL	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22203	102.2456	GEN640418 1-ELKHORN RIDGE WIND
FDNS	09ALL	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22318	101.9198	GRPRAR1-LNX3345.00 - HOLT.CO3 345.00 345KV CKT 1
FDNS	09ALL	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22318	101.9138	GRPRAR1-LNX3345.00 - YANKTON 345KV CKT Z
FDNS	09ALL	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22788	101.7945	UTICA - YANKON JCT 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22199	101.7573	GEN640428 1-BRKNBW.GEN1W0.6900
FDNS	09ALL	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.23356	101.6284	HOSKINS - NORTH NORFOLK 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22193	101.5598	BASE CASE
FDNS	09ALL	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22199	101.5565	GEN640449 W-BRKNBW.GEN2W0.6900
FDNS	09ALL	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22383	101.4827	GAVINS POINT - SPIRIT MOUND 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22563	101.1048	DAK02WAPAB2
FDNS	09ALL	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22387	101.0334	NEB02WAPAB2
FDNS	09ALL	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22483	100.9519	COLUMEAST - SHELL CREEK 345KV CKT 1
FDNS	09ALL	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22199	100.8739	GEN640010 1-GERALD GENTLEMAN STATION UNIT 1
FDNS	09ALL	0	15G	G15_008	TO->FROM	BATTLE CREEK - COUNTY LINE 115KV CKT 1	240	240	0.51665	121.2525	BLOOMFIELD - GAVINS POINT 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	TO->FROM	BATTLE CREEK - COUNTY LINE 115KV CKT 1	240	240	0.52896	117.6390	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1

SOLUTION	GROUP	SCENARIO	SEASON	SOURCE	DIRECTION	MONITORED ELEMENT	RATEA (MVA)	RATEB(MVA)	TDF	TC%LOADING (% MVA)	CONTINGENCY
FDNS	09ALL	0	15G	G15_008	TO->FROM	BATTLE CREEK - COUNTY LINE 115KV CKT 1	240	240	0.52896	117.4399	ALBION - PETERSBURG 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	TO->FROM	BATTLE CREEK - COUNTY LINE 115KV CKT 1	240	240	0.51667	116.0269	BLOOMFIELD - GAVINS POINT 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	TO->FROM	BATTLE CREEK - COUNTY LINE 115KV CKT 1	240	240	0.52892	115.0970	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1
FDNS	09ALL	0	15WP	G15_008	TO->FROM	BATTLE CREEK - COUNTY LINE 115KV CKT 1	240	240	0.52892	114.6936	ALBION - PETERSBURG 115KV CKT 1
FDNS	09NR	0	15G	G15_008	TO->FROM	BATTLE CREEK - COUNTY LINE 115KV CKT 1	240	240	0.51056	104.1686	BLOOMFIELD - GAVINS POINT 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	TO->FROM	BATTLE CREEK - COUNTY LINE 115KV CKT 1	240	240	0.47829	102.8157	WAPA-OG-2
FDNS	09ALL	0	15G	G15_008	TO->FROM	BATTLE CREEK - COUNTY LINE 115KV CKT 1	240	240	0.46337	101.2206	ALBION - GENOA 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	TO->FROM	BATTLE CREEK - COUNTY LINE 115KV CKT 1	240	240	0.51665	101.1371	CREIGHTON - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09NR	0	15G	G15_008	TO->FROM	BATTLE CREEK - COUNTY LINE 115KV CKT 1	240	240	0.52762	100.9822	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1
FDNS	09NR	0	15G	G15_008	TO->FROM	BATTLE CREEK - COUNTY LINE 115KV CKT 1	240	240	0.52762	100.7887	ALBION - PETERSBURG 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	TO->FROM	BATTLE CREEK - COUNTY LINE 115KV CKT 1	240	240	0.46337	99.9000	COLUMBUS - GENOA 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	TO->FROM	BATTLE CREEK - COUNTY LINE 115KV CKT 1	240	240	0.46387	99.7000	WAPA-OG-1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.51665	147.0794	BLOOMFIELD - GAVINS POINT 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.52896	142.5931	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.52896	142.3460	ALBION - PETERSBURG 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.51667	135.4167	BLOOMFIELD - GAVINS POINT 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.52892	134.3161	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1
FDNS	09ALL	0	15WP	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.52892	133.8170	ALBION - PETERSBURG 115KV CKT 1
FDNS	09NR	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.51056	125.8622	BLOOMFIELD - GAVINS POINT 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.47829	124.1839	WAPA-OG-2
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.46337	122.1857	ALBION - GENOA 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.51665	122.0817	CREIGHTON - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09NR	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.52762	121.9069	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1
FDNS	09NR	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.52762	121.6667	ALBION - PETERSBURG 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.46337	120.5700	COLUMBUS - GENOA 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.46387	120.3509	WAPA-OG-1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.51665	117.5003	BLOOMFIELD - CREIGHTON 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.49035	115.2128	LN-1164
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.49035	115.1983	CLEARWATER - NELIGH 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.49035	114.7418	CLEARWATER - ONEILL 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.51667	113.3626	CREIGHTON - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.46334	111.8687	ALBION - GENOA 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.45101	110.8638	LN-WAPA6
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.45101	110.8638	NEB001NPPB2
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.45101	110.8406	ONEILL - SPENCER 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.52896	110.4489	NELIGH - PETERSBRG.N7115.00 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.45101	110.4095	FT RANDAL - SPENCER 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.42223	109.7826	GAVINS POINT - HARTINGTON 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41585	109.4695	KELLY - MEADOWGROVE4230.00 230KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.42223	109.2164	NEB02WAPAB2
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.42827	109.1691	GAVINS POINT - YANKON JCT 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.42137	108.4612	DAK02WAPAB2
FDNS	09ALL	0	15WP	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.46334	108.3349	COLUMBUS - GENOA 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.46383	108.2491	WAPA-OG-1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.42426	107.9042	UTICA - YANKON JCT 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.42223	107.8994	BELDEN - HARTINGTON 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.47826	107.8480	WAPA-OG-2
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.4181	107.5977	GAVINS POINT - SPIRIT MOUND 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41524	107.1029	GEN560350 1-G10-51 0.6900
FDNS	09ALL	0	15WP	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.49035	107.0917	LN-1164
FDNS	09ALL	0	15WP	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.49035	107.0729	CLEARWATER - NELIGH 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41567	107.0244	GRAND ISLAND - MCCOOL 345KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41524	106.9029	GEN635213 3-NEAL UNIT 3
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41524	106.8714	GEN562673 1-G15_007_3 0.6900
FDNS	09NR	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.51056	106.8440	CREIGHTON - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09ALL	0	15SP	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.52891	106.7737	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41569	106.7707	MCCOOL - MOORE 345KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41617	106.6576	FT RANDAL - SIOUX CITY 230KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.4181	106.6566	MANNING - SPIRIT MOUND 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.51667	106.5995	BLOOMFIELD - CREIGHTON 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.49035	106.5073	CLEARWATER - ONEILL 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41994	106.4862	LOUP CITY - ST LIBORY 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41524	106.4673	GEN635214 4-NEAL UNIT 4
FDNS	09NR	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.47236	106.3504	WAPA-OG-2
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.4327	106.3125	ALBION - SPALDING 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41536	106.3001	KELLY - SHELL CREEK 230KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41536	106.3001	SHELL CREEK (SHELLCREEKT1) 345/230/13.8KV TRANSFORMER CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41327	106.2515	DIXONCO 230.00 - HOSKINS 230KV CKT 1
FDNSLock	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41632	106.1970	MINGO - RED WILLOW 345KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.4181	106.1103	BERSFORD - MANNING 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.43441	106.0962	NELIGH - NELIGH.EAST7115.00 115KV CKT 2
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41766	106.0703	AINSWORTH - VALENTINE 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41524	106.0090	GEN562003 1-G11_027_3 0.6900
FDNS	09ALL	0	15SP	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.52891	105.2732	ALBION - PETERSBURG 115KV CKT 1
FDNS	09NR	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.45798	105.1060	ALBION - GENOA 115KV CKT 1

SOLUTION	GROUP	SCENARIO	SEASON	SOURCE	DIRECTION	MONITORED ELEMENT	RATEA (MVA)	RATEB(MVA)	TDF	TC%LOADING (% MVA)	CONTINGENCY
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41524	104.2732	BASE CASE
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41524	103.9644	NUCOR-1
FDNS	09NR	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.45798	103.5462	COLUMBUS - GENOA 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41524	103.4965	NUCOR-2
FDNS	09NR	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.45849	103.2626	WAPA-OG-1
FDNS	09ALL	0	15WP	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.52892	103.0213	NELIGH - PETERSBRG.N7115.00 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41186	102.7005	COLUMEAST - NW68TH & HOLDREGE 345KV CKT 1
FDNSLock	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41524	102.5816	GEN659103 1-ANTELOPE VALLEY UNIT1
FDNSLock	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41524	102.5816	GEN659107 2-ANTELOPE VALLEY UNIT2
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.42557	102.5317	LN-1267
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41279	102.5277	HOSKINS - STANTON NORTH 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41496	102.5273	LAKEFIELD 3 - RAUN 345KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.42557	102.5121	EMMET - ONEILL 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41576	102.5022	FT THOMPSON - FTTHOM2-LNX3345.00 345KV CKT Z
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41576	102.4681	GRPRAR2-LNX3345.00 - YANKTON 345KV CKT Z
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41576	102.4645	FTTHOM2-LNX3345.00 - GRPRAR2-LNX3345.00 345KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.42557	102.4378	ATKINSON - EMMET 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41592	102.3115	RAUN - SIOUX CITY 345KV CKT 1
FDNS	09NR	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.51056	102.2891	BLOOMFIELD - CREIGHTON 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.42221	102.2584	GAVINS POINT - HARTINGTON 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.42557	102.2531	ATKINSON - STUART 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.42557	102.1707	AINSWORTH - STUART 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41174	102.0705	COLUMEAST - SHELL CREEK 345KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41765	101.9689	BROKEN BOW - LOUP CITY 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.42827	101.9149	GAVINS POINT - YANKON JCT 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.4068	101.8541	NORFOLK - NORTH NORFOLK 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41524	101.8401	GEN659118 1-LARAMIE RIVER UNIT1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41524	101.6732	GEN640026 1-AINSWORTH WIND
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41585	101.5661	FT RANDAL - G14_023T 230.00 230KV CKT 1
FDNS	09ALL	0	15WP	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41583	101.5124	KELLY - MEADOWGROVE4230.00 230KV CKT 1
FDNS	09ALL	0	15WP	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.42221	101.3861	NEB02WAPAB2
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41239	101.3757	SIOUX CITY - TWIN CHURCH 230KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41524	100.7210	GEN640421 1-CROFTON HILLS WIND
FDNS	09ALL	0	15WP	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.45102	100.0000	LN-WAPA6
FDNS	09ALL	0	15WP	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.45102	100.0000	NEB001NPPB2
FDNS	09ALL	0	15WP	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.45102	99.9000	ONEILL - SPENCER 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.42137	99.9000	DAK02WAPAB2
FDNS	09ALL	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.33804	188.3584	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.33804	188.2872	LN-1163-2
FDNS	09ALL	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.33804	188.0904	BATTLE CREEK - COUNTY LINE 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.33804	185.7592	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.3381	173.9791	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.3381	173.8140	LN-1163-2
FDNS	09ALL	0	15WP	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.3381	173.7954	BATTLE CREEK - COUNTY LINE 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.3381	168.7264	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1
FDNS	09NR	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.33334	156.0641	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09NR	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.33334	155.9970	LN-1163-2
FDNS	09NR	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.33334	155.8547	BATTLE CREEK - COUNTY LINE 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.24457	154.5846	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.24457	154.4058	ALBION - PETERSBURG 115KV CKT 1
FDNS	09NR	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.33334	153.7979	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.24463	143.8001	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1
FDNS	09ALL	0	15WP	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.24463	143.4418	ALBION - PETERSBURG 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.21467	139.7403	ALBION - GENOA 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.21675	139.3865	WAPA-OG-2
FDNS	09ALL	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.2145	138.7428	WAPA-OG-1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.21467	138.6095	COLUMBUS - GENOA 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.23529	136.8875	CLEARWATER - NELIGH 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.23529	136.8515	LN-1164
FDNS	09ALL	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.23529	136.4922	CLEARWATER - ONEILL 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.21544	133.5292	ONEILL - SPENCER 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.21544	133.4670	LN-WAPA6
FDNS	09ALL	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.21544	133.4670	NEB001NPPB2
FDNS	09ALL	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.21544	133.1334	FT RANDAL - SPENCER 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.24457	131.8975	NELIGH - PETERSBRG.N7115.00 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.20637	131.2938	HOSKINS - NORTH NORFOLK 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.21472	128.5990	ALBION - GENOA 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.19439	127.8131	BASE CASE
FDNS	09ALL	0	15WP	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.23535	127.4883	CLEARWATER - NELIGH 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.23535	127.4383	LN-1164
FDNS	09ALL	0	15WP	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.23535	127.0312	CLEARWATER - ONEILL 115KV CKT 1
FDNS	09NR	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.24278	126.6531	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1
FDNS	09NR	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.24278	126.4848	ALBION - PETERSBURG 115KV CKT 1
FDNS	09NR	0	15WP	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.21456	126.4292	WAPA-OG-1
FDNS	09ALL	0	15WP	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.21472	126.3803	COLUMBUS - GENOA 115KV CKT 1

SOLUTION	GROUP	SCENARIO	SEASON	SOURCE	DIRECTION	MONITORED ELEMENT	RATEA (MVA)	RATEB(MVA)	TDF	TC%LOADING (% MVA)	CONTINGENCY
FDNS	09ALL	0	15WP	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.21681	126.2910	WAPA-OG-2
FDNS	09ALL	0	15SP	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.33801	124.7388	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09ALL	0	15SP	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.33801	124.3725	LN-1163-2
FDNS	09ALL	0	15WP	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.24463	123.1594	NELIGH - PETERSBRG.N7115.00 115KV CKT 1
FDNS	09ALL	0	15SP	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.33801	122.7938	BATTLE CREEK - COUNTY LINE 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.21551	122.0913	ONEILL - SPENCER 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.21551	121.9218	LN-WAPA6
FDNS	09ALL	0	15WP	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.21551	121.9218	NEB001NPPB2
FDNS	09ALL	0	15WP	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.20643	121.3661	HOSKINS - NORTH NORFOLK 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.19445	118.7402	BASE CASE
FDNS	09NR	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.2111	115.2026	ALBION - GENOA 115KV CKT 1
FDNS	09NR	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.21312	114.7526	WAPA-OG-2
FDNS	09NR	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.21093	114.3760	WAPA-OG-1
FDNS	09NR	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.2111	114.2308	COLUMBUS - GENOA 115KV CKT 1
FDNS	09ALL	0	15SP	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.33801	113.2793	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1
FDNS	09NR	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.23251	112.9644	CLEARWATER - NELIGH 115KV CKT 1
FDNS	09NR	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.23251	112.9217	LN-1164
FDNS	09NR	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.23251	112.6119	CLEARWATER - ONEILL 115KV CKT 1
FDNS	09NR	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.19104	111.1409	FT RANDAL - UTICA JCT 230KV CKT 1
FDNS	09NR	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.2114	110.1921	ONEILL - SPENCER 115KV CKT 1
FDNS	09NR	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.19211	110.1353	DIXONCO 230.00 - TWIN CHURCH 230KV CKT 1
FDNS	09NR	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.2114	110.1349	LN-WAPA6
FDNS	09NR	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.2114	110.1349	NEB001NPPB2
FDNS	09NR	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.24278	109.9831	NELIGH - PETERSBRG.N7115.00 115KV CKT 1
FDNS	09NR	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.2114	109.8285	FT RANDAL - SPENCER 115KV CKT 1
FDNS	09NR	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.18786	109.5955	FT RANDAL - WHITE SWAN 115KV CKT 1
FDNS	09NR	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.18786	109.2877	TYNDALL - WHITE SWAN 115KV CKT 1
FDNS	09NR	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.19123	109.2832	GEN652575 1-GAVINS POINT
FDNS	09NR	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.19123	109.2832	GEN652576 2-GAVINS POINT
FDNS	09NR	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.18999	109.2460	FT THOMPSON - FTTHOM2-LNX3345.00 345KV CKT Z
FDNS	09NR	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.18999	109.2424	GRPRAR2-LNX3345.00 - YANKTON 345KV CKT Z
FDNS	09NR	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.18999	109.2373	FTTHOM2-LNX3345.00 - GRPRAR2-LNX3345.00 345KV CKT 1
FDNS	09NR	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.20298	108.9304	HOSKINS - NORTH NORFOLK 115KV CKT 1
FDNSLock	09NR	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.19123	108.8137	GEN659103 1-ANTELOPE VALLEY UNIT1
FDNSLock	09NR	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.19123	108.8137	GEN659107 2-ANTELOPE VALLEY UNIT2
FDNS	09NR	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.1906	108.6252	FT RANDAL - G14_023T 230.00 230KV CKT 1
FDNSLock	09NR	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.19123	108.5752	GEN659111 2-LELAND OLDS UNIT2
FDNS	09NR	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.19062	108.5660	RAUN - SIOUX CITY 345KV CKT 1
FDNS	09ALL	0	15SP	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.24459	107.6509	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1
FDNS	09ALL	0	15SP	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.24459	106.5787	ALBION - PETERSBURG 115KV CKT 1
FDNS	09NR	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.19123	106.0381	BASE CASE
FDNS	09NR	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.19036	103.5512	UTICA JCT - VFODNES 230KV CKT 1
FDNS	09NR	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.18027	103.2201	DAK02WAPAB2
FDNS	09NR	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.18024	103.0973	UTICA JCT (UJ KV3A) 230/115/13.2KV TRANSFORMER CKT 1
FDNS	09NR	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.19123	102.9432	GEN645062 W-TPWPBG1W 0.6900
FDNS	09NR	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.18572	101.4523	BERSFORD - MANNING 115KV CKT 1
FDNS	09NR	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.1906	100.6822	KELLY - MEADOWGROVE4230.00 230KV CKT 1
FDNS	09NR	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.19123	100.0000	GEN640431 1-LAREDO.GEN1W0.6900
FDNS	09NR	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.18999	100.0000	GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1
FDNS	09NR	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.18233	99.9000	BELDEN - HARTINGTON 115KV CKT 1
FDNS	09NR	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.18572	99.8000	MANNING - SPIRIT MOUND 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	TO->FROM	COLUMBUS - GENOA 115KV CKT 1	137	137	0.25175	104.2341	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	TO->FROM	COLUMBUS - GENOA 115KV CKT 1	137	137	0.25175	104.1876	LN-1163-2
FDNS	09ALL	0	15G	G15_008	TO->FROM	COLUMBUS - GENOA 115KV CKT 1	137	137	0.25175	104.0606	BATTLE CREEK - COUNTY LINE 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	TO->FROM	COLUMBUS - GENOA 115KV CKT 1	137	137	0.25175	102.4404	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	TO->FROM	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1	240	240	0.51665	121.5520	BLOOMFIELD - GAVINS POINT 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	TO->FROM	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1	240	240	0.52896	117.9419	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1
FDNS	09ALL	0	15G	G15_008	TO->FROM	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1	240	240	0.52896	117.7429	ALBION - PETERSBURG 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	TO->FROM	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1	240	240	0.51667	116.2834	BLOOMFIELD - GAVINS POINT 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	TO->FROM	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1	240	240	0.52892	115.3582	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1
FDNS	09ALL	0	15WP	G15_008	TO->FROM	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1	240	240	0.52892	114.9546	ALBION - PETERSBURG 115KV CKT 1
FDNS	09NR	0	15G	G15_008	TO->FROM	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1	240	240	0.51056	104.4721	BLOOMFIELD - GAVINS POINT 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	TO->FROM	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1	240	240	0.47829	103.1203	WAPA-OG-2
FDNS	09ALL	0	15G	G15_008	TO->FROM	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1	240	240	0.46337	101.5236	ALBION - GENOA 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	TO->FROM	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1	240	240	0.51665	101.4398	CREIGHTON - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09ALL	0	15SP	G15_008	TO->FROM	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1	240	240	0.52891	101.2925	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1
FDNS	09NR	0	15G	G15_008	TO->FROM	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1	240	240	0.52762	101.2895	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1
FDNS	09NR	0	15G	G15_008	TO->FROM	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1	240	240	0.52762	101.0961	ALBION - PETERSBURG 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	TO->FROM	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1	240	240	0.46337	100.2221	COLUMBUS - GENOA 115KV CKT 1
FDNS	09ALL	0	15SP	G15_008	TO->FROM	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1	240	240	0.52891	100.0656	ALBION - PETERSBURG 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	TO->FROM	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1	240	240	0.46387	100.0000	WAPA-OG-1
FDNS	09NR	0	15G	G15_008	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.03434	125.8320	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	00NR	0	15SP	G15_008	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.03308	124.5109	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	00NR	0	15WP	G15_008	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.03106	115.6280	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	09ALL	0	15G	G15_008	TO->FROM	NORFOLK - NORTH NORFOLK 115KV CKT 1	120	120	0.38233	136.8426	HOSKINS - NORTH NORFOLK 115KV CKT 1

SOLUTION	GROUP	SCENARIO	SEASON	SOURCE	DIRECTION	MONITORED ELEMENT	RATEA (MVA)	RATEB(MVA)	TDF	TC%LOADING (% MVA)	CONTINGENCY
FDNS	09NR	0	15G	G15_008	TO->FROM	NORFOLK - NORTH NORFOLK 115KV CKT 1	120	120	0.37852	116.1856	HOSKINS - NORTH NORFOLK 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	TO->FROM	NORFOLK - NORTH NORFOLK 115KV CKT 1	120	120	0.38232	113.8782	HOSKINS - NORTH NORFOLK 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.37876	155.4987	LN-1163-2
FDNS	09ALL	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.37876	155.4766	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.37876	155.2148	BATTLE CREEK - COUNTY LINE 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.37869	154.5762	LN-1163-2
FDNS	09ALL	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.37869	154.5082	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.37869	154.3516	BATTLE CREEK - COUNTY LINE 115KV CKT 1
FDNS	09ALL	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.37877	153.0423	LN-1163-2
FDNS	09ALL	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.37877	152.9264	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.37876	152.9175	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1
FDNS	09ALL	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.37877	151.1718	BATTLE CREEK - COUNTY LINE 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.37869	149.7861	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1
FDNS	09ALL	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.37877	142.3276	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1
FDNS	09NR	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.38313	131.3560	LN-1163-2
FDNS	09NR	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.38313	131.2865	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09NR	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.38313	131.1352	BATTLE CREEK - COUNTY LINE 115KV CKT 1
FDNS	09NR	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.38313	129.1919	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1
FDNS	09ALL	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.27087	127.8880	BLOOMFIELD - GAVINS POINT 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.27079	127.4120	BLOOMFIELD - GAVINS POINT 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.27083	126.1727	BLOOMFIELD - GAVINS POINT 115KV CKT 1
FDNS	09ALL	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.27441	120.4065	LN-1164
FDNS	09ALL	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.27441	120.3070	CLEARWATER - NELIGH 115KV CKT 1
FDNS	09ALL	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22272	120.1593	KELLY - MEADOWGROVE4230.00 230KV CKT 1
FDNS	09ALL	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.27087	119.9838	CREIGHTON - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09ALL	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.21621	118.1999	BROKEN BOW - LOUP CITY 115KV CKT 1
FDNS	09ALL	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.27441	117.8326	CLEARWATER - ONEILL 115KV CKT 1
FDNS	09ALL	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22321	116.6050	GRPRAR1-LNX3345.00 - HOLT.CO3 345.00 345KV CKT 1
FDNS	09ALL	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22321	116.6005	GRPRAR1-LNX3345.00 - YANKTON 345KV CKT Z
FDNS	09ALL	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22203	114.8083	GEN640010 1-GERALD GENTLEMAN STATION UNIT 1
FDNS	09ALL	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22203	114.7289	GEN640011 2-GERALD GENTLEMAN STATION UNIT 2
FDNS	09ALL	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22203	114.3698	GEN640428 1-BRKNBW.GEN1W0.6900
FDNS	09ALL	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.2308	114.3674	GAVINS POINT - YANKON JCT 115KV CKT 1
FDNS	09ALL	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22391	114.3628	NEB02WAPAB2
FDNS	09ALL	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22203	114.1779	GEN640449 W-BRKNBW.GEN2W0.6900
FDNS	09ALL	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.27079	113.7662	CREIGHTON - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09ALL	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22487	113.7240	COLUMEAST - SHELL CREEK 345KV CKT 1
FDNS	09ALL	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22391	113.7007	GAVINS POINT - HARTINGTON 115KV CKT 1
FDNS	09ALL	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22387	113.5770	GAVINS POINT - SPIRIT MOUND 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.27431	112.6940	LN-1164
FDNS	09ALL	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.27431	112.6793	CLEARWATER - NELIGH 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.27431	112.1564	CLEARWATER - ONEILL 115KV CKT 1
FDNS	09ALL	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22203	111.3164	BASE CASE
FDNS	09ALL	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22203	111.1364	NUCOR-1
FDNS	09ALL	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.21614	110.9414	BROKEN BOW - LOUP CITY 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22261	110.7582	KELLY - MEADOWGROVE4230.00 230KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.27083	110.6756	CREIGHTON - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.27079	109.5281	BLOOMFIELD - CREIGHTON 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.27436	109.2135	LN-1164
FDNS	09ALL	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.27436	109.2003	CLEARWATER - NELIGH 115KV CKT 1
FDNS	09ALL	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22272	109.1942	FT RANDAL - G14_023T 230.00 230KV CKT 1
FDNS	09ALL	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22165	109.1542	MCCOOL - MOORE 345KV CKT 1
FDNS	09ALL	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22173	108.8890	GRAND ISLAND - MCCOOL 345KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.27436	108.7892	CLEARWATER - ONEILL 115KV CKT 1
FDNS	09ALL	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22203	108.6736	GEN659111 2-LELAND OLDS UNIT2
FDNS	09ALL	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.21087	108.6432	NELIGH - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09ALL	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22203	108.4592	GEN640421 1-CROFTON HILLS WIND
FDNS	09ALL	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22203	108.4259	GEN659103 1-ANTELOPE VALLEY UNIT1
FDNS	09ALL	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22203	108.4259	GEN659107 2-ANTELOPE VALLEY UNIT2
FDNS	09ALL	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22321	108.3873	FTTHOM2-LNX3345.00 - GRPRAR2-LNX3345.00 345KV CKT 1
FDNS	09ALL	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22321	108.2667	GRPRAR2-LNX3345.00 - YANKTON 345KV CKT Z
FDNS	09ALL	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22321	108.2446	FT THOMPSON - FTTHOM2-LNX3345.00 345KV CKT Z
FDNS	09ALL	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22203	108.2082	SPALDING 115KV SWITCHED SHUNT
FDNSLock	09ALL	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22203	108.1598	SPALDING 115KV SWITCHED SHUNT
FDNS	09ALL	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.2307	107.9249	GAVINS POINT - YANKON JCT 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.27083	107.6857	BLOOMFIELD - CREIGHTON 115KV CKT 1
FDNS	09ALL	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.20607	107.4746	NELIGH - NELIGH.EAST7115.00 115KV CKT 2
FDNS	09ALL	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22203	107.4286	ALBION 115KV SWITCHED SHUNT
FDNSLock	09ALL	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22203	107.4141	ALBION 115KV SWITCHED SHUNT
FDNS	09ALL	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.24575	107.2273	LN-WAPA6
FDNS	09ALL	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.24575	107.2273	NEB001NPPB2
FDNS	09ALL	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.24575	107.1458	ONEILL - SPENCER 115KV CKT 1
FDNS	09ALL	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22268	106.8615	KELLY - MEADOWGROVE4230.00 230KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.2162	106.4689	BROKEN BOW - LOUP CITY 115KV CKT 1
FDNS	09ALL	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.24575	106.3182	FT RANDAL - SPENCER 115KV CKT 1

SOLUTION	GROUP	SCENARIO	SEASON	SOURCE	DIRECTION	MONITORED ELEMENT	RATEA (MVA)	RATEB(MVA)	TDF	TC%LOADING (% MVA)	CONTINGENCY
FDNS	09NR	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.27609	106.2997	BLOOMFIELD - GAVINS POINT 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.24567	106.2772	LN-WAPA6
FDNS	09ALL	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.24567	106.2772	NEB001NPPB2
FDNS	09ALL	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.24567	106.1937	ONEILL - SPENCER 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22193	105.9337	GEN640428 1-BRKNBW.GEN1W0.6900
FDNS	09ALL	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22203	105.8173	GEN640418 1-ELKHORN RIDGE WIND
FDNS	09ALL	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22193	105.7342	GEN640449 W-BRKNBW.GEN2W0.6900
FDNS	09ALL	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22193	105.7155	GEN640010 1-GERALD GENTLEMAN STATION UNIT 1
FDNS	09ALL	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22783	105.6697	UTICA - YANKON JCT 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22381	105.6688	NEB02WAPAB2
FDNS	09ALL	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22378	105.6554	GAVINS POINT - SPIRIT MOUND 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22309	105.6255	GRPRAR1-LNX3345.00 - YANKTON 345KV CKT Z
FDNS	09ALL	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22309	105.6248	GRPRAR1-LNX3345.00 - HOLT.CO3 345.00 345KV CKT 1
FDNS	09ALL	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.24567	105.2169	FT RANDAL - SPENCER 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22381	105.0967	GAVINS POINT - HARTINGTON 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.2335	105.0696	HOSKINS - NORTH NORFOLK 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.24572	104.9802	LN-WAPA6
FDNS	09ALL	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.24572	104.9802	NEB001NPPB2
FDNS	09ALL	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.24572	104.9474	ONEILL - SPENCER 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.24572	104.5770	FT RANDAL - SPENCER 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.23076	103.6051	GAVINS POINT - YANKON JCT 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22193	102.8386	BASE CASE
FDNS	09ALL	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22318	102.5250	GRPRAR1-LNX3345.00 - HOLT.CO3 345.00 345KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22318	102.5190	GRPRAR1-LNX3345.00 - YANKTON 345KV CKT Z
FDNS	09ALL	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22788	102.4014	UTICA - YANKON JCT 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22199	102.3605	GEN640428 1-BRKNBW.GEN1W0.6900
FDNS	09ALL	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.23356	102.2354	HOSKINS - NORTH NORFOLK 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22199	102.1597	GEN640449 W-BRKNBW.GEN2W0.6900
FDNS	09ALL	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22383	102.0894	GAVINS POINT - SPIRIT MOUND 115KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22563	101.7126	DAK02WAPAB2
FDNS	09ALL	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22387	101.6400	NEB02WAPAB2
FDNS	09ALL	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22483	101.5586	COLUMEAST - SHELL CREEK 345KV CKT 1
FDNS	09ALL	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22199	101.4769	GEN640010 1-GERALD GENTLEMAN STATION UNIT 1
FDNS	09ALL	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22193	100.7011	GEN560350 1-G10-51 0.6900
FDNS	09ALL	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.20598	100.6976	NELIGH - NELIGH.EAST7115.00 115KV CKT 2
FDNS	09ALL	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22031	100.6066	CROOKED CREEK (CR.CREEK T1) 230/115/13.8KV TRANSFORMER CKT 1
FDNS	09ALL	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22031	100.5881	BROKEN BOW - CROOKED CREEK 115KV CKT 1
FDNSLock	09ALL	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.2214	100.5780	COLUMBUS - SCHUYLER 115KV CKT 1
FDNS	09ALL	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22193	100.3937	GEN635214 4-NEAL UNIT 4
FDNS	09ALL	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22161	100.2256	GRAND ISLAND - MCCOOL 345KV CKT 1
FDNS	09ALL	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22153	100.1090	MCCOOL - MOORE 345KV CKT 1
FDNS	09ALL	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22193	100.0894	GEN635213 3-NEAL UNIT 3
FDNS	09ALL	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22193	100.0000	GEN640421 1-CROFTON HILLS WIND
FDNS	09ALL	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22193	100.0000	GEN659111 2-LELAND OLDS UNIT2
FDNS	09ALL	0	20SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22527	99.8000	HOSKINS - NELIGH.EAST3345.00 345KV CKT 1
FDNS	09ALL	0	20SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22527	99.8000	NELIGH.EAST3345.00 (NELIGH.E T1) 345/115/13.8KV TRANSFORMER CKT 1
FDNS	09ALL	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22193	99.7000	GEN659103 1-ANTELOPE VALLEY UNIT1
FDNS	09ALL	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22193	99.7000	GEN659107 2-ANTELOPE VALLEY UNIT2
FDNS	09ALL	2	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22221	107.7494	NELIGH.EAST3345.00 (NELIGH.E T1) 345/115/13.8KV TRANSFORMER CKT 1
FDNS	09ALL	2	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22221	107.7136	HOSKINS - NELIGH.EAST3345.00 345KV CKT 1
FDNS	09ALL	2	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22204	101.6329	NELIGH.EAST3345.00 (NELIGH.E T1) 345/115/13.8KV TRANSFORMER CKT 1
FDNS	09ALL	2	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22204	101.6317	HOSKINS - NELIGH.EAST3345.00 345KV CKT 1
FDNS	09ALL	2	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41517	104.2902	NELIGH.EAST3345.00 (NELIGH.E T1) 345/115/13.8KV TRANSFORMER CKT 1
FDNS	09ALL	2	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41517	104.1450	HOSKINS - NELIGH.EAST3345.00 345KV CKT 1
FDNS	09NR	2	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.19123	106.0028	HOSKINS - NELIGH.EAST3345.00 345KV CKT 1
FDNS	09NR	2	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.19123	106.0002	NELIGH.EAST3345.00 (NELIGH.E T1) 345/115/13.8KV TRANSFORMER CKT 1
FDNS	09NR	2	15G	G15_008	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.03267	125.5977	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	00NR	2	15SP	G15_008	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.03141	124.5047	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	09ALL	2	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22221	111.3408	NELIGH.EAST3345.00 (NELIGH.E T1) 345/115/13.8KV TRANSFORMER CKT 1
FDNS	09ALL	2	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22221	111.3129	HOSKINS - NELIGH.EAST3345.00 345KV CKT 1
FDNS	09ALL	2	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22204	102.9109	HOSKINS - NELIGH.EAST3345.00 345KV CKT 1
FDNS	09ALL	2	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22204	102.9105	NELIGH.EAST3345.00 (NELIGH.E T1) 345/115/13.8KV TRANSFORMER CKT 1
FDNS	09ALL	3	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22086	108.2729	NELIGH.EAST3345.00 (NELIGH.E T1) 345/115/13.8KV TRANSFORMER CKT 1
FDNS	09ALL	3	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22086	108.2422	HOSKINS - NELIGH.EAST3345.00 345KV CKT 1
FDNS	09ALL	3	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22072	101.9268	NELIGH.EAST3345.00 (NELIGH.E T1) 345/115/13.8KV TRANSFORMER CKT 1
FDNS	09ALL	3	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22072	101.9264	HOSKINS - NELIGH.EAST3345.00 345KV CKT 1
FDNS	09ALL	3	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41309	104.1950	NELIGH.EAST3345.00 (NELIGH.E T1) 345/115/13.8KV TRANSFORMER CKT 1
FDNS	09ALL	3	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41309	104.0497	HOSKINS - NELIGH.EAST3345.00 345KV CKT 1
FDNS	09NR	3	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.19072	106.0211	HOSKINS - NELIGH.EAST3345.00 345KV CKT 1
FDNS	09NR	3	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.19072	106.0184	NELIGH.EAST3345.00 (NELIGH.E T1) 345/115/13.8KV TRANSFORMER CKT 1
FDNS	09ALL	3	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22086	111.8661	NELIGH.EAST3345.00 (NELIGH.E T1) 345/115/13.8KV TRANSFORMER CKT 1
FDNS	09ALL	3	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22086	111.8427	HOSKINS - NELIGH.EAST3345.00 345KV CKT 1
FDNS	09ALL	3	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22072	103.2055	HOSKINS - NELIGH.EAST3345.00 345KV CKT 1
FDNS	09ALL	3	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22072	103.2043	NELIGH.EAST3345.00 (NELIGH.E T1) 345/115/13.8KV TRANSFORMER CKT 1
FDNS	09ALL	4	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.07192	100.0000	BASE CASE

SOLUTION	GROUP	SCENARIO	SEASON	SOURCE	DIRECTION	MONITORED ELEMENT	RATEA (MVA)	RATEB(MVA)	TDF	TC%LOADING (% MVA)	CONTINGENCY
FDNS	09ALL	4	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.3742	99.8000	NELIGH.EAST3345.00 (NELIGH.E T1) 345/115/13.8KV TRANSFORMER CKT 1
FDNS	09ALL	4	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.3742	99.7000	HOSKINS - NELIGH.EAST3345.00 345KV CKT 1
FDNS	09NR	4	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.17192	103.8590	HOSKINS - NELIGH.EAST3345.00 345KV CKT 1
FDNS	09NR	4	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.17192	103.8161	NELIGH.EAST3345.00 (NELIGH.E T1) 345/115/13.8KV TRANSFORMER CKT 1
FDNS	09ALL	4	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.07192	103.5479	BASE CASE
FDNS	08ALL	0	15WP	G15_015	FROM->TO	CHIKASKIA - KILDARE4 138KV CKT 1	143	143	0.37359	106.4486	HUNTERS7 345.00 - WOODRING 345KV CKT 1
FDNS	08ALL	0	15G	G15_015	FROM->TO	CHIKASKIA - KILDARE4 138KV CKT 1	143	143	0.37384	105.2570	HUNTERS7 345.00 - WOODRING 345KV CKT 1
FDNS	08ALL	0	15SP	G15_015	FROM->TO	CHIKASKIA - KILDARE4 138KV CKT 1	143	143	0.37268	101.8138	HUNTERS7 345.00 - WOODRING 345KV CKT 1
FDNS	00NR	0	20WP	G15_015	FROM->TO	CLEARWATER - GILL ENERGY CENTER WEST 138KV CKT 1	143	143	0.02978	113.7805	GILL ENERGY CENTER SOUTH - VIOLA 4 138.00 138KV CKT 1
FDNS	08NR	2	15G	G15_015	FROM->TO	CLEARWATER - GILL ENERGY CENTER WEST 138KV CKT 1	143	143	0.03037	140.4739	GILL ENERGY CENTER SOUTH - VIOLA 4 138.00 138KV CKT 1
FDNS	00NR	2	15SP	G15_015	FROM->TO	CLEARWATER - GILL ENERGY CENTER WEST 138KV CKT 1	143	143	0.02961	125.3745	GILL ENERGY CENTER SOUTH - VIOLA 4 138.00 138KV CKT 1
FDNS	08NR	2	15G	G15_015	FROM->TO	CLEARWATER - GILL ENERGY CENTER WEST 138KV CKT 1	143	143	0.04346	123.0914	VIOLA 7 345.00 - WICHITA 345KV CKT 1
FDNS	00NR	2	15WP	G15_015	FROM->TO	CLEARWATER - GILL ENERGY CENTER WEST 138KV CKT 1	143	143	0.0304	109.8590	GILL ENERGY CENTER SOUTH - VIOLA 4 138.00 138KV CKT 1
FDNS	08NR	2	15G	G15_015	FROM->TO	CLEARWATER - GILL ENERGY CENTER WEST 138KV CKT 1	143	143	0.03354	108.6563	HUNTERS7 345.00 - WOODRING 345KV CKT 1
FDNS	08NR	2	15G	G15_015	FROM->TO	CLEARWATER - GILL ENERGY CENTER WEST 138KV CKT 1	143	143	0.03354	99.5000	HUNTERS7 345.00 - RENFROW7 345.00 345KV CKT 1
FDNS	08NR	3	15G	G15_015	FROM->TO	CLEARWATER - GILL ENERGY CENTER WEST 138KV CKT 1	143	143	0.03262	157.5275	GILL ENERGY CENTER SOUTH - VIOLA 4 138.00 138KV CKT 1
FDNS	00NR	3	15SP	G15_015	FROM->TO	CLEARWATER - GILL ENERGY CENTER WEST 138KV CKT 1	143	143	0.03176	140.5628	GILL ENERGY CENTER SOUTH - VIOLA 4 138.00 138KV CKT 1
FDNS	08NR	3	15G	G15_015	FROM->TO	CLEARWATER - GILL ENERGY CENTER WEST 138KV CKT 1	143	143	0.04802	134.8752	VIOLA 7 345.00 - WICHITA 345KV CKT 1
FDNS	00NR	3	20SP	G15_015	FROM->TO	CLEARWATER - GILL ENERGY CENTER WEST 138KV CKT 1	143	143	0.03127	130.4082	GILL ENERGY CENTER SOUTH - VIOLA 4 138.00 138KV CKT 1
FDNS	00NR	3	20WP	G15_015	FROM->TO	CLEARWATER - GILL ENERGY CENTER WEST 138KV CKT 1	143	143	0.03206	125.6913	GILL ENERGY CENTER SOUTH - VIOLA 4 138.00 138KV CKT 1
FDNS	08NR	3	15G	G15_015	FROM->TO	CLEARWATER - GILL ENERGY CENTER WEST 138KV CKT 1	143	143	0.03928	124.9763	HUNTERS7 345.00 - WOODRING 345KV CKT 1
FDNS	00NR	3	15WP	G15_015	FROM->TO	CLEARWATER - GILL ENERGY CENTER WEST 138KV CKT 1	143	143	0.03267	121.4853	GILL ENERGY CENTER SOUTH - VIOLA 4 138.00 138KV CKT 1
FDNS	08NR	3	15G	G15_015	FROM->TO	CLEARWATER - GILL ENERGY CENTER WEST 138KV CKT 1	143	143	0.03928	113.7267	HUNTERS7 345.00 - RENFROW7 345.00 345KV CKT 1
FDNS	00NR	3	15SP	G15_015	FROM->TO	CLEARWATER - GILL ENERGY CENTER WEST 138KV CKT 1	143	143	0.03904	100.0000	HUNTERS7 345.00 - WOODRING 345KV CKT 1
FDNS	04NR	0	15G	G15_017	FROM->TO	ARNOLD - RANSOM 115KV CKT 1	79.7	79.7	0.28279	111.7192	MINGO (MINGO) 345/115/13.8KV TRANSFORMER CKT 1
FDNS	03ALL	0	15G	G15_021	FROM->TO	FPL SWITCH - MOORELAND 138KV CKT 1	287	287	0.03626	100.2134	BASE CASE
FDNS	03ALL	2	25SP	G15_021	TO->FROM	HUGOTON SUBSTATION - PIONEER NATURAL RESOURCES TAP 115KV CKT 1	159.3	159.3	0.25672	99.8000	FINNEY SWITCHING STATION - WALKTAP7 345.00 345KV CKT 1
FDNSLock-Blown up	09ALL	0	15SP	G15_023		Non-Converged Contingency	720	720	0.67593	-	GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1
FDNSLock-Blown up	09ALL	0	15G	G15_023		Non-Converged Contingency	720	720	0.67592	-	GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1
FDNSLock-Blown up	09ALL	0	15WP	G15_023		Non-Converged Contingency	720	720	0.67511	-	GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1
FDNSLock-Blown up	09ALL	2	15SP	G15_023		Non-Converged Contingency	720	720	0.67671	-	GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1
FDNSLock-Blown up	09ALL	2	15G	G15_023		Non-Converged Contingency	720	720	0.67604	-	GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1
FDNSLock-Blown up	09ALL	2	15WP	G15_023		Non-Converged Contingency	720	720	0.67552	-	GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1
FDNS	09NR	0	15G	G15_023	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.03088	125.8320	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	00NR	0	15SP	G15_023	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.02962	124.5109	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	09ALL	0	15G	G15_023	TO->FROM	GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1	720	720	1	105.6115	FT THOMPSON - FTTHOM2-LNX3345.00 345KV CKT Z
FDNS	09ALL	0	15WP	G15_023	TO->FROM	GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1	720	720	1	104.2632	FTTHOM2-LNX3345.00 - GRPRAR2-LNX3345.00 345KV CKT 1
FDNS	09ALL	0	15G	G15_023	TO->FROM	GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1	720	720	1	102.2864	GRPRAR2-LNX3345.00 - YANKTON 345KV CKT Z
FDNS	09ALL	0	15SP	G15_023	TO->FROM	GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1	720	720	1	101.7641	FT THOMPSON - FTTHOM2-LNX3345.00 345KV CKT Z
FDNS	09ALL	0	15WP	G15_023	TO->FROM	GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1	720	720	1	101.2599	FT THOMPSON - FTTHOM2-LNX3345.00 345KV CKT Z
FDNS	09ALL	0	15G	G15_023	TO->FROM	GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1	720	720	1	100.9998	FTTHOM2-LNX3345.00 - GRPRAR2-LNX3345.00 345KV CKT 1
FDNS	09ALL	0	15SP	G15_023	TO->FROM	GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1	720	720	1	100.8104	GRPRAR2-LNX3345.00 - YANKTON 345KV CKT Z
FDNS	09ALL	0	15WP	G15_023	TO->FROM	GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1	720	720	1	100.4388	GRPRAR2-LNX3345.00 - YANKTON 345KV CKT Z
FDNS	09ALL	0	15SP	G15_023	TO->FROM	GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1	720	720	1	100.1924	FTTHOM2-LNX3345.00 - GRPRAR2-LNX3345.00 345KV CKT 1
FDNS	09NR	2	15G	G15_023	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.03086	125.5977	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	00NR	2	15SP	G15_023	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.0296	124.5047	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	09ALL	2	15G	G15_023	TO->FROM	GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1	720	720	1	104.4652	FT THOMPSON - FTTHOM2-LNX3345.00 345KV CKT Z
FDNS	09ALL	2	15WP	G15_023	TO->FROM	GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1	720	720	1	103.0793	FTTHOM2-LNX3345.00 - GRPRAR2-LNX3345.00 345KV CKT 1
FDNS	09ALL	2	15G	G15_023	TO->FROM	GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1	720	720	1	102.1002	GRPRAR2-LNX3345.00 - YANKTON 345KV CKT Z
FDNS	09ALL	2	15SP	G15_023	TO->FROM	GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1	720	720	1	101.5484	FT THOMPSON - FTTHOM2-LNX3345.00 345KV CKT Z
FDNS	09ALL	2	15WP	G15_023	TO->FROM	GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1	720	720	1	101.0140	FT THOMPSON - FTTHOM2-LNX3345.00 345KV CKT Z
FDNS	09ALL	2	15SP	G15_023	TO->FROM	GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1	720	720	1	100.6774	GRPRAR2-LNX3345.00 - YANKTON 345KV CKT Z
FDNS	09ALL	2	15G	G15_023	TO->FROM	GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1	720	720	1	100.6442	FTTHOM2-LNX3345.00 - GRPRAR2-LNX3345.00 345KV CKT 1
FDNS	09ALL	2	15WP	G15_023	TO->FROM	GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1	720	720	1	100.1510	GRPRAR2-LNX3345.00 - YANKTON 345KV CKT Z
FDNS	09ALL	2	15SP	G15_023	TO->FROM	GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1	720	720	1	100.0000	FTTHOM2-LNX3345.00 - GRPRAR2-LNX3345.00 345KV CKT 1
FDNS	03ALL	0	15SP	G15_024	TO->FROM	BENTON - WICHITA 345KV CKT 1	878	956	0.25641	102.1058	GEN532751 1-WOLF CREEK GENERATING STATION UNIT 1
FDNS	03ALL	0	15SP	G15_025	TO->FROM	BENTON - WICHITA 345KV CKT 1	878	956	0.25641	102.1058	GEN532751 1-WOLF CREEK GENERATING STATION UNIT 1
FDNS	03ALL	0	15WP	G15_026	FROM->TO	BUCKNER7 345.00 - HOLCOMB 345KV CKT 1	726.6	726.6	0.43968	100.0000	G13-010T 345.00 - POST ROCK 345KV CKT 1
FDNS	03ALL	0	25SP	G15_026	FROM->TO	BUCKNER7 345.00 - HOLCOMB 345KV CKT 1	726.6	726.6	0.44454	99.8000	G13-010T 345.00 - POST ROCK 345KV CKT 1
FDNS	03ALL	0	15G	G15_026	FROM->TO	FPL SWITCH - MOORELAND 138KV CKT 1	287	287	0.0363	100.2134	BASE CASE
FDNS	03ALL	3	15WP	G15_026	FROM->TO	BUCKNER7 345.00 - HOLCOMB 345KV CKT 1	726.6	726.6	0.43881	100.0000	G13-010T 345.00 - POST ROCK 345KV CKT 1
FDNS	03ALL	0	25SP	G15_027	FROM->TO	CRKCK 3 115.00 - CUDAHY 115KV CKT 1	119.5	148.2	0.29876	114.6466	BUCKNER7 345.00 - HOLCOMB 345KV CKT 1
FDNS	03ALL	0	15WP	G15_027	FROM->TO	CRKCK 3 115.00 - CUDAHY 115KV CKT 1	119.5	148.2	0.29312	112.8578	BUCKNER7 345.00 - HOLCOMB 345KV CKT 1
FDNS	03ALL	0	20WP	G15_027	FROM->TO	CRKCK 3 115.00 - CUDAHY 115KV CKT 1	119.5	148.2	0.29819	102.2452	BUCKNER7 345.00 - HOLCOMB 345KV CKT 1
FDNS	03ALL	0	15G	G15_027	FROM->TO	CRKCK 3 115.00 - CUDAHY 115KV CKT 1	119.5	148.2	0.29299	102.0622	BUCKNER7 345.00 - HOLCOMB 345KV CKT 1
FDNS	03ALL	0	15WP	G15_027	FROM->TO	CRKCK 3 115.00 - CUDAHY 115KV CKT 1	119.5	148.2	0.29105	100.9918	BASE CASE
FDNS	03ALL	0	20SP	G15_027	FROM->TO	CRKCK 3 115.00 - CUDAHY 115KV CKT 1	119.5	148.2	0.29875	100.3302	BUCKNER7 345.00 - HOLCOMB 345KV CKT 1
FDNS	03ALL	0	25SP	G15_027	FROM->TO	CUDAHY - KISMET 3 115.00 115KV CKT 1	119.5	135.8	0.29876	117.8695	BUCKNER7 345.00 - HOLCOMB 345KV CKT 1
FDNS	03ALL	0	15WP	G15_027	FROM->TO	CUDAHY - KISMET 3 115.00 115KV CKT 1	119.5	148.2	0.29312	107.9114	BUCKNER7 345.00 - HOLCOMB 345KV CKT 1
FDNS	03ALL	0	20SP	G15_027	FROM->TO	CUDAHY - KISMET 3 115.00 115KV CKT 1	119.5	135.8	0.29875	102.7869	BUCKNER7 345.00 - HOLCOMB 345KV CKT 1
FDNS	03ALL	0	15G	G15_027	FROM->TO	FPL SWITCH - MOORELAND 138KV CKT 1	287	287	0.03469	100.2134	BASE CASE
FDNS	03ALL	0	25SP	G15_027	TO->FROM	GREENSBURG - SSTARTP3 115.00 115KV CKT 1	115.1	115.1	0.09657	119.3545	BASE CASE
FDNS	03ALL	0	20SP	G15_027	TO->FROM	GREENSBURG - SSTARTP3 115.00 115KV CKT 1	115.1	115.1	0.09642	117.3763	BASE CASE
FDNS	03ALL	0	20WP	G15_027	TO->FROM	GREENSBURG - SSTARTP3 115.00 115KV CKT 1	119.5	148.2	0.09597	115.8265	BASE CASE
FDNS	03ALL	0	15SP	G15_027	TO->FROM	GREENSBURG - SSTARTP3 115.00 115KV CKT 1	115.1	115.1	0.09725	114.7695	BASE CASE

SOLUTION	GROUP	SCENARIO	SEASON	SOURCE	DIRECTION	MONITORED ELEMENT	RATEA (MVA)	RATEB(MVA)	TDF	TC%LOADING (% MVA)	CONTINGENCY
FDNS	03ALL	0	15WP	G15_027	TO->FROM	GREENSBURG - SSTARTP3 115.00 115KV CKT 1	119.5	148.2	0.09666	109.0418	BASE CASE
FDNS	03ALL	0	15G	G15_027	TO->FROM	GREENSBURG - SSTARTP3 115.00 115KV CKT 1	119.5	134.6	0.09656	108.5867	BASE CASE
FDNS	03ALL	2	25SP	G15_027	FROM->TO	CRKCK 3 115.00 - CUDAHY 115KV CKT 1	119.5	148.2	0.36123	114.7906	BUCKNER7 345.00 - HOLCOMB 345KV CKT 1
FDNS	03ALL	2	15WP	G15_027	FROM->TO	CRKCK 3 115.00 - CUDAHY 115KV CKT 1	119.5	148.2	0.3528	110.1003	BUCKNER7 345.00 - HOLCOMB 345KV CKT 1
FDNS	03ALL	2	25SP	G15_027	FROM->TO	CRKCK 3 115.00 - CUDAHY 115KV CKT 1	119.5	148.2	0.36072	109.9181	FINNEY SWITCHING STATION - WALKTAP7 345.00 345KV CKT 1
FDNS	03ALL	2	20WP	G15_027	FROM->TO	CRKCK 3 115.00 - CUDAHY 115KV CKT 1	119.5	148.2	0.36015	103.9505	BUCKNER7 345.00 - HOLCOMB 345KV CKT 1
FDNS	03ALL	2	15G	G15_027	FROM->TO	CRKCK 3 115.00 - CUDAHY 115KV CKT 1	119.5	148.2	0.35292	102.0496	BUCKNER7 345.00 - HOLCOMB 345KV CKT 1
FDNS	03ALL	2	25SP	G15_027	FROM->TO	CRKCK 3 115.00 - CUDAHY 115KV CKT 1	119.5	148.2	0.35922	101.5683	BASE CASE
FDNS	03ALL	2	25SP	G15_027	FROM->TO	CUDAHY - KISMET 3 115.00 115KV CKT 1	119.5	135.8	0.36123	118.1751	BUCKNER7 345.00 - HOLCOMB 345KV CKT 1
FDNS	03ALL	2	25SP	G15_027	FROM->TO	CUDAHY - KISMET 3 115.00 115KV CKT 1	119.5	135.8	0.36072	112.3857	FINNEY SWITCHING STATION - WALKTAP7 345.00 345KV CKT 1
FDNS	03ALL	2	15WP	G15_027	FROM->TO	CUDAHY - KISMET 3 115.00 115KV CKT 1	119.5	148.2	0.3528	105.2764	BUCKNER7 345.00 - HOLCOMB 345KV CKT 1
FDNS	03ALL	2	20SP	G15_027	FROM->TO	CUDAHY - KISMET 3 115.00 115KV CKT 1	119.5	135.8	0.361	101.2921	BUCKNER7 345.00 - HOLCOMB 345KV CKT 1
FDNS	03ALL	2	25SP	G15_027	TO->FROM	GREENSBURG - SSTARTP3 115.00 115KV CKT 1	115.1	115.1	0.0876	119.8692	BASE CASE
FDNS	03ALL	2	20SP	G15_027	TO->FROM	GREENSBURG - SSTARTP3 115.00 115KV CKT 1	115.1	115.1	0.08755	118.3192	BASE CASE
FDNS	03ALL	2	20WP	G15_027	TO->FROM	GREENSBURG - SSTARTP3 115.00 115KV CKT 1	119.5	148.2	0.08699	116.2924	BASE CASE
FDNS	03ALL	2	15SP	G15_027	TO->FROM	GREENSBURG - SSTARTP3 115.00 115KV CKT 1	115.1	115.1	0.08843	115.7170	BASE CASE
FDNS	03ALL	2	15WP	G15_027	TO->FROM	GREENSBURG - SSTARTP3 115.00 115KV CKT 1	119.5	148.2	0.08786	110.2580	BASE CASE
FDNS	03ALL	2	15G	G15_027	TO->FROM	GREENSBURG - SSTARTP3 115.00 115KV CKT 1	119.5	134.6	0.08777	109.6848	BASE CASE
FDNS	08ALL	0	15WP	G15_028	FROM->TO	CHIKASKIA - KILDARE4 138KV CKT 1	143	143	0.34029	106.4486	HUNTERS7 345.00 - WOODRING 345KV CKT 1
FDNS	08ALL	0	15G	G15_028	FROM->TO	CHIKASKIA - KILDARE4 138KV CKT 1	143	143	0.34051	105.2570	HUNTERS7 345.00 - WOODRING 345KV CKT 1
FDNS	08ALL	0	15SP	G15_028	FROM->TO	CHIKASKIA - KILDARE4 138KV CKT 1	143	143	0.33936	101.8138	HUNTERS7 345.00 - WOODRING 345KV CKT 1
FDNS	01ALL	0	15G	G15_029	FROM->TO	FPL SWITCH - MOORELAND 138KV CKT 1	287	287	0.04822	114.0611	BASE CASE
FDNS	01ALL	0	15WP	G15_029	FROM->TO	FPL SWITCH - MOORELAND 138KV CKT 1	287	287	0.0523	106.2657	BASE CASE
FDNS	01ALL	0	20WP	G15_029	FROM->TO	FPL SWITCH - MOORELAND 138KV CKT 1	287	287	0.05278	105.9437	BASE CASE

G1: Stand Alone Power Flow Analysis (Constraints Used For Mitigation)

See next page.

SOLUTION	GROUP	SCENARIO	SEASON	SOURCE	DIRECTION	MONITORED ELEMENT	RATEA (MVA)	RATEB(MVA)	TDF	TC%LOADING (% MVA)	CONTINGENCY
FDNS	04ALL_G10_048	0	25SP	G10_048	TO->FROM	BEACH STATION - G10-48T 115.00 115KV CKT 1	80	88	0.41101	106.6117	MINGO (MINGO) 345/115/13.8KV TRANSFORMER CKT 1
FDNS	09ALL_G14_023	0	15G	G14_023	TO->FROM	FT RANDAL - G14_023T 230.00 230KV CKT 1	320	320	1	123.1182	KELLY - MEADOWGROVE4230.00 230KV CKT 1
FDNS	09ALL_G14_023	0	15SP	G14_023	TO->FROM	FT RANDAL - G14_023T 230.00 230KV CKT 1	320	320	1	122.6773	KELLY - MEADOWGROVE4230.00 230KV CKT 1
FDNS	09ALL_G14_023	0	25SP	G14_023	TO->FROM	FT RANDAL - G14_023T 230.00 230KV CKT 1	320	320	1	122.6357	KELLY - MEADOWGROVE4230.00 230KV CKT 1
FDNS	09ALL_G14_023	0	20WP	G14_023	TO->FROM	FT RANDAL - G14_023T 230.00 230KV CKT 1	320	320	1	122.5794	KELLY - MEADOWGROVE4230.00 230KV CKT 1
FDNS	09ALL_G14_023	0	15WP	G14_023	TO->FROM	FT RANDAL - G14_023T 230.00 230KV CKT 1	320	320	1	122.5172	KELLY - MEADOWGROVE4230.00 230KV CKT 1
FDNS	09ALL_G14_023	0	20SP	G14_023	TO->FROM	FT RANDAL - G14_023T 230.00 230KV CKT 1	320	320	1	122.5105	KELLY - MEADOWGROVE4230.00 230KV CKT 1
FDNS	09NR_G14_023	0	15G	G14_023	TO->FROM	FT RANDAL - G14_023T 230.00 230KV CKT 1	320	320	1	109.5358	KELLY - MEADOWGROVE4230.00 230KV CKT 1
FDNS	00NR_G14_023	0	25SP	G14_023	FROM->TO	FT RANDAL - SPENCER 115KV CKT 1	120	120	0.03376	103.2629	AINSWORTH - AINSWORTH 115KV CKT 1
FDNS	09ALL_G14_023	0	15G	G14_023	TO->FROM	KELLY - MEADOWGROVE4230.00 230KV CKT 1	368	368	1	108.9083	FT RANDAL - G14_023T 230.00 230KV CKT 1
FDNS	09ALL_G14_023	0	25SP	G14_023	TO->FROM	KELLY - MEADOWGROVE4230.00 230KV CKT 1	368	368	1	108.0742	FT RANDAL - G14_023T 230.00 230KV CKT 1
FDNS	09ALL_G14_023	0	15WP	G14_023	TO->FROM	KELLY - MEADOWGROVE4230.00 230KV CKT 1	368	368	1	107.9817	FT RANDAL - G14_023T 230.00 230KV CKT 1
FDNS	09ALL_G14_023	0	20WP	G14_023	TO->FROM	KELLY - MEADOWGROVE4230.00 230KV CKT 1	368	368	1	107.9186	FT RANDAL - G14_023T 230.00 230KV CKT 1
FDNS	09ALL_G14_023	0	20SP	G14_023	TO->FROM	KELLY - MEADOWGROVE4230.00 230KV CKT 1	368	368	1	107.6430	FT RANDAL - G14_023T 230.00 230KV CKT 1
FDNS	09ALL_G14_023	0	15SP	G14_023	TO->FROM	KELLY - MEADOWGROVE4230.00 230KV CKT 1	368	368	1	107.5517	FT RANDAL - G14_023T 230.00 230KV CKT 1
FDNS	09ALL_G14_023	2	15SP	G14_023	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.0538	101.7154	BASE CASE
FDNS	09ALL_G14_023	2	15G	G14_023	TO->FROM	KELLY - MEADOWGROVE4230.00 230KV CKT 1	368	368	0.76549	100.3423	FT RANDAL - G14_023T 230.00 230KV CKT 1
FDNS	09ALL_G14_023	2	15SP	G14_023	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.0538	105.2806	BASE CASE
FDNS	00NR_G14_059	0	15SP	G14_059	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.83828	125.1059	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	09NR_G14_059	0	15G	G14_059	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.8386	125.0772	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	09ALL_G14_059	0	15G	G14_059	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.8177	123.3034	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	09ALL_G14_059	0	15SP	G14_059	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.81869	119.9768	KEYSTONE - SIDNEY 345KV CKT 1
FDNSLock	00NR_G14_059	0	25SP	G14_059	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.83659	119.8454	KEYSTONE - SIDNEY 345KV CKT 1
FDNSLock	00NR_G14_059	0	15WP	G14_059	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.83623	118.3356	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	00NR_G14_059	0	20SP	G14_059	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.83771	117.5654	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	09ALL_G14_059	0	25SP	G14_059	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.82065	114.4593	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	09ALL_G14_059	0	20SP	G14_059	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.82061	113.8286	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	00NR_G14_059	0	20WP	G14_059	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.83661	113.7713	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	09ALL_G14_059	0	15WP	G14_059	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.81822	113.6625	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	09ALL_G14_059	0	20WP	G14_059	FROM->TO	G14-059T 230.00 - OGALLALA 230KV CKT 1	320	320	0.82066	110.1020	KEYSTONE - SIDNEY 345KV CKT 1
FDNS	09ALL	0	15G	G14_059	FROM->TO	GGS	1635	1635	0.79998	104.9857	BASE CASE
FDNS	09ALL	0	15WP	G14_059	FROM->TO	GGS	1635	1635	0.79956	102.7627	BASE CASE
FDNS	09ALL	0	15G	G14_059	FROM->TO	REDWILLMINGO	468	468	0.26096	101.0842	BASE CASE
FDNS	00NR_G14_059	0	15WP	G14_059	FROM->TO	VICTORY HILL (VICTORYHL T1) 230/115/13.8KV TRANSFORMER CKT 1	187	187	0.03485	105.2549	STEGALL - WAYSIDE 230KV CKT 1
FDNS	00NR_G14_059	0	15WP	G14_059	FROM->TO	VICTORY HILL (VICTORYHL T1) 230/115/13.8KV TRANSFORMER CKT 1	187	187	0.03485	104.6970	STEGALL - WAYSIDE 230KV CKT 1
FDNS	08ALL_G15_003	0	20SP	G15_003	FROM->TO	VIOLA 7 345.00 (VIOLA 1X) 345/138/13.8KV TRANSFORMER CKT 1	448	492.8	0.26969	100.2598	VIOLA 7 345.00 - WICHITA 345KV CKT 1
FDNS	08ALL_G15_003	2	15SP	G15_003	FROM->TO	VIOLA 7 345.00 (VIOLA 1X) 345/138/13.8KV TRANSFORMER CKT 1	448	492.8	0.26859	100.0000	VIOLA 7 345.00 - WICHITA 345KV CKT 1
FDNS	08ALL_G15_003	3	15G	G15_003	FROM->TO	CLEARWATER - GILL ENERGY CENTER WEST 138KV CKT 1	143	143	0.03979	104.5084	BASE CASE
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	ALBION - GENOA 115KV CKT 1	137	137	0.25168	105.7256	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	ALBION - GENOA 115KV CKT 1	137	137	0.25168	105.6801	LN-1163-2
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	ALBION - GENOA 115KV CKT 1	137	137	0.25168	105.5604	BATTLE CREEK - COUNTY LINE 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	ALBION - GENOA 115KV CKT 1	137	137	0.25168	104.0470	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.37877	153.7784	LN-1163-2
FDNS	09ALL_G15_008	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.37877	153.7545	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.37877	153.5026	BATTLE CREEK - COUNTY LINE 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.37878	152.4071	LN-1163-2
FDNS	09ALL_G15_008	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.37878	152.3154	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.37878	152.1589	BATTLE CREEK - COUNTY LINE 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.37877	151.2769	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1
FDNS	09ALL_G15_008	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.37888	148.4878	LN-1163-2
FDNS	09ALL_G15_008	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.37888	148.4490	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.37878	147.6394	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1
FDNS	09ALL_G15_008	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.37888	146.7160	BATTLE CREEK - COUNTY LINE 115KV CKT 1
FDNS	09ALL_G15_008	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.37888	137.9732	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1
FDNS	09NR_G15_008	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.38311	130.2259	LN-1163-2
FDNS	09NR_G15_008	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.38311	130.1442	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09NR_G15_008	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.38311	130.0031	BATTLE CREEK - COUNTY LINE 115KV CKT 1
FDNS	09NR_G15_008	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.38311	128.0991	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.27085	125.5442	BLOOMFIELD - GAVINS POINT 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.27094	125.3155	BLOOMFIELD - GAVINS POINT 115KV CKT 1
FDNS	09ALL_G15_008	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.27103	123.7227	BLOOMFIELD - GAVINS POINT 115KV CKT 1
FDNS	09ALL_G15_008	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.27464	117.0911	LN-1164
FDNS	09ALL_G15_008	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.27464	117.0035	CLEARWATER - NELIGH 115KV CKT 1
FDNS	09ALL_G15_008	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.27103	115.8835	CREIGHTON - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09ALL_G15_008	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22291	115.3832	KELLY - MEADOWGROVE4230.00 230KV CKT 1
FDNS	09ALL_G15_008	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22344	114.7415	GRPRAR1-LNX3345.00 - HOLT.CO3 345.00 345KV CKT 1
FDNS	09ALL_G15_008	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22344	114.7395	GRPRAR1-LNX3345.00 - YANKTON 345KV CKT Z
FDNS	09ALL_G15_008	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22344	114.7092	GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1
FDNS	09ALL_G15_008	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.27464	114.5434	CLEARWATER - ONEILL 115KV CKT 1
FDNS	09ALL_G15_008	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.2163	114.0338	BROKEN BOW - LOUP CITY 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.27094	111.6546	CREIGHTON - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.27452	111.1974	LN-1164
FDNS	09ALL_G15_008	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.27452	111.1809	CLEARWATER - NELIGH 115KV CKT 1
FDNS	09ALL_G15_008	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22222	111.0917	GEN640010 1-GERALD GENTLEMAN STATION UNIT 1
FDNS	09ALL_G15_008	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22222	111.0193	GEN640011 2-GERALD GENTLEMAN STATION UNIT 2

SOLUTION	GROUP	SCENARIO	SEASON	SOURCE	DIRECTION	MONITORED ELEMENT	RATEA (MVA)	RATEB(MVA)	TDF	TC%LOADING (% MVA)	CONTINGENCY
FDNS	09ALL_G15_008	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.23099	110.6775	GAVINS POINT - YANKON JCT 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.27452	110.6567	CLEARWATER - ONEILL 115KV CKT 1
FDNS	09ALL_G15_008	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22222	110.5009	GEN640428 1-BRKNBW.GEN1W0.6900
FDNS	09ALL_G15_008	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.2241	110.4242	NEB02WAPAB2
FDNS	09ALL_G15_008	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22222	110.3048	GEN640449 W-BRKNBW.GEN2W0.6900
FDNS	09ALL_G15_008	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.27085	110.0669	CREIGHTON - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09ALL_G15_008	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.2241	109.7638	GAVINS POINT - HARTINGTON 115KV CKT 1
FDNS	09ALL_G15_008	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22406	109.6318	GAVINS POINT - SPIRIT MOUND 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.2744	109.5697	LN-1164
FDNS	09ALL_G15_008	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.2744	109.5583	CLEARWATER - NELIGH 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.2744	109.1462	CLEARWATER - ONEILL 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.21621	109.0257	BROKEN BOW - LOUP CITY 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22279	107.9396	KELLY - MEADOWGROVE4230.00 230KV CKT 1
FDNS	09ALL_G15_008	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22222	107.4908	NUCOR-1
FDNS	09ALL_G15_008	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22222	107.4675	BASE CASE
FDNS	09ALL_G15_008	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.27094	107.4139	BLOOMFIELD - CREIGHTON 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.27085	107.0867	BLOOMFIELD - CREIGHTON 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.23088	106.0902	GAVINS POINT - YANKON JCT 115KV CKT 1
FDNS	09NR_G15_008	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.27598	106.0333	BLOOMFIELD - GAVINS POINT 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22329	105.6878	GRPRAR1-LNX3345.00 - HOLT.CO3 345.00 345KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22329	105.6839	GRPRAR1-LNX3345.00 - YANKTON 345KV CKT Z
FDNS	09ALL_G15_008	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22271	105.6753	KELLY - MEADOWGROVE4230.00 230KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22329	105.6567	GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.21621	105.4736	BROKEN BOW - LOUP CITY 115KV CKT 1
FDNS	09ALL_G15_008	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22222	104.8966	GEN659111 2-LELAND OLDS UNIT2
FDNS	09ALL_G15_008	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.21105	104.7592	NELIGH - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.24574	104.7518	LN-WAPA6
FDNS	09ALL_G15_008	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.24574	104.7518	NEB001NPPB2
FDNS	09ALL_G15_008	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.24574	104.7188	ONEILL - SPENCER 115KV CKT 1
FDNS	09ALL_G15_008	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22222	104.6569	GEN659103 1-ANTELOPE VALLEY UNIT1
FDNS	09ALL_G15_008	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22222	104.6569	GEN659107 2-ANTELOPE VALLEY UNIT2
FDNS	09ALL_G15_008	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22222	104.6443	GEN640421 1-CROFTON HILLS WIND
FDNS	09ALL_G15_008	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.24581	104.6241	LN-WAPA6
FDNS	09ALL_G15_008	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.24581	104.6241	NEB001NPPB2
FDNS	09ALL_G15_008	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.24581	104.5414	ONEILL - SPENCER 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22321	104.3958	GRPRAR1-LNX3345.00 - HOLT.CO3 345.00 345KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22321	104.3898	GRPRAR1-LNX3345.00 - YANKTON 345KV CKT Z
FDNS	09ALL_G15_008	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.24574	104.3585	FT RANDAL - SPENCER 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22321	104.3546	GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1
FDNS	09ALL_G15_008	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22222	104.0973	SPALDING 115KV SWITCHED SHUNT
FDNS	09ALL_G15_008	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.2221	104.0583	GEN640010 1-GERALD GENTLEMAN STATION UNIT 1
FDNSLock	09ALL_G15_008	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22222	104.0430	SPALDING 115KV SWITCHED SHUNT
FDNS	09ALL_G15_008	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.2221	103.9544	GEN640428 1-BRKNBW.GEN1W0.6900
FDNS	09ALL_G15_008	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.2221	103.7536	GEN640449 W-BRKNBW.GEN2W0.6900
FDNS	09ALL_G15_008	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.228	103.6651	UTICA - YANKON JCT 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22398	103.6491	NEB02WAPAB2
FDNS	09ALL_G15_008	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.2459	103.6248	LN-WAPA6
FDNS	09ALL_G15_008	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.2459	103.6248	NEB001NPPB2
FDNS	09ALL_G15_008	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.2221	103.6061	GEN640011 2-GERALD GENTLEMAN STATION UNIT 2
FDNS	09ALL_G15_008	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22395	103.5946	GAVINS POINT - SPIRIT MOUND 115KV CKT 1
FDNS	09ALL_G15_008	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.20625	103.5765	NELIGH - NELIGH.EAST7115.00 115KV CKT 2
FDNS	09ALL_G15_008	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.2459	103.5615	ONEILL - SPENCER 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.24581	103.5586	FT RANDAL - SPENCER 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.23078	103.4349	GAVINS POINT - YANKON JCT 115KV CKT 1
FDNS	09ALL_G15_008	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22222	103.2354	ALBION 115KV SWITCHED SHUNT
FDNSLock	09ALL_G15_008	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22222	103.2109	ALBION 115KV SWITCHED SHUNT
FDNS	09ALL_G15_008	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.23366	103.1023	HOSKINS - NORTH NORFOLK 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22398	103.0780	GAVINS POINT - HARTINGTON 115KV CKT 1
FDNS	09ALL_G15_008	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.2459	102.7393	FT RANDAL - SPENCER 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22791	102.0181	UTICA - YANKON JCT 115KV CKT 1
FDNS	09ALL_G15_008	0	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22222	102.0103	GEN640418 1-ELKHORN RIDGE WIND
FDNS	09ALL_G15_008	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22201	101.9967	GEN640428 1-BRKNBW.GEN1W0.6900
FDNS	09ALL_G15_008	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.23358	101.8735	HOSKINS - NORTH NORFOLK 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22201	101.7987	GEN640449 W-BRKNBW.GEN2W0.6900
FDNS	09ALL_G15_008	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22386	101.6438	GAVINS POINT - SPIRIT MOUND 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.2239	101.2166	NEB02WAPAB2
FDNS	09ALL_G15_008	0	15G	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22566	101.1608	DAK02WAPAB2
FDNS	09ALL_G15_008	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.2221	100.8510	BASE CASE
FDNS	09ALL_G15_008	0	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.2221	100.7772	NUCOR-1
FDNS	09ALL_G15_008	0	15G	G15_008	TO->FROM	BATTLE CREEK - COUNTY LINE 115KV CKT 1	240	240	0.5166	119.8471	BLOOMFIELD - GAVINS POINT 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	TO->FROM	BATTLE CREEK - COUNTY LINE 115KV CKT 1	240	240	0.52893	116.4639	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1
FDNS	09ALL_G15_008	0	15G	G15_008	TO->FROM	BATTLE CREEK - COUNTY LINE 115KV CKT 1	240	240	0.52893	116.2656	ALBION - PETERSBURG 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	TO->FROM	BATTLE CREEK - COUNTY LINE 115KV CKT 1	240	240	0.51641	115.7549	BLOOMFIELD - GAVINS POINT 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	TO->FROM	BATTLE CREEK - COUNTY LINE 115KV CKT 1	240	240	0.52878	114.6508	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1
FDNS	09ALL_G15_008	0	15WP	G15_008	TO->FROM	BATTLE CREEK - COUNTY LINE 115KV CKT 1	240	240	0.52878	114.2390	ALBION - PETERSBURG 115KV CKT 1

SOLUTION	GROUP	SCENARIO	SEASON	SOURCE	DIRECTION	MONITORED ELEMENT	RATEA (MVA)	RATEB(MVA)	TDF	TC%LOADING (% MVA)	CONTINGENCY
FDNS	09NR_G15_008	0	15G	G15_008	TO->FROM	BATTLE CREEK - COUNTY LINE 115KV CKT 1	240	240	0.51083	102.4990	BLOOMFIELD - GAVINS POINT 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	TO->FROM	BATTLE CREEK - COUNTY LINE 115KV CKT 1	240	240	0.47822	101.1921	WAPA-OG-2
FDNS	09ALL_G15_008	0	15G	G15_008	TO->FROM	BATTLE CREEK - COUNTY LINE 115KV CKT 1	240	240	0.5166	99.8000	CREIGHTON - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09NR_G15_008	0	15G	G15_008	TO->FROM	BATTLE CREEK - COUNTY LINE 115KV CKT 1	240	240	0.52782	99.6000	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.5166	145.3343	BLOOMFIELD - GAVINS POINT 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.52893	141.1347	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.52893	140.8888	ALBION - PETERSBURG 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.51641	135.1112	BLOOMFIELD - GAVINS POINT 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.52878	133.7457	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.52878	133.2365	ALBION - PETERSBURG 115KV CKT 1
FDNS	09NR_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.51083	123.7840	BLOOMFIELD - GAVINS POINT 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.47822	122.1517	WAPA-OG-2
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.5166	120.3678	CREIGHTON - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09NR_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.52782	120.2183	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1
FDNS	09NR_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.52782	119.9806	ALBION - PETERSBURG 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.46331	119.8972	ALBION - GENOA 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.46331	118.2918	COLUMBUS - GENOA 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.4638	118.0826	WAPA-OG-1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.5166	115.7990	BLOOMFIELD - CREIGHTON 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.49032	114.6272	LN-1164
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.49032	114.6127	CLEARWATER - NELIGH 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.49032	114.1528	CLEARWATER - ONEILL 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.51641	112.9646	CREIGHTON - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.46304	111.3571	ALBION - GENOA 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.45095	109.6526	LN-WAPA6
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.45095	109.6526	NEB001NPPB2
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.45095	109.6309	ONEILL - SPENCER 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.45095	109.2089	FT RANDAL - SPENCER 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.52893	109.1114	NELIGH - PETERSBRG.N7115.00 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.42218	108.2481	GAVINS POINT - HARTINGTON 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.42823	108.0614	GAVINS POINT - YANKON JCT 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.46304	107.8248	COLUMBUS - GENOA 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.47793	107.8008	WAPA-OG-2
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.46354	107.7485	WAPA-OG-1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.42218	107.6867	NEB02WAPAB2
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.4158	107.4510	KELLY - MEADOWGROVE4230.00 230KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.49019	107.4334	LN-1164
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.49019	107.4111	CLEARWATER - NELIGH 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.49019	106.8435	CLEARWATER - ONEILL 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.42132	106.6560	DAK02WAPAB2
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.42422	106.5464	UTICA - YANKON JCT 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.42218	106.3897	BELDEN - HARTINGTON 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.51641	106.1975	BLOOMFIELD - CREIGHTON 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41805	106.1608	GAVINS POINT - SPIRIT MOUND 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41519	105.7992	GEN560350 1-G10-51 0.6900
FDNS	09ALL_G15_008	0	15SP	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.5288	105.7874	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41519	105.5617	GEN635213 3-NEAL UNIT 3
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.43267	105.5395	ALBION - SPALDING 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41322	105.3436	DIXONCO 230.00 - HOSKINS 230KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41805	105.2287	MANNING - SPIRIT MOUND 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41989	105.1643	LOUP CITY - ST LIBORY 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41519	105.1498	GEN635214 4-NEAL UNIT 4
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.43267	104.9325	NORTH LOUP - SPALDING 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41612	104.9224	FT RANDAL - SIOUX CITY 230KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.43437	104.8872	NELIGH - NELIGH.EAST7115.00 115KV CKT 2
FDNS	09NR_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.51083	104.7965	CREIGHTON - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41571	104.7819	GRPRAR1-LNX3345.00 - HOLT.CO3 345.00 345KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41571	104.7813	GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41571	104.7766	GRPRAR1-LNX3345.00 - YANKTON 345KV CKT Z
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41761	104.7716	AINSWORTH - VALENTINE 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41561	104.7504	GRAND ISLAND - MCCOOL 345KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41519	104.7069	GEN562003 1-G11_027_3 0.6900
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41805	104.6876	BERSFORD - MANNING 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41531	104.6090	SHELL CREEK (SHELLCREEKT1) 345/230/13.8KV TRANSFORMER CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41531	104.6086	KELLY - SHELL CREEK 230KV CKT 1
FDNS	09ALL_G15_008	0	15SP	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.5288	104.2896	ALBION - PETERSBURG 115KV CKT 1
FDNS	09NR_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.47274	104.2518	WAPA-OG-2
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41519	102.9665	BASE CASE
FDNS	09NR_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.45833	102.6431	ALBION - GENOA 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.52878	102.6046	NELIGH - PETERSBRG.N7115.00 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41519	102.4528	NUCOR-1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.42198	101.9473	GAVINS POINT - HARTINGTON 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.42805	101.9031	GAVINS POINT - YANKON JCT 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41519	101.7099	NUCOR-2
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.4158	101.3087	FT RANDAL - MEADOWGROVE4230.00 230KV CKT 1

SOLUTION	GROUP	SCENARIO	SEASON	SOURCE	DIRECTION	MONITORED ELEMENT	RATEA (MVA)	RATEB(MVA)	TDF	TC%LOADING (% MVA)	CONTINGENCY
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41492	101.2686	LAKEFIELD 3 - RAUN 345KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.42554	101.2260	ATKINSON - STUART 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.42554	101.1433	AINSWORTH - STUART 115KV CKT 1
FDNS	09NR_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.45833	101.0880	COLUMBUS - GENOA 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.42198	101.0764	NEB02WAPAB2
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41761	100.8565	BROKEN BOW - LOUP CITY 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41587	100.8272	RAUN - SIOUX CITY 345KV CKT 1
FDNS	09NR_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.45884	100.8240	WAPA-OG-1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.4156	100.6833	KELLY - MEADOWGROVE4230.00 230KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41519	100.6084	GEN659118 1-LARAMIE RIVER UNIT1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.40675	100.5929	NORFOLK - NORTH NORFOLK 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41235	100.4193	SIOUX CITY - TWIN CHURCH 230KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.40669	100.3957	HOSKINS - RAUN 345KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41519	100.3721	GEN640026 1-AINSWORTH WIND
FDNS	09NR_G15_008	0	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.51083	100.2486	BLOOMFIELD - CREIGHTON 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.45074	100.1675	LN-WAPA6
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.45074	100.1675	NEB001NPPB2
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.45074	100.1113	ONEILL - SPENCER 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.33801	185.9551	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.33801	185.8835	LN-1163-2
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.33801	185.6920	BATTLE CREEK - COUNTY LINE 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.33801	183.3911	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.33794	173.0668	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.33794	172.9549	LN-1163-2
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.33794	172.8830	BATTLE CREEK - COUNTY LINE 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.33794	167.8222	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1
FDNS	09NR_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.33347	154.0333	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09NR_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.33347	153.9461	LN-1163-2
FDNS	09NR_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.33347	153.8147	BATTLE CREEK - COUNTY LINE 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.24457	153.3562	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.24457	153.1770	ALBION - PETERSBURG 115KV CKT 1
FDNS	09NR_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.33347	151.7380	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.24458	142.9533	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.24458	142.5848	ALBION - PETERSBURG 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.21464	137.8740	ALBION - GENOA 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.21673	137.7881	WAPA-OG-2
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.21448	136.8739	WAPA-OG-1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.21464	136.7501	COLUMBUS - GENOA 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.23528	136.3079	CLEARWATER - NELIGH 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.23528	136.2736	LN-1164
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.23528	135.9037	CLEARWATER - ONEILL 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.21542	132.6589	ONEILL - SPENCER 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.21542	132.5911	LN-WAPA6
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.21542	132.5911	NEB001NPPB2
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.21542	132.2855	FT RANDAL - SPENCER 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.24457	130.7948	NELIGH - PETERSBRG.N7115.00 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.20636	130.3828	HOSKINS - NORTH NORFOLK 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.2146	127.9864	ALBION - GENOA 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.23529	127.4953	CLEARWATER - NELIGH 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.23529	127.4384	LN-1164
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.23529	127.0286	CLEARWATER - ONEILL 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.19437	126.9375	BASE CASE
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.21444	125.8235	WAPA-OG-1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.2146	125.7817	COLUMBUS - GENOA 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.21668	125.7650	WAPA-OG-2
FDNS	09NR_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.24279	125.7536	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1
FDNS	09NR_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.24279	125.5845	ALBION - PETERSBURG 115KV CKT 1
FDNS	09ALL_G15_008	0	15SP	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.33784	123.3786	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09ALL_G15_008	0	15SP	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.33784	123.0397	LN-1163-2
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.24458	122.5848	NELIGH - PETERSBRG.N7115.00 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.21539	121.9871	ONEILL - SPENCER 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.21539	121.8225	LN-WAPA6
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.21539	121.8225	NEB001NPPB2
FDNS	09ALL_G15_008	0	15SP	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.33784	121.4287	BATTLE CREEK - COUNTY LINE 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.21539	121.0131	FT RANDAL - SPENCER 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.20634	120.9575	HOSKINS - NORTH NORFOLK 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.19436	118.3155	BASE CASE
FDNS	09NR_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.21118	114.0198	ALBION - GENOA 115KV CKT 1
FDNS	09NR_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.21319	113.6031	WAPA-OG-2
FDNS	09NR_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.21101	113.1836	WAPA-OG-1
FDNS	09NR_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.21118	113.0467	COLUMBUS - GENOA 115KV CKT 1
FDNS	09NR_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.2325	112.9947	CLEARWATER - NELIGH 115KV CKT 1
FDNS	09NR_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.2325	112.9439	LN-1164
FDNS	09NR_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.2325	112.6321	CLEARWATER - ONEILL 115KV CKT 1
FDNS	09ALL_G15_008	0	15SP	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.33784	112.1625	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1

SOLUTION	GROUP	SCENARIO	SEASON	SOURCE	DIRECTION	MONITORED ELEMENT	RATEA (MVA)	RATEB(MVA)	TDF	TC%LOADING (% MVA)	CONTINGENCY
FDNS	09NR_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.21146	109.7025	ONEILL - SPENCER 115KV CKT 1
FDNS	09NR_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.21146	109.6422	LN-WAPA6
FDNS	09NR_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.21146	109.6422	NEB001NPPB2
FDNS	09NR_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.19108	109.5734	FT RANDAL - UTICA JCT 230KV CKT 1
FDNS	09NR_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.24279	109.3717	NELIGH - PETERSBRG.N7115.00 115KV CKT 1
FDNS	09NR_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.21146	109.3368	FT RANDAL - SPENCER 115KV CKT 1
FDNS	09NR_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.19214	109.0823	DIXONCO 230.00 - TWIN CHURCH 230KV CKT 1
FDNS	09NR_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.19127	108.4692	GEN652575 1-GAVINS POINT
FDNS	09NR_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.19127	108.4692	GEN652576 2-GAVINS POINT
FDNS	09NR_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.1879	108.3532	FT RANDAL - WHITE SWAN 115KV CKT 1
FDNS	09NR_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.19065	108.1577	RAUN - SIOUX CITY 345KV CKT 1
FDNS	09NR_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.20303	108.1386	HOSKINS - NORTH NORFOLK 115KV CKT 1
FDNSLock	09NR_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.19127	108.0485	GEN659103 1-ANTELOPE VALLEY UNIT1
FDNSLock	09NR_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.19127	108.0485	GEN659107 2-ANTELOPE VALLEY UNIT2
FDNS	09NR_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.1879	108.0370	TYNDALL - WHITE SWAN 115KV CKT 1
FDNS	09NR_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.19127	107.8116	GEN659111 2-LELAND OLDS UNIT2
FDNS	09ALL_G15_008	0	15SP	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.24453	106.6866	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1
FDNS	09ALL_G15_008	0	15SP	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.24453	105.6131	ALBION - PETERSBURG 115KV CKT 1
FDNS	09NR_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.19127	105.3157	BASE CASE
FDNS	09NR_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.1803	102.5029	DAK02WAPAB2
FDNS	09NR_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.18028	102.3447	UTICA JCT (UJ KV3A) 230/115/13.2KV TRANSFORMER CKT 1
FDNS	09NR_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.19127	102.2323	GEN645062 W-TPWPBG1W 0.6900
FDNS	09NR_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.19003	102.1924	GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1
FDNS	09NR_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.19003	102.1917	GRPRAR1-LNX3345.00 - YANKTON 345KV CKT Z
FDNS	09NR_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.19003	102.1850	GRPRAR1-LNX3345.00 - HOLT.CO3 345.00 345KV CKT 1
FDNS	09NR_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.18576	100.8011	BERSFORD - MANNING 115KV CKT 1
FDNS	09NR_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.19063	100.5605	KELLY - MEADOWGROVE4230.00 230KV CKT 1
FDNS	09NR_G15_008	0	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.18233	99.6000	BELDEN - HARTINGTON 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	TO->FROM	COLUMBUS - GENOA 115KV CKT 1	137	137	0.25168	100.2041	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	TO->FROM	COLUMBUS - GENOA 115KV CKT 1	137	137	0.25168	100.1600	LN-1163-2
FDNS	09ALL_G15_008	0	15G	G15_008	TO->FROM	COLUMBUS - GENOA 115KV CKT 1	137	137	0.25168	100.0000	BATTLE CREEK - COUNTY LINE 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	TO->FROM	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1	240	240	0.5166	120.1472	BLOOMFIELD - GAVINS POINT 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	TO->FROM	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1	240	240	0.52893	116.7683	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1
FDNS	09ALL_G15_008	0	15G	G15_008	TO->FROM	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1	240	240	0.52893	116.5701	ALBION - PETERSBURG 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	TO->FROM	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1	240	240	0.51641	116.0126	BLOOMFIELD - GAVINS POINT 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	TO->FROM	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1	240	240	0.52878	114.9115	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1
FDNS	09ALL_G15_008	0	15WP	G15_008	TO->FROM	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1	240	240	0.52878	114.4996	ALBION - PETERSBURG 115KV CKT 1
FDNS	09NR_G15_008	0	15G	G15_008	TO->FROM	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1	240	240	0.51083	102.8029	BLOOMFIELD - GAVINS POINT 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	TO->FROM	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1	240	240	0.47822	101.4951	WAPA-OG-2
FDNS	09ALL_G15_008	0	15SP	G15_008	TO->FROM	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1	240	240	0.5288	100.5169	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1
FDNS	09ALL_G15_008	0	15G	G15_008	TO->FROM	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1	240	240	0.5166	100.0599	CREIGHTON - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09NR_G15_008	0	15G	G15_008	TO->FROM	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1	240	240	0.52782	99.9000	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1
FDNS	09NR_G15_008	0	15G	G15_008	TO->FROM	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1	240	240	0.52782	99.7000	ALBION - PETERSBURG 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	TO->FROM	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1	240	240	0.46331	99.7000	ALBION - GENOA 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	TO->FROM	NORFOLK - NORTH NORFOLK 115KV CKT 1	120	120	0.38229	134.8461	HOSKINS - NORTH NORFOLK 115KV CKT 1
FDNS	09NR_G15_008	0	15G	G15_008	TO->FROM	NORFOLK - NORTH NORFOLK 115KV CKT 1	120	120	0.37875	113.5987	HOSKINS - NORTH NORFOLK 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	TO->FROM	NORFOLK - NORTH NORFOLK 115KV CKT 1	120	120	0.38212	113.4522	HOSKINS - NORTH NORFOLK 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.37877	154.4047	LN-1163-2
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.37877	154.3809	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.37877	154.1288	BATTLE CREEK - COUNTY LINE 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.37878	153.7224	LN-1163-2
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.37878	153.6304	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.37878	153.4739	BATTLE CREEK - COUNTY LINE 115KV CKT 1
FDNS	09ALL_G15_008	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.37888	152.2486	LN-1163-2
FDNS	09ALL_G15_008	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.37888	152.2050	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.37877	151.9017	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1
FDNS	09ALL_G15_008	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.37888	150.4641	BATTLE CREEK - COUNTY LINE 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.37878	148.9517	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1
FDNS	09ALL_G15_008	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.37888	141.6919	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1
FDNS	09NR_G15_008	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.38311	130.8419	LN-1163-2
FDNS	09NR_G15_008	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.38311	130.7598	COUNTY LINE - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09NR_G15_008	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.38311	130.6191	BATTLE CREEK - COUNTY LINE 115KV CKT 1
FDNS	09NR_G15_008	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.38311	128.7145	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1
FDNS	09ALL_G15_008	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.27103	127.3914	BLOOMFIELD - GAVINS POINT 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.27094	126.6140	BLOOMFIELD - GAVINS POINT 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.27085	126.1592	BLOOMFIELD - GAVINS POINT 115KV CKT 1
FDNS	09ALL_G15_008	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.27464	120.7284	LN-1164
FDNS	09ALL_G15_008	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.27464	120.6399	CLEARWATER - NELIGH 115KV CKT 1
FDNS	09ALL_G15_008	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.27103	119.5173	CREIGHTON - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09ALL_G15_008	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22291	119.0202	KELLY - MEADOWGROVE4230.00 230KV CKT 1
FDNS	09ALL_G15_008	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22344	118.3615	GRPRAR1-LNX3345.00 - HOLT.CO3 345.00 345KV CKT 1
FDNS	09ALL_G15_008	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22344	118.3600	GRPRAR1-LNX3345.00 - YANKTON 345KV CKT Z
FDNS	09ALL_G15_008	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22344	118.3325	GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1
FDNS	09ALL_G15_008	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.27464	118.1693	CLEARWATER - ONEILL 115KV CKT 1
FDNS	09ALL_G15_008	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.2163	117.6812	BROKEN BOW - LOUP CITY 115KV CKT 1

SOLUTION	GROUP	SCENARIO	SEASON	SOURCE	DIRECTION	MONITORED ELEMENT	RATEA (MVA)	RATEB(MVA)	TDF	TC%LOADING (% MVA)	CONTINGENCY
FDNS	09ALL_G15_008	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22222	114.6842	GEN640010 1-GERALD GENTLEMAN STATION UNIT 1
FDNS	09ALL_G15_008	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22222	114.6101	GEN640011 2-GERALD GENTLEMAN STATION UNIT 2
FDNS	09ALL_G15_008	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.23099	114.2868	GAVINS POINT - YANKON JCT 115KV CKT 1
FDNS	09ALL_G15_008	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22222	114.1105	GEN640428 1-BRKNBW.GEN1W0.6900
FDNS	09ALL_G15_008	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.2241	114.0323	NEB02WAPAB2
FDNS	09ALL_G15_008	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22222	113.9103	GEN640449 W-BRKNBW.GEN2W0.6900
FDNS	09ALL_G15_008	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.2241	113.3739	GAVINS POINT - HARTINGTON 115KV CKT 1
FDNS	09ALL_G15_008	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22406	113.2375	GAVINS POINT - SPIRIT MOUND 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.27094	112.9440	CREIGHTON - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.27452	112.4864	LN-1164
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.27452	112.4699	CLEARWATER - NELIGH 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.27452	111.9452	CLEARWATER - ONEILL 115KV CKT 1
FDNS	09ALL_G15_008	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22222	111.0808	NUCOR-1
FDNS	09ALL_G15_008	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22222	111.0622	BASE CASE
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.27085	110.6767	CREIGHTON - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.21621	110.3062	BROKEN BOW - LOUP CITY 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.2744	110.1786	LN-1164
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.2744	110.1673	CLEARWATER - NELIGH 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.2744	109.7550	CLEARWATER - ONEILL 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22279	109.2289	KELLY - MEADOWGROVE4230.00 230KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.27094	108.7002	BLOOMFIELD - CREIGHTON 115KV CKT 1
FDNS	09ALL_G15_008	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22222	108.4726	GEN659111 2-LELAND OLDS UNIT2
FDNS	09ALL_G15_008	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.21105	108.3421	NELIGH - NELIGH.EAST7115.00 115KV CKT 1
FDNS	09ALL_G15_008	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22222	108.2313	GEN659103 1-ANTELOPE VALLEY UNIT1
FDNS	09ALL_G15_008	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22222	108.2313	GEN659107 2-ANTELOPE VALLEY UNIT2
FDNS	09ALL_G15_008	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22222	108.2248	GEN640421 1-CROFTON HILLS WIND
FDNS	09ALL_G15_008	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22222	107.9204	SPALDING 115KV SWITCHED SHUNT
FDNSLock	09ALL_G15_008	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22222	107.8717	SPALDING 115KV SWITCHED SHUNT
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.27085	107.6933	BLOOMFIELD - CREIGHTON 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.23088	107.3755	GAVINS POINT - YANKON JCT 115KV CKT 1
FDNS	09ALL_G15_008	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.2459	107.2029	LN-WAPA6
FDNS	09ALL_G15_008	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.2459	107.2029	NEB001NPPB2
FDNS	09ALL_G15_008	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22222	107.1602	ALBION 115KV SWITCHED SHUNT
FDNS	09ALL_G15_008	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.20625	107.1544	NELIGH - NELIGH.EAST7115.00 115KV CKT 2
FDNS	09ALL_G15_008	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.2459	107.1390	ONEILL - SPENCER 115KV CKT 1
FDNSLock	09ALL_G15_008	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22222	107.1382	ALBION 115KV SWITCHED SHUNT
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22329	106.9684	GRPRAR1-LNX3345.00 - HOLT.CO3 345.00 345KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22329	106.9646	GRPRAR1-LNX3345.00 - YANKTON 345KV CKT Z
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22329	106.9384	GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1
FDNS	09NR_G15_008	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.27598	106.6410	BLOOMFIELD - GAVINS POINT 115KV CKT 1
FDNS	09ALL_G15_008	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.2459	106.3131	FT RANDAL - SPENCER 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22271	106.2846	KELLY - MEADOWGROVE4230.00 230KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.21621	106.0779	BROKEN BOW - LOUP CITY 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.24581	105.9082	LN-WAPA6
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.24581	105.9082	NEB001NPPB2
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.24581	105.8254	ONEILL - SPENCER 115KV CKT 1
FDNS	09ALL_G15_008	0	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22222	105.5779	GEN640418 1-ELKHORN RIDGE WIND
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.24574	105.3594	LN-WAPA6
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.24574	105.3594	NEB001NPPB2
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.2221	105.3336	GEN640010 1-GERALD GENTLEMAN STATION UNIT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.24574	105.3263	ONEILL - SPENCER 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.2221	105.2325	GEN640428 1-BRKNBW.GEN1W0.6900
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.2221	105.0317	GEN640449 W-BRKNBW.GEN2W0.6900
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22321	105.0012	GRPRAR1-LNX3345.00 - HOLT.CO3 345.00 345KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22321	104.9952	GRPRAR1-LNX3345.00 - YANKTON 345KV CKT Z
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.24574	104.9660	FT RANDAL - SPENCER 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22321	104.9606	GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.228	104.9483	UTICA - YANKON JCT 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22398	104.9321	NEB02WAPAB2
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.2221	104.8821	GEN640011 2-GERALD GENTLEMAN STATION UNIT 2
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22395	104.8779	GAVINS POINT - SPIRIT MOUND 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.24581	104.8419	FT RANDAL - SPENCER 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.23366	104.3852	HOSKINS - NORTH NORFOLK 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22398	104.3616	GAVINS POINT - HARTINGTON 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.23078	104.0418	GAVINS POINT - YANKON JCT 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22791	102.6245	UTICA - YANKON JCT 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22201	102.6000	GEN640428 1-BRKNBW.GEN1W0.6900
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.23358	102.4800	HOSKINS - NORTH NORFOLK 115KV CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22201	102.4019	GEN640449 W-BRKNBW.GEN2W0.6900
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22386	102.2500	GAVINS POINT - SPIRIT MOUND 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.2221	102.1318	BASE CASE
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.2221	102.0570	NUCOR-1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.2239	101.8228	NEB02WAPAB2
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22566	101.7677	DAK02WAPAB2
FDNS	09ALL_G15_008	0	20SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22547	100.1571	NELIGH.EAST3345.00 (NELIGH.E T1) 345/115/13.8KV TRANSFORMER CKT 1

SOLUTION	GROUP	SCENARIO	SEASON	SOURCE	DIRECTION	MONITORED ELEMENT	RATEA (MVA)	RATEB(MVA)	TDF	TC%LOADING (% MVA)	CONTINGENCY
FDNS	09ALL_G15_008	0	20SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22547	100.1232	HOSKINS - NELIGH.EAST3345.00 345KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.20614	100.0000	NELIGH - NELIGH.EAST7115.00 115KV CKT 2
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22048	99.9000	BROKEN BOW - CROOKED CREEK 115KV CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22048	99.9000	CROOKED CREEK (CR.CREEK T1) 230/115/13.8KV TRANSFORMER CKT 1
FDNS	09ALL_G15_008	0	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.2221	99.8000	GEN635214 4-NEAL UNIT 4
FDNS	09ALL_G15_008	0	25SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22553	99.6000	NELIGH.EAST3345.00 (NELIGH.E T1) 345/115/13.8KV TRANSFORMER CKT 1
FDNS	09ALL_G15_008	0	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22201	99.5000	BASE CASE
FDNS	09ALL_G15_008	0	25SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22553	99.5000	HOSKINS - NELIGH.EAST3345.00 345KV CKT 1
FDNS	09ALL_G15_008	2	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22222	107.5527	NELIGH.EAST3345.00 (NELIGH.E T1) 345/115/13.8KV TRANSFORMER CKT 1
FDNS	09ALL_G15_008	2	15SP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.22222	107.5049	HOSKINS - NELIGH.EAST3345.00 345KV CKT 1
FDNS	09ALL_G15_008	2	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.2221	100.9347	NELIGH.EAST3345.00 (NELIGH.E T1) 345/115/13.8KV TRANSFORMER CKT 1
FDNS	09ALL_G15_008	2	15WP	G15_008	TO->FROM	ALBION - PETERSBURG 115KV CKT 1	137	137	0.2221	100.9254	HOSKINS - NELIGH.EAST3345.00 345KV CKT 1
FDNS	09ALL_G15_008	2	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41519	102.8856	NELIGH.EAST3345.00 (NELIGH.E T1) 345/115/13.8KV TRANSFORMER CKT 1
FDNS	09ALL_G15_008	2	15G	G15_008	FROM->TO	BATTLE CREEK - NORTH NORFOLK 115KV CKT 1	193	193	0.41519	102.8463	HOSKINS - NELIGH.EAST3345.00 345KV CKT 1
FDNS	09NR_G15_008	2	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.19127	105.3588	HOSKINS - NELIGH.EAST3345.00 345KV CKT 1
FDNS	09NR_G15_008	2	15G	G15_008	FROM->TO	BLOOMFIELD - GAVINS POINT 115KV CKT 1	120	120	0.19127	105.3270	NELIGH.EAST3345.00 (NELIGH.E T1) 345/115/13.8KV TRANSFORMER CKT 1
FDNS	09ALL_G15_008	2	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22222	111.1394	NELIGH.EAST3345.00 (NELIGH.E T1) 345/115/13.8KV TRANSFORMER CKT 1
FDNS	09ALL_G15_008	2	15SP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22222	111.1009	HOSKINS - NELIGH.EAST3345.00 345KV CKT 1
FDNS	09ALL_G15_008	2	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.2221	102.2139	NELIGH.EAST3345.00 (NELIGH.E T1) 345/115/13.8KV TRANSFORMER CKT 1
FDNS	09ALL_G15_008	2	15WP	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.2221	102.2067	HOSKINS - NELIGH.EAST3345.00 345KV CKT 1
FDNS	09ALL_G15_008	2	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22201	99.6000	HOSKINS - NELIGH.EAST3345.00 345KV CKT 1
FDNS	09ALL_G15_008	2	15G	G15_008	FROM->TO	PETERSBRG.N7115.00 - PETERSBURG 115KV CKT Z1	137	137	0.22201	99.6000	NELIGH.EAST3345.00 (NELIGH.E T1) 345/115/13.8KV TRANSFORMER CKT 1
FDNS	00NR_G15_015	0	20WP	G15_015	FROM->TO	CLEARWATER - GILL ENERGY CENTER WEST 138KV CKT 1	143	143	0.02978	103.5213	GILL ENERGY CENTER SOUTH - VIOLA 4 138.00 138KV CKT 1
FDNS	04NR_G15_017	0	15G	G15_017_G	FROM->TO	ARNOLD - RANSOM 115KV CKT 1	79.7	79.7	0.28279	103.8764	MINGO (MINGO) 345/115/13.8KV TRANSFORMER CKT 1
FDNS	00_G15_017	0	15SP	G15_017_SP	FROM->TO	ARNOLD - RANSOM 115KV CKT 1	79.7	79.7	0.27835	102.9439	MINGO (MINGO) 345/115/13.8KV TRANSFORMER CKT 1
FDNS	00_G15_017	0	20SP	G15_017_SP	FROM->TO	ARNOLD - RANSOM 115KV CKT 1	79.7	79.7	0.27796	102.5233	MINGO (MINGO) 345/115/13.8KV TRANSFORMER CKT 1
FDNS	00_G15_017	0	15WP	G15_017_WP	FROM->TO	ARNOLD - RANSOM 115KV CKT 1	79.7	79.7	0.27824	125.2399	MINGO (MINGO) 345/115/13.8KV TRANSFORMER CKT 1
FDNS	00_G15_017	0	20WP	G15_017_WP	FROM->TO	ARNOLD - RANSOM 115KV CKT 1	79.7	79.7	0.27791	121.7379	MINGO (MINGO) 345/115/13.8KV TRANSFORMER CKT 1
FDNS	00_G15_017	0	15WP	G15_017_WP	FROM->TO	ARNOLD - RANSOM 115KV CKT 1	79.7	79.7	0.06853	100.8358	BASE CASE
FDNS	03ALL_G15_021	0	20SP	G15_021	FROM->TO	PILE - SCOTT CITY 115KV CKT 1	195.4	195.4	0.35929	99.7000	HOLCOMB (HOLCOMB) 345/115/13.8KV TRANSFORMER CKT 1
FDNSLock-Blown up	09ALL_G15_023	0	15SP	G15_023		GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1	720	720	0.67701	76.2030	BASE CASE
FDNSLock-Blown up	09ALL_G15_023	0	15G	G15_023		GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1	720	720	0.67611	61.9200	BASE CASE
FDNSLock-Blown up	09ALL_G15_023	0	15WP	G15_023		GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1	720	720	0.67609	57.8345	BASE CASE
FDNS	09ALL_G15_023	0	15G	G15_023	TO->FROM	GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1	720	720	1	104.7511	FTTHOM2-LNX3345.00 - GRPRAR2-LNX3345.00 345KV CKT 1
FDNS	09ALL_G15_023	0	15WP	G15_023	TO->FROM	GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1	720	720	1	102.2539	FTTHOM2-LNX3345.00 - GRPRAR2-LNX3345.00 345KV CKT 1
FDNS	09ALL_G15_023	0	15SP	G15_023	TO->FROM	GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1	720	720	1	102.2227	FTTHOM2-LNX3345.00 - GRPRAR2-LNX3345.00 345KV CKT 1
FDNS	09ALL_G15_023	0	15G	G15_023	TO->FROM	GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1	720	720	1	101.4100	FT THOMPSON - FTTHOM2-LNX3345.00 345KV CKT Z
FDNS	09ALL_G15_023	0	15SP	G15_023	TO->FROM	GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1	720	720	1	100.7893	FT THOMPSON - FTTHOM2-LNX3345.00 345KV CKT Z
FDNS	09ALL_G15_023	0	15WP	G15_023	TO->FROM	GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1	720	720	1	100.6396	FT THOMPSON - FTTHOM2-LNX3345.00 345KV CKT Z
FDNS	09ALL_G15_023	0	15G	G15_023	TO->FROM	GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1	720	720	1	100.4577	GRPRAR2-LNX3345.00 - YANKTON 345KV CKT Z
FDNS	09ALL_G15_023	0	15SP	G15_023	TO->FROM	GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1	720	720	1	99.8000	GRPRAR2-LNX3345.00 - YANKTON 345KV CKT Z
FDNS	09ALL_G15_023	0	15WP	G15_023	TO->FROM	GRAND ISLAND - HOLT.CO3 345.00 345KV CKT 1	720	720	1	99.8000	GRPRAR2-LNX3345.00 - YANKTON 345KV CKT Z
FDNS	03ALL_G15_026	0	15WP	G15_026	FROM->TO	BUCKNER7 345.00 - HOLCOMB 345KV CKT 1	726.6	726.6	0.43946	100.9471	G13-010T 345.00 - POST ROCK 345KV CKT 1
FDNS	03ALL_G15_026	0	25SP	G15_026	FROM->TO	BUCKNER7 345.00 - HOLCOMB 345KV CKT 1	726.6	726.6	0.4447	99.6000	G13-010T 345.00 - POST ROCK 345KV CKT 1
FDNS	03ALL_G15_026	2	15WP	G15_026	FROM->TO	BUCKNER7 345.00 - HOLCOMB 345KV CKT 1	726.6	726.6	0.439	103.2758	G13-010T 345.00 - POST ROCK 345KV CKT 1
FDNS	03ALL_G15_026	3	15WP	G15_026	FROM->TO	BUCKNER7 345.00 - HOLCOMB 345KV CKT 1	726.6	726.6	0.43898	103.5354	G13-010T 345.00 - POST ROCK 345KV CKT 1
FDNS	03ALL_G15_027	0	15SP	G15_027	TO->FROM	CIMARRON RIVER TAP - KISMET 3 115.00 115KV CKT 1	133.9	133.9	0.29351	101.2377	BUCKNER7 345.00 - HOLCOMB 345KV CKT 1
FDNS	03ALL_G15_027	0	15WP	G15_027	FROM->TO	CRKCK 3 115.00 - CUDAHY 115KV CKT 1	119.5	148.2	0.29291	116.1348	BUCKNER7 345.00 - HOLCOMB 345KV CKT 1
FDNS	03ALL_G15_027	0	25SP	G15_027	FROM->TO	CRKCK 3 115.00 - CUDAHY 115KV CKT 1	119.5	148.2	0.29907	106.9612	BUCKNER7 345.00 - HOLCOMB 345KV CKT 1
FDNS	03ALL_G15_027	0	15G	G15_027	FROM->TO	CRKCK 3 115.00 - CUDAHY 115KV CKT 1	119.5	148.2	0.29302	103.7400	BUCKNER7 345.00 - HOLCOMB 345KV CKT 1
FDNS	03ALL_G15_027	0	20WP	G15_027	FROM->TO	CRKCK 3 115.00 - CUDAHY 115KV CKT 1	119.5	148.2	0.29817	103.1630	BUCKNER7 345.00 - HOLCOMB 345KV CKT 1
FDNS	03ALL_G15_027	0	15WP	G15_027	FROM->TO	CRKCK 3 115.00 - CUDAHY 115KV CKT 1	119.5	148.2	0.29085	101.9051	BASE CASE
FDNS	03ALL_G15_027	0	15WP	G15_027	FROM->TO	CUDAHY - KISMET 3 115.00 115KV CKT 1	119.5	148.2	0.29291	111.2472	BUCKNER7 345.00 - HOLCOMB 345KV CKT 1
FDNS	03ALL_G15_027	0	25SP	G15_027	FROM->TO	CUDAHY - KISMET 3 115.00 115KV CKT 1	119.5	135.8	0.29907	109.6682	BUCKNER7 345.00 - HOLCOMB 345KV CKT 1
FDNS	03ALL_G15_027	0	15SP	G15_027	FROM->TO	CUDAHY - KISMET 3 115.00 115KV CKT 1	119.5	135.8	0.29351	101.6053	BUCKNER7 345.00 - HOLCOMB 345KV CKT 1
FDNS	03ALL_G15_027	0	25SP	G15_027	TO->FROM	GREENSBURG - SSTARTP3 115.00 115KV CKT 1	115.1	115.1	0.09647	120.9227	BASE CASE
FDNS	03ALL_G15_027	0	20SP	G15_027	TO->FROM	GREENSBURG - SSTARTP3 115.00 115KV CKT 1	115.1	115.1	0.09641	118.4084	BASE CASE
FDNS	03ALL_G15_027	0	20WP	G15_027	TO->FROM	GREENSBURG - SSTARTP3 115.00 115KV CKT 1	119.5	148.2	0.09588	115.7845	BASE CASE
FDNS	03ALL_G15_027	0	15SP	G15_027	TO->FROM	GREENSBURG - SSTARTP3 115.00 115KV CKT 1	115.1	115.1	0.09702	113.9602	BASE CASE
FDNS	03ALL_G15_027	0	15WP	G15_027	TO->FROM	GREENSBURG - SSTARTP3 115.00 115KV CKT 1	119.5	148.2	0.09648	108.5667	BASE CASE
FDNS	03ALL_G15_027	0	15G	G15_027	TO->FROM	GREENSBURG - SSTARTP3 115.00 115KV CKT 1	119.5	134.6	0.09641	108.4852	BASE CASE
FDNS	03ALL_G15_027	2	15SP	G15_027	TO->FROM	CIMARRON RIVER TAP - KISMET 3 115.00 115KV CKT 1	133.9	133.9	0.30997	109.8176	SPP-SEPC-07
FDNS	03ALL_G15_027	2	15G	G15_027	TO->FROM	CIMARRON RIVER TAP - KISMET 3 115.00 115KV CKT 1	150.4	150.4	0.30954	103.1219	CTU SUBLETTE - HASKELL 115KV CKT 1
FDNS	03ALL_G15_027	2	15G	G15_027	TO->FROM	CIMARRON RIVER TAP - KISMET 3 115.00 115KV CKT 1	150.4	150.4	0.30954	99.9000	HASKELL - SEWARD-3 115KV CKT 1
FDNS	01ALL_G15_029	0	15G	G15_029	FROM->TO	FPL SWITCH - MOORELAND 138KV CKT 1	287	287	0.04799	108.8314	BASE CASE

H: Power Flow Analysis (Other Constraints Not Requiring Mitigation)

Available upon request. Contact SPP Generation Interconnection Studies for details.

H1: Stand Alone Power Flow Analysis (Other Constraints Not Requiring Mitigation)

Available upon request. Contact SPP Generation Interconnection Studies for details.

I: Power Flow Analysis (Constraints from Multi-Contingencies)

Available upon request. Contact SPP Generation Interconnection Studies for details.

J: Group 1 Dynamic Stability Analysis Report

See ABB study report on next page

DEFINITIVE IMPACT STUDY
DISIS-2015-001 (GROUP 01)

FINAL REPORT

July 23, 2015

SUBMITTED TO:
Southwest Power Pool
201 Worthen Drive
Little Rock, AR 72223

SUBMITTED BY:
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Technical Report

Southwest Power Pool	**No.** 2015-E15796	
Definitive Impact Study DISIS-2015-001 (Group 01)	7/23/2015	# Pages 20

Author(s):	**Reviewed by:**	**Approved by:**
Lang Chen	Shu Liu	Willie Wong

Executive Summary

Southwest Power Pool (SPP) has commissioned ABB Inc., to perform a Definitive Impact Study for DISIS-2015-001 (Group 01) which includes generation interconnection request GEN-2015-029 (161 MW wind farm connected at the Tatonga 345 kV substation).

The objective of this study is to evaluate the impact of project GEN-2015-029 on the existing and future planning system. The study is performed on three system scenarios provided by SPP:

- 2015 Summer Peak Case
- 2015 Winter Peak Case
- 2025 Summer Peak Case

Results of the stability analysis show that the studied system is stable following all simulated faults with the proposed GEN-2015-029 project in-service. There are no voltage violations in the monitored area and the local synchronous generators show good damping performance which meets the criteria specified.

System short-circuit current levels at up to five buses away from the point of interconnection were calculated and tabulated for SPP's reference.

Power Factor Analysis was performed to ensure the studied project meets FERC and SPP power factor requirements for wind farm interconnections. The results show that a 17MVAr capacitor bank is required on the wind farm's substation 34.5kV bus for 2015 summer peak case, an 18MVAr capacitor bank is required for the 2015 winter peak case, and no capacitor bank is required for 2025 summer peak case. These capacitor bank sizes are only estimates based on the information provided by the Interconnection Customer for its collector system design. Final needs will be based on final designs of the collector system determined by the Interconnection Customer to meet the power factor requirement.

The Low/No Wind analysis shows that a 13.41 MVAr shunt reactor is required to bring the MVAr flow in the POI down to approximate zero under low/no wind conditions for all three studied seasons. The reactor bank size is approximate and the final size will be determined in the final facility and collector system design.

Based on the results of stability analysis it can be concluded that **the proposed GEN-2015-029 project does not adversely impact the stability of the SPP system**.

The results of this analysis are based on available data and assumptions made at the time of conducting this study. If any of the data and/or assumptions made in developing the study model change, the results provided in this report may not apply.

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1 INTRODUCTION

Southwest Power Pool (SPP) has commissioned ABB Inc., to perform a Definitive Impact Study for DISIS-2015-001 (Group 01) which includes generation interconnection request GEN-2015-029 (161 MW wind farm connected at the Tatonga 345 kV substation) as shown in Table 1-1.

Table 1-1: Group 01 Generation Interconnection Requests

Request	Size (MW)	Generator Model	POI
GEN-2015-029	161	GE 2.3MW (70 generators)	Tatonga 345kV (515407)

The objective of this study is to evaluate the impact of project GEN-2015-029 on the existing and future planning system. The study is performed on three system scenarios provided by SPP:

- 2015 Summer Peak Case
- 2015 Winter Peak Case
- 2025 Summer Peak Case

SPP provided the study cases for all three system scenarios with GEN-2015-029 included. One line diagrams of the local area for all three seasons are shown in Figure 1-1. The studied generator is circled red.

The three system scenarios supplied by SPP included the following prior queued projects for Group1:

Table 1-2: Group 01 Prior Queued Projects

Request	Size (MW)	Generator Model	Point of Interconnection
GEN-2001-014	94.5	Suzlon 2.1MW	Fort Supply 138kV (520920)
GEN-2001-037	102	GE 1.5MW	Moorland – Woodward 138kV (515785)
GEN-2005-008	120	GE 1.5MW	Woodward 138kV (514785)
GEN-2006-024S	18.9	Suzlon 2.1MW	Buffalo Bear 69kV (521120)
GEN-2006-046	132	Mitsubishi 2.4MW	Dewey 138kV (514787)
GEN-2007-021	200	GE 1.6MW	Tatonga 345kV (515407)
GEN-2007-043	200	GE 1.6	Minco 345kV (514801)
GEN-2007-044	299.2	GE 1.6MW	Tatonga 345kV (515407)
GEN-2007-050	170.2	Siemens 2.3MW	Woodward 138kV (515376)
GEN-2007-062	765	GE 1.5MW	Woodward 345kV (515375)
GEN-2008-003	101.2	Siemens 2.3MW	Woodward 138kV (515376)
GEN-2008-044	197.8	Siemens SWT 2.3MW	Tatonga 345kV (515407)
GEN-2010-011	29.7	Siemens SWT 2.3MW	Tatonga 345kV (515407) (Addition to Gen-2008-044 34.5kV bus (515450)

Request	Size (MW)	Generator Model	Point of Interconnection
GEN-2010-040	298.5	RePower 2.05MW	Cimarron 345kV (514901)
GEN-2011-010	100.8	GE 1.6MW	Minco 345kV (514801)
GEN-2011-019	299	Siemens 2.3MW	Woodward 345kV (515375)
GEN-2011-020	299	Siemens 2.3MW	Woodward 345kV (515375)
GEN-2011-051	104.4	Vestas V90 1.8MW	Tap on the Woodward - Tatonga 345kV line (G11_051-TAP, 562075)
GEN-2011-054	298	Vestas V100 2.0MW	Cimarron 345kV (514901)
GEN-2014-002	10.53 increase (Pmax=209.4)	GE 97.4m 1.79MW (579256)	Tatonga 345kV (515407)
GEN-2014-003	15.84 increase (Pmax=315)	GE 97.4m 1.79MW (579271,579275)	Tatonga 345kV (515407)
GEN-2014-005	5.67 increase (Pmax=106.5)	GE 97.4m 1.79MW (514113)	Minco 345kV (514801)
GEN-2014-020	100.0	Vestas V110 2.0MW	Tuttle 138kV (511501)
GEN-2014-056	250.0	GE 2.0MW	Minco 345kV (514801)

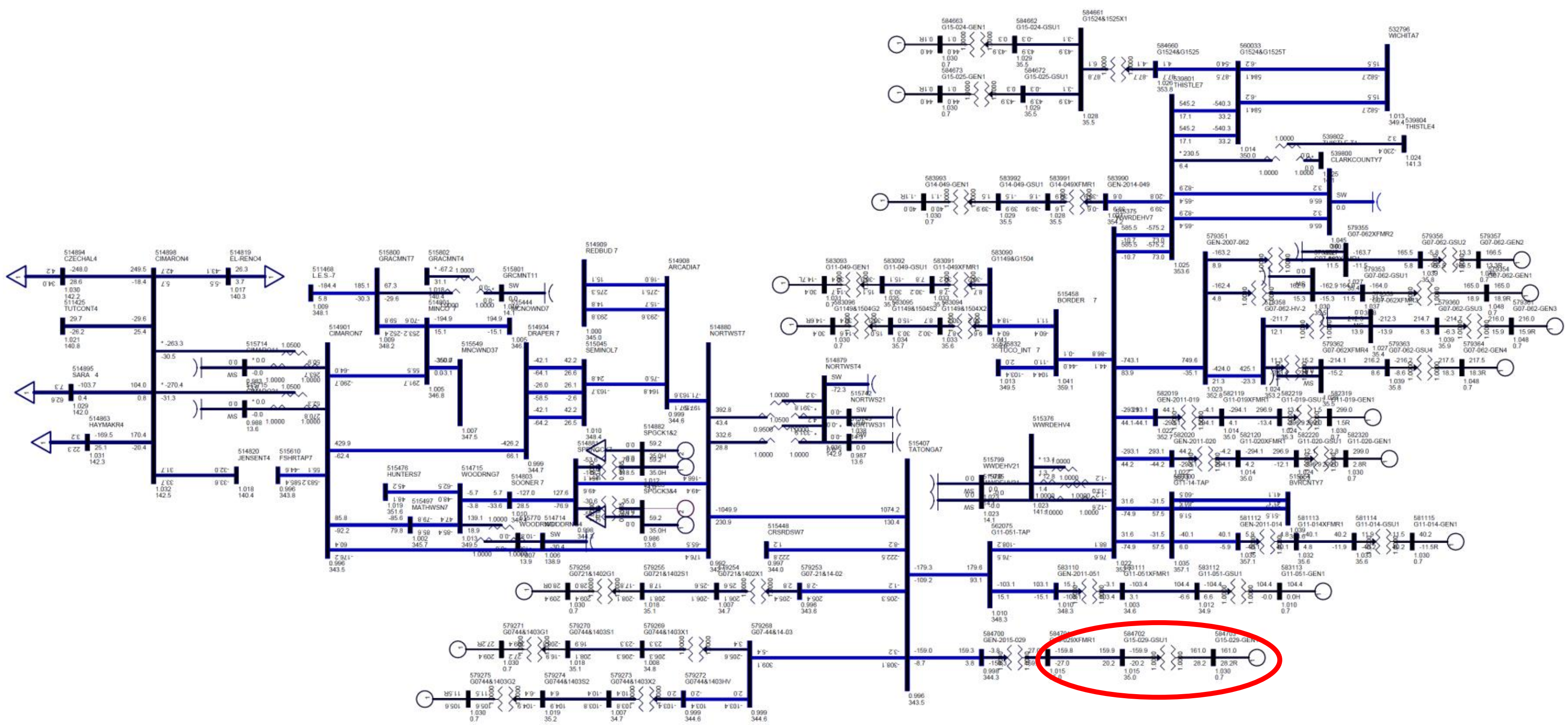


Figure 1-1 (a): One Line Diagram of Tatonga Area for 2015 Summer Peak Case

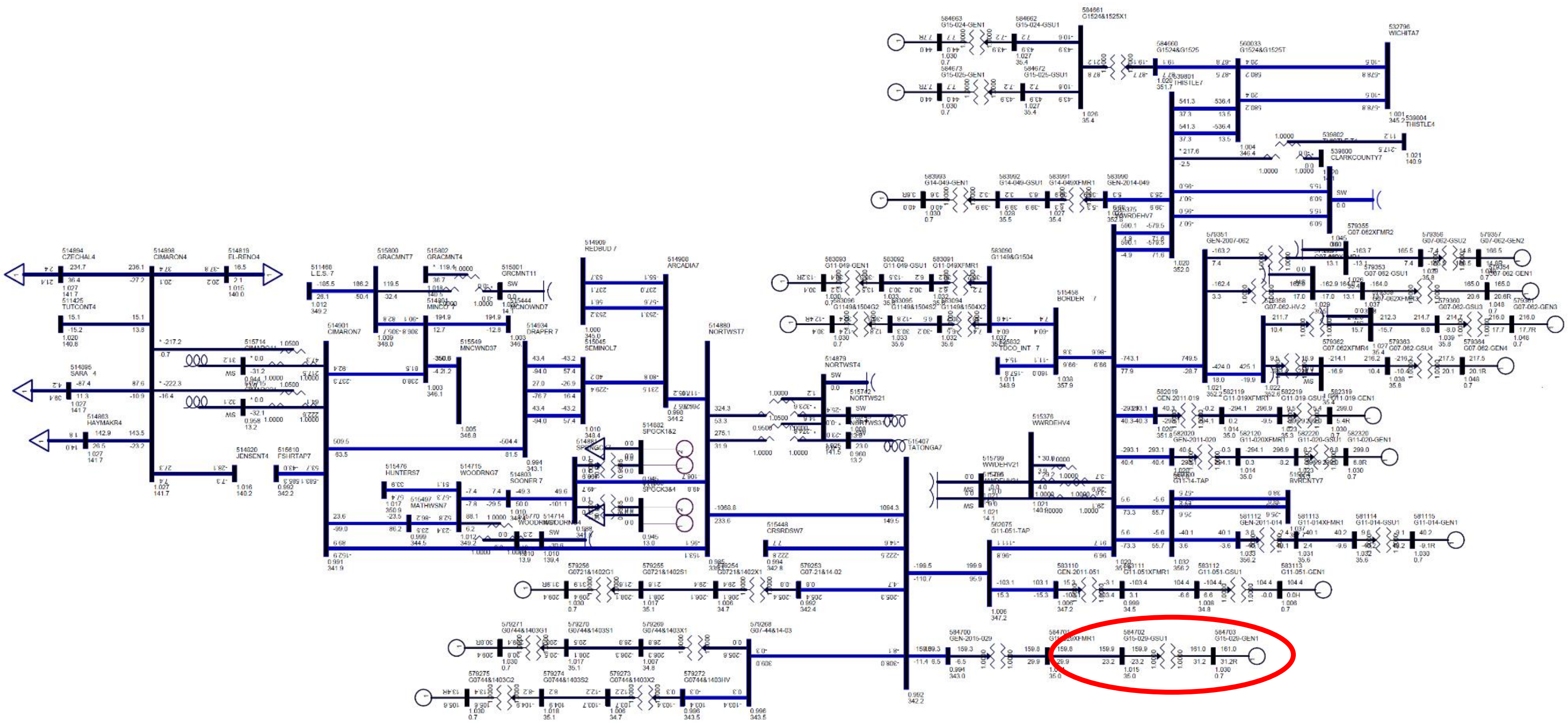


Figure 1-2 (b): One Line Diagram of Tatonga Area for 2015 Winter Peak Case

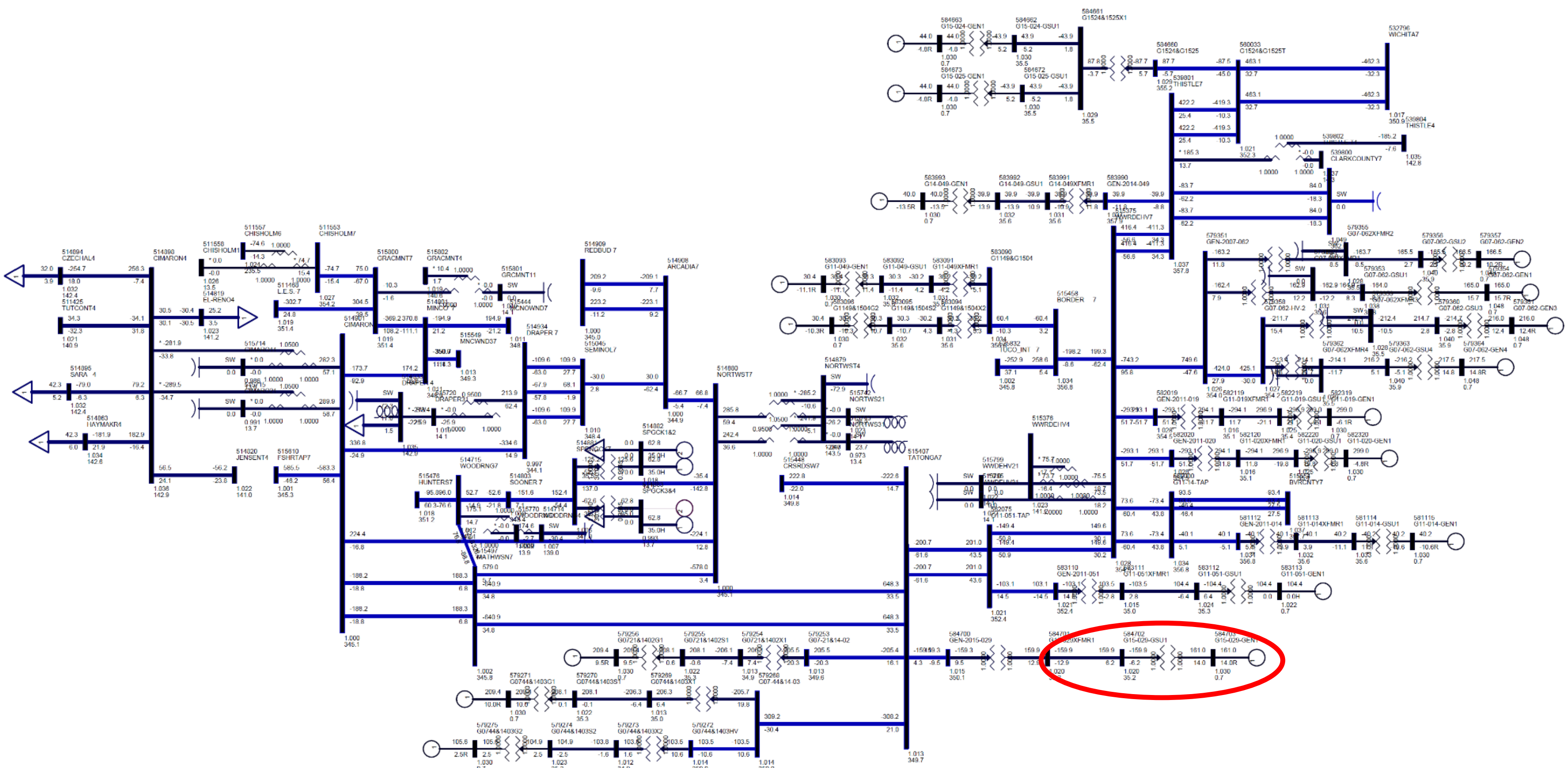


Figure 1-3 (c): One Line Diagram of Tatonga Area for 2025 Summer Peak Case

2 STABILITY ANALYSIS

In this study, ABB investigated the stability of the system for faults in the vicinity of the proposed plant as defined by SPP. The studied faults involve three-phase transformer faults with normal clearing, three-phase line faults with normal clearing and re-closing test, and single-line-to-ground (SLG) faults with stuck breaker.

2.1 STABILITY ANALYSIS METHODOLOGY

Stability analysis is performed to determine whether the electric system would meet stability criteria following the addition of the GEN-2015-029 project.

Stability analysis was performed using Siemens-PTI's PSS/E dynamics program V32.1.0.

All the faults listed in Table 2-1 were simulated for 20 seconds.

Table 2-1: List of Faults for Stability Analysis

Cont. No.	Cont. Name	Description
1	FLT01-3PH	3 phase fault on Cimarron 345kV (514901) to Minco 345kV (514801) CKT 1, near Cimarron. a. Apply fault at the Cimarron 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
2	FLT02-3PH	3 phase fault on Cimarron 345kV (514901) to Northwest 345kV (514880) CKT 1, near Cimarron. a. Apply fault at the Cimarron 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
3	FLT03-3PH	3 phase fault on Cimarron 345kV (514901) to Draper 345kV (514934) CKT 1, near Cimarron. a. Apply fault at the Cimarron 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
4	FLT04-3PH	3 phase fault on Cimarron 345kV (514901) to Mathewson 345kV (515497) CKT 1, near Mathewson. a. Apply fault at the Mathewson 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
5	FLT05-3PH 2025SP Only	3 phase fault on the on Cimarron 345kV (514901) to Mathewson 345kV (515497) CKT 1 and 2, near Cimarron. a. Apply fault at the Cimarron 345kV bus. b. Clear fault after 5 cycles and trip the faulted lines (CKT 1 and 2).
6	FLT06-3PH	3 phase fault on the Cimarron 345kV (514901) to Cimarron 138kV (514898) to Cimarron 13.8kV (515714) XFMR CKT 1, near Cimarron 345kV. a. Apply fault at the Cimarron 345kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.

Cont. No.	Cont. Name	Description
7	FLT07-3PH	3 phase fault on Minco 345kV (514801) to Gracemont 345kV (515800) CKT 1, near Minco. a. Apply fault at the Minco 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
8	FLT08-3PH	3 phase fault on Northwest 345kV (514880) to Spring Creek 345kV (514881) CKT 1, near Northwest. a. Apply fault at the Northwest 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
9	FLT09-3PH	3 phase fault on Northwest 345kV (514880) to Arcadia 345kV (514908) CKT 1, near Northwest. a. Apply fault at the Northwest 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
10	FLT10-3PH	3 phase fault on Northwest 345kV (514880) to Northwest 138kV (514879) to Northwest 13.8kV (515742) XFMR CKT 1, near Northwest 345kV. a. Apply fault at the Northwest 345kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
11	FLT11-3PH	3 phase fault on Draper 345kV (514934) to Seminole 345kV (515045) CKT 1, near Draper. a. Apply fault at the Draper 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
12	FLT12-3PH	3 phase fault on Draper 345kV (514934) to Seminole 345kV (515045) CKT 3, near Draper. a. Apply fault at the Draper 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
13	FLT13-3PH 2025SP Only	3 phase fault on the Draper 345kV (514934) to Draper 138kV (514933) to Draper 13.8kV (515720) XFMR CKT 1, near Draper 345kV. a. Apply fault at the Draper 345kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
14	FLT14-3PH	3 phase fault on Mathewson 345kV (515497) to Woodwring 345kV (514715) CKT1, near Mathewson. a. Apply fault at the Mathewson 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
15	FLT15-3PH 2025SP Only	3 phase fault on Mathewson 345kV (515497) to Northwest 345kV (514880) CKT1, near Mathewson. a. Apply fault at the Mathewson 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
16	FLT16-3PH 2025SP Only	3 phase fault on Tatonga 345kV (515407) to Mathewson 345kV (515497) CKT1 and 2, near Tatonga. a. Apply fault at the Tatonga 345kV bus. b. Clear fault after 5 cycles and trip the faulted lines (CKT1 and 2).

Cont. No.	Cont. Name	Description
17	FLT17-3PH	3 phase fault on Tatonga 345kV (515407) to G11-051 Tap 345kV (562075) CKT1, near Tatonga. a. Apply fault at the Tatonga 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
18	FLT18-3PH	3 phase fault on Gracemont 345kV (515800) to LES 345kV (511468) CKT1, near Gracemont. a. Apply fault at the Gracemont 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
19	FLT19-3PH 2025SP Only	3 phase fault on Gracemont 345kV (515800) to Chisholm 345kV (511533) CKT1, near Gracemont. a. Apply fault at the Gracemont 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
20	FLT20-3PH	3 phase fault on the Gracemont 345kV (515800) to Gracemont 138kV (515802) to Gracemont 13.8kV (515801) XFMR CKT 1, near Gracemont 345kV. a. Apply fault at the Gracemont 345kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
21	FLT21-3PH 2025SP Only	3 phase fault on the Chisholm 345kV (511553) to LES 230kV (511557) to Chisholm 13.2kV (511558) XFMR CKT 2, near Chisholm 345kV. a. Apply fault at the Chisholm 345kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
22	FLT22-3PH	3 phase fault on Spring Creek 345kV (514881) to Sooner 345kV (514803) CKT1, near Spring Creek. a. Apply fault at the Spring Creek 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
23	FLT23-3PH	3 phase fault on Arcadia 345kV (514908) to Seminole 345kV (515045) CKT2, near Arcadia. a. Apply fault at the Arcadia 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
24	FLT24-3PH	3 phase fault on Woodring 345kV (514715) to Sooner 345kV (514803) CKT1, near Woodring. a. Apply fault at the Woodring 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
25	FLT25-3PH	3 phase fault on Woodring 345kV (514715) to Hunter 345kV (515476) CKT1, near Woodring. a. Apply fault at the Woodring 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
26	FLT26-3PH	3 phase fault on the Woodring 345kV (514715) to Woodring 138kV (514714) to Woodring 13.8kV (515770) XFMR CKT 1, near Woodring 345kV. a. Apply fault at the Woodring 345kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.

Cont. No.	Cont. Name	Description
27	FLT27-3PH	3 phase fault on G11-051 Tap 345kV (562075) to Woodward 345kV (515375) CKT1, near G11-051 Tap. a. Apply fault at the G11-051 Tap 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
28	FLT28-3PH 2025SP Only	3 phase fault on G11-051 Tap 345kV (562075) to Woodward 345kV (515375) CKT 1 and 2, near G11-051 Tap. a. Apply fault at the G11-051 Tap 345kV bus. b. Clear fault after 5 cycles and trip the faulted lines (CKT1 and 2).
29	FLT29-3PH	3 phase fault on Woodward 345kV (515375) to Border 345kV (515458) CKT1, near Woodward. a. Apply fault at the Woodward 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
30	FLT30-3PH	3 phase fault on Woodward 345kV (515375) to G11-14-Tap 345kV (560000) CKT1, near Woodward. a. Apply fault at the Woodward 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
31	FLT31-3PH	3 phase fault on Woodward 345kV (515375) to G11-14-Tap 345kV (560000) CKT 1 and 2, near Woodward. a. Apply fault at the Woodward 345kV bus. b. Clear fault after 5 cycles and trip the faulted lines (CKT1 and 2).
32	FLT32-3PH	3 phase fault on Woodward 345kV (515375) to Thistle 345kV (539801) CKT1, near Woodward. a. Apply fault at the Woodward 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
33	FLT33-3PH	3 phase fault on Woodward 345kV (515375) to Thistle 345kV (539801) CKT 1 and 2, near Woodward. a. Apply fault at the Woodward 345kV bus. b. Clear fault after 5 cycles and trip the faulted lines (CKT1 and 2).
34	FLT34-3PH	3 phase fault on the Woodward 345kV (515375) to Woodward 138kV (515376) to Woodward 13.8kV (515795) XFMR CKT 1, near Woodward 345kV. a. Apply fault at the Woodward 345kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
35	FLT35-3PH	3 phase fault on Border 345kV (515458) to Tuco 345kV (525832) CKT1, near Border. a. Apply fault at the Border 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
36	FLT36-3PH	3 phase fault on the Thistle 345kV (539801) to Wichita 345kV (532796) CKT 1, near Thistle. a. Apply fault at the Thistle 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
37	FLT37-3PH	3 phase fault on the Thistle 345kV (539801) to Wichita 345kV (532796) CKT 1 and 2, near Thistle. a. Apply fault at the Thistle 345kV bus. b. Clear fault after 5 cycles and trip the faulted lines (CKT 1 and 2).

Cont. No.	Cont. Name	Description
38	FLT38-3PH 2015WP & 2015SP Only	3 phase fault Tatonga 345kV (515407) to Northwest 345kV (514880) CKT 1, near Tatonga. a. Apply fault at the Tatonga 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
39	FLT39-3PH 2025SP	3 phase Tatonga (515407) to Mathewson 345kV (515497) CKT 1, near Tatonga. a. Apply fault at the Tatonga 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
40	FLT40-3PH	3 phase fault on the Tuttle Conoco Tap 138kV (511425) to Cimarron 138kV (514898) CKT 1, near Tuttle Conoco Tap. a. Apply fault at the Tuttle Conoco Tap 138kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
41	FLT11-3PH	3 phase fault on the Cimarron 138kV (514898) to El Reno 138kV (514819) CKT 1, near Cimarron. a. Apply fault at the Cimarron 138kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
42	FLT42-3PH	3 phase fault on the Cimarron 138kV (514898) to Jensen Tap 138kV (514820) CKT 1, near Cimarron. a. Apply fault at the Cimarron 138kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
43	FLT43-3PH	3 phase fault on the Cimarron 138kV (514898) to Haymaker 138kV (514863) CKT 1, near Cimarron. a. Apply fault at the Cimarron 138kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
44	FLT44-3PH	3 phase fault on the Cimarron 138kV (514898) to Czech Hall 138kV (514894) CKT 1, near Cimarron. a. Apply fault at the Cimarron 138kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
45	FLT45-3PH	3 phase fault on the Cimarron 138kV (514898) to Sara 138kV (514895) CKT 1, near Cimarron. a. Apply fault at the Cimarron 138kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
46	FLT46-PO	**Prior Outage of Cimarron (514901) – Draper (514934) 345kV;** 3 phase fault on the Northwest (514880) - Arcadia (514908) 345kV near Northwest a. Apply fault at the Northwest 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Cont. No.	Cont. Name	Description
47	FLT47-PO	**Prior Outage of Northwest (514880) – Arcadia (514908) 345kV;** 3 phase fault on the Cimarron (514901) – Draper (514934) 345kV line near Cimarron a. Apply fault at the Cimarron 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
48	FLT48-SB	**Stuck Breaker at Cimarron (514901)** Apply single phase fault at Cimarron 345kV bus. b. Clear fault after 16 cycles and trip the following elements c. Cimarron (514901)-Draper (514934) 345kV line d. Cimarron (514901)-Northwest (514880) 345kV line.
49 *	FLT49-PO 2015SP and 2015WP only	**Prior Outage of Woodward (515375)-Thistle (539801) 345kV:** 3 phase fault on Tatonga (515407) – Northwest (514880) 345kV line near Tatonga. a. Apply fault at the Tatonga 345kV bus. b. Clear fault after 5 cycles and trip the faulted line.
50	FLT50-PO	**Prior Outage of Woodward (515375)-GEN-2011-051 (562075) 345kV:** 3 phase fault on the Northwest (514880) – Arcadia (514908) near Northwest a. Apply fault at the Northwest 345kV bus. b. Clear fault after 5 cycles and trip the faulted line.

***Only one of the transmission lines between Woodward and Thistle was disconnected as prior outage.**

Single- line-to-ground faults were simulated with the standard method of applying fault impedance to the positive sequence network to represent the effect of the negative and zero sequence networks on the positive sequence network. The SLG fault impedance was computed by assuming a positive sequence voltage at the fault location at approximately 60% of pre-fault voltage, which is a typical value.

The Southwest Pool Disturbance Performance Criteria Requirements in Appendix A were used to evaluate the system response during the initial transient period following a disturbance on the system. Generator response and bus voltages (115 kV and above) in Area 520, 524, 525, 526, 531, 534, and 536 were monitored to ensure the system performance meets criteria requirements. Rotor angles of the nearby synchronous machines were investigated to make sure they maintained synchronism and had adequate damping following system faults.

Any wind generator must comply with FERC Order 661A on low voltage ride through requirements for wind farms. Therefore, the wind generators should not be tripped off line for faults by under voltage relay actuation. Generator speed of pre-queued projects was also monitored to ensure they stay online under system contingencies. For contingencies that result in a prior queued project tripping off-line; the contingency shall be re-run with the prior queued project's voltage and frequency tripping disabled.

2.2 STUDY RESULTS

The results of all studied disturbances show **no** instability problems or voltage violations for all three seasons (see Table 2-2: Summary of Results). All generators in the studied system are kept online without tripping following all simulated faults.

Table 2-2 Study Results Summary

Contingency	2015SP	2015WP	2025SP
FLT01-3PH	Stable	Stable	Stable
FLT02-3PH	Stable	Stable	Stable
FLT03-3PH	Stable	Stable	Stable
FLT04-3PH	Stable	Stable	Stable
FLT05-3PH	N/A	N/A	Stable
FLT06-3PH	Stable	Stable	Stable
FLT07-3PH	Stable	Stable	Stable
FLT08-3PH	Stable	Stable	Stable
FLT09-3PH	Stable	Stable	Stable
FLT10-3PH	Stable	Stable	Stable
FLT11-3PH	Stable	Stable	Stable
FLT12-3PH	Stable	Stable	Stable
FLT13-3PH	N/A	N/A	Stable
FLT14-3PH	Stable	Stable	Stable
FLT15-3PH	N/A	N/A	Stable
FLT16-3PH	N/A	N/A	Stable
FLT17-3PH	Stable	Stable	Stable
FLT18-3PH	Stable	Stable	Stable
FLT19-3PH	N/A	N/A	Stable
FLT20-3PH	Stable	Stable	Stable
FLT21-3PH	N/A	N/A	Stable
FLT22-3PH	Stable	Stable	Stable
FLT23-3PH	Stable	Stable	Stable
FLT24-3PH	Stable	Stable	Stable
FLT25-3PH	Stable	Stable	Stable
FLT26-3PH	Stable	Stable	Stable
FLT27-3PH	Stable	Stable	Stable
FLT28-3PH	N/A	N/A	Stable
FLT29-3PH	Stable	Stable	Stable
FLT30-3PH	Stable	Stable	Stable
FLT31-3PH	Stable	Stable	Stable
FLT32-3PH	Stable	Stable	Stable
FLT33-3PH	Stable	Stable	Stable
FLT34-3PH	Stable	Stable	Stable
FLT35-3PH	Stable	Stable	Stable
FLT36-3PH	Stable	Stable	Stable
FLT37-3PH	Stable	Stable	Stable
FLT38-3PH	Stable	Stable	N/A
FLT39-3PH	N/A	N/A	Stable
FLT40-3PH	Stable	Stable	Stable
FLT41-3PH	Stable	Stable	Stable
FLT42-3PH	Stable	Stable	Stable
FLT43-3PH	Stable	Stable	Stable

Contingency	2015SP	2015WP	2025SP
FLT44-3PH	Stable	Stable	Stable
FLT45-3PH	Stable	Stable	Stable
FLT46-PO	Stable	Stable	Stable
FLT47-PO	Stable	Stable	Stable
FLT48-SB	Stable	Stable	Stable
FLT49-PO	Stable	Stable	N/A
FLT50-PO	Stable	Stable	Stable

Figure 2-1 shows the response of the studied generator following fault FLT01-3PH for 2015 Summer Peak case. The machine speed, active and reactive power output and terminal voltage are plotted to show the generator response. All the simulation plots are included in Appendix B.

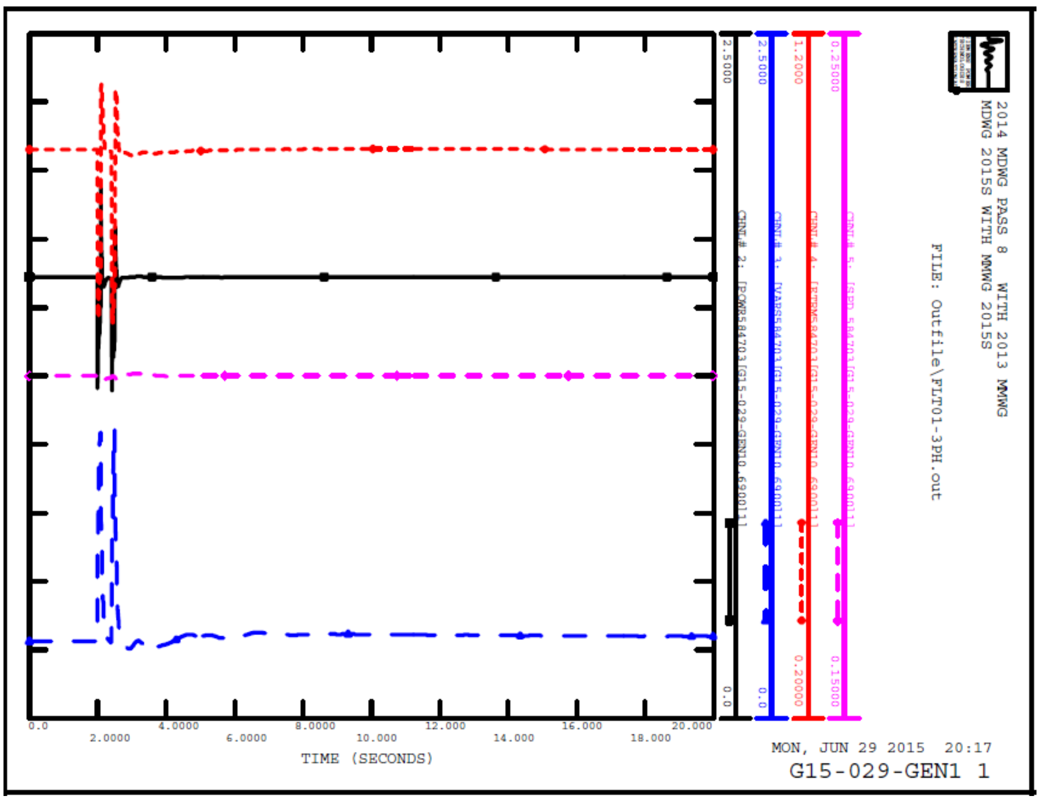


Figure 2-1 GEN-2015-029 Response Following Fault FLT01-3PH for 2015 Summer Peak Case

3 SHORT CIRCUIT ANALYSIS

Short circuit analysis was performed on the 2025 Summer Peak power flow case using the PSS/E program. Since the power flow model does not contain negative and zero sequence data, only three-phase symmetrical fault current levels were calculated at up to five buses away from the point of interconnection.

Table 3-1 tabulates all the three-phase fault current levels, and the calculated values were listed here for SPP's reference.

Table 3-1 Three-Phase Fault Currents

Number	Name	3PH(Amp)	Number	Name	3PH(Amp)
525824	TUCO_TR1 113.200	31857.5	514852	SLVRLAK4 138.00	31637.4
525825	TUCO_TR2 113.200	23936.2	514853	DVISION4 138.00	34309.8
515576	RANCHRD7 345.00	13065.1	514854	BRADEN 4 138.00	30485
525830	TUCO_INT 6230.00	22743.3	521006	MARSHAL4 138.00	7739.8
525832	TUCO_INT 7345.00	12198.6	515375	WWRDEHV7 345.00	20032
531469	SPERVIL7 345.00	14624	515376	WWRDEHV4 138.00	25604.1
515757	SEMINO21 14.400	23361.9	512817	CLEVLND1 13.800	12436
515600	KNGFSHR7 345.00	11016.7	584500	GEN-2015-006345.00	11313.3
515601	KNGFSR11 34.500	30625.3	583990	GEN-2014-049345.00	8028
515602	KNGFSR12 34.500	30716	583991	G14-049XFMR134.500	24691.4
515603	KNGFSRT1 13.800	53721	514873	LNEOAK 4 138.00	26399.9
525844	ELK_1 118.000	43931.8	515484	CHSHMVW1 34.500	18135.5
515605	CANADN7 345.00	11318.9	532796	WICHITA7 345.00	25093.2
515606	CANDN11 34.500	18886.7	515722	EL RENO1 13.200	9832.5
515607	CANDN12 34.500	19232	532798	VIOLA 7 345.00	13894
515608	CANDNT1 13.800	34483.7	514879	NORTWST4 138.00	41369.9
515609	CANDNT2 13.800	34883.9	514880	NORTWST7 345.00	29635.6
515610	FSHRTAP7 345.00	15945.1	514881	SPRNGCK7 345.00	21472.4
515621	OPENSKY7 345.00	11745.3	515394	KEENAN 4 138.00	9165.1
584660	G1524&G1525 345.00	5206.9	514883	SPGCK3&4 13.800	78628.4
573501	GEN-2008-047345.00	13596.5	515396	OUSPRT T 9.9600	31057
511553	CHISHOLM7 345.00	5481.3	514885	NORTWS41 13.800	49733.1
512694	CLEVLND7 345.00	14597	515398	OUSPRT 4 138.00	9762.9
583750	GEN-2013-029345.00	11568	514893	XEROX 4 138.00	27357.4
582219	G11-019-GSU134.500	35152.5	514894	CZECHAL4 138.00	26514.7
582220	G11-020-GSU134.500	35187.8	515407	TATONGA7 345.00	16200.8
514949	SOONRTP4 138.00	20947.5	515408	CRSRDX-WTG2 0.6900	130484.2
583760	GEN-2013-030345.00	12355	515409	CRSRDX-CB2 34.500	12441.3

Number	Name	3PH(Amp)	Number	Name	3PH(Amp)
539803	IRONWOOD7 345.00	14144.4	514898	CIMARON4 138.00	40536.3
526936	YOAKUM_345 345.00	9430.2	514899	REDBUD1S 18.000	80094.5
515224	MUSKOGE7 345.00	28535.2	514900	REDBUD2S 18.000	80094.5
514863	HAYMAKR4 138.00	25741.8	514901	CIMARON7 345.00	30175.9
510907	PITTSB-7 345.00	13328.7	509782	R.S.S.-7 345.00	30060
300138	4CLEVLND 138.00	15847.3	514905	REDBUD3S 18.000	80094.5
515700	ARCADI41 13.800	68661.8	514906	JNSKAMO4 138.00	20474.4
515703	ARCADI21 13.800	49229	514907	ARCADIA4 138.00	39777.4
515704	ARCADI31 13.800	45074.7	514908	ARCADIA7 345.00	24649.2
515604	KNGFSRT2 13.800	53836.6	514909	REDBUD 7 345.00	23713
525845	ELK_4 1 18.000	43921.4	514910	REDBUD1G 18.000	76945.9
515714	CIMARO11 13.800	37192.4	514911	REDBUD2G 18.000	76945.9
515715	CIMARO21 13.800	51965.6	514912	REDBUD3G 18.000	76945.9
515720	DRAPER31 13.800	49636.4	515042	SEMINL3G 20.900	188899.6
515721	DRAPER41 13.800	49636.4	584060	GEN-2014-056345.00	8216.4
515785	WINDFRM4 138.00	18897.8	515443	MNCOWND1 34.500	28201.3
560010	G14-037-TAP 345.00	16917	515444	MCNOWND7 345.00	16007.5
514703	FAIRMNT4 138.00	10676.1	514933	DRAPER 4 138.00	39253.1
514704	MILLERT4 138.00	20369	514934	DRAPER 7 345.00	21319.6
514707	PERRY 4 138.00	11028.1	515447	MORISNT4 138.00	13499.9
514708	OTTER 4 138.00	9547.4	515448	CRSRDSW7 345.00	11513.8
514709	FRMNTAP4 138.00	16651	515449	CRSRDW11 34.500	16663.7
514710	WAUKOMI4 138.00	9401.3	515450	CRSRDW21 34.500	17588.1
514711	WAUKOTP4 138.00	14703.4	515451	CRSRDWT1 13.800	27016.7
539800	CLARKCOUNTY7345.00	12740.9	515452	CRSRDWT2 13.800	27888.4
539801	THISTLE7 345.00	15999.2	514942	REDBUD4G 18.000	40225.7
514714	WOODRNG4 138.00	17991	560000	G11-14-TAP 345.00	14627
514715	WOODRNG7 345.00	16837	515392	KEENAN T 9.9600	38823.5
539804	THISTLE4 138.00	16889.2	515458	BORDER 7345.00	5117.1
515742	NORTWS21 13.800	49909.2	582019	GEN-2011-019345.00	20032
515743	NORTWS31 13.800	49841.2	582020	GEN-2011-020345.00	20032
514731	SO4TH 4 138.00	14288.2	515461	RNDBARN4 138.00	37952.4
515756	SEMINO11 14.400	38203.9	515393	KEENAN 1 34.500	16196.3
514733	MARSHL 4 138.00	7775.7	515465	LGARBER4 138.00	21025.5
515760	SOONER 1 13.800	42594.5	515466	MITCHSB4 138.00	21133.7
579253	G07-21&14-02345.00	13466.6	515479	CHSHMVE1 34.500	17905.7
579254	G0721&1402X134.500	25640.4	514882	SPGCK1&2 13.800	116919.2

Number	Name	3PH(Amp)	Number	Name	3PH(Amp)
579255	G0721&1402S134.500	24351.2	515471	NW164TH4 138.00	34363.4
579256	G0721&1402G10.6900	1023890.4	514961	GM 4 138.00	19426.1
515770	WOODRNG1 13.800	24428.6	515476	HUNTERS7 345.00	12747.3
515771	WOODWR21 13.200	20608.5	515477	CHSHLMV7 345.00	12729.8
583370	GEN-2012-024345.00	10181.9	514713	WRVALLY4 138.00	8733.8
515445	MNCOWNDT 13.800	49945.9	515481	STHLAKE4 138.00	20865.4
579268	G07-44&14-03345.00	9112.1	515482	CHSHMVET 13.200	38607
579269	G0744&1403X134.500	24972.9	562075	G11-051-TAP 345.00	16558.1
579270	G0744&1403S134.500	23769.2	509852	T.NO.--7 345.00	23284.5
579271	G0744&1403G10.6900	1006036.8	539802	THISTLE T1 13.800	8421.2
579272	G0744&1403HV345.00	9112.1	515397	OUSPRT 1 34.500	13701.6
579273	G0744&1403X234.500	14737	560033	G1524&G1525T345.00	19836.8
579274	G0744&1403S234.500	13630.4	560027	G14-074-TAP 345.00	6576.8
579275	G0744&1403G20.6900	555919.4	515497	MATHWSN7 345.00	28604.1
515792	DRAPER21 13.800	69887	515485	CHSHMVWT 13.200	38542.8
582008	GEN-2011-008345.00	10301.3	583090	G1149&G1504 345.00	4687
515795	WWDEHV31 13.800	61875.2	583091	G11-049XFMR134.500	15518.9
515799	WWDEHV21 13.800	61535.2	583094	G1149&1504X234.500	15546.5
515800	GRACMNT7 345.00	14628	515003	BARNES 4 138.00	16155.5
515801	GRCMNT11 13.800	45843.3	511424	T-CONCO4 138.00	7032.1
515802	GRACMNT4 138.00	28567.9	511425	TUTCONT4 138.00	10835.8
514782	WODWRD 2 69.000	12099.1	583110	GEN-2011-051345.00	16558.1
514783	WOODWR11 24.900	25453.1	583111	G11-051XFMR134.500	20652.1
514785	WOODWRD4 138.00	20901	583112	G11-051-GSU134.500	20178.2
514787	DEWEY 4 138.00	6627.9	583113	G11-051-GEN10.6900	933665.8
514940	REDBUD4S 18.000	80089.6	514001	CRSRD-WTG1 0.6900	589028.8
514796	IODINE-4 138.00	7201.4	514002	CRSRD-CB1 34.500	15180.6
514798	SNRPMPT4 138.00	20414.5	514003	CRSRD-WTG2 0.6900	659051.1
514801	MINCO 7 345.00	16051.4	514004	CRSRD-CB2 34.500	16318.7
514802	SOONER 4 138.00	30977.5	515543	RENFROW7 345.00	13173.7
514803	SOONER 7 345.00	22864.6	515544	RENFROW4 138.00	14650.5
514805	SOONER1G 22.000	178145.7	515545	RENFRO11 13.800	50467.6
514806	SOONER2G 20.000	201326.8	514895	SARA 4 138.00	18809.1
514851	QUAILCK4 138.00	28631.1	515549	MNCWND37 345.00	11166
583490	GEN-2012-041345.00	11568.2	515550	MNCWND31 34.500	25084.9
584450	GEN-2015-001345.00	13065.1	515551	MNCWND3T 13.800	45721
514819	EL-RENO4 138.00	15271.2	511501	TUTTLE4 138.00	10728.2

Number	Name	3PH(Amp)	Number	Name	3PH(Amp)
514820	JENSENT4 138.00	15163	515041	SEMINL2G 17.100	194722.2
514821	JENSEN 4 138.00	10773.9	515554	BVRCNTY7 345.00	16237.1
514823	ROMNOSE4 138.00	4084.6	515044	SEMINOL4 138.00	58223.4
514827	CTNWOOD4 138.00	16391.7	515045	SEMINOL7 345.00	28250.8
514828	KETCHTP4 138.00	26002.5	582119	G11-019XFMR134.500	37089.7
514946	MIDWEST4 138.00	31254.9	582120	G11-020XFMR134.500	37112.1
514834	KETCH 4 138.00	26449	584170	GEN-2014-064138.00	9476.5
584470	GEN-2015-003345.00	9709	511468	L.E.S.-7 345.00	12132.4
579351	GEN-2007-062345.00	8609.6	578542	GEN-2010-001345.00	13297.2
579352	G07-062XFMR134.500	20725.9	584690	GEN-2015-030345.00	17765.8
579353	G07-062-GSU134.500	20123	584691	G15-030XFMR134.500	26430.5
514818	ELRENO 2 69.000	7323	539638	FLATRDG3 138.00	15180.1
579355	G07-062XFMR234.500	20626.1	581112	GEN-2011-014345.00	10788.7
579356	G07-062-GSU234.500	19540	581113	G11-014XFMR134.500	23605.4
579358	G07-062-HV-2345.00	6591.1	584700	GEN-2015-029345.00	9754.6
579359	G07-062XFMR334.500	24076.8	584701	G15-029XFMR134.500	18913.7
514864	PIEDMNT4 138.00	22140.3	584702	G15-029-GSU134.500	18898.8
579362	G07-062XFMR434.500	24144	584703	G15-029-GEN10.6900	787971.8
515363	CENT 4 138.00	4014.1			

4 POWER FACTOR ANALYSIS

Since the studied project is a renewable energy project, power factor analysis was performed on three provided cluster scenarios upon SPP's request.

4.1 POWER FACTOR ANALYSIS METHODOLOGY

Power Factor Analysis was performed for the studied wind farm under system intact and contingency conditions. All stability faults shown in Table 2-1 were analyzed as power flow contingencies. The power factor requirements for the wind farm were determined to maintain the voltage at the POI to the schedule voltage which is the higher of the POI voltage in the provided base case or 1.0 per unit. Fictitious var generator was added to the studied wind farm to maintain the scheduled voltage following all studied contingencies. The MW and Mvar injections from the studied wind farm at the POI were recorded and the power factors were calculated for all contingencies. The most lagging and most leading power factors determine the minimum power factor range capability required for the studied wind farm.

If more than one studied project share the same POI, the projects were grouped together and common power factor requirements were determined for this group of studied projects. With this method, none of the studied projects is required to provide more or less than its fair share of the reactive power requirements at the same POI. If a prior-queued project is connected at the same POI as the studied project, the prior-queued project was not grouped with the studied project since its reactive power requirements was determined in previous studies. However, the voltage schedules of the prior-queued project and the studied project at the same POI were coordinated and the local existing capacitor banks were set to their maximum capability, if necessary.

Per FERC and SPP requirements, if the power factor needed to maintain the scheduled voltage is less than 0.95 lagging or leading, the requirements is limited to 0.95 lagging or leading.

If the required power factor at the POI is beyond the capability of the studied wind turbine, the approximate size of the additional capacitors were determined.

4.2 STUDY RESULTS

Table 4-1 summarizes the power factor analysis results. It is shown in the table that a 17MVAr capacitor bank is required on the wind farm's substation 34.5kV bus (584701) for 2015 summer peak case, and an 18MVAr capacitor bank is required for the 2015 winter peak case. No additional capacitor bank is needed for the 2025 summer peak case. These capacitor bank sizes are only estimates based on the information provided by the Interconnection Customer for its collector system design. Final needs will be based on final designs of the collector system determined by the Interconnection Customer to meet the power factor requirement.

Stability results show that the additional reactive power resources are not required to be dynamically controlled. However, any change in wind turbine model could change the stability results, which may show a need for dynamically controlled reactive power devices.

The detailed power factor analysis results for each studied contingency are provided in Appendix C.

Table 4-1 Power Factor Analysis Results

Request	Size (MW)	Generator Model	POI	Scenario	Final PF Requirement		Capacitor Requirement (Mvar)3
					Leading[1]	Lagging[2]	
GEN-2015-029	161	GE 2.3MW	Tatonga 345kV (515407)	15SP	1.0	0.950	17
				15WP	1.0	0.950	18
				25SP	0.998	0.983	N/A

Notes:
1. Leading is when the generator is absorbing reactive power from the transmission grid.
2. Lagging is when the generator is providing reactive power to the transmission grid.
3. Approximate sizes as discussed in this report Section 4.

5 LOW WIND/NO WIND ANALYSIS

In this study, ABB investigated the GEN-2015-029 project for low wind/no wind conditions, since the interconnected wind farm is connected to a 345kV bus.

5.1 LOW/NO WIND ANALYSIS METHODOLOGY

Low wind/No wind analysis is performed to determine the required shunt reactor size at the study project substation high side bus to bring the MVAr flow into the POI down to approximately zero.

For each studied scenario, the studied wind generator and capacitor bank (none in this case) was switched out of service with the collector system as modeled remaining in service. The resulting reactive power injection into the transmission network coming from the capacitance of the project's transmission lines and collector cables was measured. Then, the required shunt reactor size was calculated to bring the MVAr flow into the POI down to approximately zero.

5.2 STUDY RESULTS

Table 5-1 summaries the Low/No Wind analysis results. It is shown that 13.41 MVAr shunt reactor at the substation high side bus (584700) is required to bring the MVAr flow in the POI down to approximately zero under low/no wind conditions for all three studied seasons. This reactor bank size is approximate to be finalized during final facility and collector system design.

Table 5-1 Low/No Wind Analysis Results

Scenario	Reactive Power Injection at POI (MVAr)	Bus 584700 Volt (pu)	Required Shunt Reactor (MVAr)
15SP	13.41	1.0002	**13.41**
15WP	13.30	0.9961	**13.41**
25SP	13.86	1.0167	**13.41**

6 CONCLUSIONS

Southwest Power Pool (SPP) has commissioned ABB Inc., to perform a Definitive Impact Study for DISIS-2015-001 (Group 01) which includes generation interconnection request GEN-2015-029 (161 MW wind farm connected at the Tatonga 345 kV substation).

Request	Size (MW)	Generator Model	POI
GEN-2015-029	161	GE 2.3MW	Tatonga 345kV (515407)

The objective of this study is to evaluate the impact of project GEN-2015-029 on the existing and future planning system. The study is performed on three system scenarios provided by SPP:

- 2015 Summer Peak Case
- 2015 Winter Peak Case
- 2025 Summer Peak Case

Results of the stability analysis show that the studied system is stable following all simulated faults with the proposed GEN-2015-029 project in-service. There are no voltage violations in the monitored area and the local synchronous generators show good damping performance which meets the criteria specified.

System short-circuit current levels at up to five buses away from the point of interconnection were calculated and tabulated for SPP's reference.

Power Factor Analysis was performed to ensure the studied project meets FERC and SPP power factor requirements for wind farm interconnections. The results show that a 17MVAr capacitor bank is required on the wind farm's substation 34.5kV bus for 2015 summer peak case, an 18MVAr capacitor bank is required for the 2015 winter peak case, and no capacitor bank is required for 2025 summer peak case. These capacitor bank sizes are only estimates based on the information provided by the Interconnection Customer for its collector system design. Final needs will be based on final designs of the collector system determined by the Interconnection Customer to meet the power factor requirement.

The Low/No Wind analysis shows that a 13.41 MVAr shunt reactor is required to bring the MVAr flow in the POI down to approximate zero under low/no wind conditions for all three studied seasons. The reactor bank size is approximate and the final size will be determined in the final facility and collector system design.

Based on the results of stability analysis it can be concluded that **the proposed GEN-2015-029 project does not adversely impact the stability of the SPP system**.

The results of this analysis are based on available data and assumptions made at the time of conducting this study. If any of the data and/or assumptions made in developing the study model change, the results provided in this report may not apply.

APPENDIX A SOUTHWEST POWER POOL DISTURBANCE PERFORMANCE CRITERIA REQUIREMENTS

OVERVIEW

These Disturbance Performance Requirements ("Requirements") shall be applicable to the Bulk Electric System within the Southwest Power Pool Planning Area. Utilization of these Requirements applies to all registered entities within the Southwest Power Pool Planning Area. These Requirements shall not be applicable to facilities that are not part of Bulk Electric System. More stringent Requirements are at the sole discretion of each Transmission Owner.

Transient and dynamic stability assessments are generally performed to assure adequate avoidance of loss of generator synchronism and prevention of system voltage collapse within the first 20 seconds after a system disturbance. These Requirements provide a basis for evaluating the system response during the initial transient period following a disturbance on the Bulk Electric System by establishing minimum requirements for machine rotor angle damping and transient voltage recovery.

ROTOR ANGLE DAMPING REQUIREMENT

Machine Rotor Angles shall exhibit well damped angular oscillations [as defined below] and acceptable power swings following a disturbance on the Bulk Electric System for all NERC Category A, B and C events.

Well damped angular oscillations shall meet one of the following two requirements when calculated directly from the rotor angle:

1. Successive Positive Peak Ratio (SPPR) must be less than or equal to 0.95 where SPPR is calculated as follows:

$$\text{SPPR} = \frac{\text{Peak Rotor Angle of } 2^{nd} \text{ Positive Swing Peak}}{\text{Peak Rotor Angle of } 1^{st} \text{ Positive Swing Peak}} \leq 0.95$$

   -or- Damping Factor % = (1 – SPPR) x 100% $\geq$ 5%

   The machine rotor angle damping ratio may be determined by appropriate modal analysis (i.e. Prony Analysis) where the following equivalent requirement must be met:

   Damping Ratio $\geq$ 0.0081633

2. Successive Positive Peak Ratio Five (SPPR5) must be less than or equal to 0.774 where SPPR5 is calculated as follows:

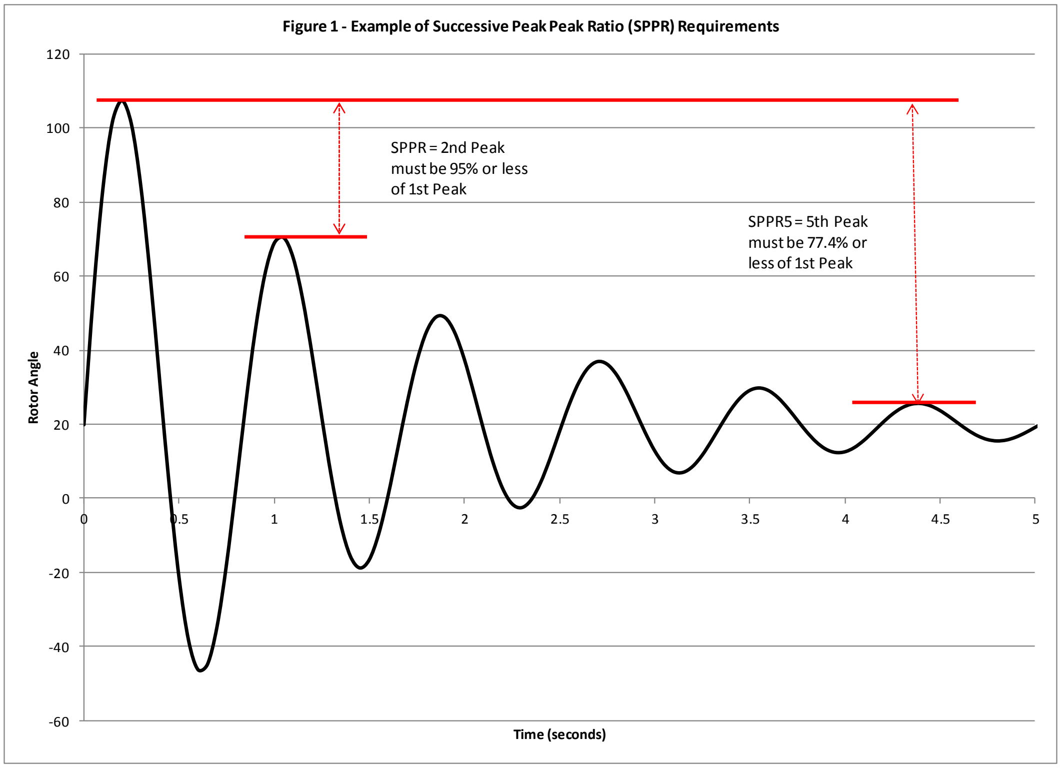
$$\text{SPPR5} = \frac{\text{Peak Rotor Angle of }5^{th}\text{ Positive Swing Peak}}{\text{Peak Rotor Angle of }1^{st}\text{ Positive Swing Peak}} \leq 0.774$$

-or- Damping Factor % = (1 – SPPR5) x 100% $\geq$ 22.6%

The machine rotor angle damping ratio may be determined by appropriate modal analysis (i.e. Prony Analysis) where the following equivalent requirement must be met:

Damping Ratio $\geq$ 0.0081633

Qualitatively, these Requirements are shown in Figure 1 below.



TRANSIENT VOLTAGE RECOVERY REQUIREMENT

Any time after a disturbance is cleared; bus voltages on the Bulk Electric System shall not swing outside of the bandwidth of 0.70 per unit to 1.20 per unit.

Qualitatively, this Requirement is shown in Figure 2 below.

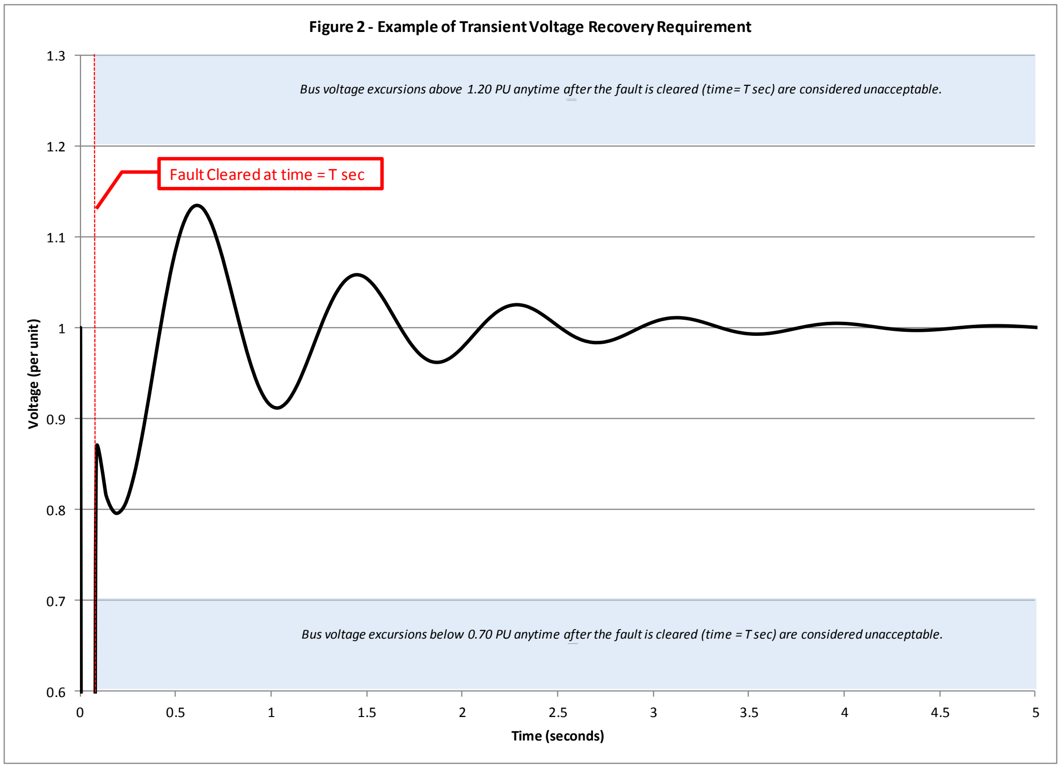


Figure 2 - Example of Transient Voltage Recovery Requirement
Bus voltage excursions above 1.20 PU anytime after the fault is cleared (time= T sec) are considered unacceptable.
Fault Cleared at time = T sec
Bus voltage excursions below 0.70 PU anytime after the fault is cleared (time = T sec) are considered unacceptable.
Voltage (per unit)
1.3
1.2
1.1
1
0.9
0.8
0.7
0.6
0
0.5
1
1.5
2
2.5
3
3.5
4
4.5
5
Time (seconds)

APPENDIX B SIMULATION PLOTS FOR STABILITY ANALYSIS

APPENDIX C POWER FACTOR ANALYSIS RESULTS

Appendix C – Power Factor Analysis Results

All the contingency numbers shown in this appendix match with the fault numbers shown in Table 2-1.

C.1 GEN-2015-029 2015 Summer Peak Case

The GEN-2015-029 POI voltage is 0.9957 pu in the provided 2015 summer peak case. Therefore, the power factor requirements for the wind farm were determined to maintain the voltage at the POI to 1.0 per unit. The lowest lagging and leading power factors are highlighted in the table below.

Outage No.		MW	Mvar	PF	
System Intact	0	-159	-5.1	0.999	lagging
Contingency	1	-159	-8.5	0.999	lagging
Contingency	2	-159	-5.4	0.999	lagging
Contingency	3	-159	-5.3	0.999	lagging
Contingency	4	-159	-5.5	0.999	lagging
Contingency	6	-159	-4.7	1	lagging
Contingency	7	-159	-4	1	lagging
Contingency	8	-159	-9.9	0.998	lagging
Contingency	9	-159	-6.3	0.999	lagging
Contingency	10	-159	-3.9	1	lagging
Contingency	11	-159	-5.3	0.999	lagging
Contingency	12	-159	-5.3	0.999	lagging
Contingency	14	-159	-5.4	0.999	lagging
Contingency	17	-159	-10.9	0.998	lagging
Contingency	18	-159	-4.2	1	lagging
Contingency	20	-159	-5.1	0.999	lagging
Contingency	22	-159	-5.9	0.999	lagging
Contingency	23	-159	-4.8	1	lagging
Contingency	24	-159	-5.1	0.999	lagging
Contingency	25	-159	-5.6	0.999	lagging
Contingency	26	-159	-4.7	1	lagging
Contingency	27	-159	-16.3	0.995	lagging
Contingency	29	-159	-10.1	0.998	lagging
Contingency	30	-159	-7.7	0.999	lagging
Contingency	31	-159	-14.8	0.996	lagging
Contingency	32	-159.1	-20.3	0.992	lagging
Contingency	33	-159	-83.6	**0.885**	lagging
Contingency	34	-159	-5	1	lagging
Contingency	35	-159	-7.8	0.999	lagging
Contingency	36	-159	-9.1	0.998	lagging
Contingency	37	-159.1	-26.6	0.986	lagging

Outage No.		MW	Mvar	PF	
Contingency	38	-159	-8.5	0.999	lagging
Contingency	40	-159	-5.1	0.999	lagging
Contingency	41	-159	-5.1	0.999	lagging
Contingency	42	-159	-5	1	lagging
Contingency	43	-159	-5.5	0.999	lagging
Contingency	44	-159	-5.4	0.999	lagging
Contingency	45	-159	-5	1	lagging
Contingency	46	-159	-6.6	0.999	lagging
Contingency	47	-159	-6.6	0.999	lagging
Contingency	49	-159	-21.3	0.991	lagging
Contingency	50	-159	-18.4	0.993	lagging

C.2 GEN-2015-029 2015 Winter Peak Case

The GEN-2015-029 POI voltage is 0.9919 pu in the provided 2015 winter peak case. Therefore, the power factor requirements for the wind farm were determined to maintain the voltage at the POI to 1.0 per unit. The lowest lagging and leading power factors are highlighted in the table below.

Outage No.		MW	Mvar	PF	
System Intact	0	-159	-10.3	0.998	lagging
Contingency	1	-159	-13.9	0.996	lagging
Contingency	2	-159	-11.6	0.997	lagging
Contingency	3	-159	-10.7	0.998	lagging
Contingency	4	-159	-11.4	0.997	lagging
Contingency	6	-159	-9.8	0.998	lagging
Contingency	7	-159	-9.1	0.998	lagging
Contingency	8	-159	-12.7	0.997	lagging
Contingency	9	-159	-12.8	0.997	lagging
Contingency	10	-159	-8.8	0.998	lagging
Contingency	11	-159	-10.7	0.998	lagging
Contingency	12	-159	-10.6	0.998	lagging
Contingency	14	-159	-11.2	0.998	lagging
Contingency	17	-159	-12.8	0.997	lagging
Contingency	18	-159	-9.5	0.998	lagging
Contingency	20	-159	-10.2	0.998	lagging
Contingency	22	-159	-12.6	0.997	lagging
Contingency	23	-159	-9.9	0.998	lagging
Contingency	24	-159	-10.3	0.998	lagging
Contingency	25	-159	-10.9	0.998	lagging
Contingency	26	-159	-10.1	0.998	lagging

Outage No.		MW	Mvar	PF	
Contingency	27	-159	-18.3	0.993	lagging
Contingency	29	-159.1	-16.5	0.995	lagging
Contingency	30	-159	-12.7	0.997	lagging
Contingency	31	-159	-18.2	0.994	lagging
Contingency	32	-159.1	-27.2	0.986	lagging
Contingency	33	-158.8	-129.2	**0.776**	lagging
Contingency	34	-159	-10.2	0.998	lagging
Contingency	35	-159	-14.1	0.996	lagging
Contingency	36	-159	-14.4	0.996	lagging
Contingency	37	-159.1	-33.5	0.978	lagging
Contingency	38	-159	-10.4	0.998	lagging
Contingency	40	-159	-10.3	0.998	lagging
Contingency	41	-159	-10.4	0.998	lagging
Contingency	42	-159	-10.3	0.998	lagging
Contingency	43	-159	-10.6	0.998	lagging
Contingency	44	-159	-10.7	0.998	lagging
Contingency	45	-159	-10.3	0.998	lagging
Contingency	46	-159	-13.6	0.996	lagging
Contingency	47	-159	-13.6	0.996	lagging
Contingency	49	-159.1	-25.3	0.988	lagging
Contingency	50	-159.1	-22	0.991	lagging

C.3 GEN-2015-029 2025 Summer Peak Case

The GEN-2015-029 POI voltage is 1.0135 pu in the provided 2025 summer peak case. Therefore, the power factor requirements for the wind farm were determined to maintain the voltage at the POI to 1.0135 pu per unit. The lowest lagging and leading power factors are highlighted in the table below.

Outage No.		MW	Mvar	PF	
System Intact	0	-159	9.1	0.998	leading
Contingency	1	-159.1	4.2	1	leading
Contingency	2	-159	8.7	0.999	leading
Contingency	3	-159	8.8	0.998	leading
Contingency	4	-159	9.3	0.998	leading
Contingency	5	-159	9.3	0.998	leading
Contingency	6	-159	10.2	0.998	leading
Contingency	7	-159.1	7.9	0.999	leading
Contingency	8	-159.1	4.4	1	leading
Contingency	9	-159	9.1	0.998	leading
Contingency	10	-159	10.2	0.998	leading

Outage No.		MW	Mvar	PF	
Contingency	11	-159	8.3	0.999	leading
Contingency	12	-159	8.5	0.999	leading
Contingency	13	-159	9.4	0.998	leading
Contingency	14	-159.1	7.1	0.999	leading
Contingency	15	-159	10.7	0.998	leading
Contingency	16	-159.1	-0.2	1	lagging
Contingency	17	-159.1	1.4	1	leading
Contingency	18	-159	9.3	0.998	leading
Contingency	19	-159	9	0.998	leading
Contingency	20	-159	9.1	0.998	leading
Contingency	21	-159	10	0.998	leading
Contingency	22	-159	8.2	0.999	leading
Contingency	23	-159	9	0.998	leading
Contingency	24	-159	8.9	0.998	leading
Contingency	25	-159	8.4	0.999	leading
Contingency	26	-159	10.2	0.998	leading
Contingency	27	-159.1	3.9	1	leading
Contingency	28	-159.1	2.3	1	leading
Contingency	29	-159.1	0.5	1	leading
Contingency	30	-159.1	5.3	0.999	leading
Contingency	31	-159.1	-3.9	1	lagging
Contingency	32	-159.1	-4.2	1	lagging
Contingency	33	-159.1	-29.3	**0.983**	lagging
Contingency	34	-159	10	0.998	leading
Contingency	35	-159.1	4.6	1	leading
Contingency	36	-159.1	6.9	0.999	leading
Contingency	37	-159.1	-3.1	1	lagging
Contingency	39	-159.1	0.7	1	leading
Contingency	40	-159	9.4	0.998	leading
Contingency	41	-159	9.2	0.998	leading
Contingency	42	-159	9.3	0.998	leading
Contingency	43	-159	9	0.998	leading
Contingency	44	-159	9.3	0.998	leading
Contingency	45	-159	9.4	0.998	leading
Contingency	46	-159	8.5	0.999	leading
Contingency	47	-159	8.5	0.999	leading
Contingency	50	-159.1	3.9	1	leading

K: Group 2 Dynamic Stability Analysis Report

This appendix will be updated when Group 2 study is completed.

L: Group 3 Dynamic Stability Analysis Report

See S&C study report on next page

S&C ELECTRIC COMPANY
Excellence Through Innovation

DISIS-2015-001 (GROUP 03)

LITTLE ROCK, AR

SOUTHWEST POWER POOL

DEFINITIVE INTERCONNECTION SYSTEM IMPACT STUDY

S&C PROJECT NUMBER: 9406

DOCUMENT NUMBER: E-850

REVISION: 0

FINAL REPORT

CONFIDENTIAL

JULY 24, 2015

S&C ELECTRIC COMPANY
Excellence Through Innovation

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(See Appendix D-8 Submitted in a Separate File)

9) "GEN-2015-027"

Dynamic Stability Plots For 2025 Summer Peak Case

(See Appendix D-9 Submitted in a Separate File)

10) "ASGI-2015-001"

Dynamic Stability Plots For 2015 Summer Peak Case

(See Appendix D-10 Submitted in a Separate File)

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(See Appendix D-11 Submitted in a Separate File)

12) "ASGI-2015-001"

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(See Appendix D-12 Submitted in a Separate File)

Appendix E

Power factor Analysis Results

Appendix F

Short-Circuit Study Results

(See Appendix F Submitted in Separate Files)

1. Executive Summary

S&C Electric Company (S&C) has performed a Definitive Interconnection System Impact Study, DISIS-2015-001 (Group 3), in response to a request through Southwest Power Pool (SPP) tariff studies. Group 3 consists of four (4) generation interconnection study projects (GEN-2015-001, GEN-2015-026, GEN-2015-027, and ASGI-2015-001). GEN-2015-001 is a solar farm project, GEN-2015-026 and GEN-2015-027 are wind farm projects, and ASGI-2015-001 is a natural gas combustion turbine project.

S&C has performed dynamic stability analysis for Group 3 under Cluster and Stand-Alone scenarios. For the Cluster scenario, the aforementioned four interconnection requests and prior-queued projects specified in the scope of work were studied at 100% output power using the Cluster base cases (2015 Summer Peak and Winter Peak Cases and 2025 Summer Peak Case) provided by SPP. For the Stand-Alone scenario, the individual interconnection request was added in SPP's Stand-Alone base case and was dispatched in accordance with SPP's supplied dispatch. There are four (4) Stand-Alone models for each season.

The results of dynamic stability analysis under Cluster and Stand-Alone scenarios indicated that, except during Contingency #6, Group 3 is expected to successfully ride through each N-1, N-1-1, and N-2 fault contingencies specified by SPP and the nearby areas will retain frequency and voltage stability. The generator G12-024-GEN1 (bus 583373) and SSWIND 1 (bus 539762) are consistently tripping during Contingency #6. After discussion with SPP it was decided that in order to mitigate this tripping, generation curtailment shall be brought into effect. Also, during the course of the study, the generator GEN-2015-021 (located at bus 584633) tripped during several contingencies due to its over-frequency protection. This issue was discussed with SPP and turned out to be a known issue from previous studies. The recommended solution was to adopt the extended frequency ride-through setting in the dynamics model of this generator. Furthermore, the study project and nearby generators in the study area meet transient voltage recovery requirements as specified by SPP.

S&C has performed power factor analysis for Group 3 under the Cluster scenario. Requirements for the voltage schedule at the point of interconnection (POI) for the power factor analysis is 1.0 p.u. voltage or the voltage schedule in the provided base case (whichever is higher). The power factor analyses were performed for all N-1 (or N-1-1 for prior-outage contingencies) three-phase contingencies specified by SPP. The power factor at each of the POI buses was analyzed and compared to the typical reactive capability of the wind farm from 0.95 lagging to 0.95 leading. The results of power factor analysis revealed that the solar farm represented by GEN-2015-021 and wind farms represented by GEN-2015-026 and GEN-2015-027 are required to maintain a power factor of 0.95 lagging (capacitive) to 0.95 leading (inductive) at the POI to meet SPP's requirements.

S&C has performed analysis of no wind conditions on the Cluster scenarios for wind farm projects that are interconnected to a 345-kV or 230-kV bus. The analysis consists of determining the amount of reactive power required to offset the reactive power injected by the project into the transmission network. For interconnection request project GEN-2015-026 (345 kV), applying a 4.5 Mvar, 345-kV shunt reactor can reduce the Mvar flow into the POI to approximately zero in all three Peak Cases.

S&C also performed short-circuit analysis on the power flow models for the 2025 Summer Peak Season for each generator using the Cluster Scenario model. A 3-phase fault is applied on buses up to 5 levels away from the POI of each interconnection request project and the results of the study are presented in Appendix F.

2. Introduction

S&C has performed a Definitive Interconnection System Impact Study, DISIS-2015-001, for Group 3 in response to a request through the SPP Tariff studies. Group 3 consist of four (4) new interconnection requests listed in Table 1. The study cases also contain the prior-queued projects listed in

Table 2. Group 3 and prior-queued projects were studied at 100% power output using 2015 Summer and Winter Peak Cases and 2025 Summer Peak Case provided by SPP.

Table 1: Generation Interconnection Requests in Group 3

Project	Size (MW)	Generator Model	Generator Bus	Point of Interconnection (POI)	POI Bus
GEN-2015-021	20.0	AE	584633	Johnson Corner 115 kV	531424
GEN-2015-026[1]	8.3 Uprate (173.88 Total)	Siemens	531302	Buckner 345 kV	531501
GEN-2015-027[2]	4.5 Uprate (103.845 Total)	Siemens	532003	Crooked Creek 115 kV	539783
ASGI-2015-001	4.27 Summer 6.13 Winter	GENSAL	584713	Ninnescah 115 kV	539648

1. Uprate of GEN-2010-009 (165.60 MW) for total facility rating of 173.88 MW.
2. Uprate of GEN-2008-079 (98.9 MW) for total facility rating of 103.845 MW.

Table 2: Prior Queued Projects

Request	Size (MW)	Generator Model	Point of Interconnection
GEN-2001-039A	104	GE 1.6 MW (539762)	Shooting Star 115 kV (539763)
GEN-2002-025A	150	GE 1.5 MW (542902)	Spearville 230 kV (539695)
GEN-2004-014	154.5	GE 1.5 MW (539757)	Spearville 230 kV (539695)
GEN-2005-012	250.7	Siemens 2.3 MW (539811, 539814)	Ironwood 345 kV (539803)
GEN-2006-006	205.5	GE 1.5 MW (562704)	Spearville 345 kV (531469)
GEN-2006-021	100	Clipper 2.5 MW (531215)	Flat Ridge 138 kV (539638)
GEN-2007-040	200.1	Siemens 2.3 MW (531304)	Buckner 345 kV (531501)
GEN-2008-018	250	GE 1.85 MW (523116)	Finney 345 kV (523853)
GEN-2008-079	98.9	Siemens 2.3 MW (532003)	CRKCK 115 kV line (539783)
GEN-2008-124	200.1	Siemens 2.3 MW (579483, 579486)	Ironwood 345 kV (539803)
GEN-2010-009	165.6	Siemens 2.3 MW (531302)	Buckner 345 kV (531501)
GEN-2010-045	197.8	Siemens 2.3 MW (580054, 580055)	Buckner 345 kV (531501)
GEN-2011-008	600	GE 1.6 MW (582208, 582408, 582598, 582978)	Clark County 345 kV (539800)
GEN-2011-016	200.1	Siemens 2.3 MW (582316)	Spearville 345 kV (531469)
GEN-2011-017	299	Siemens 2.3 MW (582317)	Tap on Spearville – Post Rock 345 kV line (G11-017 POI, 560242)
GEN-2012-007	85.8 Summer 120 Winter	GENSAL (531201, 531202)	Rubart 115 kV (531200)
ASGI-2012-006	20.74 Summer 21.21 Winter	GENSAL (583223)	ABBK 69 kV (531494)
GEN-2012-024	180	Vestas V112-3.0MW (583373)	Clark County 345 kV (539800)
GEN-2013-010	99	Siemens 3.0 MW (583603)	GEN-2013-010 Tap 345 kV (562334) (Tap on Spearville to Post Rock 345 kV line)
GEN-2014-049	200	GE 2.0 MW (583993)	Thistle 345 kV (539801)

3. Transmission System and Study Area

The interconnection requests in Group 3 will interconnect into Sunflower Electric Power Corporation's system (SUNC, Area # 534).

In addition to that area, the following areas were also monitored:

- American Electric Power West (AEPW, Area #520)
- Oklahoma Gas & Electric (OKGE, Area # 524)
- Western Farmers Electric corporation (WFEC, Area #525)
- Southwestern Public Services (SPS, Area #526)
- Midwest Energy (MIDW, Area #531)
- Westar Energy, Inc. (WERE, Area #536)
- Nebraska Public Power District (NPPD, Area #640)
- Omaha Public Power District (OPPD, Area #645)
- Lincoln Electric System (LES, Area #650)
- Western Area Power Administration (WAPA, Area #652)

4. Power Flow Base Cases

DISIS-2015-001 (Group 3) and prior-queued projects were modeled as aggregates of generating units. The aggregate models were part of the base case supplied by SPP. The following power flow base cases were provided by SPP:

Cluster Scenario

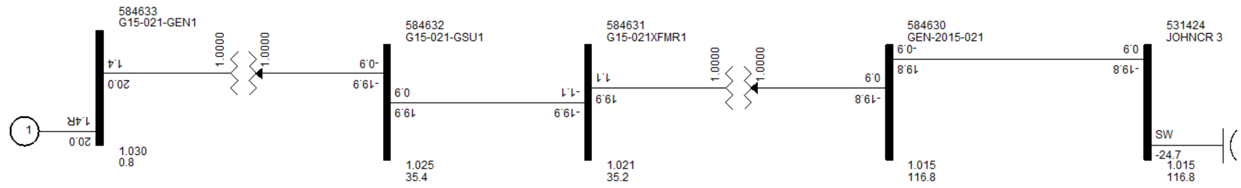
- **MDWG14-15SP_DIS1501_G03_Sensitivity.SAV** – 2015 Summer Peak Case, which includes aggregate representation of interconnect requests for DISIS-2015-001 (Group 3) and prior queued projects at 100% output power.
- **MDWG14-15WP_DIS1501_G03_Sensitivity.SAV** – 2015 Winter Peak Case, which includes aggregate representation of interconnect requests for DISIS-2015-001 (Group 3) and prior queued projects at 100% output power.
- **MDWG14-25SP_DIS1501_G03_Sensitivity.SAV** – 2025 Summer Peak Case, which includes aggregate representation of interconnect requests for DISIS-2015-001 (Group 3) and prior queued projects at 100% output power.

Stand-Alone Scenario

- **MDWG14-15SP_DIS1501_G03-SA.SAV** – 2015 Summer Peak Case, in which all new <u>interconnect requests are initially disconnected</u> and <u>only one interconnection request</u> will be connected under each Stand-Alone scenario.
- **MDWG14-15WP_DIS1501_G03-SA.SAV** – 2015 Winter Peak Case, in which all new <u>interconnect requests are initially disconnected</u> and <u>only one interconnection request</u> will be connected under each Stand-Alone scenario.
- **MDWG14-25SP_DIS1501_G03-SA.SAV** – 2025 Summer Peak Case, in which all new <u>interconnect requests are initially disconnected</u> and <u>only one interconnection request</u> will be connected under each Stand-Alone scenario.

5. Power Flow Model

Power flow base models for the study project were provided by SPP. The models were created in PSS/E 32.2.1. One-line diagrams for each of the interconnection request projects were created by S&C and depicted in Figure 1.



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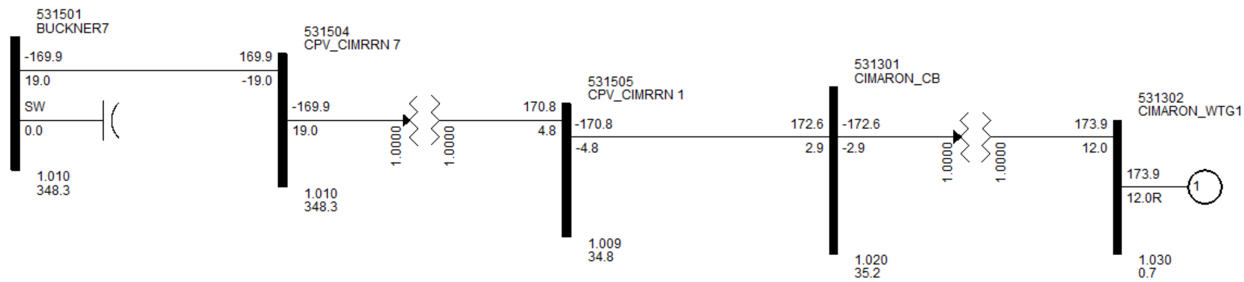

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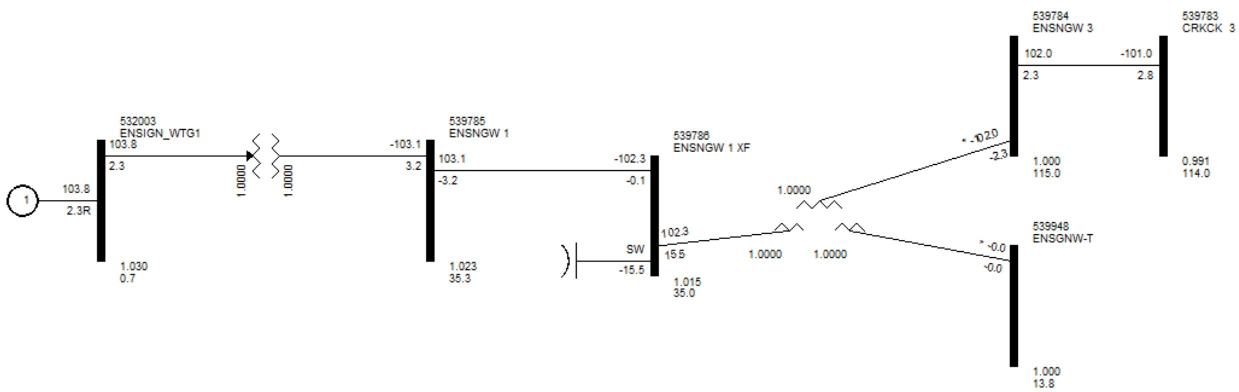
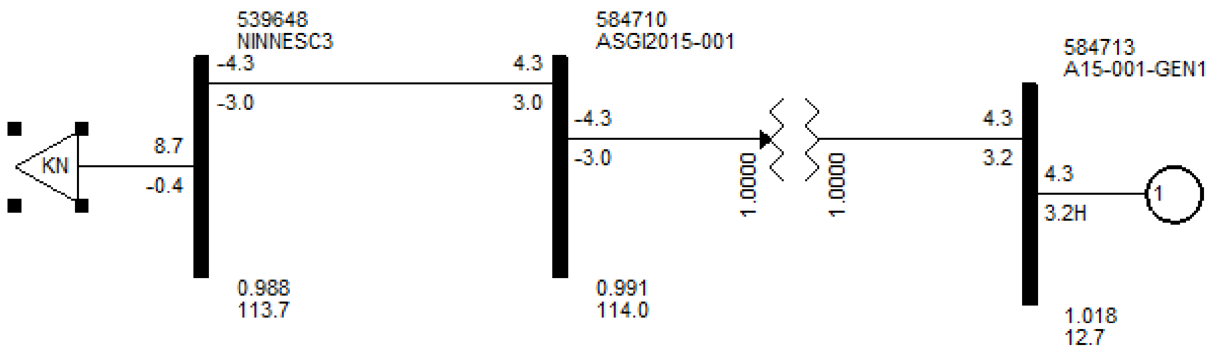


(c)



(d)

Figure 1. Simplified one-line diagrams of the interconnection requests (a) GEN-2015-021, (b) GEN-2015-026, (c) GEN-2015-027, and (d) ASGI-2015-001.

6. Dynamic Stability Analysis

6.1. Assumptions

Dynamic stability analysis was performed for the fault contingencies specified by SPP, which are listed in Appendix A.

Note that single line-to-ground faults were simulated in a manner consistent with currently accepted practices, i.e. to assume that a single line-to-ground fault will cause a positive-sequence voltage drop at the fault location to 60% of nominal. Three phase faults were simulated as bolted faults.

6.2. Stability Criteria

Disturbances, including three-phase and single-phase to ground faults, should not cause synchronous and asynchronous plants to become unstable or disconnect from the transmission grid. The criterion for synchronous generator stability as defined by NERC is: "power system stability is defined as that condition in which the difference of the angular positions of synchronous machine rotor becomes constant following an aperiodic system disturbance."

Voltage magnitudes and frequencies at terminals of asynchronous generators should not exceed magnitudes and durations that will cause protection elements to operate. Furthermore, the response after the disturbance needs to be studied at the terminals of the machine to insure that there are no sustained oscillations in power output, speed, frequency, etc.

Voltage magnitudes and angles after the disturbance should settle to a constant and acceptable operating level. Frequencies should settle to the acceptable range within nominal 60 Hz power frequency.

SPP has two specific transient stability requirements as summarized below. These requirements will be elaborated in more detail in the SPP Disturbance Performance Requirements provided in Appendix B. This document provides a basis for evaluating the system response during the initial transient period following a disturbance on the bulk electric system by establishing minimum requirements for machine rotor angle damping and transient voltage recovery.

- **Angular Oscillations**: for study projects that include synchronous machines, rotor angle oscillations should meet the damping requirements described in Appendix B. For other projects that do not include synchronous machines, but based on engineering judgment have questionable rotor angle oscillation, damping should also meet the requirements described in Appendix B.
- **Transient Voltage Recovery**: for the transient voltage recovery requirement in Appendix B, the bus voltages to be included are those at the point of interconnection for each study generator. Other voltages in the area should be checked for this requirement if the terminal voltage of other machines in the monitored area appears to have voltage recovery issues.

6.3. DYNAMIC STABILITY RESULTS

Dynamic studies were performed under Cluster and Stand-Alone scenarios for each of peak seasons. See Appendix C for dynamic stability plots of the Group 3 under Cluster scenarios. See Appendix D for dynamic stability plots for Stand-Alone scenarios. Each contingency study consists of (40) subplots:

- Subplot #1 are the (6) monitor system phase angle channels in the original snapshot file provided by SPP.
- Subplot #2 to Subplot #32 are results for (31) generators in the scope of study.
- Subplots #33 to Subplot #36 are voltages at the POI buses in the scope of study.
- Subplots #37 to Subplot #40 are frequencies at the POI buses in the scope of study.

Results of dynamic stability analysis for Cluster and Stand-Alone scenarios indicated that, with the exception of one contingency, Group 3 is expected to successfully ride through each fault contingency specified by SPP and the nearby areas will retain frequency and voltage stability. In all results, with the exception of Contingency #6, there is no observation of generator tripping or disconnection from the transmission grid. The results of the studies are summarized in Table 3.

Table 3: Summary of Transient Stability Results

Cont. No.	Cont. Name	2015 Summer Peak	2015 Winter Peak	2025 Summer Peak
1	FLT01-3PH	STABLE	STABLE	STABLE
2	FLT02-3PH	STABLE	STABLE	STABLE
3	FLT03-3PH	STABLE	STABLE	STABLE
4	FLT04-3PH	STABLE	STABLE	STABLE
5	FLT05-3PH	STABLE	STABLE	STABLE
6	FLT06-3PH	UNSTABLE Tripping of G12-024-GEN1 and SSWIND 1, followed by cascade tripping of other generators listed in Table 4 *		
7	FLT07-3PH	STABLE	STABLE	STABLE
8	FLT08-3PH	STABLE	STABLE	STABLE
9	FLT09-3PH	STABLE	STABLE	STABLE
10	FLT10-3PH	STABLE	STABLE	STABLE
11	FLT11-3PH	STABLE	STABLE	STABLE
12	FLT12-3PH	STABLE	STABLE	STABLE
13	FLT13-3PH	STABLE	STABLE	STABLE
14	FLT14-3PH	STABLE	STABLE	STABLE
15	FLT15-3PH	STABLE	STABLE	STABLE
16	FLT16-3PH	STABLE	STABLE	STABLE
17	FLT17-3PH	STABLE	STABLE	STABLE
18	FLT18-3PH	STABLE	STABLE	STABLE
19	FLT19-3PH	STABLE	STABLE	STABLE
20	FLT20-3PH	STABLE	STABLE	STABLE
21	FLT21-3PH	STABLE	STABLE	STABLE
22	FLT22-3PH	STABLE	STABLE	STABLE
23	FLT23-3PH	STABLE	STABLE	STABLE
24	FLT24-3PH	STABLE	STABLE	STABLE
25	FLT25-3PH	STABLE	STABLE	STABLE
26	FLT26-3PH	STABLE	STABLE	STABLE
27	FLT27-3PH	STABLE	STABLE	STABLE
28	FLT28-3PH	STABLE	STABLE	STABLE
29	FLT29-3PH	STABLE	STABLE	STABLE
30	FLT30-3PH	STABLE	STABLE	STABLE
31	FLT31-3PH	STABLE	STABLE	STABLE
32	FLT32-3PH	STABLE	STABLE	STABLE
33	FLT33-PO	STABLE	STABLE	STABLE
34	FLT34-PO	STABLE	STABLE	STABLE
35	FLT35-PO	STABLE	STABLE	STABLE
36	FLT36-SB	STABLE	STABLE	STABLE
37	FLT37- SB	STABLE	STABLE	STABLE
38	FLT38- SB	STABLE	STABLE	STABLE
39	FLT39- SB	STABLE	STABLE	STABLE
40	FLT40-PO	STABLE	STABLE	STABLE
41	FLT41-3PH	STABLE	STABLE	STABLE
42	FLT42-3PH	STABLE	STABLE	STABLE

Cont. No.	Cont. Name	2015 Summer Peak	2015 Winter Peak	2025 Summer Peak
43	FLT43-3PH	STABLE	STABLE	STABLE
44	FLT44-3PH	STABLE	STABLE	STABLE
45	FLT45-3PH	STABLE	STABLE	STABLE
46	FLT46-3PH	STABLE	STABLE	STABLE
47	FLT47-3PH	STABLE	STABLE	STABLE
48	FLT48-3PH	STABLE	STABLE	STABLE
49	FLT49-3PH	STABLE	STABLE	STABLE
50	FLT50-3PH	STABLE	STABLE	STABLE
51	FLT51-3PH	STABLE	STABLE	STABLE
52	FLT52-3PH	STABLE	STABLE	STABLE
53	FLT53-3PH	STABLE	STABLE	STABLE
54	FLT54-3PH	STABLE	STABLE	STABLE
55	FLT55-3PH	STABLE	STABLE	STABLE
56	FLT56-3PH	UNSTABLE Tripping of GEN-2015-021 corrected by adjusting over-frequency parameters of the generator	UNSTABLE Tripping of GEN-2015-021 corrected by adjusting over-frequency parameters of the generator	STABLE
57	FLT57-3PH	UNSTABLE Tripping of GEN-2015-021 corrected by adjusting over-frequency parameters of the generator	UNSTABLE Tripping of GEN-2015-021 corrected by adjusting over-frequency parameters of the generator	STABLE
58	FLT58-3PH	STABLE	STABLE	STABLE
59	FLT59-3PH	STABLE	STABLE	STABLE
60	FLT60-3PH	STABLE	STABLE	STABLE
61	FLT61-3PH	STABLE	STABLE	STABLE
62	FLT62-3PH	STABLE	STABLE	STABLE
63	FLT63-3PH	STABLE	STABLE	STABLE
64	FLT64-3PH	STABLE	STABLE	STABLE
65	FLT65-3PH	STABLE	STABLE	STABLE
66	FLT66-3PH	STABLE	STABLE	STABLE
67	FLT67-3PH	UNSTABLE Tripping of GEN-2015-021 corrected by adjusting over-frequency parameters of the generator	UNSTABLE Tripping of GEN-2015-021 corrected by adjusting over-frequency parameters of the generator	STABLE
68	FLT68-3PH	UNSTABLE Tripping of GEN-2015-021 corrected by adjusting over-frequency parameters of the generator response file	UNSTABLE Tripping of GEN-2015-021 corrected by adjusting over-frequency parameters of the generator response file	STABLE
69	FLT69-3PH	UNSTABLE	UNSTABLE	STABLE

Cont. No.	Cont. Name	2015 Summer Peak	2015 Winter Peak	2025 Summer Peak
		Tripping of GEN-2015-021 corrected by adjusting over-frequency parameters of the generator	Tripping of GEN-2015-021 corrected by adjusting over-frequency parameters of the generator	
70	FLT70-3PH	UNSTABLE Tripping of GEN-2015-021 corrected by adjusting over-frequency parameters of the generator	UNSTABLE Tripping of GEN-2015-021 corrected by adjusting over-frequency parameters of the generator	STABLE
71	FLT71-3PH	STABLE	STABLE	STABLE
72	FLT72-3PH	STABLE	STABLE	STABLE
73	FLT73-3PH	STABLE	STABLE	STABLE
74	FLT74-3PH	STABLE	STABLE	STABLE
75	FLT75-3PH	STABLE	STABLE	STABLE
76	FLT76-3PH	STABLE	STABLE	STABLE
77	FLT77-3PH	STABLE	STABLE	STABLE
78	FLT78-3PH	STABLE	STABLE	STABLE
79	FLT79-3PH	STABLE	STABLE	STABLE
80	FLT80-3PH	STABLE	STABLE	STABLE
81	FLT81-3PH	STABLE	STABLE	STABLE
82	FLT82-3PH	STABLE	STABLE	STABLE
83	FLT83-3PH	STABLE	STABLE	STABLE
84	FLT84-3PH	STABLE	STABLE	STABLE
85	FLT85-3PH	STABLE	STABLE	STABLE
86	FLT86-3PH	STABLE	STABLE	STABLE
87	FLT87-3PH	STABLE	STABLE	STABLE
88	FLT88-3PH	STABLE	STABLE	STABLE
89	FLT89-3PH	STABLE	STABLE	STABLE
90	FLT90-3PH	STABLE	STABLE	STABLE

* Contingency #6 is an N-2 fault contingency scenario, wherein a fault applied on the 345 kV Thistle bus (539801) is cleared by tripping the two lines connecting the 345 kV Thistle bus (539801) to the 345 kV Clark County bus (539800), followed by a consequent reclosing and tripping. In this contingency, it is observed that the generators G12-024-GEN1 (bus 583373) and SSWIND 1 (bus 539762) are tripping for most Cluster and Sand-Alone scenarios. Table 4 lists the generators tripping during Contingency #6 for different peak cases.

Table 4: Generators tripping during Contingency #6

Peak Case	Generator
Summer 2015 Cluster Case	SSWIND 1 (539762)
Winter 2015 Cluster Case	*No Tripping*
Summer 2025 Cluster Case	SSWIND 1 (539762)
	G12-024-GEN1 (583373)
	SPEARVILLE WTG (539757)
	G06-006-GEN1 (562704)
	GPW G1 (542902)
Summer 2015 Stand-Alone Cases	SSWIND 1 (539762)
	G12-024-GEN1 (583373)
Winter 2015 Stand-Alone Cases	G12-024-GEN1 (583373)
Summer 2025 Stand-Alone Cases	SSWIND 1 (539762)
	G12-024-GEN1 (583373)
	SPEARVILLE WTG (539757)
	G06-006-GEN1 (562704)
	GPW G1 (542902)

SPP has stated that the tripping of generators during Contingency #6 shall be mitigated by curtailing the generation to a level that is yet to be determined.

It should also be noted that during the dynamic stability simulations, GEN-2015-021 (bus 584633) tripped in several contingencies due to its over-frequency protection. After discussion with SPP, it was identified that this issue can be resolved by adjusting the over-frequency parameters of the generator's extended ride-through option in the generator's dynamic model. As specified by SPP, the DYRE file needs to be modified so that GEN-2015-021 has frequency parameters as shown in the Table 5 below:

Table 5: Extended ride-through parameters of the generator GEN-2015-021

Description of change	**Over-frequency setpoint** (CON(J+16))	**Tripping delay time** (CON(J+17))
Existing	60.5	0.02
Recommended	62.5	2.00

In addition, Group 3 interconnection requests are expected to meet SPP's transient voltage recovery requirements.

7. Power Factor Analysis

7.1. Power Factor Requirements at the Point of Interconnection

SPP has specific voltage requirements for interconnecting renewable energy projects (including wind and solar generation). These interconnection projects must maintain a power factor required to hold a voltage schedule at the POI consistent with the voltage schedule in the provided base case or 1.0 p.u. voltage (whichever is higher). The voltage requirements must also be met during single (or N-1-1 for prior-outage contingencies) transmission facility outage contingencies specified by SPP. The base case voltages at the POI for each of three Peak cases are listed in Table 6. The transmission facility outage contingencies considered in the power factor analysis were specified by SPP and listed in Appendix A. The outages considered by SPP for the power factor analysis are three phase contingency conditions. Those outages are either line outages or transformer outages due to the faults. A few cases include the prior-outage condition as well as tripping of equipment due to faults. Those cases form the N-1-1 contingencies in this study.

Table 6: Base Case Voltages at the POI of the Generation Interconnection Request

Request	POI	2015 Summer Peak (p.u.)	2015 Winter Peak (p.u.)	2025 Summer Peak (p.u.)
GEN-2015-021	531424	1.009	1.013	1.015
GEN-2015-026	531501	1.010	1.012	1.010
GEN-2015-027	539783	0.994	0.997	0.991

7.2. Power Factor Analysis Results

The results of power factor analysis are summarized in Appendix E. The power factor requirement for the interconnection projects were then compared to the required power factor at the POI. According to FERC Order No. 661-A, interconnection projects are not typically required to operate beyond a power factor range of 0.95 leading/lagging at the POI for voltages from 0.95 to 1.05 of nominal. Then, the power factor level outside of 0.95 leading to 0.95 lagging are highlighted with the pink color and summarized in table below.

Table 7: Interconnection Request Power Factor Requirements outside 0.95 leading to 0.95 lagging

GEN-2015-021

	2015 Summer Peak					2015 Winter Peak					2025 Summer Peak				
Cont. No.	P(MW)	Q(MVAR)	Power Factor		V(PU)	P(MW)	Q(MVAR)	Power Factor		V(PU)	P(MW)	Q(MVAR)	Power Factor		V(PU)
31	20.0	9.7	0.90	Lagging	1.009	20.0	8.7	0.92	Lagging	1.0132	20.0	8.3	0.92	Lagging	1.0154
56	20.0	-16.1	0.78	Leading	1.009	20.0	-4.7	0.97	Leading	1.0132	20.0	-16.1	0.78	Leading	1.0154
57	20.0	-11.3	0.87	Leading	1.009	20.0	-1.6	1.00	Leading	1.0132	20.0	-11.3	0.87	Leading	1.0154
58	20.0	-8.9	0.91	Leading	1.009	20.0	-1.2	1.00	Leading	1.0132	20.0	-8.9	0.91	Leading	1.0154
69	20.0	-8.1	0.93	Leading	1.009	20.0	-7.4	0.94	Leading	1.0132	20.0	-10.2	0.89	Leading	1.0154
70	20.0	7.3	0.97	Lagging	1.009	20.0	2.9	0.99	Lagging	1.0132	20.0	4.0	0.98	Lagging	1.0154

GEN-2015-026

	2015 Summer Peak					2015 Winter Peak					2025 Summer Peak				
Cont. No.	P(MW)	Q(MVAR)	Power Factor		V(PU)	P(MW)	Q(MVAR)	Power Factor		V(PU)	P(MW)	Q(MVAR)	Power Factor		V(PU)
5	173.9	710.2	0.93	Lagging	1.0099	173.9	75.2	0.92	Lagging	1.0115	173.9	65.3	0.94	Lagging	1.0096
8	173.9	106.6	0.85	Lagging	1.0099	173.9	109.4	0.85	Lagging	1.0115	173.9	92.4	0.88	Lagging	1.0096
12	173.9	-39.7	0.97	Leading	1.0099	173.9	-58.9	0.95	Leading	1.0115	173.9	-58.9	0.95	Leading	1.0096
17	173.9	117.9	0.83	Lagging	1.0099	173.9	141.5	0.78	Lagging	1.0115	173.9	100.4	0.87	Lagging	1.0096
21	173.9	56.1	0.95	Lagging	1.0099	173.9	38.9	0.98	Lagging	1.0115	173.9	74.7	0.92	Lagging	1.0096
33	173.9	86.3	0.90	Lagging	1.0099	173.9	95.3	0.88	Lagging	1.0115	173.9	81.6	0.91	Lagging	1.0096
34	173.9	75.9	0.92	Lagging	1.0099	173.9	81.7	0.91	Lagging	1.0115	173.9	67.6	0.93	Lagging	1.0096
40	173.9	-22.0	0.99	Leading	1.0099	173.9	-58.1	0.95	Leading	1.0115	173.9	-22.0	0.99	Leading	1.0096

Based on the results of the power factor analysis, interconnection requests should meet the following requirements listed in Table 8 to maintain nominal voltage at the POI:

Table 8: Summary of Power Factor Analysis at the POI

Request	Capacity	POI	Power Factor at POI	
			Leading (absorbing vars)	Lagging (providing vars)
GEN-2015-021	20.0 MW	Johnson Corner 115 kV (531424)	0.78	0.90
GEN-2015-026	173.9 MW	Buckner 345 kV (531501)	0.95	0.83
GEN-2015-027	102.9 MW	Crooked Creek (539783)	0.99	0.82

NOTE: Per the SPP Tariff as reactive power is required for all projects, the final requirement in the GIA will be the pro-forma 95% lagging to 95% leading at the point of interconnection.

8. No Wind Conditions Analysis

For the wind farm interconnection requests that interconnect to a 230-kV or 345-kV bus, an analysis of the project for no power production due to no or low wind conditions was performed. The analysis consists of determining the amount of reactive power required to offset the reactive power injected by the project into the transmission network. The size of a shunt reactor placed at the interconnection request project's substation high side bus to reduce the Mvar flow into the POI to approximately zero was determined. As shown in Table 9, installation of a 4.5 Mvar, 345-kV shunt reactor can reduce the Mvar flow into the POI to practically zero in all three Peak cases.

Table 9: Inductive Reactive Power (i.e. Shunt Reactor) Required at the High-Voltage Side Main Transformer of the Wind Farm to Offset the Capacitive Reactive Power Injected by the Project (Mvar)

Request	POI	2015 Summer Peak	2015 Winter Peak	2025 Summer Peak
GEN-2015-026*	531501	4.5	4.5	4.5

* Note that to accurately measure the reactive power injected only from collector system of GEN-2015-026 project, we disconnected GEN-2007-040 and GEN-2010-045 project and the switched capacitor, which share the same POI with GEN-2015-026 project.

9. SHORT-CIRCUIT STUDY

A short-circuit study has been performed on the power flow models for the 2025 Summer Peak Season for each generator using the Cluster Scenario model. Short-circuit analysis includes applying a 3-phase fault on buses up to 5 levels away from the POI of each interconnection request project. PSS/E "Automatic Sequence Fault Calculation (ASCC)" fault analysis module was used for the purpose of short-circuit analysis. The results of the short-circuit analysis have been recorded for all the buses up to five buses away from the point of interconnection of each interconnection request project. Detailed results of the short-circuit study are provided in Appendix F.

10. Conclusions and Recommendations

- Dynamic analysis results under Cluster and Stand-Alone Scenarios indicate that DISIS-2015-001(Group 3) interconnection request projects are expected to successfully interconnect into the transmission system at 100% output power and at the desired location. Dynamic stability analysis also indicates that, with the exception of Contingency #6, Group 3 is expected to ride through all N-1, N-1-1, and N-2 fault contingencies specified by SPP and the nearby areas will retain angular, frequency and voltage stability. Thus, Group 3 is expected to meet SPP's transient voltage recovery requirement.

- As discussed with SPP, extended over-frequency protection settings of the generator GEN-2015-021 should be adjusted to allow ride-through capability during the fault contingencies listed in Appendix A.

- The results of power factor analysis indicate that the solar farm represented by GEN-2015-021 and the wind farms represented by GEN-2015-026 and GEN-2015-027 are required to maintain a power factor of 0.95 lagging to 0.95 leading at the POI to meet SPP's requirements.

- An analysis on the project for no-wind power production due to no or low wind conditions indicated that for GEN-2015-026, which is connected to SPP's 345-kV system, applying a 4.5 Mvar, 345-kV shunt reactor on the substation high-side bus can reduce the Mvar flow into the POI to approximately zero in all three Peak cases.

- A short-circuit study has been performed on the power flow models for the 2025 Summer Peak Season for each generator using the Cluster Scenario model. A 3-phase fault is applied on buses up to 5 levels away from the POI of each interconnection request project and the results of the study have been presented.

APPENDIX A

SPP'S FAULT DEFINITIONS FOR GROUP 3

Table 10: Fault Definitions (Group 3) Specified by SPP

Cont. No.	Cont. Name	Description	GEN-2015-021	GEN-2015-026	GEN-2015-027	ASGI-2015-001
1	FLT01-3PH	3 phase fault on the Thistle 345KV (539801) to Woodward 345KV (515375) CKT 1, near Thistle. a. Apply fault at the Thistle 345KV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.				X
2	FLT02-3PH	3 phase fault on the Thistle 345KV (539801) to Woodward 345KV (515375) CKT 1 and 2, near Thistle. a. Apply fault at the Thistle 345KV bus. b. Clear fault after 5 cycles by tripping the faulted lines (CKT 1 and 2). c. Wait 20 cycles, and then re-close the lines in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the lines in (b) and remove fault.		X		X
3	FLT03-3PH	3 phase fault on the Thistle 345KV (539801) to GEN-2015-024 &GEN-2015-025 Tap 345KV (560033) CKT 1, near Thistle. a. Apply fault at the Thistle 345KV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.				X
4	FLT04-3PH	3 phase fault on the Thistle 345KV (539801) to GEN-2015-024 &GEN-2015-025 Tap 345KV (560033) CKT 1 and 2, near Thistle. a. Apply fault at the Thistle 345KV bus. b. Clear fault after 5 cycles by tripping the faulted lines (CKT 1 and 2). c. Wait 20 cycles, and then re-close the lines in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the lines in (b) and remove fault.				X
5	FLT05-3PH	3 phase fault on the Thistle 345KV (539801) to Clark County 345KV (539800) CKT 1, near Thistle. a. Apply fault at the Thistle 345KV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.		X		X
6	FLT06-3PH	3 phase fault on the Thistle 345KV (539801) to Clark County 345KV (539800) CKT 1 and 2, near Thistle. a. Apply fault at the Thistle 345KV bus. b. Clear fault after 5 cycles by tripping the faulted lines (CKT 1 and 2). c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.		X		X
7	FLT07-3PH	3 phase fault on the Thistle 345KV (539801) to Thistle 138kV (539804) to Thistle 13.8kV (539802) XMFR CKT 1, near Thistle 345kV. a. Apply fault at the Thistle 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.		X		X

Cont. No.	Cont. Name	Description	GEN-2015-021	GEN-2015-026	GEN-2015-027	ASGI-2015-001
8	FLT08-3PH	3 phase fault on the G13-010 Tap 345KV (562334) to G11-017 Tap 345KV (560242) CKT 1 near G13-010 Tap. a. Apply fault at the G13-010 Tap 345KV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.		X		
9	FLT09-3PH	3 phase fault on the Post Rock 345KV (530583) to Post Rock 230kV (530584) to Post Rock 13.8kV (530673) XMFR CKT 1, near Post Rock 345kV. a. Apply fault at the Post Rock 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.		X		
10	FLT10-3PH	3 phase fault on the Knoll 230KV (530558) to Knoll 115kV (530561) to Knoll 11.49kV (530629) XMFR CKT 1, near Knoll 230kV. a. Apply fault at the Knoll 230kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.		X		X
11	FLT11-3PH	3 phase fault on the G11-017 Tap 345KV (560242) to Spearville 345KV (531469) CKT 1 near G11-017 Tap. a. Apply fault at the G11-017 Tap 345KV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.		X		
12	FLT12-3PH	3 phase fault on the Spearville 345KV (531469) to Buckner 345KV (531501) CKT 1 near Spearville. a. Apply fault at the Spearville 345KV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.		X		X
13	FLT13-3PH	3 phase fault on the Spearville 345KV (531469) to Clark County 345KV (539800) CKT 1 near Spearville. a. Apply fault at the Spearville 345KV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.		X		
14	FLT14-3PH	3 phase fault on the Spearville 345KV (531469) to Ironwood 345KV (539803) CKT 1 near Spearville. a. Apply fault at the Spearville 345KV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.		X		
15	FLT15-3PH	3 phase fault on the Spearville 345KV (531469) to Spearville 230kV (539695) to Spearville 13.8kV (531468) XMFR CKT 1, near Spearville 345kV. a. Apply fault at the Spearville 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.		X	X	

Cont. No.	Cont. Name	Description	GEN-2015-021	GEN-2015-026	GEN-2015-027	ASGI-2015-001
16	FLT16-3PH	3 phase fault on the Spearville 345KV (531469) to Spearville 115kv (539759) to Spearville 13.8kV (539960) XMFR CKT 1, near Spearville 345kV. a. Apply fault at the Spearville 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.		X	X	
17	FLT17-3PH	3 phase fault on the Buckner 345KV (531501) to Holcomb 345KV (531449) CKT 1 near Buckner. a. Apply fault at the Buckner 345KV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.		X		
18	FLT18-3PH	3 phase fault on the Clark County 345KV (539800) to Ironwood 345KV (539803) CKT 1 near Clark County. a. Apply fault at the Clark County 345KV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.		X		
19	FLT19-3PH	3 phase fault on Clark County 345KV (539800) to Ironwood 345KV (539803) CKT 1 near Clark County. a. Apply fault at the Clark County 345KV bus. b. Clear fault after 5 cycles by tripping the faulted lines— 1. the Clark County 345KV (539800) to Ironwood 345KV (539803) CKT 1 2. the Spearville 345KV (531469) to Clark County 345KV (539800) CKT 1		X		
20	FLT20-3PH	3 phase fault on the Holcomb 345KV (531449) to Finney 345KV (523853) CKT 1 near Holcomb. a. Apply fault at the Holcomb 345KV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.		X		
21	FLT21-3PH	3 phase fault on the Finney 345KV (523853) to Hitchland 345KV (523097) CKT 1 near Finney. a. Apply fault at the Finney 345KV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.		X		
22	FLT22-3PH	3 phase fault on the Finney 345KV (523853) to Lamar 345KV (599950) CKT 1 near Finney. a. Apply fault at the Finney 345KV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Block DC tie at 599950 (SPP_43_Lamar). From LAMAR 345 kV(599950) to LAMAR 230kV (599951)		X		

Cont. No.	Cont. Name	Description	GEN-2015-021	GEN-2015-026	GEN-2015-027	ASGI-2015-001
23	FLT23-3PH	3 phase fault on the Setab 345KV (531465) to Mingo 345KV (531451) CKT 1 near Setab. a. Apply fault at the Setab 345KV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.		X		
24	FLT24-3PH	3 phase fault on the Mingo 345KV (531451) to Red Willow 345KV (640325) CKT 1 near Mingo. a. Apply fault at the Mingo 345KV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.		X		
25	FLT25-3PH	3 phase fault on the Hitchland 345KV (523097) to G14-037 Tap 345KV (560010) CKT 1 near Hitchland. a. Apply fault at the Hitchland 345KV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.		X		
26	FLT26-3PH	3 phase fault on the Hitchland 345KV (523097) to G14-037 Tap 345KV (560010) CKT 1 and 2, near Hitchland. a. Apply fault at the Hitchland 345KV bus. b. Clear fault after 5 cycles by tripping the faulted lines (CKT 1 and 2). c. Wait 20 cycles, and then re-close the lines in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the lines in (b) and remove fault.		X		
27	FLT27-3PH	3 phase fault on the Hitchland 345KV (523097) to G14-038 Tap 345KV (560011) CKT 1 near Hitchland. a. Apply fault at the Hitchland 345KV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.		X		
28	FLT28-3PH	3 phase fault on the Hitchland 345KV (523097) to Hitchland 230kv (523095) to Hitchland 13.8kV (523091) XMFR CKT 1, near Hitchland 345kV. a. Apply fault at the Hitchland 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.		X		
29	FLT29-3PH	3 phase fault on the Mingo 345KV (531451) to Mingo 115kv (531429) to Mingo 13.8kV (531452) XMFR CKT 1, near Mingo 345kV. a. Apply fault at the Mingo 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.		X		
30	FLT30-3PH	3 phase fault on the Holcomb 345KV (539449) to Setab 345KV (531465) CKT 1 near Holcomb. a. Apply fault at the Holcomb 345KV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.		X		

Cont. No.	Cont. Name	Description	GEN-2015-021	GEN-2015-026	GEN-2015-027	ASGI-2015-001
31	FLT31-3PH	3 phase fault on the Holcomb 345KV (531449) to Holcomb 115kv (531448) to Holcomb 13.8kV (531450) XMFR CKT 1, near Holcomb 345kV. a. Apply fault at the Holcomb 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.		X		
32	FLT32-3PH	3 phase fault on the Setab 345KV (531465) to Setab 115kv (531464) to Setab 13.8kV (531259) XMFR CKT 1, near Setab 345kV. a. Apply fault at the Setab 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.		X		
33	FLT33-PO	**Prior outage on the Thistle – Clark County 345kV CKT 1** 3 phase fault on Thistle (539801) to Woodward (515375)) 345kV CKT 1 a. Prior outage Thistle (539801) to Clark County (539800)) 345kV CKT 1 (solve network for steady state solution) b. 3 phase fault on the Thistle (539801) to Woodward (515375) 345kV CKT 1 line near Thistle c. Clear fault after 5 cycles and trip the faulted line. d. Wait 20 cycles, and then re-close the line in (b) back into the fault. e. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.		X		
34	FLT34- PO	**Prior outage on the the GEN-2015-024 & GEN-2015-025 Tap – Wichita 345kV CKT 1 line** 3 phase fault on Thistle (539801) to Clark County (539800) 345kV CKT 1 a. Prior outage GEN-2015-024 & GEN-2015-025 Tap (560033) to Wichita (532796) CKT 1 345kV line (solve network for steady state solution) b. 3 phase fault on the Thistle (539801) to Clark County (539800) 345kV CKT 1 line near Thistle c. Clear fault after 5 cycles and trip the faulted line. d. Wait 20 cycles, and then re-close the line in (b) back into the fault. e. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.		X		
35	FLT35-PO	**Prior outage on the Spearville – Buckner 345kV line** 3 phase fault on GEN 2013-010-TAP (562334) to Post Rock (530583) a. Prior outage the Spearville (531469) to Buckner (531501) 345kV line (solve network for steady state solution) b. 3 phase fault on the GEN 2013-010-TAP (562334) to Post Rock (530583) 345kV line near GEN 2013-010-TAP c. Clear fault after 5 cycles and trip the faulted line. d. Wait 20 cycles, and then re-close the line in (b) back into the fault. e. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.		X		
36	FLT36-SB	**Thistle 345kV Stuck Breaker** a. Apply single phase fault at the Thistle (539801) 345kV bus b. Wait 16 cycles, and then drop Thistle (539801) – Woodward (515375) 345kV circuit 1 and remove fault		X		

Cont. No.	Cont. Name	Description	GEN-2015-021	GEN-2015-026	GEN-2015-027	ASGI-2015-001
37	FLT37-SB	**Thistle 345kV Stuck Breaker** a. Apply single phase fault at the Thistle (539801) 345kV bus b. Wait 16 cycles, and then drop Thistle (539801) – GEN-2015-024 & GEN-2015-025 Tap (560033) 345kV circuit 1 and remove fault		X		
38	FLT38-SB	**Thistle 345kV Stuck Breaker** a. Apply single phase fault at the Thistle (539801) 345kV bus b. Wait 16 cycles, and then drop Thistle (539801) – Clark County (539800) 345kV circuit 1 and remove fault		X		
39	FLT39-SB	**Thistle 345kV Stuck Breaker** a. Apply single phase fault at the Thistle (539801) 345kV bus b. Wait 16 cycles, and then drop Thistle (539801) 345kV – Thistle (539804) 138kV transformer circuit 1 and Thistle 13.8 kV (539802) and remove fault		X		
40	FLT40-PO	**Prior outage on the Spearville – Clark County 345kV line** 3 phase fault on Spearville (531469) to Buckner (531501) 345kV a. Prior outage the Spearville (531469) to Clark County (539800) 345kV line (solve network for steady state solution) b. 3 phase fault on the Spearville (531469) to Buckner (531501) 345kV line near Spearville c. Clear fault after 5 cycles and trip the faulted line. d. Wait 20 cycles, and then re-close the line in (b) back into the fault. e. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.		X		
41	FLT41-3PH	3 phase fault on the Ninnescah (539648) to RVRoad (539651) 115kV line ckt 1, near Ninnescah. a. Apply fault at the Ninnescah 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.				X
42	FLT42-3PH	3 phase fault on the Ninnescah (539648) to St. John (539696) 115kV line ckt 1, near Ninnescah. a. Apply fault at the Ninnescah 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.				X
43	FLT43-3PH	3 phase fault on the Seward (539692) to SEWRDMW (530679) 115kV line ckt 1, near Seward. a. Apply fault at the Seward 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.				X

Cont. No.	Cont. Name	Description	GEN-2015-021	GEN-2015-026	GEN-2015-027	ASGI-2015-001
44	FLT44-3PH	3 phase fault on the Seward (539692) to Great Bend Tap (539666) 115kV line ckt 1, near Seward. a. Apply fault at the Seward 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.				X
45	FLT45-3PH	3 phase fault on the St. John (530624) to Huntsville (530618) 115kV line ckt 1, near St. John. a. Apply fault at the St. John 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.				X
46	FLT46-3PH	3 phase fault on the Barber (539760) to Medicine Lodge (539673) 115kV line ckt 1, near Barber. a. Apply fault at the Barber 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.				X
47	FLT47-3PH	3 phase fault on the Barber (539760) 115kV to Barber (539674) 138kV/(539917) 2.72kV transformer at the 115kV bus. a. Apply fault at the Barber 115kV bus. b. Clear fault after 5 cycles by tripping the transformer				X
48	FLT48-3PH	3 phase fault on the Flatridge (539638) to Harper (539668) 138kV line ckt 1, near Flatridge. a. Apply fault at the Flatridge 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.				X
49	FLT49-3PH	3 phase fault on the Flatridge (539638) to Harper (539668) 138kV line ckt 1, near Flatridge. a. Apply fault at the Flatridge 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.				X
50	FLT50-3PH	3 phase fault on the Flatridge (539638) to Thistle (539804) 138kV line ckt 1, near Flatridge. a. Apply fault at the Flatridge 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.				X
51	FLT51-3PH	3 phase fault on the HEC (533419) to Huntsville (530618) 115kV line ckt 1, near HEC. a. Apply fault at the HEC 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.				X

Cont. No.	Cont. Name	Description	GEN-2015-021	GEN-2015-026	GEN-2015-027	ASGI-2015-001
52	FLT52-3PH	3 phase fault on the HEC (533419) to Circle (533413) 115kV line ckt 1, near HEC. a. Apply fault at the HEC 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.				X
53	FLT53-3PH	3 phase fault on the HEC (533419) to 43Loran (533440) 115kV line ckt 1, near HEC. a. Apply fault at the HEC 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.				X
54	FLT54-3PH	3 phase fault on the Circle (533413) 115kV to Circle (532871) 230kV/(532892) 13.8kV transformer at the 115kV bus. a. Apply fault at the Circle 115kV bus. b. Clear fault after 5 cycles by tripping the transformer				X
55	FLT55-3PH	3 phase fault on the Great Bend (539678) 115kV to Great Bend (539679) 138kV/(539920) 13.8kV transformer at the 115kV bus. a. Apply fault at the Great Bend 115kV bus. b. Clear fault after 5 cycles by tripping the transformer				X
56	FLT56-3PH	3 phase fault on the Johnson Corner (531424) to Johnson (531381) 115kV line ckt 1, near Johnson Corner. a. Apply fault at the Johnson Corner 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	X			
57	FLT57-3PH	3 phase fault on the Johnson Corner (531424) to Bear Creek (531473) 115kV line ckt 1, near Johnson Corner. a. Apply fault at the Johnson Corner 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	X			
58	FLT58-3PH	3 phase fault on the Syracuse (531437) to Bear Creek (531473) 115kV line ckt 1, near Syracuse. a. Apply fault at the Syracuse 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	X			
59	FLT59-3PH	3 phase fault on the Syracuse (531437) to Tribune (531439) 115kV line ckt 1, near Syracuse. a. Apply fault at the Syracuse 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	X			

Cont. No.	Cont. Name	Description	GEN-2015-021	GEN-2015-026	GEN-2015-027	ASGI-2015-001
60	FLT60-3PH	3 phase fault on the Syracuse (531437) to Williamson (531440) 115kV line ckt 1, near Syracuse. a. Apply fault at the Syracuse 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	X			
61	FLT61-3PH	3 phase fault on the Tribune Switch (531438) to Palmer (531431) 115kV line ckt 1, near Tribune Switch. a. Apply fault at the Tribune Switch 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	X			
62	FLT62-3PH	3 phase fault on the Tribune Switch (531438) to Selkirk (531434) 115kV line ckt 1, near Tribune Switch. a. Apply fault at the Tribune Switch 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	X			
63	FLT63-3PH	3 phase fault on the Tribune Switch (531438) to Tribune (531439) 115kV line ckt 1, near Tribune Switch. a. Apply fault at the Tribune Switch 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	X			
64	FLT64-3PH	3 phase fault on the Fletcher (531420) to PK_GOAB (531400) 115kV line ckt 1, near Fletcher. a. Apply fault at the Fletcher 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	X			
65	FLT65-3PH	3 phase fault on the Fletcher (531420) to Williamson (531440) 115kV line ckt 1, near Fletcher. a. Apply fault at the Fletcher 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	X			
66	FLT66-3PH	3 phase fault on the Fletcher (531420) to Holcomb (531448) 115kV line ckt 1, near Fletcher. a. Apply fault at the Fletcher 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	X			

Cont. No.	Cont. Name	Description	GEN-2015-021	GEN-2015-026	GEN-2015-027	ASGI-2015-001
67	FLT67-3PH	3 phase fault on the Pioneer (531391) to Hickock (531378) 115kV line ckt 1, near Pioneer. a. Apply fault at the Pioneer 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	X			
68	FLT68-3PH	3 phase fault on the Pioneer (531391) to PK_GOAB (531400) 115kV line ckt 1, near Pioneer. a. Apply fault at the Pioneer 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	X			
69	FLT69-3PH	3 phase fault on the Pioneer (531391) to Grant Tap (531483) 115kV line ckt 1, near Pioneer. a. Apply fault at the Pioneer 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	X			
70	FLT70-3PH	3 phase fault on the Pioneer (531391) to Ulysses Plant (531490) 115kV line ckt 1, near Pioneer. a. Apply fault at the Pioneer 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	X			
71	FLT71-3PH	3 phase fault on the Pioneer Tap (531392) to CMX Tap (531203) 115kV line ckt 1, near Pioneer Tap. a. Apply fault at the Pioneer Tap 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	X			
72	FLT72-3PH	3 phase fault on the Pioneer Tap (531392) to Plymel (531393) 115kV line ckt 1, near Pioneer Tap. a. Apply fault at the Pioneer Tap 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	X			
73	FLT73-3PH	3 phase fault on the Pioneer Tap (531392) to Sublette (531398) 115kV line ckt 1, near Pioneer Tap. a. Apply fault at the Pioneer Tap 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	X			

Cont. No.	Cont. Name	Description	GEN-2015-021	GEN-2015-026	GEN-2015-027	ASGI-2015-001
74	FLT74-3PH	3 phase fault on the Pioneer Tap (531392) to Satanta Tap (531442) 115kV line ckt 1, near Pioneer Tap. a. Apply fault at the Pioneer Tap 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	X			
75	FLT75-3PH	3 phase fault on the Crooked Creek (539783) to Cudahy (539659) 115kV line ckt 1, near Crooked Creek. a. Apply fault at the Crooked Creek 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.			X	
76	FLT76-3PH	3 phase fault on the Crooked Creek (539783) to Ft. Dodge (539671) 115kV line ckt 1, near Crooked Creek. a. Apply fault at the Crooked Creek 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.			X	
77	FLT77-3PH	3 phase fault on the Cimarron River Tap (539652) to Kismet (539646) 115kV line ckt 1, near Cimarron River Tap. a. Apply fault at the Cimarron River Tap 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.			X	
78	FLT78-3PH	3 phase fault on the Cimarron River Tap (539652) to Cimarron Plant (539654) 115kV line ckt 1, near Cimarron River Tap. a. Apply fault at the Cimarron River Tap 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.			X	
79	FLT79-3PH	3 phase fault on the Cimarron River Tap (539652) to East Liberal (539672) 115kV line ckt 1, near Cimarron River Tap. a. Apply fault at the Cimarron River Tap 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.			X	
80	FLT80-3PH	3 phase fault on the Cimarron River Plant (539654) to Walkmeyer (531405) 115kV line ckt 1, near Cimarron River Plant. a. Apply fault at the Cimarron River Plant 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.			X	

Cont. No.	Cont. Name	Description	GEN-2015-021	GEN-2015-026	GEN-2015-027	ASGI-2015-001
81	FLT81-3PH	3 phase fault on the Cimarron River Plant (539654) to Hayne (539640) 115kV line ckt 1, near Cimarron River Plant. a. Apply fault at the Cimarron River Plant 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.			X	
82	FLT82-3PH	3 phase fault on the Seward (531467) to North Cimarron (539749) 115kV line ckt 1, near Seward. a. Apply fault at the Seward 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.			X	
83	FLT83-3PH	3 phase fault on the Ft. Dodge (539671) to DC Beef (539645) 115kV line ckt 1, near Ft. Dodge. a. Apply fault at the Ft. Dodge 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.			X	
84	FLT84-3PH	3 phase fault on the North Ft. Dodge (539771) to Ft. Dodge (539671) 115kV line ckt 2, near North Ft. Dodge. a. Apply fault at the North Ft. Dodge 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.			X	
85	FLT85-3PH	3 phase fault on the North Ft. Dodge (539771) to South Dodge (539688) 115kV line ckt 1, near North Ft. Dodge. a. Apply fault at the North Ft. Dodge 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.			X	
86	FLT86-3PH	3 phase fault on the North Ft. Dodge (539771) to Spearville (539694) 115kV line ckt 1, near North Ft. Dodge. a. Apply fault at the North Ft. Dodge 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.			X	
87	FLT87-3PH	3 phase fault on the North Ft. Dodge (539771) to Ford (539758) 115kV line ckt 1, near North Ft. Dodge. a. Apply fault at the North Ft. Dodge 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.			X	

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Cont. No.	Cont. Name	Description	GEN-2015-021	GEN-2015-026	GEN-2015-027	ASGI-2015-001
88	FLT88-3PH	3 phase fault on the North Ft. Dodge (539771) to Spearville (539759) 115kV line ckt 1, near North Ft. Dodge. a. Apply fault at the North Ft. Dodge 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.			X	
89	FLT89-3PH	3 phase fault on the Wichita 345KV (532796) to GEN-2015-024 & GEN-2015-025 Tap 345KV (560033) CKT 1, near GEN-2015-024 & GEN-2015-025 Tap. a. Apply fault at the GEN-2015-024 & GEN-2015-025 Tap 345KV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.				X
90	FLT90-3PH	3 phase fault on the Wichita 345KV (532796) to GEN-2015-024 & GEN-2015-025 Tap 345KV (560033) CKT 1 and 2, near GEN-2015-024 & GEN-2015-025 Tap. a. Apply fault at the GEN-2015-024 & GEN-2015-025 Tap 345KV bus. b. Clear fault after 5 cycles by tripping the faulted lines (CKT 1 and 2). c. Wait 20 cycles, and then re-close the lines in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the lines in (b) and remove fault.				X

APPENDIX B

SOUTHWEST POWER POOL DISTURBANCE PERFORMANCE REQUIREMENTS

OVERVIEW

These Disturbance Performance Requirements ("Requirements") shall be applicable to the Bulk Electric System within the Southwest Power Pool Planning Area. Utilization of these Requirements applies to all registered entities within the Southwest Power Pool Planning Area. These Requirements shall not be applicable to facilities that are not part of Bulk Electric System. More stringent Requirements are at the sole discretion of each Transmission Owner.

Transient and dynamic stability assessments are generally performed to assure adequate avoidance of loss of generator synchronism and prevention of system voltage collapse within the first 20 seconds after a system disturbance. These Requirements provide a basis for evaluating the system response during the initial transient period following a disturbance on the Bulk Electric System by establishing minimum requirements for machine rotor angle damping and transient voltage recovery.

ROTOR ANGLE DAMPING REQUIREMENT

Machine Rotor Angles shall exhibit well damped angular oscillations [as defined below] and acceptable power swings following a disturbance on the Bulk Electric System for all NERC Category A, B and C events.

Well damped angular oscillations shall meet one of the following two requirements when calculated directly from the rotor angle:

1. Successive Positive Peak Ratio (SPPR) must be less than or equal to 0.95 where SPPR is calculated as follows:

$$\text{SPPR} = \frac{\text{Peak Rotor Angle of } 2^{nd} \text{ Positive Swing Peak}}{\text{Peak Rotor Angle of } 1^{st} \text{ Positive Swing Peak}} \leq 0.95$$

   -or- Damping Factor % = (1 – SPPR) x 100% $\geq$ 5%

   The machine rotor angle damping ratio may be determined by appropriate modal analysis (i.e. Prony Analysis) where the following equivalent requirement must be met:

   Damping Ratio $\geq$ 0.0081633

2. Successive Positive Peak Ratio Five (SPPR5) must be less than or equal to 0.774 where SPPR5 is calculated as follows:

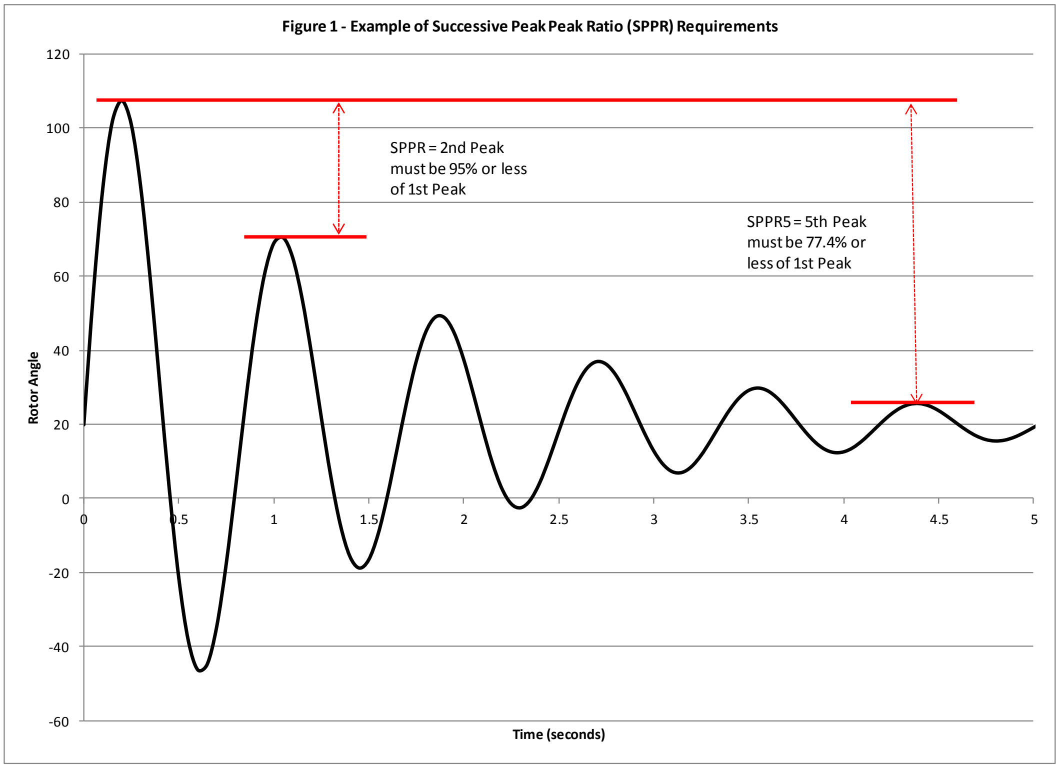
$$\text{SPPR5} = \frac{\text{Peak Rotor Angle of } 5^{th} \text{ Positive Swing Peak}}{\text{Peak Rotor Angle of } 1^{st} \text{ Positive Swing Peak}} \leq 0.774$$

   -or- Damping Factor % = (1 – SPPR) x 100% $\geq$ 22.6%

The machine rotor angle damping ratio may be determined by appropriate modal analysis (i.e. Prony Analysis) where the following equivalent requirement must be met:

Damping Ratio ≥ 0.0081633

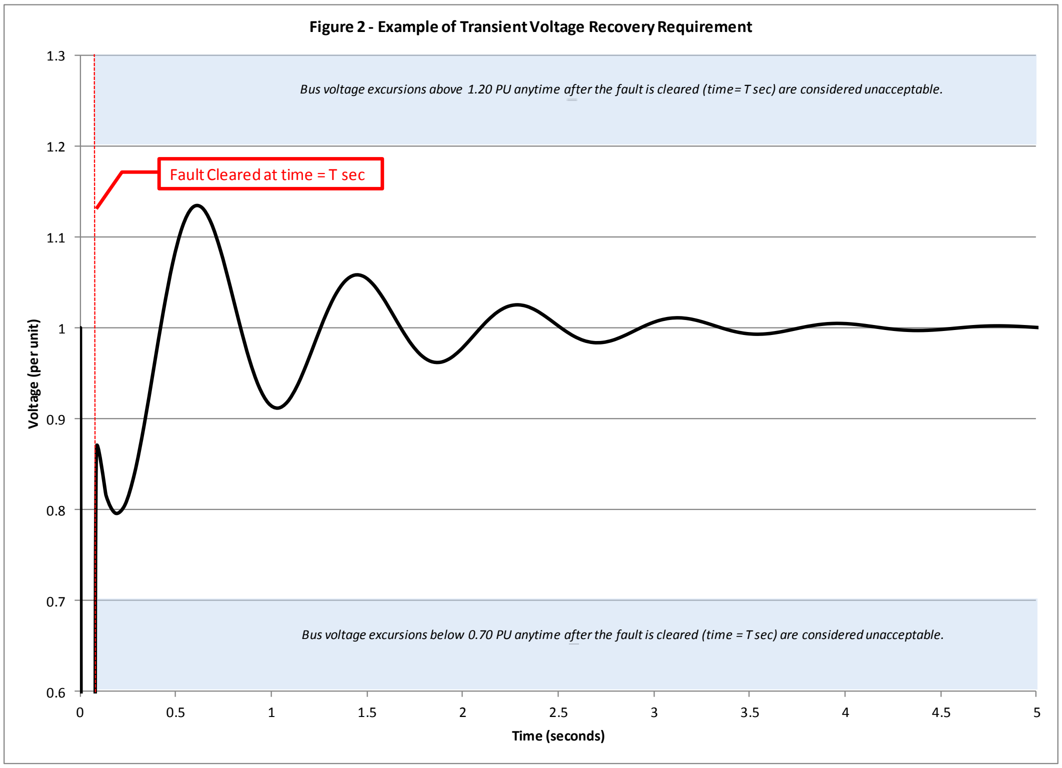
Qualitatively, these Requirements are shown below:



TRANSIENT VOLTAGE RECOVERY REQUIREMENT

Any time after a disturbance is cleared; bus voltages on the Bulk Electric System shall not swing outside of the bandwidth of 0.70 per unit to 1.20 per unit.

Qualitatively, this Requirement is shown below:



APPENDIX C

DYNAMIC STABILITY PLOTS FOR CLUSTER SCENARIO

1)

DYNAMIC STABILITY PLOTS FOR 2015 SUMMER PEAK CASE

(SEE APPENDIX C-1 SUBMITTED IN A SEPARATE FILE)

2)

DYNAMIC STABILITY PLOTS FOR 2015 WINTER PEAK CASE

(SEE APPENDIX C-2 SUBMITTED IN A SEPARATE FILE)

3)

DYNAMIC STABILITY PLOTS FOR 2025 SUMMER PEAK CASE

(SEE APPENDIX C-3 SUBMITTED IN A SEPARATE FILE)

APPENDIX D

DYNAMIC STABILITY PLOTS FOR STAND-ALONE SCENARIO

1)

"GEN-2015-021"

DYNAMIC STABILITY PLOTS FOR 2015 SUMMER PEAK CASE

(SEE APPENDIX D-1 SUBMITTED IN A SEPARATE FILE)

2)

"GEN-2015-021"

DYNAMIC STABILITY PLOTS FOR 2015 WINTER PEAK CASE

(SEE APPENDIX D-2 SUBMITTED IN A SEPARATE FILE)

3)

"GEN-2015-021"

DYNAMIC STABILITY PLOTS FOR 2025 SUMMER PEAK CASE

(SEE APPENDIX D-3 SUBMITTED IN A SEPARATE FILE)

4)

"GEN-2015-026"

DYNAMIC STABILITY PLOTS FOR 2015 SUMMER PEAK CASE

(SEE APPENDIX D-4 SUBMITTED IN A SEPARATE FILE)

5)

"GEN-2015-026"

DYNAMIC STABILITY PLOTS FOR 2015 WINTER PEAK CASE

(SEE APPENDIX D-5 SUBMITTED IN A SEPARATE FILE)

6)

"GEN-2015-026"

DYNAMIC STABILITY PLOTS FOR 2025 SUMMER PEAK CASE

(SEE APPENDIX D-6 SUBMITTED IN A SEPARATE FILE)

7)

"GEN-2015-027"

DYNAMIC STABILITY PLOTS FOR 2015 SUMMER PEAK CASE

(SEE APPENDIX D-7 SUBMITTED IN A SEPARATE FILE)

8)

"GEN-2015-027"

DYNAMIC STABILITY PLOTS FOR 2015 WINTER PEAK CASE

(SEE APPENDIX D-8 SUBMITTED IN A SEPARATE FILE)

9)

"GEN-2015-027"

DYNAMIC STABILITY PLOTS FOR 2025 SUMMER PEAK CASE

(SEE APPENDIX D-9 SUBMITTED IN A SEPARATE FILE)

10)

"ASGI-2015-001"

DYNAMIC STABILITY PLOTS FOR 2015 SUMMER PEAK CASE

(SEE APPENDIX D-10 SUBMITTED IN A SEPARATE FILE)

11)

"ASGI-2015-001"

DYNAMIC STABILITY PLOTS FOR 2015 WINTER PEAK CASE

(SEE APPENDIX D-11 SUBMITTED IN A SEPARATE FILE)

12)

"ASGI-2015-001"

DYNAMIC STABILITY PLOTS FOR 2025 SUMMER PEAK CASE

(SEE APPENDIX D-12 SUBMITTED IN A SEPARATE FILE)

APPENDIX E

POWER FACTOR ANALYSIS RESULTS

Power Factor Requirements for GEN-2015-021 Interconnection Request

	2015 Summer Peak				2015 Winter Peak				2025 Summer Peak			
Cont. No.	P (MW)	Q (MVAR)	Power Factor		P (MW)	Q (MVAR)	Power Factor		P (MW)	Q (MVAR)	Power Factor	
0	20.0	-0.2	1.00	leading	20.0	-0.8	1.00	leading	20.0	-1.3	1.00	leading
1	20.0	-0.1	1.00	leading	20.0	-0.5	1.00	leading	20.0	-0.8	1.00	leading
3	20.0	0.2	1.00	lagging	20.0	-0.2	1.00	leading	20.0	-1.0	1.00	leading
5	20.0	1.5	1.00	lagging	20.0	1.5	1.00	lagging	20.0	0.5	1.00	lagging
7	20.0	-0.2	1.00	leading	20.0	-0.8	1.00	leading	20.0	-1.3	1.00	leading
8	20.0	3.1	0.99	lagging	20.0	2.6	0.99	lagging	20.0	1.6	1.00	lagging
9	20.0	0.5	1.00	lagging	20.0	-0.2	1.00	leading	20.0	-0.7	1.00	leading
10	20.0	-0.1	1.00	leading	20.0	-0.7	1.00	leading	20.0	-1.2	1.00	leading
11	20.0	1.3	1.00	lagging	20.0	0.8	1.00	lagging	20.0	0.0	1.00	
12	20.0	3.1	0.99	lagging	20.0	1.6	1.00	lagging	20.0	2.3	0.99	lagging
13	20.0	0.1	1.00	lagging	20.0	-0.4	1.00	leading	20.0	-0.9	1.00	leading
14	20.0	-0.3	1.00	leading	20.0	-0.9	1.00	leading	20.0	-1.3	1.00	leading
15	20.0	-0.1	1.00	leading	20.0	-0.7	1.00	leading	20.0	-1.2	1.00	leading
16	20.0	-0.3	1.00	leading	20.0	-0.7	1.00	leading	20.0	-1.3	1.00	leading
17	20.0	-5.4	0.97	leading	20.0	-4.0	0.98	leading	20.0	-5.4	0.97	leading
18	20.0	0.1	1.00	lagging	20.0	-0.4	1.00	leading	20.0	-0.9	1.00	leading
20	20.0	2.0	1.00	lagging	20.0	2.0	1.00	lagging	20.0	1.1	1.00	lagging
21	20.0	3.6	0.98	lagging	20.0	2.5	0.99	lagging	20.0	3.9	0.98	lagging
23	20.0	3.2	0.99	lagging	20.0	1.6	1.00	lagging	20.0	2.5	0.99	lagging
24	20.0	0.9	1.00	lagging	20.0	0.8	1.00	lagging	20.0	0.2	1.00	lagging
25	20.0	-0.2	1.00	leading	20.0	-0.7	1.00	leading	20.0	-1.2	1.00	leading
27	20.0	-0.1	1.00	leading	20.0	-0.6	1.00	leading	20.0	-1.0	1.00	leading
28	20.0	0.0	1.00		20.0	-0.6	1.00	leading	20.0	-0.9	1.00	leading
29	20.0	-0.2	1.00	leading	20.0	-0.4	1.00	leading	20.0	-1.2	1.00	leading
30	20.0	2.9	0.99	lagging	20.0	1.0	1.00	lagging	20.0	2.0	1.00	lagging
31	20.0	9.7	0.90	lagging	20.0	8.7	0.92	lagging	20.0	8.3	0.92	lagging
32	20.0	1.8	1.00	lagging	20.0	1.4	1.00	lagging	20.0	0.7	1.00	lagging
33	20.0	1.6	1.00	lagging	20.0	1.7	1.00	lagging	20.0	0.9	1.00	lagging
34	20.0	1.6	1.00	lagging	20.0	1.6	1.00	lagging	20.0	0.6	1.00	lagging
35	20.0	4.0	0.98	lagging	20.0	2.8	0.99	lagging	20.0	1.9	1.00	lagging
40	20.0	2.2	0.99	lagging	20.0	1.7	1.00	lagging	20.0	2.2	0.99	lagging
41	20.0	-1.3	1.00	leading	20.0	-0.8	1.00	leading	20.0	-1.3	1.00	leading
42	20.0	-1.3	1.00	leading	20.0	-0.8	1.00	leading	20.0	-1.3	1.00	leading
43	20.0	-1.3	1.00	leading	20.0	-0.8	1.00	leading	20.0	-1.3	1.00	leading
44	20.0	-1.2	1.00	leading	20.0	-0.7	1.00	leading	20.0	-1.2	1.00	leading
45	20.0	-1.2	1.00	leading	20.0	-0.7	1.00	leading	20.0	-1.2	1.00	leading

46	20.0	-1.2	1.00	leading	20.0	-0.4	1.00	leading	20.0	-1.2	1.00	leading
47	20.0	-1.3	1.00	leading	20.0	-0.7	1.00	leading	20.0	-1.3	1.00	leading
48	20.0	-1.2	1.00	leading	20.0	-0.6	1.00	leading	20.0	-1.2	1.00	leading
49	20.0	-1.2	1.00	leading	20.0	-0.6	1.00	leading	20.0	-1.2	1.00	leading
50	20.0	-1.3	1.00	leading	20.0	-0.8	1.00	leading	20.0	-1.3	1.00	leading
51	20.0	-1.2	1.00	leading	20.0	-0.7	1.00	leading	20.0	-1.2	1.00	leading
52	20.0	-1.3	1.00	leading	20.0	-0.8	1.00	leading	20.0	-1.3	1.00	leading
53	20.0	-1.3	1.00	leading	20.0	-0.8	1.00	leading	20.0	-1.3	1.00	leading
54	20.0	-1.2	1.00	leading	20.0	-0.7	1.00	leading	20.0	-1.2	1.00	leading
55	20.0	-1.2	1.00	leading	20.0	-0.7	1.00	leading	20.0	-1.2	1.00	leading
56	20.0	-16.1	0.78	leading	20.0	-4.7	0.97	leading	20.0	-16.1	0.78	leading
57	20.0	-11.3	0.87	leading	20.0	-1.6	1.00	leading	20.0	-11.3	0.87	leading
58	20.0	-8.9	0.91	leading	20.0	-1.2	1.00	leading	20.0	-8.9	0.91	leading
59	20.0	-0.6	1.00	leading	20.0	1.8	1.00	lagging	20.0	-0.6	1.00	leading
60	20.0	-5.5	0.96	leading	20.0	-3.1	0.99	leading	20.0	-5.5	0.96	leading
61	20.0	-0.2	1.00	leading	20.0	-0.6	1.00	leading	20.0	-1.4	1.00	leading
62	20.0	1.6	1.00	lagging	20.0	0.7	1.00	lagging	20.0	0.1	1.00	lagging
63	20.0	0.9	1.00	lagging	20.0	0.7	1.00	lagging	20.0	-1.1	1.00	leading
64	20.0	4.3	0.98	lagging	20.0	3.7	0.98	lagging	20.0	4.1	0.98	lagging
65	20.0	-3.3	0.99	leading	20.0	-3.3	0.99	leading	20.0	-5.3	0.97	leading
66	20.0	-1.1	1.00	leading	20.0	-2.8	0.99	leading	20.0	-2.3	0.99	leading
67	20.0	3.9	0.98	lagging	20.0	-0.5	1.00	leading	20.0	3.3	0.99	lagging
68	20.0	3.9	0.98	lagging	20.0	3.4	0.99	lagging	20.0	3.6	0.98	lagging
69	20.0	-8.1	0.93	leading	20.0	-7.4	0.94	leading	20.0	-10.2	0.89	leading
70	20.0	7.3	0.94	lagging	20.0	2.9	0.99	lagging	20.0	4.0	0.98	lagging
71	20.0	-1.8	1.00	leading	20.0	-1.8	1.00	leading	20.0	-2.8	0.99	leading
72	20.0	3.5	0.99	lagging	20.0	4.9	0.97	lagging	20.0	3.0	0.99	lagging
73	20.0	-0.2	1.00	leading	20.0	-0.8	1.00	leading	20.0	-1.3	1.00	leading
74	20.0	-1.7	1.00	leading	20.0	-0.1	1.00	leading	20.0	0.9	1.00	lagging
75	20.0	4.5	0.98	lagging	20.0	4.9	0.97	lagging	20.0	3.6	0.98	lagging
76	20.0	-0.3	1.00	leading	20.0	-0.8	1.00	leading	20.0	-1.4	1.00	leading
77	20.0	3.3	0.99	lagging	20.0	4.1	0.98	lagging	20.0	2.3	0.99	lagging
78	20.0	0.1	1.00	lagging	20.0	0.0	1.00		20.0	-1.1	1.00	leading
79	20.0	0.0	1.00		20.0	-0.5	1.00	leading	20.0	-1.0	1.00	leading
80	20.0	-0.7	1.00	leading	20.0	-3.2	0.99	leading	20.0	-0.3	1.00	leading
81	20.0	-0.4	1.00	leading	20.0	-1.0	1.00	leading	20.0	-1.5	1.00	leading
82	20.0	0.8	1.00	lagging	20.0	-0.8	1.00	leading	20.0	-0.1	1.00	leading
83	20.0	-0.2	1.00	leading	20.0	-0.8	1.00	leading	20.0	-1.3	1.00	leading
84	20.0	-0.2	1.00	leading	20.0	-0.8	1.00	leading	20.0	-1.3	1.00	leading
85	20.0	-0.2	1.00	leading	20.0	-0.8	1.00	leading	20.0	-1.3	1.00	leading
86	20.0	-0.3	1.00	leading	20.0	-0.7	1.00	leading	20.0	-1.3	1.00	leading

87	20.0	-0.2	1.00	leading	20.0	-0.7	1.00	leading	20.0	-1.3	1.00	leading
88	20.0	-0.3	1.00	leading	20.0	-0.7	1.00	leading	20.0	-1.3	1.00	leading
89	20.0	-0.1	1.00	leading	20.0	-0.6	1.00	leading	20.0	-1.1	1.00	leading

Power Factor Requirements for GEN-2015-026 Interconnection Request

Cont. No.	2015 Summer Peak P (MW)	Q (MVAR)	Power Factor		2015 Winter Peak P (MW)	Q (MVAR)	Power Factor		2025 Summer Peak P (MW)	Q (MVAR)	Power Factor	
0	173.9	-18.2	0.99	leading	173.9	-20.5	0.99	leading	173.88	-19.7	0.99	leading
1	173.9	-1.0	1.00	leading	173.9	-1.2	1.00	leading	173.88	0.6	1.00	lagging
3	173.9	-1.5	1.00	leading	173.9	-1.6	1.00	leading	173.88	-8.8	1.00	leading
5	173.9	70.2	0.93	lagging	173.9	75.2	0.92	lagging	173.88	65.3	0.94	lagging
7	173.9	-19.6	0.99	leading	173.9	-20.8	0.99	leading	173.88	-21.9	0.99	leading
8	173.9	106.6	0.85	lagging	173.9	109.4	0.85	lagging	173.88	92.4	0.88	lagging
9	173.9	2.4	1.00	lagging	173.9	2.4	1.00	lagging	173.88	-1.3	1.00	leading
10	173.9	-17.2	1.00	leading	173.9	-19.4	0.99	leading	173.88	-22.7	0.99	leading
11	173.9	40.1	0.97	lagging	173.9	40.6	0.97	lagging	173.88	35.8	0.98	lagging
12	173.9	-39.7	0.97	leading	173.9	-58.9	0.95	leading	173.88	-22.9	0.99	leading
13	173.9	0.6	1.00	lagging	173.9	-1.9	1.00	leading	173.88	-1.5	1.00	leading
14	173.9	-24.3	0.99	leading	173.9	-29.0	0.99	leading	173.88	-27.9	0.99	leading
15	173.9	-36.4	0.98	leading	173.9	-35.7	0.98	leading	173.88	-33.0	0.98	leading
16	173.9	-19.9	0.99	leading	173.9	-21.6	0.99	leading	173.88	-22.6	0.99	leading
17	173.9	117.9	0.83	lagging	173.9	141.5	0.78	lagging	173.88	100.4	0.87	lagging
18	173.9	1.8	1.00	lagging	173.9	-0.5	1.00	leading	173.88	0.4	1.00	lagging
20	173.9	36.7	0.98	lagging	173.9	34.5	0.98	lagging	173.88	26.1	0.99	lagging
21	173.9	56.1	0.95	lagging	173.9	38.9	0.98	lagging	173.88	74.7	0.92	lagging
23	173.9	38.5	0.98	lagging	173.9	28.3	0.99	lagging	173.88	39.4	0.98	lagging
24	173.9	29.1	0.99	lagging	173.9	31.2	0.98	lagging	173.88	28.0	0.99	lagging
25	173.9	-17.6	0.99	leading	173.9	-19.9	0.99	leading	173.88	-19.0	0.99	leading
27	173.9	-15.3	1.00	leading	173.9	-17.4	1.00	leading	173.88	-16.1	1.00	leading
28	173.9	-18.1	0.99	leading	173.9	-20.2	0.99	leading	173.88	-19.5	0.99	leading
29	173.9	-21.3	0.99	leading	173.9	-22.3	0.99	leading	173.88	-22.6	0.99	leading
30	173.9	44.0	0.97	lagging	173.9	42.0	0.97	lagging	173.88	40.2	0.97	lagging
31	173.9	-45.0	0.97	leading	173.9	-41.9	0.97	leading	173.88	-44.9	0.97	leading
32	173.9	-22.9	0.99	leading	173.9	-20.9	0.99	leading	173.88	-25.1	0.99	leading
33	173.9	86.3	0.90	lagging	173.9	95.3	0.88	lagging	173.88	81.6	0.91	lagging
34	173.9	75.9	0.92	lagging	173.9	81.7	0.91	lagging	173.88	67.6	0.93	lagging
35	173.9	-29.5	0.99	leading	173.9	-51.1	0.96	leading	173.88	-21.7	0.99	leading
40	173.9	-22.0	0.99	leading	173.9	-58.1	0.95	leading	173.88	-22.0	0.99	leading
41	173.9	-18.8	0.99	leading	173.9	-19.4	0.99	leading	173.88	-18.8	0.99	leading
42	173.9	-19.0	0.99	leading	173.9	-19.5	0.99	leading	173.88	-19.0	0.99	leading
43	173.9	-19.7	0.99	leading	173.9	-20.4	0.99	leading	173.88	-19.7	0.99	leading
44	173.9	-18.9	0.99	leading	173.9	-19.7	0.99	leading	173.88	-18.9	0.99	leading
45	173.9	-18.5	0.99	leading	173.9	-19.2	0.99	leading	173.88	-18.5	0.99	leading

46	173.9	-10.7	1.00	leading	173.9	-2.7	1.00	leading	173.88	-10.7	1.00	leading
47	173.9	-19.7	0.99	leading	173.9	-18.3	0.99	leading	173.88	-19.7	0.99	leading
48	173.9	-14.9	1.00	leading	173.9	-14.0	1.00	leading	173.88	-14.9	1.00	leading
49	173.9	-14.9	1.00	leading	173.9	-14.0	1.00	leading	173.88	-14.9	1.00	leading
50	173.9	-21.9	0.99	leading	173.9	-20.8	0.99	leading	173.88	-21.9	0.99	leading
51	173.9	-18.7	0.99	leading	173.9	-19.5	0.99	leading	173.88	-18.7	0.99	leading
52	173.9	-19.6	0.99	leading	173.9	-20.2	0.99	leading	173.88	-19.6	0.99	leading
53	173.9	-19.4	0.99	leading	173.9	-20.0	0.99	leading	173.88	-19.4	0.99	leading
54	173.9	-18.2	0.99	leading	173.9	-19.2	0.99	leading	173.88	-18.2	0.99	leading
55	173.9	-19.8	0.99	leading	173.9	-19.4	0.99	leading	173.88	-19.8	0.99	leading
56	173.9	-17.4	1.00	leading	173.9	-18.4	0.99	leading	173.88	-17.4	1.00	leading
57	173.9	-17.2	1.00	leading	173.9	-19.7	0.99	leading	173.88	-17.2	1.00	leading
58	173.9	-17.6	0.99	leading	173.9	-19.8	0.99	leading	173.88	-17.6	0.99	leading
59	173.9	-18.8	0.99	leading	173.9	-20.0	0.99	leading	173.88	-18.8	0.99	leading
60	173.9	-17.0	1.00	leading	173.9	-18.3	0.99	leading	173.88	-17.0	1.00	leading
61	173.9	-15.8	1.00	leading	173.9	-19.2	0.99	leading	173.88	-17.7	0.99	leading
62	173.9	-17.9	0.99	leading	173.9	-20.2	0.99	leading	173.88	-19.3	0.99	leading
63	173.9	-18.0	0.99	leading	173.9	-20.6	0.99	leading	173.88	-19.4	0.99	leading
64	173.9	-17.4	1.00	leading	173.9	-19.3	0.99	leading	173.88	-18.8	0.99	leading
65	173.9	-15.3	1.00	leading	173.9	-18.0	0.99	leading	173.88	-16.8	1.00	leading
66	173.9	-11.5	1.00	leading	173.9	-13.3	1.00	leading	173.88	-11.9	1.00	leading
67	173.9	-17.6	0.99	leading	173.9	-20.2	0.99	leading	173.88	-19.2	0.99	leading
68	173.9	-17.6	0.99	leading	173.9	-19.7	0.99	leading	173.88	-18.9	0.99	leading
69	173.9	-18.0	0.99	leading	173.9	-21.0	0.99	leading	173.88	-19.3	0.99	leading
70	173.9	-19.3	0.99	leading	173.9	-21.1	0.99	leading	173.88	-20.3	0.99	leading
71	173.9	-15.2	1.00	leading	173.9	-17.4	1.00	leading	173.88	-17.2	1.00	leading
72	173.9	-15.5	1.00	leading	173.9	-18.8	0.99	leading	173.88	-16.2	1.00	leading
73	173.9	-18.2	0.99	leading	173.9	-20.5	0.99	leading	173.88	-19.7	0.99	leading
74	173.9	17.8	0.99	lagging	173.9	-22.5	0.99	leading	173.88	-18.4	0.99	leading
75	173.9	-2.8	1.00	leading	173.9	2.0	1.00	lagging	173.88	-5.8	1.00	leading
76	173.9	-17.4	1.00	leading	173.9	-19.0	0.99	leading	173.88	-18.3	0.99	leading
77	173.9	-5.4	1.00	leading	173.9	-0.1	1.00	leading	173.88	-8.6	1.00	leading
78	173.9	-17.9	0.99	leading	173.9	-19.1	0.99	leading	173.88	-19.6	0.99	leading
79	173.9	-16.5	1.00	leading	173.9	-19.1	0.99	leading	173.88	-17.9	0.99	leading
80	173.9	-18.1	0.99	leading	173.9	-20.2	0.99	leading	173.88	-19.6	0.99	leading
81	173.9	-17.3	1.00	leading	173.9	-20.2	0.99	leading	173.88	-18.7	0.99	leading
82	173.9	-18.1	0.99	leading	173.9	-22.9	0.99	leading	173.88	-18.9	0.99	leading
83	173.9	-18.2	0.99	leading	173.9	-20.5	0.99	leading	173.88	-19.7	0.99	leading
84	173.9	-18.2	0.99	leading	173.9	-20.4	0.99	leading	173.88	-19.7	0.99	leading
85	173.9	-18.2	0.99	leading	173.9	-20.5	0.99	leading	173.88	-19.7	0.99	leading
86	173.9	-18.4	0.99	leading	173.9	-20.3	0.99	leading	173.88	-20.9	0.99	leading

87	173.9	-15.1	1.00	leading	173.9	-17.2	1.00	leading	173.88	-16.7	1.00	leading
88	173.9	-19.8	0.99	leading	173.9	-21.5	0.99	leading	173.88	-22.5	0.99	leading
89	173.9	-13.1	1.00	leading	173.9	-14.7	1.00	leading	173.88	-16.5	1.00	leading

Power Factor Requirements for GEN-2015-027 Interconnection Request

	2015 Summer Peak				2015 Winter Peak				2025 Summer Peak			
Cont. No.	P (MW)	Q (MVAR)	Power Factor		P (MW)	Q (MVAR)	Power Factor		P (MW)	Q (MVAR)	Power Factor	
0	102.9	1.4	1.00	lagging	102.9	-3.0	1.00	leading	102.9	4.7	1.00	lagging
1	102.9	2.7	1.00	lagging	102.9	-1.5	1.00	leading	102.9	6.4	1.00	lagging
3	102.9	2.7	1.00	lagging	102.9	-1.4	1.00	leading	102.9	5.6	1.00	lagging
5	102.9	7.5	1.00	lagging	102.9	4.4	1.00	lagging	102.9	10.6	0.99	lagging
7	102.9	2.1	1.00	lagging	102.9	-2.4	1.00	leading	102.9	5.0	1.00	lagging
8	102.9	9.6	1.00	lagging	102.9	7.0	1.00	lagging	102.9	12.0	0.99	lagging
9	102.9	3.0	1.00	lagging	102.9	-1.2	1.00	leading	102.9	6.1	1.00	lagging
10	102.9	1.5	1.00	lagging	102.9	-2.8	1.00	leading	102.9	4.5	1.00	lagging
11	102.9	5.4	1.00	lagging	102.9	1.8	1.00	lagging	102.9	8.4	1.00	lagging
12	102.9	-0.8	1.00	leading	102.9	-5.3	1.00	leading	102.9	2.6	1.00	lagging
13	102.9	2.5	1.00	lagging	102.9	-1.7	1.00	leading	102.9	5.8	1.00	lagging
14	102.9	1.1	1.00	lagging	102.9	-3.4	1.00	leading	102.9	4.3	1.00	lagging
15	102.9	4.0	1.00	lagging	102.9	-0.8	1.00	leading	102.9	6.4	1.00	lagging
16	102.9	3.1	1.00	lagging	102.9	-0.2	1.00	leading	102.9	7.0	1.00	lagging
17	102.9	11.1	0.99	lagging	102.9	12.5	0.99	lagging	102.9	14.5	0.99	lagging
18	102.9	2.6	1.00	lagging	102.9	-1.6	1.00	leading	102.9	5.9	1.00	lagging
20	102.9	2.8	1.00	lagging	102.9	-0.9	1.00	leading	102.9	8.5	1.00	lagging
21	102.9	8.3	1.00	lagging	102.9	3.2	1.00	lagging	102.9	15.6	0.99	lagging
23	102.9	2.6	1.00	lagging	102.9	-2.1	1.00	leading	102.9	6.1	1.00	lagging
24	102.9	2.6	1.00	lagging	102.9	-1.8	1.00	leading	102.9	5.9	1.00	lagging
25	102.9	1.4	1.00	lagging	102.9	-3.0	1.00	leading	102.9	4.7	1.00	lagging
27	102.9	1.7	1.00	lagging	102.9	-2.7	1.00	leading	102.9	5.3	1.00	lagging
28	102.9	2.1	1.00	lagging	102.9	-2.4	1.00	leading	102.9	5.7	1.00	lagging
29	102.9	1.4	1.00	lagging	102.9	-3.0	1.00	leading	102.9	4.6	1.00	lagging
30	102.9	3.2	1.00	lagging	102.9	-1.1	1.00	leading	102.9	6.5	1.00	lagging
31	102.9	1.1	1.00	lagging	102.9	-1.4	1.00	leading	102.9	4.5	1.00	lagging
32	102.9	1.7	1.00	lagging	102.9	-2.5	1.00	leading	102.9	4.9	1.00	lagging
33	102.9	8.7	1.00	lagging	102.9	6.0	1.00	lagging	102.9	12.1	0.99	lagging
34	102.9	7.9	1.00	lagging	102.9	4.9	1.00	lagging	102.9	10.8	0.99	lagging
35	102.9	18.4	0.98	lagging	102.9	23.1	0.98	lagging	102.9	18.3	0.98	lagging
40	102.9	4.3	1.00	lagging	102.9	-3.1	1.00	leading	102.9	4.3	1.00	lagging
41	102.9	4.9	1.00	lagging	102.9	-2.7	1.00	leading	102.9	4.9	1.00	lagging
42	102.9	4.8	1.00	lagging	102.9	-2.7	1.00	leading	102.9	4.8	1.00	lagging
43	102.9	4.6	1.00	lagging	102.9	-3.0	1.00	leading	102.9	4.6	1.00	lagging
44	102.9	4.7	1.00	lagging	102.9	-2.9	1.00	leading	102.9	4.7	1.00	lagging
45	102.9	4.8	1.00	lagging	102.9	-2.9	1.00	leading	102.9	4.8	1.00	lagging

46	102.9	9.5	1.00	lagging	102.9	6.8	1.00	lagging	102.9	9.5	1.00	lagging
47	102.9	5.7	1.00	lagging	102.9	-1.3	1.00	leading	102.9	5.7	1.00	lagging
48	102.9	5.1	1.00	lagging	102.9	-2.3	1.00	leading	102.9	5.1	1.00	lagging
49	102.9	5.1	1.00	lagging	102.9	-2.3	1.00	leading	102.9	5.1	1.00	lagging
50	102.9	5.0	1.00	lagging	102.9	-2.4	1.00	leading	102.9	5.0	1.00	lagging
51	102.9	4.8	1.00	lagging	102.9	-2.9	1.00	leading	102.9	4.8	1.00	lagging
52	102.9	4.7	1.00	lagging	102.9	-2.9	1.00	leading	102.9	4.7	1.00	lagging
53	102.9	4.7	1.00	lagging	102.9	-2.9	1.00	leading	102.9	4.7	1.00	lagging
54	102.9	4.8	1.00	lagging	102.9	-2.8	1.00	leading	102.9	4.8	1.00	lagging
55	102.9	4.7	1.00	lagging	102.9	-2.8	1.00	leading	102.9	4.7	1.00	lagging
56	102.9	5.9	1.00	lagging	102.9	-2.0	1.00	leading	102.9	5.9	1.00	lagging
57	102.9	4.9	1.00	lagging	102.9	-2.8	1.00	leading	102.9	4.9	1.00	lagging
58	102.9	5.1	1.00	lagging	102.9	-2.7	1.00	leading	102.9	5.1	1.00	lagging
59	102.9	4.5	1.00	lagging	102.9	-3.0	1.00	leading	102.9	4.5	1.00	lagging
60	102.9	5.0	1.00	lagging	102.9	-2.6	1.00	leading	102.9	5.0	1.00	lagging
61	102.9	1.2	1.00	lagging	102.9	-3.1	1.00	leading	102.9	4.5	1.00	lagging
62	102.9	1.6	1.00	lagging	102.9	-2.7	1.00	leading	102.9	4.9	1.00	lagging
63	102.9	1.3	1.00	lagging	102.9	-3.0	1.00	leading	102.9	4.5	1.00	lagging
64	102.9	2.5	1.00	lagging	102.9	-1.5	1.00	leading	102.9	5.9	1.00	lagging
65	102.9	1.7	1.00	lagging	102.9	-2.6	1.00	leading	102.9	5.1	1.00	lagging
66	102.9	4.2	1.00	lagging	102.9	-0.1	1.00	leading	102.9	7.8	1.00	lagging
67	102.9	1.9	1.00	lagging	102.9	-2.9	1.00	leading	102.9	5.3	1.00	lagging
68	102.9	2.4	1.00	lagging	102.9	-1.5	1.00	leading	102.9	5.8	1.00	lagging
69	102.9	8.4	1.00	lagging	102.9	4.0	1.00	lagging	102.9	12.2	0.99	lagging
70	102.9	0.9	1.00	lagging	102.9	-3.3	1.00	leading	102.9	4.3	1.00	lagging
71	102.9	3.1	1.00	lagging	102.9	-0.8	1.00	leading	102.9	6.4	1.00	lagging
72	102.9	4.7	1.00	lagging	102.9	2.9	1.00	lagging	102.9	7.9	1.00	lagging
73	102.9	1.4	1.00	lagging	102.9	-3.0	1.00	leading	102.9	4.7	1.00	lagging
74	102.9	-10.7	0.99	leading	102.9	8.7	1.00	lagging	102.9	13.2	0.99	lagging
75	102.9	-6.7	1.00	leading	102.9	-9.7	1.00	leading	102.9	-3.1	1.00	leading
76	102.9	-4.8	1.00	leading	102.9	-8.3	1.00	leading	102.9	-4.8	1.00	leading
77	102.9	-4.5	1.00	leading	102.9	-11.3	0.99	leading	102.9	-0.1	1.00	leading
78	102.9	0.6	1.00	lagging	102.9	-3.3	1.00	leading	102.9	5.3	1.00	lagging
79	102.9	1.2	1.00	lagging	102.9	-3.2	1.00	leading	102.9	4.1	1.00	lagging
80	102.9	2.5	1.00	lagging	102.9	1.8	1.00	lagging	102.9	4.4	1.00	lagging
81	102.9	2.8	1.00	lagging	102.9	-2.4	1.00	leading	102.9	6.4	1.00	lagging
82	102.9	6.9	1.00	lagging	102.9	6.7	1.00	lagging	102.9	8.7	1.00	lagging
83	102.9	1.4	1.00	lagging	102.9	-3.0	1.00	leading	102.9	4.7	1.00	lagging
84	102.9	1.4	1.00	lagging	102.9	-3.0	1.00	leading	102.9	4.6	1.00	lagging
85	102.9	1.4	1.00	lagging	102.9	-3.0	1.00	leading	102.9	4.7	1.00	lagging
86	102.9	2.7	1.00	lagging	102.9	-0.2	1.00	leading	102.9	6.4	1.00	lagging

87	102.9	3.7	1.00	lagging	102.9	-0.5	1.00	leading	102.9	6.7	1.00	lagging
88	102.9	3.4	1.00	lagging	102.9	0.1	1.00	lagging	102.9	7.3	1.00	lagging
89	102.9	1.8	1.00	lagging	102.9	-2.5	1.00	leading	102.9	5.0	1.00	lagging

APPENDIX F

SHORT-CIRCUIT STUDY RESULTS

(SEE APPENDIX F SUBMITTED IN SEPARATE FILES)

M: Group 4 Dynamic Stability Analysis Report

See Power-tek study report on next page

Southwestern Power Pool Inc. (SPP)

Definitive Impact Study

DISIS-2015-001 (Group 04)

Final Report Submitted to
Southwest Power Pool Inc.
July 2015

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TABLE OF CONTENTS

1. Executive Summary

The DISIS-2015-001 (Group 04) Impact Study is a generation interconnection study performed by POWER-tek Global Inc. for Southwest Power Pool (SPP). This report presents the results of impact study comprising of power factor, short circuit, and stability analyses for both cluster and stand-alone scenarios of the proposed interconnection projects under DISIS-2015-001 (Group 04) ("The Projects") as described in Table 1.1 below:

Table 1.1: Interconnection Request

Request	Size (MW)	Generator Model	Point of Interconnection (POI)
GEN-2010-048	70	Nordex 2.5MW (28 generators)	Tap on the Ross Beach to Redline 115kV line (560336)
GEN-2015-017	155 Summer 172 Winter	GENROU	Mingo 115kV (531429)

Power factor analysis, short circuit analysis up to 5 Buses away from each point of interconnection (POI), and transient stability simulations were performed for the Projects in service at its full output. SPP provided three base cases for Summer-2015, Winter-2015, and Summer-2025, each comprising of a power flow, sequence data and corresponding dynamics database. The previous queued request projects were already modeled in the base cases. The power factor analysis consists of running all N-1, three phase contingencies shown in the Fault Definitions table (Table 3 in the RFP) in power flow to advise the necessary power factor at the POI for each contingency.

The power factor analysis indicates that interconnection requests i.e., GEN-2010-048, and GEN-2015-017 are required to provide reactive power as indicated in Tables 3.2.2 through 3.2.4. Per the SPP OATT, the Interconnection Customer will be required to provide 95% lagging (supplying vars) and 95% leading (absorbing vars) at the POI.

To offset the capacitive effects of the collector system and transmission line of the wind farm under low wind or no wind conditions, the inductive reactive support analysis was performed for summer 2015 scenario. The analysis indicates that at POI i.e., Tap on the Ross Beach to Redline 115kV line (560336) 2.9 MVAR MVAR reactor is required at Bus 580062 to maintain zero MVAR flow for the GEN-2010-048 generator lead. Maintaining zero MVar flow at the POI at all times is not possible with static reactor banks. It will be determined on a case by case basis for each generator as to whether additional reactor banks are required for low wind conditions.

The short circuit analysis is performed on the power flow models for the 2025 summer peak season for cluster scenario model. The results are documented for both 3 phase fault as well as single line to ground fault up to 5 buses away from the POI i.e., Tap on the Ross Beach to Redline 115kV line (560336), and Mingo 115kV (531429).

There are no impacts on the stability performance of the SPP system during both cluster and stand-alone scenarios for the contingencies tested on the provided base cases. The study machines stayed on-line and stable for all simulated faults. The Project stability simulations with forty five (45) specified test disturbances did not show instability problems in the SPP system. Any oscillations were damped out.

2. Introduction

2.1. Project Overview and Assumptions

The DISIS-2015-001 (Group 04) Impact Study is a generation interconnection study performed by POWER-tek Global Inc. for SPP. This report presents the results of impact study comprising of power factor, short circuit analysis, and stability analyses for both cluster and stand-alone scenarios of the proposed interconnection projects under DISIS-2015-001 (Group 04) ("The Projects") as described in Table 2.1.1 below:

Table 2.1.1: Interconnection requests

Request	Size (MW)	Wind Turbine Model	Point of Interconnection
GEN-2010-048	70	Nordex 2.5MW (28 generators)	Tap on the Ross Beach to Redline 115kV line (560336)
GEN-2015-017	155 Summer 172 Winter	GENROU	Mingo 115kV (531429)

Figure 2.1.1, and Figure 2.1.2respectively show the single line diagram for the interconnection of the Projects to present and planned system of SPP. This arrangement was modeled and studied in power flow cases for these projects.

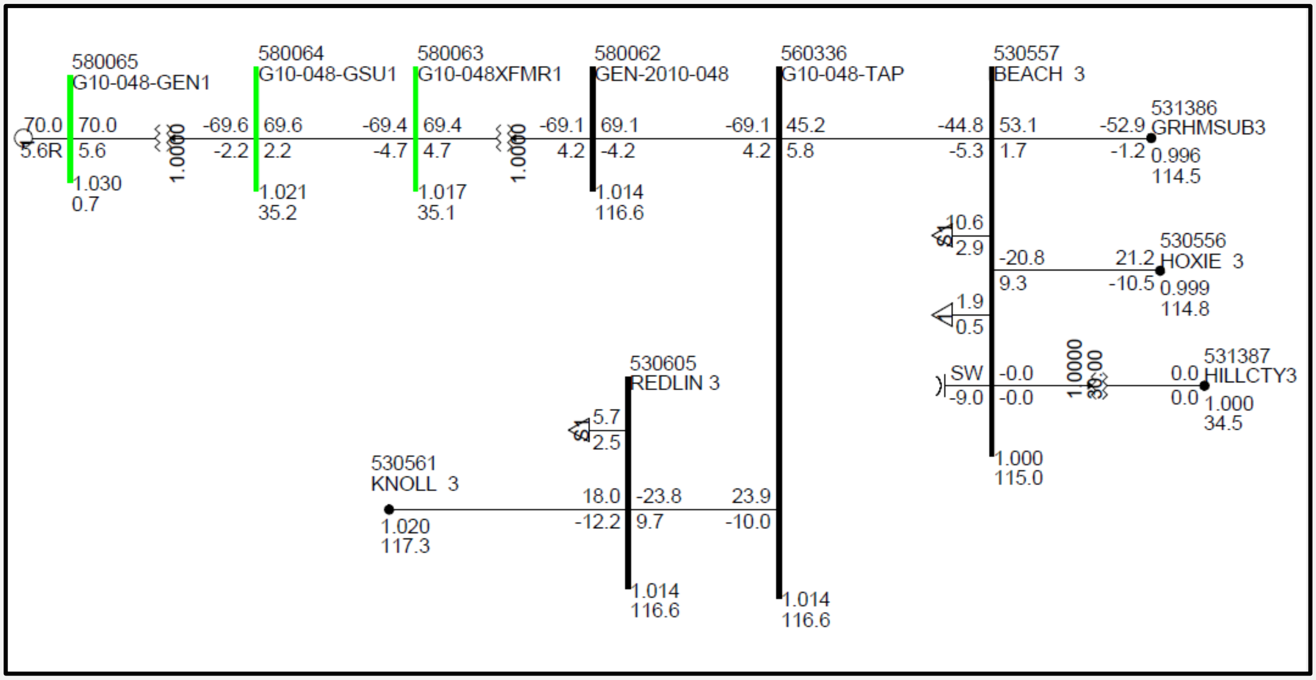

Figure 2.1.1: Power flow single line diagram for GEN-2010-048 and surrounding system components

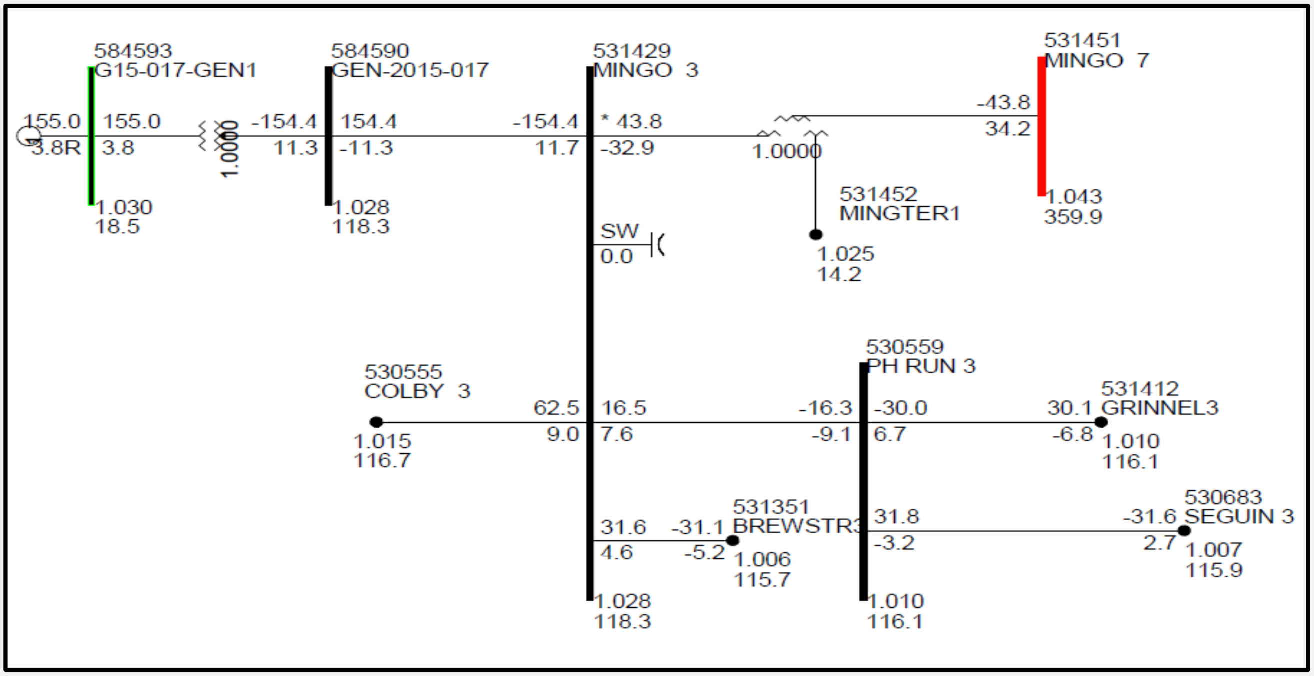

Figure 2.1.2: Power flow single line diagram for GEN-2015-017 and surrounding system components

Appendix-D contains the machines, interconnection, and machines user model parameters.

Table 2.1.2 below shows the list of prior queued projects modeled in the base case.

Table 2.1.2: List of previous queued request projects

Request	Size (MW)	Wind Turbine Model	Point of Interconnection
GEN-2001-039M	99.0	Vestas V90VCRS 3.0MW	Central Plains 115kV (531485)
GEN-2003-006A	201.0	Vestes V90VCRS	Elm Creek 230kV (539639)
GEN-2003-019	249.3	GE 1.5MW & Vestas 3.0MW	Smoky Hills 230kV (530592)
GEN-2006-031	76.0	GENROU (530674, Machine ID 01; 530675, Machine ID 07)	Knoll 115kV (530561)
GEN-2008-017	300.0	GE 1.5MW	Setab 345kV (531465)
GEN-2008-092	201.0	GE 1.5MW	Knoll 230kV (530558)
GEN-2009-008	198.9	GE 1.7MW	South Hays 230kV (530582)
GEN-2009-020/GEN-2014-025	50.75	Siemens SWT-2.415MW-108	Tap on the Balzine to Nekoma 69kV line (560306)
GEN-2010-057	201.0	GE 1.5MW	Rice County 230kV (530686)

Request	Size (MW)	Wind Turbine Model	Point of Interconnection
ASGI-2013-004	27.6 Summer 36.6 Winter	GENSAL (583693)	Morris 115kV (531430)
GEN-2013-033	28.0 (uprate of GEN-2006-031)	GENSAL (Bus 530675, Machine ID 10)	Knoll 115kV (530561)
GEN-2014-041	123.1	Siemens SWT-2.415MW-108	Arnold 115kV (531409)

ATC (Available Transfer Capability) studies were not performed as part of this study. These studies will be required at the time transmission service is actually requested. Additional transmission upgrades may be required based on that analysis.

Study assumptions in general have been based on the specific information and data provided by SPP. The accuracy of the conclusions contained within this study is dependent on the assumptions made with respect to other generation additions and transmission improvements planned by other entities. Changes in the assumptions of the timing of other generation additions or transmission improvements may affect this study's conclusions.

2.2. Objectives

The objectives of the study are to conduct power factor analysis and to determine the impact on system stability of interconnecting the proposed wind farms to SPP's transmission system.

2.3. Models and Simulations Tools Used

Version 32 of the Siemens, PSS/E^{TM} power system simulation program was used in this study.

SPP provided its latest stability database cases for summer-2015, winter-2015, and summer-2025 peak seasons. The Project's PSS/E model had been developed prior to this study and was included in the power flow case and the dynamics database. Machines, interconnection and dynamic model data for the Project plants is provided in Appendix D.

Power flow single line diagram of the projects in summer 2015 peak condition are shown in Figure 2.1.1, and Figure 2.1.2 respectively. These Figures shows that wind farms model includes representation of the radial transmission line, the substation transformer from transmission voltage (115kV and 345kV) to 34.5V. The remainder of each wind farm is represented by lumped equivalents including a generator, a step-up transformer, and collector system impedance.

No special modeling is required of line relays in these cases, except for the special modeling related to the wind-turbine tripping.

All generators in Areas 520, 524, 525, 526, 531, 534, 536, and 640 were monitored.

3. Power Factor Analysis

3.1. Methodology

Power factor analysis was conducted for the Project using the following methodology:

1. Replace the wind farm by a generator at the high side bus 345 kV, 138 kV, 115kV, or 69 kV bus, as applicable, with the MW of the wind farms at that point of interconnection.
2. Turn off the wind farm as modeled (as well as previous queued projects at the same point of interconnection).
3. Model a var generator at the Project's high voltage side, 345 kV, 138 kV, 115kV, or 69kV bus, as applicable. The var generator is set to hold a voltage schedule at the POI consistent with the voltage schedule in the provided power flow cases for summer and winter or 1.0 pu voltage, whichever is higher.
4. Perform the steady state contingency analysis to determine the power factor necessary at the POI for each contingency.
5. If the required power factor at the POI is beyond the capability of the studied wind turbines to meet (at the POI) capacitor banks may be considered for the stability analysis. The preference is to locate the capacitance banks on the 34.5 kV customer side. Factors to sizing capacitor banks include:
   - 5.1. The ability of the wind farm to meet FERC Order 661A (low voltage ride through) with and without capacitor banks.
   - 5.2. The ability of the wind farm to meet FERC Order 661A (wind farm recovery to pre-fault voltage).
   - 5.3. If wind farms trips on high voltage, power factor lower than unity may be required.

3.2. Analysis

Analysis was performed for the proposed Projects with all prior queued projects in service. A var generator was modeled at the point of interconnection and was set to hold a voltage schedule at the POI consistent with the voltage schedule in the provided power flow cases or 1 p.u. whichever is higher. The voltages for these Projects are summarized in Table 3.2.1. All upgrades and instructions were made in the base cases. No other changes were made in the base cases provided other than the addition of the var generators. Contingency analysis was run for provided list of contingencies.

Table 3.2.1: POI voltages for the summer and winter peak cases

Request	Point of Interconnection	Size (MW)	Base Case Voltage (p.u.)		
			Summer 2015 Peak	Winter 2015 Peak	Summer 2025 Peak
GEN-2010-048	Tap on the Ross Beach to Redline 115kV line (560336)	70	1.014	1.025	1.01
GEN-2015-017	Mingo 115kV (531429)	155 Summer 172 Winter	1.028	1.024	1.027

The details of the var requirement during contingencies are highlighted in Table 3.2.2, 3.2.3 and 3.2.4. The highest and the lowest values obtained are highlighted in these tables.

1. For 2015 summer case (GEN-2010-048 analysis): The maximum var generator supply is 4.6 MVARs at 1.0 (lagging power factor) for the outage of 530561 [KNOLL 3 115.00] TO BUS 530551 [SALINE 3 115.00] CKT outage. The minimum var requirement is -23.6 MVAR at 0.95 (leading power factor) for outage of 560336 [G10-048-TAP 115.00] TO BUS 530557 [BEACH 3 115.00] CKT outage.
2. For 2015 summer case (GEN-2015-017 analysis): The maximum var generator supply is 16.6 MVARs at 0.99 (lagging power factor) for the outage of 531456 [NESSCTY3 115.00] TO BUS 531414 [RANSOM 3 115.00] CKT outage. The minimum var requirement is -24.7 MVAR at 0.99 (leading power factor) for outage of 640325 [REDWILO3 345.00] TO BUS 640183 [GENTLMN3 345.00] CKT outage.

Table 3.2.2: Var Generator output in 2015 summer peak case for DISIS-2015-001 (Group 04)

2015 Summer Peak Case Power Factor Study:

Generation Interconnection Request Analysis						**GEN-2010-048**		**GEN-2015-017**	
Rated MW of Wind Farms OR at POI (MW) Rated MVAR of Wind Farms OR at POI (MVAR)						MW at POI **70.0** MVAR at POI **21.2**		MW at POI **155** MVAR at POI **96**	
Cont. Name	**From Bus (# & Name)**		**To Bus (# & Name)**		**ID**	**MVAR at POI**	**P.F at POI**	**MVAR at POI**	**P.F at POI**
	Base Case MVAR Flow				N/A	-4.1	1.00	-12.8	1.00
FLT01-3PH	530582	S HAYS6 230.00	530584	POSTROCK6 230.00	CKT 1	-4.1	1.00	-12.6	1.00
FLT02-3PH	530558	KNOLL 6 230.00	530592	SMOKYHL6 230.00	CKT 1	-3.8	1.00	-12.2	1.00
FLT03-3PH	530561	KNOLL 3 115.00	530551	SALINE 3 115.00	CKT 1	4.6	1.00	-9.8	1.00
FLT04-3PH	530561	KNOLL 3 115.00	530581	N HAYS3 115.00	CKT 1	-4.2	1.00	-12.6	1.00
FLT05-3PH	530561	KNOLL 3 115.00	530605	REDLIN 3 115.00	CKT 1	3.1	1.00	-9.6	1.00

Generation Interconnection Request Analysis Rated MW of Wind Farms OR at POI (MW) Rated MVAR of Wind Farms OR at POI (MVAR)						GEN-2010-048 MW at POI **70.0** MVAR at POI **21.2**		GEN-2015-017 MW at POI **155** MVAR at POI **96**	
Cont. Name	**From Bus (# & Name)**		**To Bus (# & Name)**		**ID**	**MVAR at POI**	**P.F at POI**	**MVAR at POI**	**P.F at POI**
FLT06-3PH	531456	NESSCTY3 115.00	531414	RANSOM 3 115.00	CKT 1	2.7	1.00	16.6	0.99
FLT07-3PH	531456	NESSCTY3 115.00	531359	BEELER 3 115.00	CKT 1	-4.1	1.00	-12.6	1.00
FLT08-3PH	530583	POSTROCK7 345.00	530584	POSTROCK6 230.00	T/F	-3.7	1.00	-11.1	1.00
FLT09-3PH	530558	KNOLL 6 230.00	530561	KNOLL 3 115.00	T/F	-3.6	1.00	-13.3	1.00
FLT10-3PH	560336	G10-048-TAP 115.00	530557	BEACH 3 115.00	CKT 1	-23.6	0.95	-4.8	1.00
FLT11-3PH	560336	G10-048-TAP 115.00	530605	REDLIN 3 115.00	CKT 1	-6.5	1.00	-8.2	1.00
FLT12-3PH	530557	BEACH 3 115.00	530556	HOXIE 3 115.00	CKT 1	0.1	1.00	-9.8	1.00
FLT13-3PH	530557	BEACH 3 115.00	531386	GRHMSUB3 115.00	CKT 1	-4.1	1.00	-12.8	1.00
FLT14-3PH	530555	COLBY 3 115.00	530554	ATWOOD 3 115.00	CKT 1	2.8	1.00	-4.7	1.00
FLT15-3PH	530555	COLBY 3 115.00	530682	SEGNTP 3 115.00	CKT 1	-2.8	1.00	-10.5	1.00
FLT16-3PH	530555	COLBY 3 115.00	531429	MINGO 3 115.00	CKT 1	3.0	1.00	-15.2	1.00
FLT17-3PH	531429	MINGO 3 115.00	530559	PH RUN 3 115.00	CKT 1	-1.6	1.00	-18.1	0.99
FLT18-3PH	531429	MINGO 3 115.00	531351	BREWSTR3 115.00	CKT 1	-3.2	1.00	-18.9	0.99
FLT19-3PH	531451	MINGO 7 345.00	531429	MINGO 3 115.00	T/F	1.7	1.00	14.5	1.00
FLT20-3PH	531451	MINGO 7 345.00	640325	REDWILO3 345.00	CKT 1	-0.1	1.00	4.7	1.00
FLT21-3PH	531451	MINGO 7 345.00	531465	SETAB 7 345.00	CKT 1	-5.1	1.00	-11.0	1.00
FLT22-3PH	531465	SETAB 7 345.00	531449	HOLCOMB7 345.00	CKT 1	-0.9	1.00	-1.2	1.00
FLT23-3PH	531465	SETAB 7 345.00	531464	SETAB 3 115.00	T/F	-3.9	1.00	-14.8	1.00
FLT24-3PH	531373	RHOADES3 115.00	531372	NORCATR3 115.00	CKT 1	-4.9	1.00	-11.8	1.00
FLT25-3PH	531373	RHOADES3 115.00	531386	GRHMSUB3 115.00	CKT 1	-14.3	0.98	-11.0	1.00
FLT26-3PH	531373	RHOADES3 115.00	539685	PHLBURG3 115.00	CKT 1	-7.9	0.99	-11.8	1.00
FLT27-3PH	530558	KNOLL 6 230.00	530584	POSTROCK6 230.00	CKT 1	-4.0	1.00	-12.3	1.00

Generation Interconnection Request Analysis Rated MW of Wind Farms OR at POI (MW) Rated MVAR of Wind Farms OR at POI (MVAR)						GEN-2010-048 MW at POI **70.0** MVAR at POI **21.2**		GEN-2015-017 MW at POI **155** MVAR at POI **96**	
Cont. Name	**From Bus (# & Name)**		**To Bus (# & Name)**		**ID**	**MVAR at POI**	**P.F at POI**	**MVAR at POI**	**P.F at POI**
FLT28-3PH	530558	KNOLL 6 230.00	530592	SMOKYHL6 230.00	CKT 1	-3.8	1.00	-12.2	1.00
FLT29-3PH	530607	NESCTY 3 115.00	530606	ALXNDR 3 115.00	CKT 1	-2.2	1.00	-3.1	1.00
FLT30-3PH	530559	PH RUN 3 115.00	530683	SEGUIN 3 115.00	CKT 1	-2.3	1.00	-11.0	1.00
FLT31-3PH	530559	PH RUN 3 115.00	531412	GRINNEL3 115.00	CKT 1	-4.5	1.00	-15.4	1.00
FLT32-3PH	531357	RULETON3 115.00	531356	NSI TAP3 115.00	CKT 1	-4.1	1.00	-12.9	1.00
FLT33-3PH	531357	RULETON3 115.00	531368	LAWNRID3 115.00	CKT 1	-3.0	1.00	-13.4	1.00
FLT34-3PH	530554	ATWOOD 3 115.00	531364	ATWODSW3 115.00	CKT 1	3.6	1.00	-11.6	1.00
FLT35-3PH	530554	ATWOOD 3 115.00	531488	BVERVLLY 115.00	CKT 1	-3.9	1.00	-13.2	1.00
FLT36-3PH	531449	HOLCOMB7 345.00	523853	FINNEY 7345.00	CKT 1	-3.2	1.00	-1.6	1.00
FLT37-3PH	531449	HOLCOMB7 345.00	531501	BUCKNER7 345.00	CKT 1	-1.4	1.00	-7.2	1.00
FLT38-3PH	531449	HOLCOMB7 345.00	531448	HOLCOMB3 115.00	T/F	-3.6	1.00	-9.8	1.00
FLT39-3PH	640325	REDWILO3 345.00	640183	GENTLMN3 345.00	CKT 1	-4.6	1.00	-24.7	0.99
FLT40-3PH	640325	REDWILO3 345.00	640326	REDWILO7 115.00	T/F	-3.4	1.00	-12.6	1.00
FLT41-3PH	640183	GENTLMN3 345.00	640252	KEYSTON3 345.00	CKT 1	-4.2	1.00	-13.7	1.00
FLT42-3PH	640183	GENTLMN3 345.00	640374	SWEET W3 345.00	CKT 1	-3.1	1.00	-13.0	1.00

3. For 2015 winter case (GEN-2010-048 analysis): The maximum var generator supply is 1.9 MVARs at 1.0 (lagging power factor) for the outage of 531451 [MINGO 7 345.00] TO BUS 531429 [MINGO 3 115.00] T/F outage. The minimum var requirement is -17.6 MVAR at 0.97 (leading power factor) for outage of 560336 [G10-048-TAP 115.00] TO BUS 530557 [BEACH 3 115.00] CKT outage.
4. For 2015 winter case (GEN-2015-017 analysis): The maximum var generator supply is 22.5 MVARs at 0.99 (lagging power factor) for the outage of 531456 [NESSCTY3 115.00] TO BUS 531414 [RANSOM 3 115.00] CKT outage. The minimum var requirement is -19.3 MVAR at 0.99 (leading power factor) for outage of 640325 [REDWILO3 345.00] TO BUS 640183 [GENTLMN3 345.00] CKT outage.

Table 3.2.3: Var generator output in 2015 Winter peak case for DISIS-2015-001 (Group 04)

2015 Winter Peak Case Power Factor Study:

Generation Interconnection Request Analysis Rated MW of Wind Farms OR at POI (MW) Rated MVAR of Wind Farms OR at POI (MVAR)						GEN-2010-048 MW at POI **70.0** MVAR at POI **21.2**		GEN-2015-017 MW at POI **172** MVAR at POI **106.6**	
Cont. Name	**From Bus (# & Name)**		**To Bus (# & Name)**		**ID**	**MVAR at POI**	**P.F at POI**	**MVAR at POI**	**P.F at POI**
	Base Case MVAR Flow				N/A	-8.6	0.99	-7.2	1.00
FLT01-3PH	530582	S HAYS6 230.00	530584	POSTROCK6 230.00	CKT 1	-8.2	0.99	-6.8	1.00
FLT02-3PH	530558	KNOLL 6 230.00	530592	SMOKYHL6 230.00	CKT 1	-7.6	0.99	-6.2	1.00
FLT03-3PH	530561	KNOLL 3 115.00	530551	SALINE 3 115.00	CKT 1	-2.8	1.00	-5.9	1.00
FLT04-3PH	530561	KNOLL 3 115.00	530581	N HAYS3 115.00	CKT 1	-8.7	0.99	-7.0	1.00
FLT05-3PH	530561	KNOLL 3 115.00	530605	REDLIN 3 115.00	CKT 1	-5.1	1.00	-2.1	1.00
FLT06-3PH	531456	NESSCTY3 115.00	531414	RANSOM 3 115.00	CKT 1	-2.0	1.00	22.5	0.99
FLT07-3PH	531456	NESSCTY3 115.00	531359	BEELER 3 115.00	CKT 1	-8.4	0.99	-6.5	1.00
FLT08-3PH	530583	POSTROCK7 345.00	530584	POSTROCK6 230.00	T/F	-7.7	0.99	-2.8	1.00
FLT09-3PH	530558	KNOLL 6 230.00	530561	KNOLL 3 115.00	T/F	-6.7	1.00	-7.3	1.00
FLT10-3PH	560336	G10-048-TAP 115.00	530557	BEACH 3 115.00	CKT 1	-17.6	0.97	-5.9	1.00
FLT11-3PH	560336	G10-048-TAP 115.00	530605	REDLIN 3 115.00	CKT 1	-13.7	0.98	-2.0	1.00
FLT12-3PH	530557	BEACH 3 115.00	530556	HOXIE 3 115.00	CKT 1	-6.5	1.00	-1.9	1.00
FLT13-3PH	530557	BEACH 3 115.00	531386	GRHMSUB3 115.00	CKT 1	-8.6	0.99	-7.2	1.00
FLT14-3PH	530555	COLBY 3 115.00	530554	ATWOOD 3 115.00	CKT 1	-5.1	1.00	-2.6	1.00
FLT15-3PH	530555	COLBY 3 115.00	530682	SEGNTP 3 115.00	CKT 1	-9.1	0.99	-6.1	1.00
FLT16-3PH	530555	COLBY 3 115.00	531429	MINGO 3 115.00	CKT 1	-9.3	0.99	-13.3	1.00
FLT17-3PH	531429	MINGO 3 115.00	530559	PH RUN 3 115.00	CKT 1	-7.2	0.99	-9.3	1.00
FLT18-3PH	531429	MINGO 3 115.00	531351	BREWSTR3 115.00	CKT 1	-7.4	0.99	-5.3	1.00
FLT19-3PH	531451	MINGO 7 345.00	531429	MINGO 3 115.00	T/F	1.9	1.00	-16.7	1.00

Generation Interconnection Request Analysis Rated MW of Wind Farms OR at POI (MW) Rated MVAR of Wind Farms OR at POI (MVAR)						GEN-2010-048 MW at POI **70.0** MVAR at POI **21.2**		GEN-2015-017 MW at POI **172** MVAR at POI **106.6**	
Cont. Name	**From Bus (# & Name)**		**To Bus (# & Name)**		**ID**	**MVAR at POI**	**P.F at POI**	**MVAR at POI**	**P.F at POI**
FLT20-3PH	531451	MINGO 7 345.00	640325	REDWILO3 345.00	CKT 1	-2.4	1.00	17.3	0.99
FLT21-3PH	531451	MINGO 7 345.00	531465	SETAB 7 345.00	CKT 1	-10.3	0.99	-17.7	0.99
FLT22-3PH	531465	SETAB 7 345.00	531449	HOLCOMB7 345.00	CKT 1	-2.2	1.00	10.5	1.00
FLT23-3PH	531465	SETAB 7 345.00	531464	SETAB 3 115.00	T/F	-8.3	0.99	-6.3	1.00
FLT24-3PH	531373	RHOADES3 115.00	531372	NORCATR3 115.00	CKT 1	-8.7	0.99	-4.9	1.00
FLT25-3PH	531373	RHOADES3 115.00	531386	GRHMSUB3 115.00	CKT 1	-13.3	0.98	-5.6	1.00
FLT26-3PH	531373	RHOADES3 115.00	539685	PHLBURG3 115.00	CKT 1	-12.5	0.98	-7.3	1.00
FLT27-3PH	530558	KNOLL 6 230.00	530584	POSTROCK6 230.00	CKT 1	-8.9	0.99	-5.6	1.00
FLT28-3PH	530558	KNOLL 6 230.00	530592	SMOKYHL6 230.00	CKT 1	-7.6	0.99	-6.2	1.00
FLT29-3PH	530607	NESCTY 3 115.00	53060 6	ALXNDR 3 115.00	CKT 1	-6.4	1.00	4.9	1.00
FLT30-3PH	530559	PH RUN 3 115.00	530683	SEGUIN 3 115.00	CKT 1	-7.7	0.99	-4.3	1.00
FLT31-3PH	530559	PH RUN 3 115.00	531412	GRINNEL3 115.00	CKT 1	-9.1	0.99	-9.8	1.00
FLT32-3PH	531357	RULETON3 115.00	531356	NSI TAP3 115.00	CKT 1	-8.4	0.99	-6.1	1.00
FLT33-3PH	531357	RULETON3 115.00	531368	LAWNRID3 115.00	CKT 1	-7.8	0.99	-7.4	1.00
FLT34-3PH	530554	ATWOOD 3 115.00	531364	ATWODSW3 115.00	CKT 1	-4.3	1.00	-6.3	1.00
FLT35-3PH	530554	ATWOOD 3 115.00	531488	BVERVLLY 115.00	CKT 1	-7.9	0.99	-8.0	1.00
FLT36-3PH	531449	HOLCOMB7 345.00	523853	FINNEY 7345.00	CKT 1	-7.0	1.00	7.2	1.00
FLT37-3PH	531449	HOLCOMB7 345.00	531501	BUCKNER7 345.00	CKT 1	-5.4	1.00	-0.6	1.00
FLT38-3PH	531449	HOLCOMB7 345.00	531448	HOLCOMB3 115.00	T/F	-8.4	0.99	-9.9	1.00
FLT39-3PH	640325	REDWILO3 345.00	640183	GENTLMN3 345.00	CKT 1	-9.3	0.99	-19.3	0.99
FLT40-3PH	640325	REDWILO3 345.00	640326	REDWILO7 115.00	T/F	-7.7	0.99	-5.6	1.00
FLT41-3PH	640183	GENTLMN3 345.00	640252	KEYSTON3 345.00	CKT 1	-8.7	0.99	-7.1	1.00

Generation Interconnection Request Analysis Rated MW of Wind Farms OR at POI (MW) Rated MVAR of Wind Farms OR at POI (MVAR)						GEN-2010-048 MW at POI **70.0** MVAR at POI **21.2**		GEN-2015-017 MW at POI **172** MVAR at POI **106.6**	
Cont. Name	**From Bus (# & Name)**		**To Bus (# & Name)**		**ID**	**MVAR at POI**	**P.F at POI**	**MVAR at POI**	**P.F at POI**
FLT42-3PH	640183	GENTLMN3 345.00	640374	SWEET W3 345.00	CKT 1	-5.4	1.00	-6.9	1.00

5. For 2015 summer case (GEN-2010-048 analysis): The maximum var generator supply is 8.1 MVARs at 0.99 (lagging power factor) for the outage of 530561 [KNOLL 3 115.00] TO BUS 530551 [SALINE 3 115.00] CKT outage. The minimum var requirement is -24.4 MVAR at 0.94 (leading power factor) for outage of 560336 [G10-048-TAP 115.00] TO BUS 530557 [BEACH 3 115.00] CKT outage.
6. For 2015 summer case (GEN-2015-017 analysis): The maximum var generator supply is 16.3 MVARs at 0.99 (lagging power factor) for the outage of 531456 [NESSCTY3 115.00] TO BUS 531414 [RANSOM 3 115.00] CKT outage. The minimum var requirement is -20.9 MVAR at 0.99 (leading power factor) for outage of 640325 [REDWILO3 345.00] TO BUS 640183 [GENTLMN3 345.00] CKT outage.

Table 3.2.3: Var generator output in 2025 summer peak case for DISIS-2015-001 (Group 04)

2025 Summer Peak Case Power Factor Study:

Generation Interconnection Request Analysis Rated MW of Wind Farms OR at POI (MW) Rated MVAR of Wind Farms OR at POI (MVAR)						GEN-2010-048 MW at POI **70.0** MVAR at POI **21.2**		GEN-2015-017 MW at POI **155** MVAR at POI **96**	
Cont. Name	**From Bus (# & Name)**		**To Bus (# & Name)**		**ID**	**MVAR at POI**	**P.F at POI**	**MVAR at POI**	**P.F at POI**
	Base Case MVAR Flow				N/A	-3.1	1.00	-10.4	1.00
FLT01-3PH	530582	S HAYS6 230.00	530584	POSTROCK6 230.00	CKT 1	-3.0	1.00	-10.1	1.00
FLT02-3PH	530558	KNOLL 6 230.00	530592	SMOKYHL6 230.00	CKT 1	-2.8	1.00	-9.9	1.00
FLT03-3PH	530561	KNOLL 3 115.00	530551	SALINE 3 115.00	CKT 1	8.1	0.99	-4.5	1.00
FLT04-3PH	530561	KNOLL 3 115.00	530581	N HAYS3 115.00	CKT 1	-3.1	1.00	-10.1	1.00
FLT05-3PH	530561	KNOLL 3 115.00	530605	REDLIN 3 115.00	CKT 1	5.7	1.00	-6.3	1.00
FLT06-3PH	531456	NESSCTY3 115.00	531414	RANSOM 3 115.00	CKT 1	2.8	1.00	16.3	0.99
FLT07-3PH	531456	NESSCTY3 115.00	531359	BEELER 3 115.00	CKT 1	-3.0	1.00	-9.7	1.00
FLT08-3PH	530583	POSTROCK7 345.00	530584	POSTROCK6 230.00	T/F	-1.8	1.00	-7.3	1.00
FLT09-3PH	530558	KNOLL 6 230.00	530561	KNOLL 3 115.00	T/F	-2.6	1.00	-11.1	1.00

Generation Interconnection Request Analysis Rated MW of Wind Farms OR at POI (MW) Rated MVAR of Wind Farms OR at POI (MVAR)						GEN-2010-048 MW at POI **70.0** MVAR at POI **21.2**		GEN-2015-017 MW at POI **155** MVAR at POI **96**	
Cont. Name	**From Bus (# & Name)**		**To Bus (# & Name)**		**ID**	**MVAR at POI**	**P.F at POI**	**MVAR at POI**	**P.F at POI**
FLT10-3PH	560336	G10-048-TAP 115.00	530557	BEACH 3 115.00	CKT 1	-24.4	0.94	0.2	1.00
FLT11-3PH	560336	G10-048-TAP 115.00	530605	REDLIN 3 115.00	CKT 1	-5.2	1.00	-4.7	1.00
FLT12-3PH	530557	BEACH 3 115.00	530556	HOXIE 3 115.00	CKT 1	1.5	1.00	-6.7	1.00
FLT13-3PH	530557	BEACH 3 115.00	531386	GRHMSUB3 115.00	CKT 1	-3.1	1.00	-10.4	1.00
FLT14-3PH	530555	COLBY 3 115.00	530554	ATWOOD 3 115.00	CKT 1	3.2	1.00	-5.1	1.00
FLT15-3PH	530555	COLBY 3 115.00	530682	SEGNTP 3 115.00	CKT 1	-0.9	1.00	-9.3	1.00
FLT16-3PH	530555	COLBY 3 115.00	531429	MINGO 3 115.00	CKT 1	5.7	1.00	-12.2	1.00
FLT17-3PH	531429	MINGO 3 115.00	530559	PH RUN 3 115.00	CKT 1	0.5	1.00	-16.0	0.99
FLT18-3PH	531429	MINGO 3 115.00	531351	BREWSTR3 115.00	CKT 1	-2.2	1.00	-11.8	1.00
FLT19-3PH	531451	MINGO 7 345.00	531429	MINGO 3 115.00	T/F	1.8	1.00	14.5	1.00
FLT20-3PH	531451	MINGO 7 345.00	640325	REDWILO3 345.00	CKT 1	0.7	1.00	7.0	1.00
FLT21-3PH	531451	MINGO 7 345.00	531465	SETAB 7 345.00	CKT 1	-3.5	1.00	-8.8	1.00
FLT22-3PH	531465	SETAB 7 345.00	531449	HOLCOMB7 345.00	CKT 1	-0.5	1.00	-0.5	1.00
FLT23-3PH	531465	SETAB 7 345.00	531464	SETAB 3 115.00	T/F	-2.8	1.00	-11.6	1.00
FLT24-3PH	531373	RHOADES3 115.00	531372	NORCATR3 115.00	CKT 1	-3.7	1.00	-7.9	1.00
FLT25-3PH	531373	RHOADES3 115.00	531386	GRHMSUB3 115.00	CKT 1	-12.2	0.99	-7.2	1.00
FLT26-3PH	531373	RHOADES3 115.00	539685	PHLBURG3 115.00	CKT 1	-5.1	1.00	-9.9	1.00
FLT27-3PH	530558	KNOLL 6 230.00	530584	POSTROCK6 230.00	CKT 1	-2.6	1.00	-9.5	1.00
FLT28-3PH	530558	KNOLL 6 230.00	530592	SMOKYHL6 230.00	CKT 1	-2.8	1.00	-9.9	1.00
FLT29-3PH	530607	NESCTY 3 115.00	53060 6	ALXNDR 3 115.00	CKT 1	-1.5	1.00	-1.7	1.00
FLT30-3PH	530559	PH RUN 3 115.00	530683	SEGUIN 3 115.00	CKT 1	-0.8	1.00	-7.3	1.00
FLT31-3PH	530559	PH RUN 3 115.00	531412	GRINNEL3 115.00	CKT 1	-4.0	1.00	-14.9	1.00

Generation Interconnection Request Analysis Rated MW of Wind Farms OR at POI (MW) Rated MVAR of Wind Farms OR at POI (MVAR)						GEN-2010-048 MW at POI **70.0** MVAR at POI **21.2**		GEN-2015-017 MW at POI **155** MVAR at POI **96**	
Cont. Name	**From Bus (# & Name)**		**To Bus (# & Name)**		**ID**	**MVAR at POI**	**P.F at POI**	**MVAR at POI**	**P.F at POI**
FLT32-3PH	531357	RULETON3 115.00	531356	NSI TAP3 115.00	CKT 1	-3.6	1.00	-13.4	1.00
FLT33-3PH	531357	RULETON3 115.00	531368	LAWNRID3 115.00	CKT 1	-0.7	1.00	-9.6	1.00
FLT34-3PH	530554	ATWOOD 3 115.00	531364	ATWODSW3 115.00	CKT 1	5.2	1.00	-12.1	1.00
FLT35-3PH	530554	ATWOOD 3 115.00	531488	BVERVLLY 115.00	CKT 1	-2.3	1.00	-9.5	1.00
FLT36-3PH	531449	HOLCOMB7 345.00	523853	FINNEY 7345.00	CKT 1	-1.1	1.00	0.3	1.00
FLT37-3PH	531449	HOLCOMB7 345.00	531501	BUCKNER7 345.00	CKT 1	-0.5	1.00	-1.8	1.00
FLT38-3PH	531449	HOLCOMB7 345.00	531448	HOLCOMB3 115.00	T/F	-2.3	1.00	-5.4	1.00
FLT39-3PH	640325	REDWILO3 345.00	640183	GENTLMN3 345.00	CKT 1	-3.7	1.00	-20.9	0.99
FLT40-3PH	640325	REDWILO3 345.00	640326	REDWILO7 115.00	T/F	-2.7	1.00	-11.1	1.00
FLT41-3PH	640183	GENTLMN3 345.00	640252	KEYSTON3 345.00	CKT 1	-3.2	1.00	-10.9	1.00
FLT42-3PH	640183	GENTLMN3 345.00	640374	SWEET W3 345.00	CKT 1	-2.6	1.00	-11.1	1.00

3.3. Conclusions

The power factor analysis indicates the DISIS-2015-001 (Group 04) interconnection requests i.e., GEN-2010-048, and GEN-2015-017 are required to maintain the SPP standard power factor at the point of interconnection i.e., Tap on the Ross Beach to Redline 115kV line (560336), and Mingo 115kV (531429) based on the contingencies studied.

Per the SPP OATT, the Interconnection Customer will be required to provide 95% lagging (supplying vars) and 95% leading (absorbing vars) at the POI.

4. Inductive Reactive Support Analysis

Analysis for low wind/no wind conditions in cluster scenario is performed for the proposed wind generators requests. To offset the capacitive effects of the collector system and transmission line of the wind farm under low wind or no wind conditions, analysis was performed for winter-2015 scenario to calculate the Inductive Reactive Support at point of interconnection for each interconnection request under project DISIS-2015-001 (Group 04) .

Following methodology was adopted as communicated by SPP:

1. Switch the generator and capacitor bank (if installed) out of service with the collector system as modeled remaining in service.
2. Calculate the amount of inductive reactive support required at the 34.5kV collector buses which would result in zero VAR flow at the POI."

The inductive reactive support analysis for wind generator GEN-2010-048 performed for summer-2015 scenario which indicates that at POI i.e., Tap on the Ross Beach to Redline 115kV line (560336) 2.9 MVAR reactor is required at Bus 580062 to maintain zero MVAR flow for the GEN-2010-048 generator lead.

Maintaining zero MVar flow at the POI at all times is not possible with static reactor banks. It will be determined on a case by case basis for each generator as to whether additional reactor banks are required for low wind conditions.

The single line diagram for wind generators showing the inductive reactive requirement for Gen-2010-048 is shown in Figure 4.1.1:

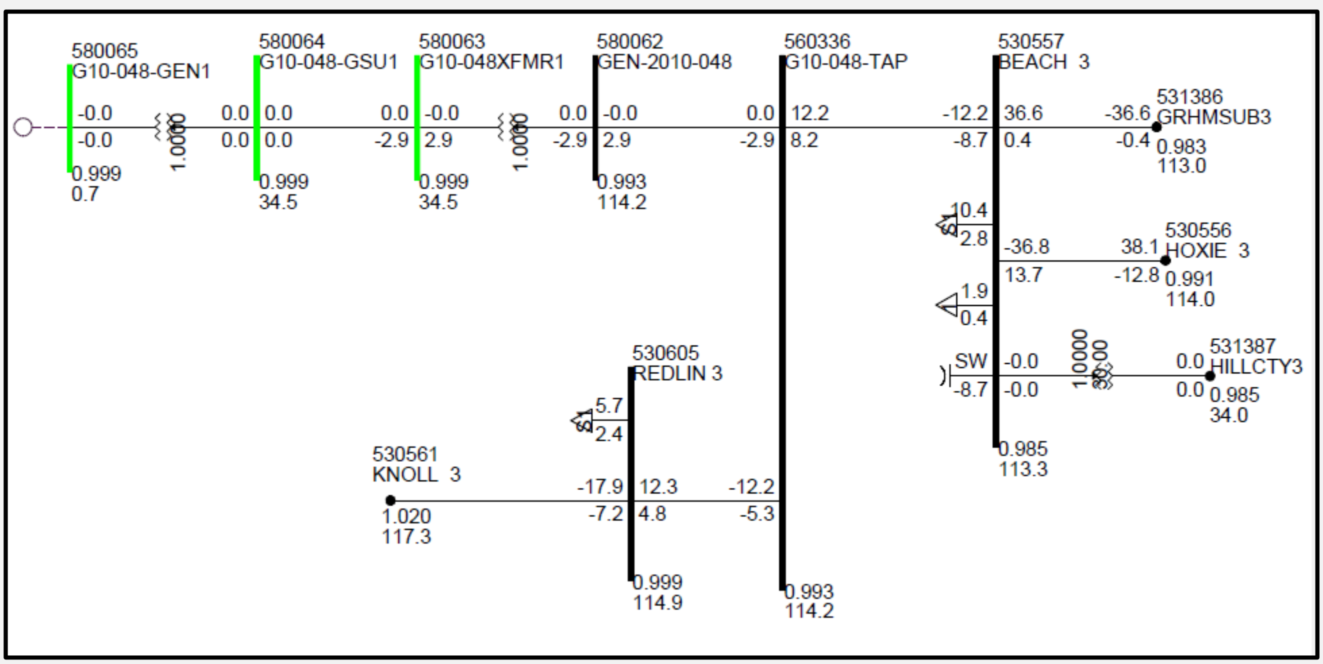

Figure 4.1.1: Inductive reactive requirement for GEN-2010-048

5. Short Circuit Analysis

The short circuit analysis out five buses away was performed for 2025 summer peak case for each interconnection request under project cluster scenario of DISIS-2015-001 (Group 04). No outage was assumed in the system model.

5.1. Short Circuit Result for POI Tap on the Ross Beach to Redline 115kV line (560336)

The results of the short circuit analysis for POI i.e., Tap on the Ross Beach to Redline 115kV line (560336) are tabulated below in table 5.1.1.

Table 5.1.1: Short circuit results for Tap on the Ross Beach to Redline 115kV line (560336)

Bus #	Bus Name	Level Away	Fault Current (Amperes)	
			3 PH	SLG
560336	G10-048-TAP 115.00	0 Level	4228.1	3342.4
530557	BEACH 3 115.00	1 Level	3400.6	3282.4
530605	REDLIN 3 115.00	1 Level	3741.8	2726.5
580062	GEN-2010-048115.00	1 Level	1433.4	937.4
530556	HOXIE 3 115.00	2 Level	1979.2	1300.2
530561	KNOLL 3 115.00	2 Level	4860.9	3762
531386	GRHMSUB3 115.00	2 Level	1582.5	1045.3
531387	HILLCTY3 34.500	2 Level	0	0
580063	G10-048XFMR134.500	2 Level	4778.2	3124.4
530551	SALINE 3 115.00	3 Level	506.8	498.9
530558	KNOLL 6 230.00	3 Level	1880.6	1555.4
530581	N HAYS3 115.00	3 Level	905.5	545.5
530629	KNLL1 1 11.490	3 Level	0	0
530676	GMEC 3 115.00	3 Level	1370.1	1251.7
530677	OGALATP3 115.00	3 Level	154.8	160.2
530682	SEGNTP 3 115.00	3 Level	1962.1	1263.8
531373	RHOADES3 115.00	3 Level	1672.1	1139.1
580064	G10-048-GSU134.500	3 Level	4751.2	3074.2
530555	COLBY 3 115.00	4 Level	1752.7	1318.6
530560	WKNNY 3 115.00	4 Level	144.3	148.2

Bus #	Bus Name	Level Away	Fault Current (Amperes)	
			3 PH	SLG
530584	POSTROCK6 230.00	4 Level	1272.2	1100.1
530590	BEMIS 3 115.00	4 Level	82.6	93
530591	VINE 3 115.00	4 Level	1002.3	636.3
530592	SMOKYHL6 230.00	4 Level	1457.4	1417.6
530674	GMECG1 1 13.800	4 Level	5601.6	5145.2
530675	GMECG2 1 13.800	4 Level	5820	5419.5
530683	SEGUIN 3 115.00	4 Level	1031.3	671.7
531366	CNORTON3 115.00	4 Level	0	0
531372	NORCATR3 115.00	4 Level	606.5	391.2
531492	OG ONEOK 115.00	4 Level	12	13.2
539685	PHLBURG3 115.00	4 Level	1164.7	835.1
539686	PLAINVL3 115.00	4 Level	519.1	488.5
579470	GEN-2008-092230.00	4 Level	991.6	986
580065	G10-048-GEN10.6600	4 Level	48353.8	160693.2
530554	ATWOOD 3 115.00	5 Level	792.1	605.2
530559	PH RUN 3 115.00	5 Level	1174	828.2
530562	HAYS 3 115.00	5 Level	1263.7	842.1
530582	S HAYS6 230.00	5 Level	1197.1	1072.5
530583	POSTROCK7 345.00	5 Level	1092.5	952.6
530593	SMKYP1 6 230.00	5 Level	508.6	504.2
530599	SMKYP2 6 230.00	5 Level	745.8	738.8
530644	COLBY 2 69.000	5 Level	266	225.6
530645	CLBYT1 1 13.800	5 Level	1293.8	1259.4
530673	POSTROCK1 13.800	5 Level	0	0
531429	MINGO 3 115.00	5 Level	2774.7	2214.2
531457	OBER T 3 115.00	5 Level	623.3	415.5
532873	SUMMIT 6 230.00	5 Level	1691.5	1696.2
539693	SMITH-C3 115.00	5 Level	894	607.2
539724	PHLBURG1 34.500	5 Level	667.6	799.2

Bus #	Bus Name	Level Away	Fault Current (Amperes)	
			3 PH	SLG
539725	PLAINVL1 34.500	5 Level	709.2	806.7
539927	PHLBUG-T 13.800	5 Level	0	0
539928	PLAINV-T 13.800	5 Level	0	0
579471	G08-092XFMR134.500	5 Level	3399.4	3381.2
579474	G08-092XFMR234.500	5 Level	3211.4	3191.8

5.2. Short Circuit Result for POI Mingo 115kV (531429)

The results of the short circuit analysis for POI i.e. Mingo 115kV (531429) are tabulated below in table 5.2.1.

Table 5.2.1: Short circuit results for Mingo 115kV (531429)

Bus #	Bus Name	Level Away	Fault Current (Amperes)	
			3 PH	SLG
531429	MINGO 3 115.00	0 Level	12465.1	12268.9
530555	COLBY 3 115.00	1 Level	2380.1	2294.2
530559	PH RUN 3 115.00	1 Level	1730	1480.6
531351	BREWSTR3 115.00	1 Level	875.3	721.6
531451	MINGO 7 345.00	1 Level	4431	3936.1
531452	MINGTER1 13.800	1 Level	0	0
584590	GEN-2015-017115.00	1 Level	7091.6	4734.4
530554	ATWOOD 3 115.00	2 Level	797.2	633.1
530644	COLBY 2 69.000	2 Level	718.4	498
530645	CLBYT1 1 13.800	2 Level	2942.6	2308.8
530682	SEGNTP 3 115.00	2 Level	1263.6	999.7
530683	SEGUIN 3 115.00	2 Level	442.7	418.2
531353	GOODLND3 115.00	2 Level	873.9	712.9
531412	GRINNEL3 115.00	2 Level	1332.5	1016.9
531465	SETAB 7 345.00	2 Level	2783.2	2523.7
584593	G15-017-GEN118.000	2 Level	45307	30247.6
640325	REDWILO3 345.00	2 Level	1969.5	1753.7

Bus #	Bus Name	Level Away	Fault Current (Amperes)	
			3 PH	SLG
530556	HOXIE 3 115.00	3 Level	1319.7	1024.5
530646	CLBY34 1 34.500	3 Level	1436.8	996
531259	SETAB 1 13.800	3 Level	0	0
531364	ATWODSW3 115.00	3 Level	753.8	553
531411	GOVE 3 115.00	3 Level	1336.3	1024.6
531443	GODLNDT3 115.00	3 Level	895	754.5
531449	HOLCOMB7 345.00	3 Level	2945.9	2645.8
531464	SETAB 3 115.00	3 Level	474.5	505.2
531488	BVERVLLY 115.00	3 Level	75.4	62
531609	WDCTWF-1 345.00	3 Level	955.7	957.1
640183	GENTLMN3 345.00	3 Level	3410.4	3217.7
640326	REDWILO7 115.00	3 Level	1975.3	2022.9
640327	REDWILO9 13.800	3 Level	0	0
523853	FINNEY 7345.00	4 Level	1568.2	1502.6
530557	BEACH 3 115.00	4 Level	1680.4	1366.8
530647	CLBY-DSL 13.000	4 Level	3812.8	2643
531220	HERNTAP3 115.00	4 Level	772.7	577.2
531357	RULETON3 115.00	4 Level	969.9	803
531369	NATWOOD3 115.00	4 Level	6.8	11
531409	ARNOLD3 115.00	4 Level	1795	1572.5
531416	CTYSERT3 115.00	4 Level	363.8	421.2
531433	SCOTCTY3 115.00	4 Level	645	547.4
531444	GOODCTY3 115.00	4 Level	29.6	62.8
531448	HOLCOMB3 115.00	4 Level	4073.6	4109.7
531450	HOLCTER1 13.800	4 Level	0	0
531487	MCDONLD3 115.00	4 Level	90.9	82.4
531489	ONEOK 3 115.00	4 Level	5.2	9
531501	BUCKNER7 345.00	4 Level	1473.8	1354.3
531610	WDCTWF-7 34.500	4 Level	3256.4	3257.8

Bus #	Bus Name	Level Away	Fault Current (Amperes)	
			3 PH	SLG
531998	HOLCOMB_2-ST22.000	4 Level	8001.6	8426.2
531999	HOLCOMB_1-CT18.000	4 Level	4723.2	6335.4
579427	G08-017XFMR234.500	4 Level	3151	3157
579428	G08-017XFMR334.500	4 Level	3151	3156.8
640011	GENTLM2G 24.000	4 Level	32848.4	34487.4
640082	BEVERLY7 115.00	4 Level	694.9	689.6
640184	GENTLMN4 230.00	4 Level	3183.1	3145.3
640185	G.GENT19 13.800	4 Level	0	0
640252	KEYSTON3 345.00	4 Level	796	768.5
640269	MCCOOK 7 115.00	4 Level	1241.8	1304.7
640365	STOCKVL7 115.00	4 Level	610.9	573.5
640374	SWEET W3 345.00	4 Level	1928	1935.8
640500	CHERRYC3 345.00	4 Level	567.6	561.2
643066	GENTLEMANT2913.800	4 Level	0	0
523097	HITCHLAND 7345.00	5 Level	2358.2	2297.2
523118	BUFF_DUNES 7345.00	5 Level	212	224.1
531256	SCOTCTY1 13.800	5 Level	0	0
531356	NSI TAP3 115.00	5 Level	891.2	672.7
531362	MANNGT 3 115.00	5 Level	319.3	288.3
531365	BIRDCTY3 115.00	5 Level	92.4	82.1
531367	HERNDON3 115.00	5 Level	766.5	561.8
531368	LAWNRID3 115.00	5 Level	122.7	129.3
531379	JONES3 115.00	5 Level	213.7	219.5
531386	GRHMSUB3 115.00	5 Level	424.3	474.1
531387	HILLCTY3 34.500	5 Level	0	0
531393	PLYMELL3 115.00	5 Level	1050.1	1056.1
531414	RANSOM 3 115.00	5 Level	1062.4	935.8
531418	CTYSERV3 115.00	5 Level	28.4	31
531420	FLETCHR3 115.00	5 Level	991.6	973.1

Bus #	Bus Name	Level Away	Fault Current (Amperes)	
			3 PH	SLG
531427	SCOTCTY2 69.000	5 Level	5.4	5.8
531432	PILE 3 115.00	5 Level	581.3	424.5
531445	GRDNCTY3 115.00	5 Level	1916.1	1873.7
531447	HOLCGEN1 22.000	5 Level	16872.2	18233.6
531469	SPERVIL7 345.00	5 Level	1613.2	1566.8
531485	CNTRLPL3 115.00	5 Level	1059.9	1107.9
531502	CIMRRN 7 345.00	5 Level	149.2	141.2
531504	CPV_CIMRRN 7345.00	5 Level	128.6	122.2
560336	G10-048-TAP 115.00	5 Level	1592.9	1244
579423	G08-017-GSU134.500	5 Level	3256.4	3257.8
579424	G08-017-GSU234.500	5 Level	3151	3157
579425	G08-017-GSU334.500	5 Level	3151	3156.8
580049	GEN-2010-045345.00	5 Level	148.2	140.2
584250	GEN-2014-041115.00	5 Level	1178.4	1156.6
599950	LAMAR7 345.00	5 Level	0	0
640010	GENTLM1G 23.000	5 Level	33402.4	34768
640017	MCCOOK G 13.800	5 Level	4893.6	4931.2
640065	AXTELL 3 345.00	5 Level	1459.9	1468.9
640083	BEVERLY8 69.000	5 Level	707.2	752.8
640100	CAMBRIG7 115.00	5 Level	643.7	605.8
640167	ENDERS 7 115.00	5 Level	608.4	573.9
640253	KEYSTON7 115.00	5 Level	1292.4	1320.3
640254	KEYSTON9 13.800	5 Level	0	0
640270	MCCOOK 8 69.000	5 Level	505.7	540.4
640286	N.PLATT4 230.00	5 Level	2666.4	2679
640287	N.PLATT7 115.00	5 Level	3538.3	3537.7
640302	OGALALA4 230.00	5 Level	688.2	689.9
640366	STOCKVL8 69.000	5 Level	759.7	794.3
640510	HOLT.CO3 345.00	5 Level	1031.5	1014.3

Bus #	Bus Name	Level Away	Fault Current (Amperes)	
			3 PH	SLG
643017	BEVERLY T1 913.800	5 Level	0	0
643018	BEVERLY T2 913.800	5 Level	0	0
643099	MCCOOK T1 913.800	5 Level	0	0
643100	MCCOOK T3 913.800	5 Level	0	0
643146	STOCKVLLET1913.800	5 Level	0	0
652571	GR ISLD3 345.00	5 Level	2187	2200.1
659133	SIDNEY 3 345.00	5 Level	1115	1106.2

6. Stability Analysis for Cluster Scenario

6.1. Faults Simulated

Forty Five (45) faults were considered for the transient stability simulations which included three phase faults, as well as single phase line faults, at the locations defined by SPP in the RFP. Single-phase line faults were simulated by applying fault impedance to the positive sequence network at the fault location. As per the SPP current practice to compute the fault levels, the fault impedance was computed to give a positive sequence voltage at the specified fault location of approximately 60% of pre-fault voltage.

Concurrently and previously queued projects as respectively shown in Table-1 and Table-2 of the study request i.e., GEN-2001-039M, GEN-2003-006A, GEN-2003-019, GEN-2006-031, GEN-2008-017, GEN-2008-092, GEN-2009-008, GEN-2009-020/GEN-2014-025, GEN-2010-057, ASGI-2013-004, GEN-2013-033, GEN-2014-041 as well as areas number 520, 524, 525, 526, 531, 534, 536, and 640 were monitored during all the simulations. Table 6.1.1 shows the list of simulated contingencies. This table also shows the fault clearing time and the time delay before re-closing for all the study contingencies.

Simulations were performed with a 0.1-second steady-state run followed by the appropriate disturbance as described in Table 6.1.1. Simulations were run for minimum 15-second duration to confirm proper machine damping.

Table 6.1.1 summarizes the overall results for all faults simulations of cluster scenario. Complete sets of plots for summer-2015, winter-2015, and summer-2025 peak seasons for each fault are included in Appendices A, B and C respectively.

Table 6.1.1: List of simulated faults for cluster scenario stability analysis

Cont. #	Contingency Name	Description	2015 Summer Results	2015 Winter Results	2025 Summer Results
1	FLT01-3PH	3 phase fault on South Hays 230kV (530582) to Post Rock 230KV (530584) CKT 1, near South Hays. a. Apply fault at the South Hays 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
2	FLT02-3PH	3 phase fault on the Knoll 230kV (530558) to Smokey Hill 230V (530592) CKT 1, near Knoll. a. Apply fault at the Knoll 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
3	FLT03-3PH	3 phase fault on the Knoll 115kV (530561) to Saline 115kV (530551) CKT 1, near Knoll. a. Apply fault at the Knoll 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
4	FLT04-3PH	3 phase fault on the Knoll 115kV (530561) to North Hays 115kV (530581) CKT 1, near Knoll. a. Apply fault at the Knoll 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
5	FLT05-3PH	3 phase fault on the Knoll 115kV (530561) to Redline 115kV (530605) CKT 1, near Knoll. a. Apply fault at the Knoll 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable

Cont. #	Contingency Name	Description	2015 Summer Results	2015 Winter Results	2025 Summer Results
6	FLT06-3PH	3 phase fault on the Ness City 115kV (531456) to Ransom 115kV (531414) CKT 1, near Ness City. a. Apply fault at the Ness City 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
7	FLT07-3PH	3 phase fault on the Ness City 115kV (531456) to Beeler 115kV (531359) CKT 1, near Ness City. a. Apply fault at the Ness City 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
8	FLT08-3PH	3 phase fault on the Post Rock 230KV (530584) to Post Rock 345kV (530583) to Post Rock 13.8kVkV (530673) XFMR CKT 1, near Post Rock 230 kV. a. Apply fault at the Post Rock 230kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.	Stable	Stable	Stable
9	FLT09-3PH	3 phase fault on the Knoll 230kV (530558) to Knoll 115kV (530561) to Knoll 11.49kV (530629) XFMR CKT 1, near Knoll 230 kV. a. Apply fault at the Knoll 230kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.	Stable	Stable	Stable
10	FLT10-3PH	3 phase fault on the G10-048 Tap 115kV (560336) to Beach 115kV (530557) CKT 1, near G10-048 Tap. a. Apply fault at the G10-048 Tap 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable

Cont. #	Contingency Name	Description	2015 Summer Results	2015 Winter Results	2025 Summer Results
11	FLT11-3PH	3 phase fault on the G10-048 Tap 115kV (560336) to Redline 115kV (530605) CKT 1, near G10-048 Tap. a. Apply fault at the G10-048 Tap 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
12	FLT12-3PH	3 phase fault on the Beach 115kV (530557) to Hoxie 115kV (530556) CKT 1, near Beach. a. Apply fault at the Beach 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
13	FLT13-3PH	3 phase fault on the Beach 115kV (530557) to Graham 115kV (531386) CKT 1, near Beach. a. Apply fault at the Beach 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
14	FLT14-3PH	3 phase fault on the Colby 115kV (530555) to Atwood 115kV (530554) CKT 1, near Colby. a. Apply fault at the Colby 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
15	FLT15-3PH	3 phase fault on the Colby 115kV (530555) to Seguin Tap 115kV (530682) CKT 1, near Colby. a. Apply fault at the Colby 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable

Cont. #	Contingency Name	Description	2015 Summer Results	2015 Winter Results	2025 Summer Results
16	FLT16-3PH	3 phase fault on the Colby 115kV (530555) to Mingo 115kV (531429) CKT 1, near Colby. a. Apply fault at the Colby 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
17	FLT17-3PH	3 phase fault on the Mingo 115kV (531429) to Pheasant Run 115kV (530559) CKT 1, near Mingo. a. Apply fault at the Mingo 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
18	FLT18-3PH	3 phase fault on the Mingo 115kV (531429) to Brewster 115kV (531351) CKT 1, near Mingo. a. Apply fault at the Mingo 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
19	FLT19-3PH	3 phase fault on the Mingo 115kV (531429) to Mingo 345kV (531451) to Mingo 13.8kV (531452) XFMR CKT 1, near Mingo 115kV. a. Apply fault at the Mingo 115kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.	Stable	Stable	Stable
20	FLT20-3PH	3 phase fault on the Mingo 345kV (531451) to Red Willow 345kV (640325) CKT 1, near Mingo. a. Apply fault at the Mingo 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable

Cont. #	Contingency Name	Description	2015 Summer Results	2015 Winter Results	2025 Summer Results
21	FLT21-3PH	3 phase fault on the Mingo 345kV (531451) to Setab 345kV (531465) CKT 1, near Mingo. a. Apply fault at the Mingo 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
22	FLT22-3PH	3 phase fault on the Setab 345kV (531465) to Holcomb 345kV (531449) CKT 1, near Setab. a. Apply fault at the Setab 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
23	FLT23-3PH	3 phase fault on the Setab 345kV (531465) to Setab 115kV (531464) to Setab 13.8kV (531259) XFMR CKT 1, near Setab 345kV. a. Apply fault at the Setab 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.	Stable	Stable	Stable
24	FLT24-3PH	3 phase fault on the Rhoades 115kV (531373) to Norcatr 115kV (531372) CKT 1, near Rhoades. a. Apply fault at the Rhoades 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
25	FLT25-3PH	3 phase fault on the Rhoades 115kV (531373) to Graham 115kV (531386) CKT 1, near Rhoades. a. Apply fault at the Rhoades 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable

Cont. #	Contingency Name	Description	2015 Summer Results	2015 Winter Results	2025 Summer Results
26	FLT26-3PH	3 phase fault on the Rhoades 115kV (531373) to Phillipsburg 115kV (539685) CKT 1, near Rhoades. a. Apply fault at the Rhoades 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
27	FLT27-3PH	3 phase fault on the Knoll 230kV (530558) to Postrock 230kV (530584) CKT 1, near Knoll. a. Apply fault at the Knoll 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
28	FLT28-3PH	3 phase fault on the Knoll 230kV (530558) to Smoky Hill 230kV (530592) CKT 1, near Knoll. a. Apply fault at the Knoll 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
29	FLT29-3PH	3 phase fault on the Ness City 115kV (530607) to Alexander 115kV (530606) CKT 1, near Ness City. a. Apply fault at the Ness City 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
30	FLT30-3PH	3 phase fault on the Pheasant Run 115kV (530559) to Seguin 115kV (530683) CKT 1, near Pheasant Run. a. Apply fault at the Pheasant Run 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable

Cont. #	Contingency Name	Description	2015 Summer Results	2015 Winter Results	2025 Summer Results
31	FLT31-3PH	3 phase fault on the Pheasant Run 115kV (530559) to Grinnel 115kV (531412) CKT 1, near Pheasant Run. a. Apply fault at the Pheasant Run 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
32	FLT32-3PH	3 phase fault on the Ruleton 115kV (531357) to NSI Tap 115kV (531356) CKT 1, near Ruleton. a. Apply fault at the Ruleton 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
33	FLT33-3PH	3 phase fault on the Ruleton 115kV (531357) to Lawn Ridge 115kV (531368) CKT 1, near Ruleton. a. Apply fault at the Ruleton 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
34	FLT34-3PH	3 phase fault on the Atwood 115kV (530554) to Atwood SW 115kV (531364) CKT 1, near Atwood. a. Apply fault at the Atwood 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
35	FLT35-3PH	3 phase fault on the Atwood 115kV (530554) to Beaver Valley 115kV (531488) CKT 1, near Atwood. a. Apply fault at the Atwood 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable

Cont. #	Contingency Name	Description	2015 Summer Results	2015 Winter Results	2025 Summer Results
36	FLT36-3PH	3 phase fault on the Holcomb 345kV (531449) to Finney 345kV (523853) CKT 1, near Holcomb. a. Apply fault at the Holcomb 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
37	FLT37-3PH	3 phase fault on the Holcomb 345kV (531449) to Buckner 345kV (531501) CKT 1, near Holcomb. a. Apply fault at the Holcomb 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
38	FLT38-3PH	3 phase fault on the Holcomb 345kV (531449) to Holcomb 115kV (531448) to Holcomb 13.8kV (531450) XFMR CKT 1, near Holcomb 345kV. a. Apply fault at the Holcomb 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.	Stable	Stable	Stable
39	FLT39-3PH	3 phase fault on the Red Willow 345kV (640325) to Gentleman 345kV (640183) CKT 1, near Red Willow. a. Apply fault at the Red Willow 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
40	FLT40-3PH	3 phase fault on the Red Willow 345kV (640325) to Red Willow 115kV (640326) to Red Willow 13.8kV (640327) XFMR CKT 1, near Red Willow 345kV. a. Apply fault at the Red Willow 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.	Stable	Stable	Stable

Cont. #	Contingency Name	Description	2015 Summer Results	2015 Winter Results	2025 Summer Results
41	FLT41-3PH	3 phase fault on the Gentleman 345kV (640183) to Keystone 345kV (640252) CKT 1, near Gentleman. a. Apply fault at the Gentleman 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
42	FLT42-3PH	3 phase fault on the Gentleman 345kV (640183) to Sweetwater 345kV (640374) CKT 1, near Gentleman. a. Apply fault at the Gentleman 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
43	FLT43-PO	**Prior Outage of Knoll to N Hays 115kV**. 3 phase fault on the Ross Beach to GEN-2010-048 Tap 115kV. a. Prior outage Knoll (530561) 115kV to N Hays (530581) 115kV (solve network for steady state solution). b. 3 phase fault on the Ross Beach (530557) 115kV to GEN-2010-048 Tap (560336) 115kV, near Ross Beach 115kV. c. Leave fault on for 5 cycles, then trip the faulted line in (b).	Stable	Stable	Stable
44	FLT44-SB	**Knoll 115kV Stuck Breaker** a. Apply single phase fault at the Knoll (530561) 115kV bus on the Knoll – Red Line (530605) 115kV line. b. Wait 16 cycles, and then drop Knoll (530558) 230kV to Knoll (530561) 115kV (530629) 11.49kV transformer. c. Trip Knoll to Red Line 115kV and remove the fault.	Stable	Stable	Stable
45	FLT45-SB	**Mingo 115kV Stuck Breaker** a. Apply single phase fault at the Mingo (531429)115kV bus on the Mingo – Brewster (531351) 115kV line. b. Wait 16 cycles, and then trip Mingo (531429) to Brewster (531351) 115kV. c. Trip Mingo (531429) to Colby (530555) 115kV and remove the fault.	Stable	Stable	Stable

6.2. Simulation Results for Cluster Scenario

For cluster scenario, there are no impacts on the stability performance of the SPP system for the contingencies tested on the SPP provided base cases.

7. Stability Analysis for Stand-Alone Scenarios

For stand-alone scenario, selective contingencies are simulated for each interconnection request at 100% capacity of each generator at the POI.

7.1. Fault Simulated for GEN-2010-048 Request

Table 7.1.1, summarizes the overall results for all simulations for GEN-2010-048 request. Complete sets of plots for summer-2015, winter-2015, and summer-2025 peak seasons for each fault for GEN-2010-048 are in Appendices E1, E2, and E3 respectively.

Table 7.1.1: List of simulated faults for stand-alone stability analysis (GEN-2010-048)

Cont. #	Contingency Name	Description	2015 Summer Results	2015 Winter Results	2025 Summer Results
1	FLT01-3PH	3 phase fault on South Hays 230kV (530582) to Post Rock 230KV (530584) CKT 1, near South Hays. a. Apply fault at the South Hays 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
2	FLT02-3PH	3 phase fault on the Knoll 230kV (530558) to Smokey Hill 230V (530592) CKT 1, near Knoll. a. Apply fault at the Knoll 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
3	FLT03-3PH	3 phase fault on the Knoll 115kV (530561) to Saline 115kV (530551) CKT 1, near Knoll. a. Apply fault at the Knoll 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable

Cont. #	Contingency Name	Description	2015 Summer Results	2015 Winter Results	2025 Summer Results
4	FLT04-3PH	3 phase fault on the Knoll 115kV (530561) to North Hays 115kV (530581) CKT 1, near Knoll. a. Apply fault at the Knoll 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
5	FLT05-3PH	3 phase fault on the Knoll 115kV (530561) to Redline 115kV (530605) CKT 1, near Knoll. a. Apply fault at the Knoll 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
8	FLT08-3PH	3 phase fault on the Post Rock 230KV (530584) to Post Rock 345kV (530583) to Post Rock 13.8kVkV (530673) XFMR CKT 1, near Post Rock 230 kV. a. Apply fault at the Post Rock 230kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.	Stable	Stable	Stable
9	FLT09-3PH	3 phase fault on the Knoll 230kV (530558) to Knoll 115kV (530561) to Knoll 11.49kV (530629) XFMR CKT 1, near Knoll 230 kV. a. Apply fault at the Knoll 230kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.	Stable	Stable	Stable
10	FLT10-3PH	3 phase fault on the G10-048 Tap 115kV (560336) to Beach 115kV (530557) CKT 1, near G10-048 Tap. a. Apply fault at the G10-048 Tap 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable

Cont. #	Contingency Name	Description	2015 Summer Results	2015 Winter Results	2025 Summer Results
11	FLT11-3PH	3 phase fault on the G10-048 Tap 115kV (560336) to Redline 115kV (530605) CKT 1, near G10-048 Tap. a. Apply fault at the G10-048 Tap 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
12	FLT12-3PH	3 phase fault on the Beach 115kV (530557) to Hoxie 115kV (530556) CKT 1, near Beach. a. Apply fault at the Beach 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
13	FLT13-3PH	3 phase fault on the Beach 115kV (530557) to Graham 115kV (531386) CKT 1, near Beach. a. Apply fault at the Beach 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
14	FLT14-3PH	3 phase fault on the Colby 115kV (530555) to Atwood 115kV (530554) CKT 1, near Colby. a. Apply fault at the Colby 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
15	FLT15-3PH	3 phase fault on the Colby 115kV (530555) to Seguin Tap 115kV (530682) CKT 1, near Colby. a. Apply fault at the Colby 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable

Cont. #	Contingency Name	Description	2015 Summer Results	2015 Winter Results	2025 Summer Results
16	FLT16-3PH	3 phase fault on the Colby 115kV (530555) to Mingo 115kV (531429) CKT 1, near Colby. a. Apply fault at the Colby 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
20	FLT20-3PH	3 phase fault on the Mingo 345kV (531451) to Red Willow 345kV (640325) CKT 1, near Mingo. a. Apply fault at the Mingo 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
24	FLT24-3PH	3 phase fault on the Rhoades 115kV (531373) to Norcatr 115kV (531372) CKT 1, near Rhoades. a. Apply fault at the Rhoades 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
25	FLT25-3PH	3 phase fault on the Rhoades 115kV (531373) to Graham 115kV (531386) CKT 1, near Rhoades. a. Apply fault at the Rhoades 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
26	FLT26-3PH	3 phase fault on the Rhoades 115kV (531373) to Phillipsburg 115kV (539685) CKT 1, near Rhoades. a. Apply fault at the Rhoades 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable

Cont. #	Contingency Name	Description	2015 Summer Results	2015 Winter Results	2025 Summer Results
27	FLT27-3PH	3 phase fault on the Knoll 230kV (530558) to Postrock 230kV (530584) CKT 1, near Knoll. a. Apply fault at the Knoll 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
28	FLT28-3PH	3 phase fault on the Knoll 230kV (530558) to Smoky Hill 230kV (530592) CKT 1, near Knoll. a. Apply fault at the Knoll 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
43	FLT43-PO	**Prior Outage of Knoll to N Hays 115kV**. 3 phase fault on the Ross Beach to GEN-2010-048 Tap 115kV. a. Prior outage Knoll (530561) 115kV to N Hays (530581) 115kV (solve network for steady state solution). b. 3 phase fault on the Ross Beach (530557) 115kV to GEN-2010-048 Tap (560336) 115kV, near Ross Beach 115kV. c. Leave fault on for 5 cycles, then trip the faulted line in (b).	Stable	Stable	Stable
44	FLT44-SB	**Knoll 115kV Stuck Breaker** a. Apply single phase fault at the Knoll (530561) 115kV bus on the Knoll – Red Line (530605) 115kV line. b. Wait 16 cycles, and then drop Knoll (530558) 230kV to Knoll (530561) 115kV (530629) 11.49kV transformer. c. Trip Knoll to Red Line 115kV and remove the fault.	Stable	Stable	Stable

Note: For stand-alone scenario GEN-2010-048, the other requested machine GEN-2015-017 was out of service and therefore GEN-2015-017 is reflected in the plots of appendix E1, E2, and E3

7.2. Fault Simulated for GEN-2015-017 Request

Table 7.2.1, summarizes the overall results for all simulations for GEN-2015-017 request. Complete sets of plots for summer-2015, winter-2015, and summer-2025 peak seasons for each fault for GEN-2015-017 are in Appendices F1, F2, and F3 respectively.

Table 7.2.1: List of simulated faults for stability analysis (GEN-2015-017)

Cont. #	Contingency Name	Description	2015 Summer Results	2015 Winter Results	2025 Summer Results
6	FLT06-3PH	3 phase fault on the Ness City 115kV (531456) to Ransom 115kV (531414) CKT 1, near Ness City. a. Apply fault at the Ness City 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
7	FLT07-3PH	3 phase fault on the Ness City 115kV (531456) to Beeler 115kV (531359) CKT 1, near Ness City. a. Apply fault at the Ness City 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
12	FLT12-3PH	3 phase fault on the Beach 115kV (530557) to Hoxie 115kV (530556) CKT 1, near Beach. a. Apply fault at the Beach 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
14	FLT14-3PH	3 phase fault on the Colby 115kV (530555) to Atwood 115kV (530554) CKT 1, near Colby. a. Apply fault at the Colby 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
15	FLT15-3PH	3 phase fault on the Colby 115kV (530555) to Seguin Tap 115kV (530682) CKT 1, near Colby. a. Apply fault at the Colby 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable

Cont. #	Contingency Name	Description	2015 Summer Results	2015 Winter Results	2025 Summer Results
16	FLT16-3PH	3 phase fault on the Colby 115kV (530555) to Mingo 115kV (531429) CKT 1, near Colby. a. Apply fault at the Colby 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
17	FLT17-3PH	3 phase fault on the Mingo 115kV (531429) to Pheasant Run 115kV (530559) CKT 1, near Mingo. a. Apply fault at the Mingo 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
18	FLT18-3PH	3 phase fault on the Mingo 115kV (531429) to Brewster 115kV (531351) CKT 1, near Mingo. a. Apply fault at the Mingo 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
19	FLT19-3PH	3 phase fault on the Mingo 115kV (531429) to Mingo 345kV (531451) to Mingo 13.8kV (531452) XFMR CKT 1, near Mingo 115kV. a. Apply fault at the Mingo 115kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.	Stable	Stable	Stable
20	FLT20-3PH	3 phase fault on the Mingo 345kV (531451) to Red Willow 345kV (640325) CKT 1, near Mingo. a. Apply fault at the Mingo 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable

Cont. #	Contingency Name	Description	2015 Summer Results	2015 Winter Results	2025 Summer Results
21	FLT21-3PH	3 phase fault on the Mingo 345kV (531451) to Setab 345kV (531465) CKT 1, near Mingo. a. Apply fault at the Mingo 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
22	FLT22-3PH	3 phase fault on the Setab 345kV (531465) to Holcomb 345kV (531449) CKT 1, near Setab. a. Apply fault at the Setab 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
23	FLT23-3PH	3 phase fault on the Setab 345kV (531465) to Setab 115kV (531464) to Setab 13.8kV (531259) XFMR CKT 1, near Setab 345kV. a. Apply fault at the Setab 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.	Stable	Stable	Stable
29	FLT29-3PH	3 phase fault on the Ness City 115kV (530607) to Alexander 115kV (530606) CKT 1, near Ness City. a. Apply fault at the Ness City 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
30	FLT30-3PH	3 phase fault on the Pheasant Run 115kV (530559) to Seguin 115kV (530683) CKT 1, near Pheasant Run. a. Apply fault at the Pheasant Run 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable

Cont. #	Contingency Name	Description	2015 Summer Results	2015 Winter Results	2025 Summer Results
31	FLT31-3PH	3 phase fault on the Pheasant Run 115kV (530559) to Grinnel 115kV (531412) CKT 1, near Pheasant Run. a. Apply fault at the Pheasant Run 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
32	FLT32-3PH	3 phase fault on the Ruleton 115kV (531357) to NSI Tap 115kV (531356) CKT 1, near Ruleton. a. Apply fault at the Ruleton 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
33	FLT33-3PH	3 phase fault on the Ruleton 115kV (531357) to Lawn Ridge 115kV (531368) CKT 1, near Ruleton. a. Apply fault at the Ruleton 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
34	FLT34-3PH	3 phase fault on the Atwood 115kV (530554) to Atwood SW 115kV (531364) CKT 1, near Atwood. a. Apply fault at the Atwood 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
35	FLT35-3PH	3 phase fault on the Atwood 115kV (530554) to Beaver Valley 115kV (531488) CKT 1, near Atwood. a. Apply fault at the Atwood 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable

Cont. #	Contingency Name	Description	2015 Summer Results	2015 Winter Results	2025 Summer Results
36	FLT36-3PH	3 phase fault on the Holcomb 345kV (531449) to Finney 345kV (523853) CKT 1, near Holcomb. a. Apply fault at the Holcomb 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
37	FLT37-3PH	3 phase fault on the Holcomb 345kV (531449) to Buckner 345kV (531501) CKT 1, near Holcomb. a. Apply fault at the Holcomb 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
38	FLT38-3PH	3 phase fault on the Holcomb 345kV (531449) to Holcomb 115kV (531448) to Holcomb 13.8kV (531450) XFMR CKT 1, near Holcomb 345kV. a. Apply fault at the Holcomb 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.	Stable	Stable	Stable
39	FLT39-3PH	3 phase fault on the Red Willow 345kV (640325) to Gentleman 345kV (640183) CKT 1, near Red Willow. a. Apply fault at the Red Willow 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
40	FLT40-3PH	3 phase fault on the Red Willow 345kV (640325) to Red Willow 115kV (640326) to Red Willow 13.8kV (640327) XFMR CKT 1, near Red Willow 345kV. a. Apply fault at the Red Willow 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.	Stable	Stable	Stable

Cont. #	Contingency Name	Description	2015 Summer Results	2015 Winter Results	2025 Summer Results
41	FLT41-3PH	3 phase fault on the Gentleman 345kV (640183) to Keystone 345kV (640252) CKT 1, near Gentleman. a. Apply fault at the Gentleman 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
42	FLT42-3PH	3 phase fault on the Gentleman 345kV (640183) to Sweetwater 345kV (640374) CKT 1, near Gentleman. a. Apply fault at the Gentleman 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
45	FLT45-SB	**Mingo 115kV Stuck Breaker** a. Apply single phase fault at the Mingo (531429)115kV bus on the Mingo – Brewster (531351) 115kV line. b. Wait 16 cycles, and then trip Mingo (531429) to Brewster (531351) 115kV. c. Trip Mingo (531429) to Colby (530555) 115kV and remove the fault.	Stable	Stable	Stable

Note: For stand-alone scenario GEN-2015-017, the other requested machine GEN-2010-048 was out of service and therefore GEN-2010-048 is reflected in the plots of Appendices F1, F2, and F3

7.3.Simulation Results for Stand-Alone Scenarios

There are no impacts on the stability performance for stand-alone scenarios of the SPP system for the contingencies tested on the SPP provided base cases.

8. Conclusions

The findings of the impact study for the proposed interconnection projects under DISIS-2015-001 (Group 04) considered 100% of their proposed installed capacity is as follows:

1. The power factor analysis indicates the DISIS-2015-001 (Group 04) interconnection requests i.e., GEN-2010-048, and GEN-2015-017 are required to maintain the SPP standard power factor at the point of interconnection i.e., Tap on the Ross Beach to Redline 115kV line (560336), and Mingo 115kV (531429) based on the contingencies studied. Per the SPP OATT, the Interconnection Customer will be required to provide 95% lagging (supplying vars) and 95% leading (absorbing vars) at the POI

2. The inductive reactive support analysis for wind generator GEN-2010-048 performed for summer-2015 scenario which indicates that at POI i.e., Tap on the Ross Beach to Redline 115kV line (560336) 2.9 MVAR reactor is required at Bus 580062 to maintain zero MVAR flow for the GEN-2010-048 generator lead. Maintaining zero MVar flow at the POI at all times is not possible with static reactor banks. It will be determined on a case by case basis for each generator as to whether additional reactor banks are required for low wind conditions.

3. The short circuit analysis is performed on the power flow models for the 2025 summer peak season for cluster scenario model. The results are documented for both 3 phase fault as well as single line to ground fault up to 5 buses away from the POI i.e., Tap on the Ross Beach to Redline 115kV line (560336), and Mingo 115kV (531429).

4. There are no impacts on the stability performance of the SPP system during both cluster and stand-alone scenarios for the contingencies tested on the provided base cases. The study machines stayed on-line and stable for all simulated faults. The Project stability simulations with forty five (45) specified test disturbances did not show instability problems in the SPP system. Any oscillations were damped out.

9. Appendix A:2015 Summer Peak Case Stability Run Plots – Cluster

10. Appendix B:2015 Winter Peak Case Stability Run Plots – Cluster

11. Appendix C:2025 Summer Peak Case Stability Run Plots – Cluster

12. Appendix D:Project Model Data

13. Appendix E1: 2015 Summer Peak Case Stability Run Plots for GEN-2010-048 Stand-Alone Scenario

14. Appendix E2:2015 Winter Peak Case Stability Run Plots for GEN-2010-048 Stand-Alone Scenario

15. Appendix E3:2025 Summer Peak Case Stability Run Plots for GEN-2010-048 Stand-Alone Scenario

16. Appendix F1: 2015 Summer Peak Case Stability Run Plots for GEN-2015-017 Stand-Alone Scenario

17. Appendix F2:2015 Winter Peak Case Stability Run Plots for GEN-2015-017 Stand-Alone Scenario

18. Appendix F3:2025 Summer Peak Case Stability Run Plots for GEN-2015-017 Stand-Alone Scenario

N: Group 5 Dynamic Stability Analysis Report

This appendix will be updated when Group 5 study is completed.

O: Group 6 Dynamic Stability Analysis Report

This appendix will be updated when Group 6 study is completed.

P: Group 7 Dynamic Stability Analysis Report

This appendix will be updated when Group 7 study is completed.

Q: Group 8 Dynamic Stability Analysis Report

See MEPPI study report on next page

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Southwest Power Pool, Inc. (SPP)

DISIS-2015-001 (Group 08) Definitive Impact Study

Final Report

PXE-1074
Revision #00

July 2015

Submitted By:
Mitsubishi Electric Power Products, Inc. (MEPPI)
Power Systems Engineering Services Department
Warrendale, PA

Title: **DISIS-2015-001 (Group 8) Definitive Impact Study: Final Report PXE-1074**
Date: July 2015

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Approved: Elizabeth M. Cook; Senior Engineer, Power Systems Engineering Dept. *Elizabeth M. Cook*

EXECUTIVE SUMMARY

SPP requested a Definitive Interconnection System Impact Study (DISIS). The DISIS required a Stability Analysis, Short Circuit Analysis, Power Factor Analysis, and Low Wind/No Wind Analysis detailing the impacts of the interconnecting projects as shown in Table ES-1.

Table ES-1
Interconnection Projects Evaluated

Request	Size (MW)	Generator Model	Point of Interconnection
GEN-2015-001	200	Vestas V110 2.0MW	Ranch Road 345kV
GEN-2015-003	200	Vestas V110 2.0MW	Renfrow 345kV
GEN-2015-015	154.6	Siemens 2.3MW with Power Boost (115kW => 2.415MW)	Tap Medford Tap – Coyote 138kV
GEN-2015-016	200	Vestas V110 2.0MW	Tap Centerville – Marmaton 161kV
GEN-2015-024	220	GE 2.0MW	Tap Wichita - Thistle 345kV circuit 1
GEN-2015-025	220	GE 2.0MW	Tap Wichita - Thistle 345kV circuit 2
GEN-2015-028	3.0 uprate to GEN-2009-025 for total 62.8MW	Siemens 2.3MW with Power Boost (115kW => 2.415MW)	Nardins 69kV
GEN-2015-030	200.1	GE 2.3MW	Sooner 345kV
ASGI-2015-004	54.300 Summer 56.364 Winter	GENSAL	Coffeyville Municipal Light & Power Northern Industrial Park Substation 69kV

SUMMARY OF STABILITY ANALYSIS

The Stability Analysis determined that there were no contingencies that resulted in system instability, generation tripping offline, or voltage violations for the 2015 Summer Peak, 2015 Winter Peak, and 2025 Summer Peak conditions when all generation interconnection requests were at 100% output for both the Cluster Scenario study and the Stand Alone Scenario study. Thus, no mitigations or upgrades were required.

Note contingencies, FLT01-3PH and FLT03-3PH, required the “LVRT extreme UV limit” value in the “VWVRP7” dynamic model of GEN-2015-001 to be changed from 0.05 p.u. to 0.0 p.u. in order for GEN-2015-001 to remain online, as discussed with SPP. The dynamic file modification was used to complete the analysis.

Several voltage buses consistently fell outside of the 0.95 p.u. to 1.05 p.u. range. All instances were observed for pre-fault conditions and since all voltages returned to pre-fault conditions, no mitigation was required.

SUMMARY OF THE SHORT CIRCUIT ANALYSIS

The short circuit analysis was performed on the 2025 Summer Peak power flow for all study projects. Refer to Table ES-2 for a list of maximum fault currents observed for each study project.

Table ES-2
List of Maximum Fault Currents Observed for Each Study Project

Study Project	POI Name	Fault Current at POI (kA)	Maximum Fault Current (kA)	Fault Location	Bus Voltage (kV)
GEN-2015-001	Ranch Road 345 kV	12.91	41.57	NORTWST4	138
GEN-2015-003	Renfrow 345 kV	12.87	41.57	NORTWST4	138
GEN-2015-015	Tap Medford - Coyote 138 kV	8.51	24.56	WICHITA7	345
GEN-2015-016	Tap Centerville - Marmaton 161 kV	7.26	24.67	LACYGNE7	345
GEN-2015-024	Tap Witchita - Thistle 345 kV circuit 1	24.56	41.45	EVANS S4	138
GEN-2015-025	Tap Witchita - Thistle 345 kV circuit 2				
GEN-2015-028	Nardins 69 kV	5.52	15.67	WHEAGLE4	138
GEN-2015-030	Sooner 345 kV	22.77	57.59	SEMINOL4	138
ASGI-2015-004	Coffeyville Municipal Light & Power Northern Industrial Park Substation 69 kV	8.59	26.11	ONETA--7	345

SUMMARY OF POWER FACTOR ANALYSIS

For all the generators that follow, the power factor is measured at the point of interconnection (POI).

Study Generator GEN-2015-001

The Power Factor Analysis shows that GEN-2015-001 has a power factor range of 0.957 to 0.999 leading (absorbing) for the 2015 Summer Peak conditions, a power factor range of 0.980

leading (absorbing) to 1.00 (unity) for the 2015 Winter Peak conditions, and a power factor range of 0.986 to 0.999 leading (absorbing) for the 2025 Summer Peak conditions.

Study Generator GEN-2015-003

The Power Factor Analysis shows that GEN-2015-003 has a power factor range of 0.979 lagging (supplying) to 0.986 leading (absorbing) for the 2015 Summer Peak conditions, a power factor range of 0.898 lagging (supplying) to 0.994 leading (absorbing) for the 2015 Winter Peak conditions, and a power factor range of 0.983 leading (supplying) to 1.00 (unity) for the 2025 Summer Peak conditions.

Study Generator GEN-2015-015

The Power Factor Analysis shows that GEN-2015-015 has a power factor range of 0.946 lagging (supplying) to 0.991 leading (absorbing) for the 2015 Summer Peak conditions, a power factor range of 0.959 lagging (supplying) to 0.991 leading (absorbing) for the 2015 Winter Peak conditions, and a power factor range of 0.991 lagging (supplying) to 0.996 leading (absorbing) for the 2025 Summer Peak conditions.

Study Generator GEN-2015-016

The Power Factor Analysis shows that GEN-2015-016 has a power factor range of 0.971 to 0.997 leading (absorbing) for the 2015 Summer Peak conditions, a power factor range of 0.968 to 0.996 leading (absorbing) for the 2015 Winter Peak conditions, and a power factor range of 0.975 to 0.997 leading (absorbing) for the 2025 Summer Peak conditions.

Study Generators GEN-2015-024 and GEN-2015-025 (Tap Wichita – Thistle circuit 1&2)

The Power Factor Analysis shows that the Wichita generation has a power factor range of 0.897 lagging (supplying) to 1.00 (unity) for the 2015 Summer Peak conditions, a power factor range of 0.655 to 0.883 lagging (supplying) for the 2015 Winter Peak conditions, and a power factor range of 0.911 lagging (supplying) to 0.999 leading (absorbing) for the 2025 Summer Peak conditions.

Study Generator GEN-2015-028

The Power Factor Analysis shows that GEN-2015-028 has a power factor range of 0.947 to 0.999 leading (supplying) for the 2015 Summer Peak conditions, a power factor range of 0.997 lagging (supplying) to 0.971 leading (absorbing) for the 2015 Winter Peak conditions, and a power factor range of 0.990 lagging (supplying) to 0.975 leading (absorbing) for the 2025 Summer Peak conditions.

Study Generator GEN-2015-030

The Power Factor Analysis shows that GEN-2015-030 has a power factor range of 0.902 to 0.998 lagging (supplying) for the 2015 Summer Peak conditions, a power factor range of 0.857

to 0.995 lagging (supplying) for the 2015 Winter Peak conditions, and a power factor range of 0/945 lagging (supplying) to 1.00 (unity) for the 2025 Summer Peak conditions.

SUMMARY OF LOW WIND/NO WIND ANALYSIS

The amount of reactive power injected into the transmission network was recorded at the point of interconnection for GEN-2015-001, GEN-2015-003, GEN-2015-024, GEN-2015-025, and GEN-2015-030 for each season. The maximum reactance needed for zero Mvar flow was 57.1 Mvar for GEN-2015-024 and GEN-2015-025 (Tap Wichita – Thistle circuit 1&2). The minimum reactance needed for zero Mvar flow was 9.8 Mvar for GEN-2015-030 (Sooner 345 kV).

Table of Contents

SECTION 1: OBJECTIVES

The objective of this report is to provide Southwest Power Pool, Inc. (SPP) with the deliverables for the "DISIS-2015-001 (Group 8) Definitive Impact Study." SPP requested an Interconnection System Impact Study for nine (9) generation interconnections for 2015 Summer Peak, 2015 Winter Peak, and 2025 Summer Peak, which requires a Stability Analysis, Short Circuit Analysis, Power Factor Analysis, Low Wind/No Wind Analysis, and an Impact Study Report.

SECTION 2: BACKGROUND

The Siemens Power Technologies, Inc. PSS/E power system simulation program Version 32.2.0 was used for this study. SPP provided the stability database cases for 2015 Summer Peak, 2015 Winter Peak, and 2025 Summer Peak conditions and a list of contingencies to be examined. The model includes the study projects shown in Table 2-1 and the previously queued projects listed in Table 2-2. Refer to Appendix A for the steady-state and dynamic model data for the study projects. A power flow one-line diagram for each generation interconnection project is shown in Figures 2-1 through 2-8. Note that the one-line diagrams represent the 2015 Summer Peak case.

The Stability Analysis determined the impacts of the new interconnecting projects on the stability and voltage recovery of the nearby system and the ability of the interconnecting projects to meet FERC Order 661A. If problems with stability or voltage recovery are identified, the need for reactive compensation or system upgrades will be investigated. Three-phase faults and single line-to-ground faults will be examined as listed in Table 2-3. Note that all contingencies listed were examined for the cluster scenario, and specified contingencies (indicated by an X) were examined for each Stand Alone generator.

A Short Circuit Analysis was performed on the 2025 Summer Peak study year for each study generator in the Cluster Scenario. The study was performed five buses out from the study generator's point of interconnection and results were documented.

The Power Factor Analysis determined the power factor at the point of interconnection for the wind or solar interconnection projects for pre-contingency and post-contingency conditions. The N-1, three phase contingencies listed in Table 2-3 were used in the Power Factor analysis.

The Low Wind/No Wind Analysis was completed for wind or solar farm interconnections that interconnect to a 345 kV or 230 kV bus. This analysis determined if reactive support is needed to have an Mvar flow of approximately zero at the point of interconnection (POI).

Table 2-1
Interconnection Projects Evaluated

Request	Size (MW)	Generator Model	Point of Interconnection
GEN-2015-001	200	Vestas V110 2.0MW	Ranch Road 345kV
GEN-2015-003	200	Vestas V110 2.0MW	Renfrow 345kV
GEN-2015-015	154.6	Siemens 2.3MW with Power Boost (115kW => 2.415MW)	Tap Medford Tap – Coyote 138kV
GEN-2015-016	200	Vestas V110 2.0MW	Tap Centerville – Marmaton 161kV
GEN-2015-024	220	GE 2.0MW	Tap Wichita - Thistle 345kV circuit 1
GEN-2015-025	220	GE 2.0MW	Tap Wichita - Thistle 345kV circuit 2
GEN-2015-028	3.0 uprate to GEN-2009-025 for total 62.8MW	Siemens 2.3MW with Power Boost (115kW => 2.415MW)	Nardins 69kV
GEN-2015-030	200.1	GE 2.3MW	Sooner 345kV
ASGI-2015-004	54.300 Summer 56.364 Winter	GENSAL	Coffeyville Municipal Light & Power Northern Industrial Park Substation 69kV

Table 2-2
Previously Queued Nearby Interconnection Projects Included

Request	Size (MW)	Generator Model	Point of Interconnection
GEN-2002-004	199.5	GE.1.5MW	Latham 345kV (532800)
GEN-2005-013	199.8	Vestes V90 1.8MW	Caney River 345kV (532780)
GEN-2007-025	299.2	GE 1.6MW	Viola 345kV (532798)
GEN-2008-013	300	G.E. 1.68MW	Hunter 345kV (515476)
GEN-2008-021	1261 Summer 1283 Winter	GENROU	Wolf Creek 345kV (532797)
GEN-2008-098	100.8	Vestas V100 1.8MW	Tap on the Wolf Creek – LaCygne 345kV line (560004)
GEN-2009-025	59.8	Siemens 2.3MW	Tap on the Deerck – Sincblk 69KV line (515528)
GEN-2010-003	100.8	Vestas V100 1.8MW	Tap on the Wolf Creek – LaCygne 345kV line (560004)
GEN-2010-005	299.2	GE 1.6MW	Viola 345kV (532798)
ASGI-2010-006	150	GE1.5MW	Remington 138kV (301369)
GEN-2010-055	4.8	GENROU	Wekiwa 138kV (509757)
GEN-2011-057	150.4	GE 1.6MW	Creswell 138kV (532981)
GEN-2012-027	150.7	GE 1.62MW	Shidler 138kV (510403)
KCPL Distributed: Osawatomie	76	GENROU (543078)	Paola 161kV
GEN-2012-032	300	Vestas V112 3.0MW	Tap Rose Hill-Sooner 345kV (562318)
GEN-2012-033	98.8	GE 1.62MW	Tap Bunch Creek-South 4th 138kV(562303)
GEN-2012-040	76.5	GE 1.7MW	Chilocco 138kV (521198)
GEN-2012-041	85 Summer 121.5 Winter	GENROU	Tap Rose Hill-Sooner 345kV (562318)
GEN-2013-012	4 x 168.0MW Summer 4 x 215MW Winter	GENROU (514910) (514911) (514911) (514942)	Redbud 345kV (514909)
GEN-2013-028	516.4 Summer 559.5 Winter	GENROU (583743, 583746)	Tap on Tulsa N to GRDA1 345kV (562423)
GEN-2013-029	300	Vestas V100 VCSS 2MW (583753, 583756)	Renfrow 345kV(515543)
GEN-2014-001	200.6	GE 1.7MW 100m (583853,583856)	Tap Wichita to Emporia Energy Center 345kV (562476)

Table 2-2 (Continued)
Previously Queued Nearby Interconnection Projects Included

Request	Size (MW)	Generator Model	Point of Interconnection
GEN-2014-028	35 (Uprate) (Pgen=259W/2	GENROU	Riverton 161kV (547469)
GEN-2014-064	248.4	GE 2.3MW	Otter 138kV (514708)
ASGI-2014-014	56.4W/54.3S	GENROU	Ferguson 69kV (512664)

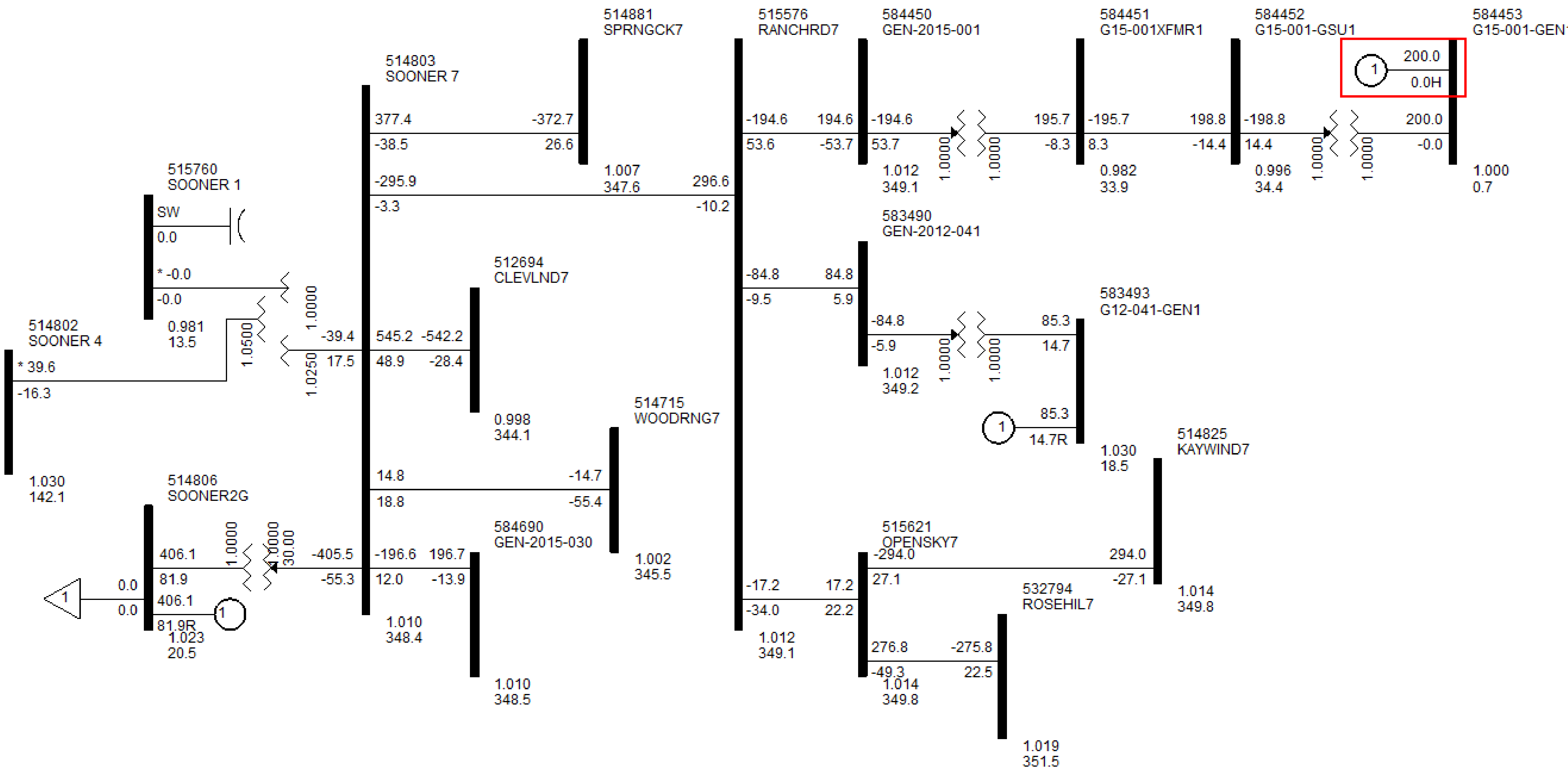

Figure 2-1. Power flow one-line diagram for interconnection project at the Ranch Road 345kV POI (GEN-2015-001)

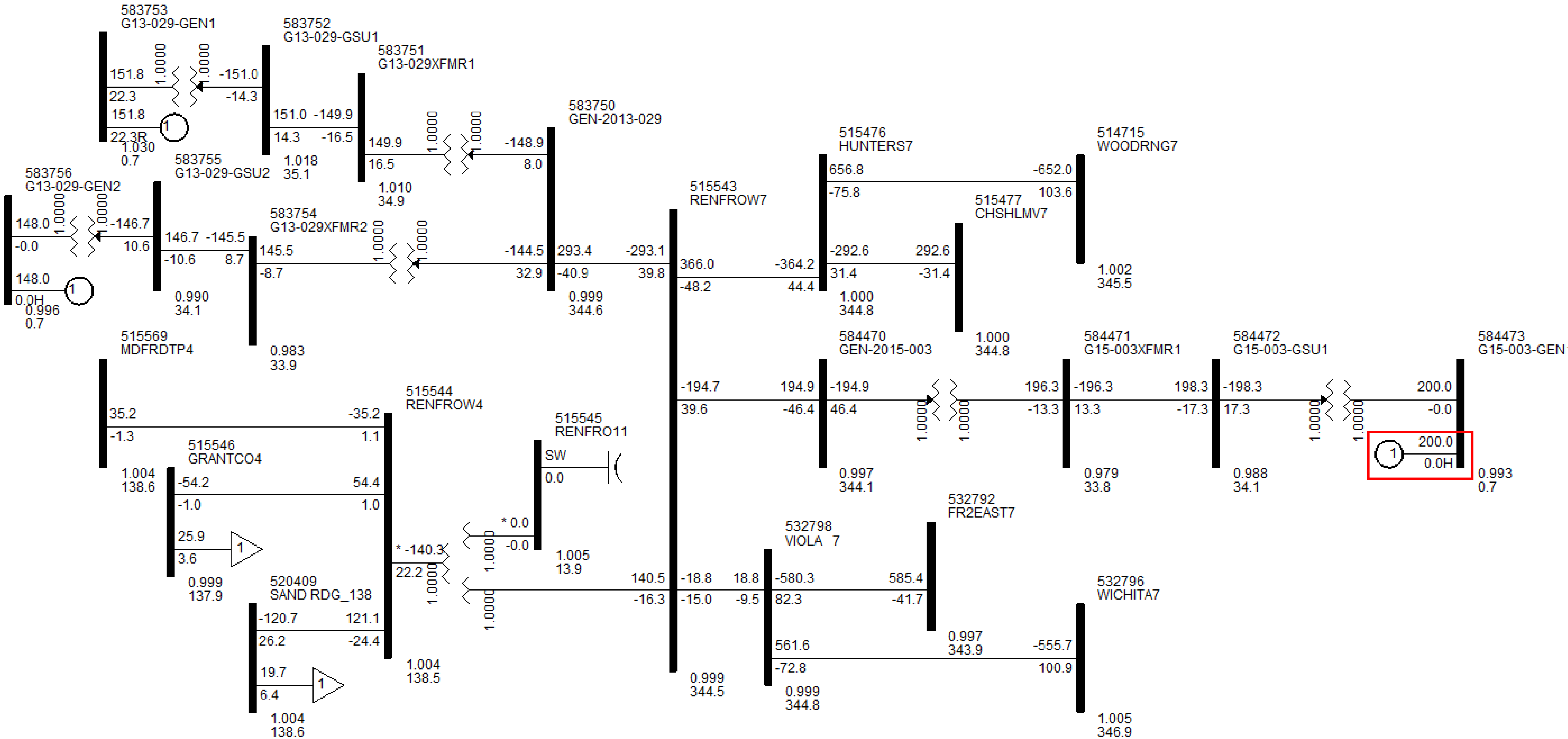

Figure 2-2. Power flow one-line diagram for interconnection project at the Renfrow 345kV POI (GEN-2015-003)

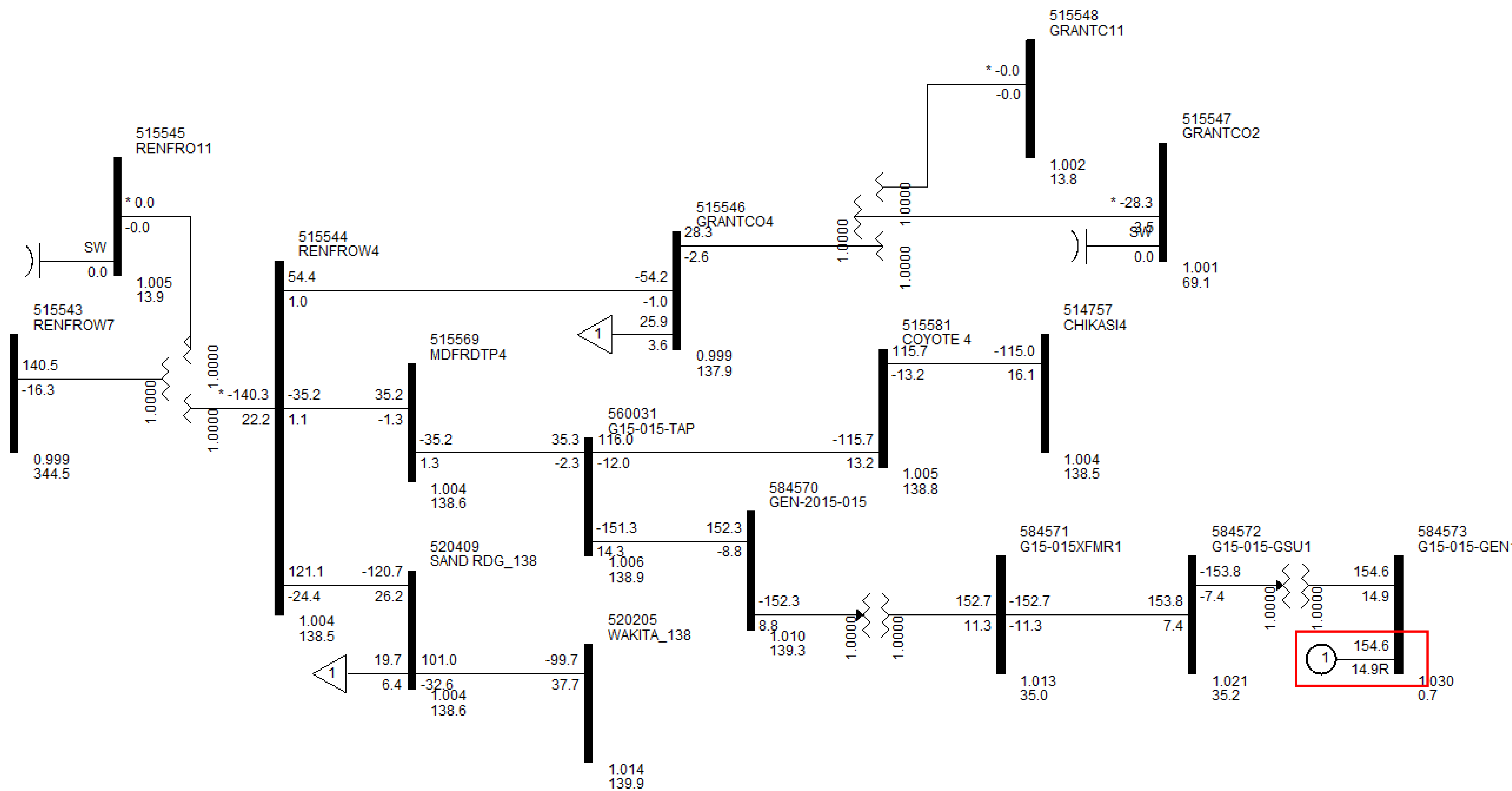

Figure 2-3. Power flow one-line diagram for interconnection project at the Tap Medford Tap POI (GEN-2015-015)

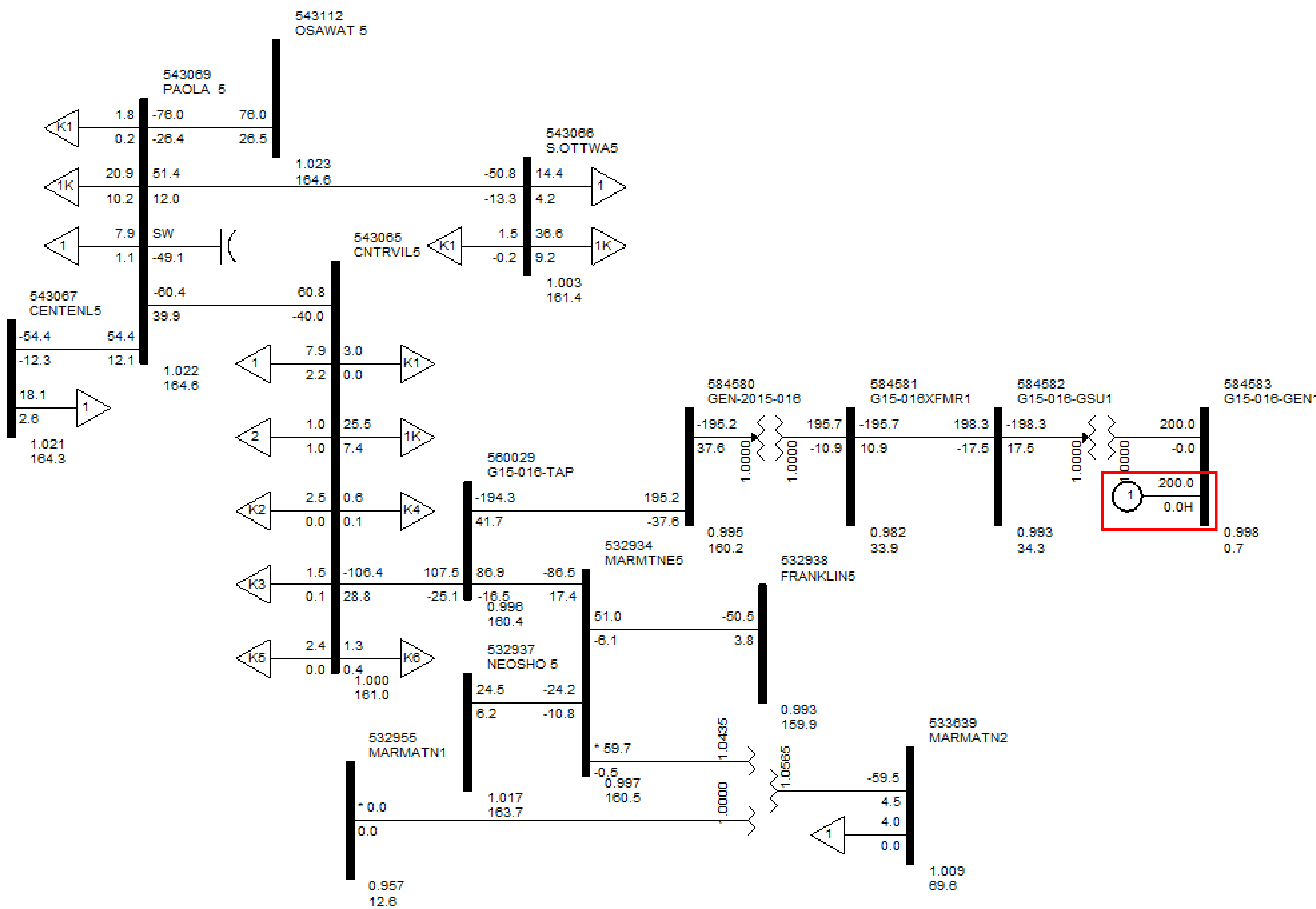

Figure 2-4. Power flow one-line diagram for interconnection project at the Tap Centerville POI (GEN-2015-016)

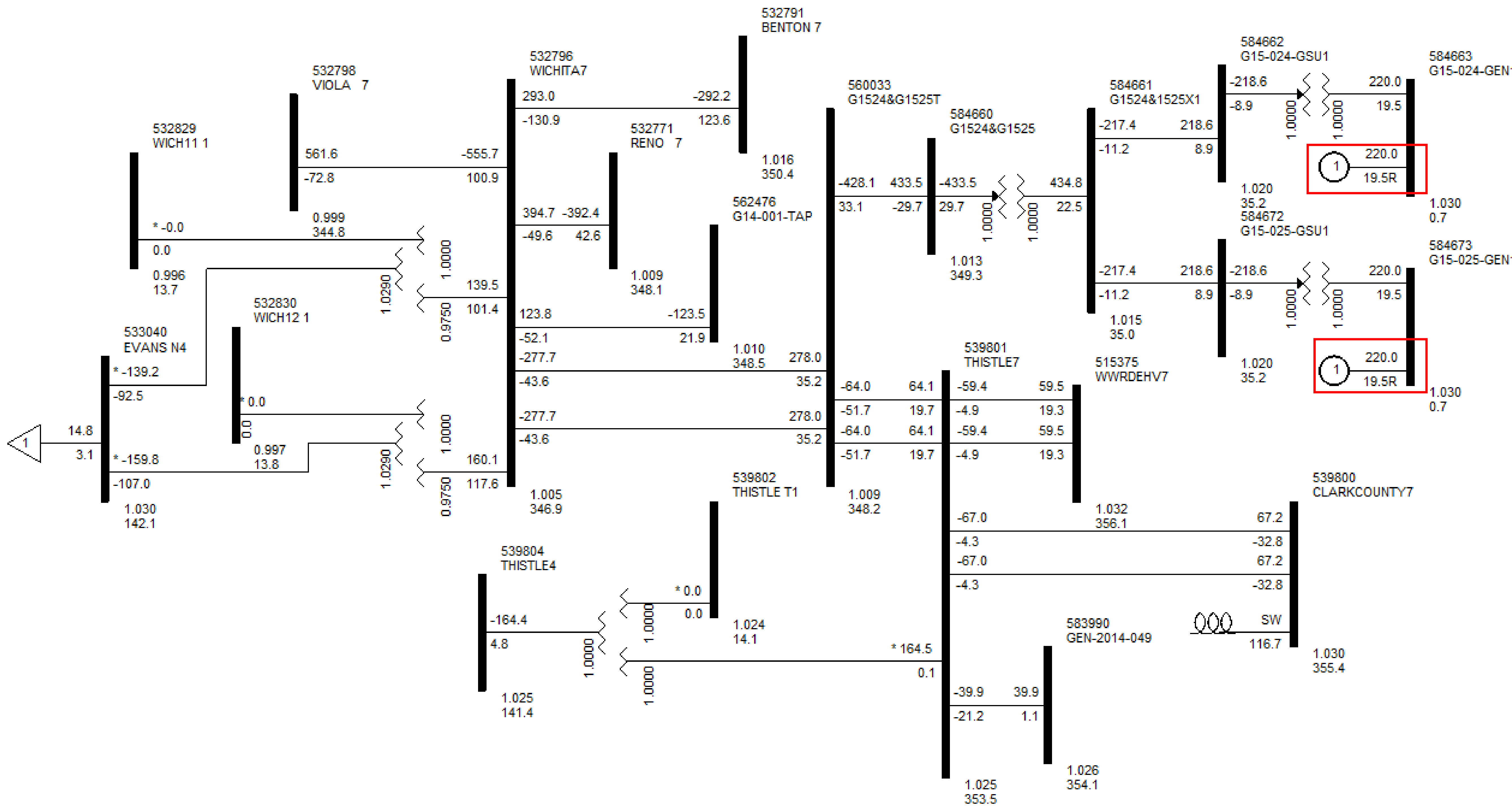

Figure 2-5. Power flow one-line diagram for interconnection project at the Tap Wichita – Thistle 345kV POI (GEN-2015-024, GEN-2015-025)

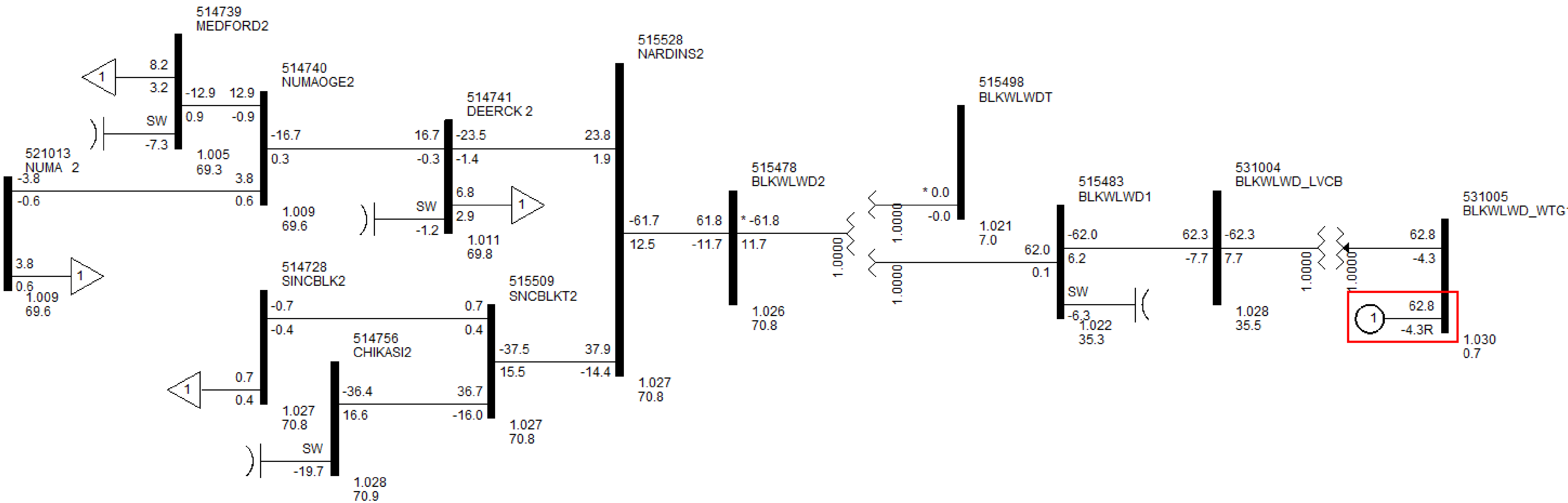

Figure 2-6. Power flow one-line diagram for interconnection project at the Nardins 69kV POI (GEN-2015-028)

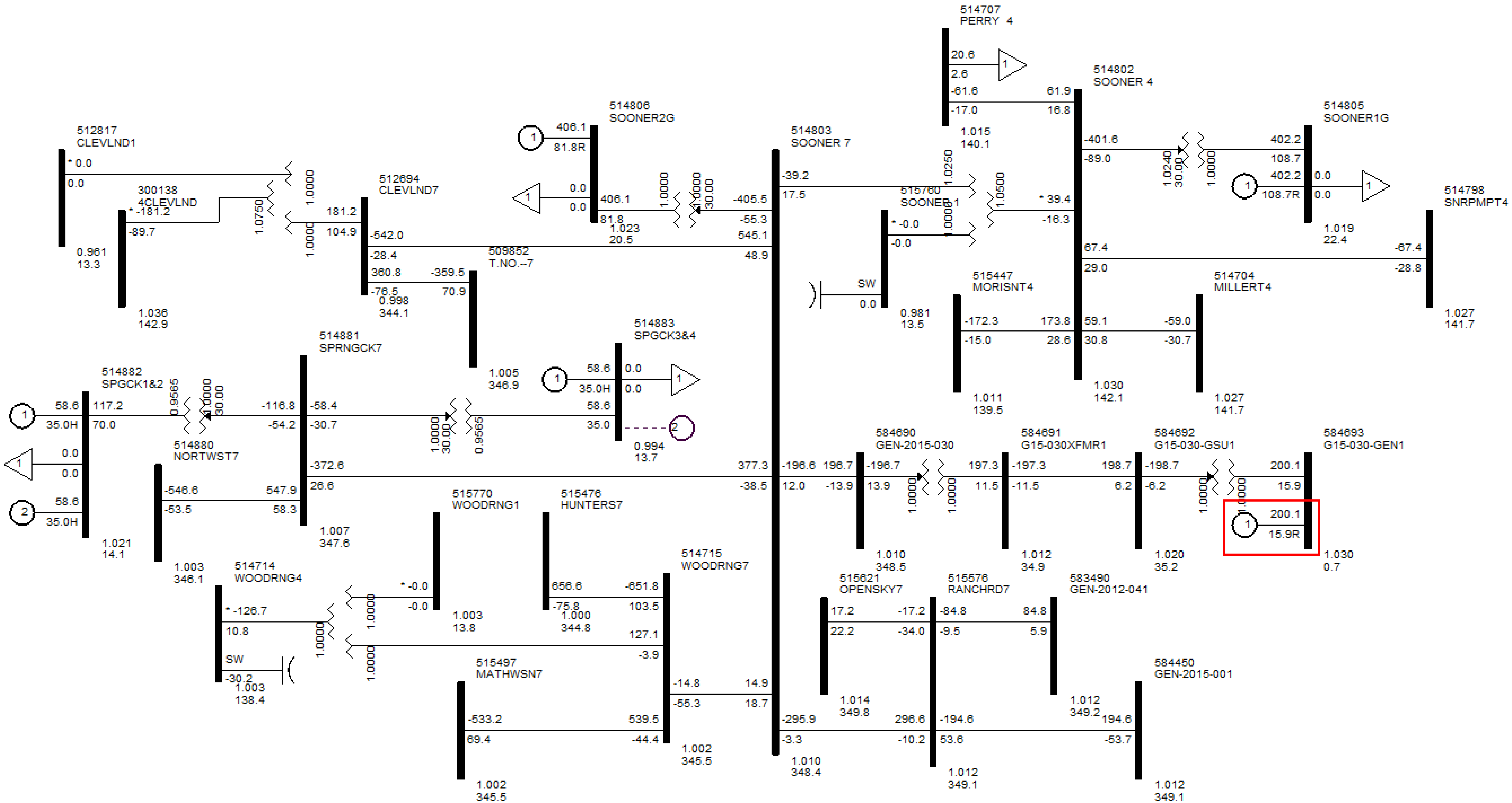

Figure 2-7. Power flow one-line diagram for interconnection project at the Sooner 345kV POI (GEN-2015-030)

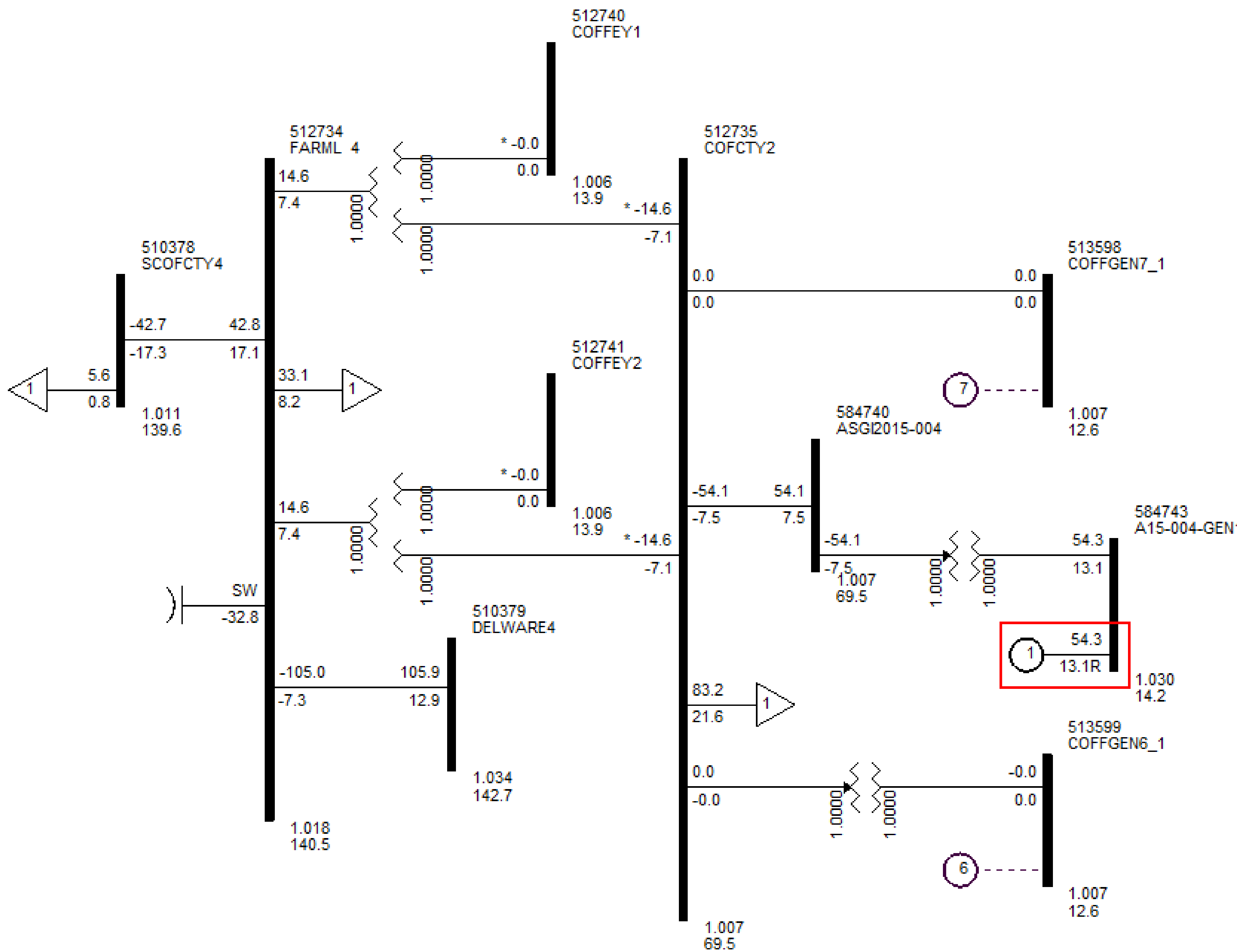

Figure 2-8. Power flow one-line diagram for interconnection project at the Coffeyville Municipal Light & Power Northern Industrial Park Substation 69kV POI (ASGI-2015-004)

Table 2-3
Case List with Contingency Description

Cont. No.	Cont. Name	Description	GEN-2015-001	GEN-2015-003	GEN-2015-015	GEN-2015-016	GEN-2015-024 GEN-2015-025	GEN-2015-028	GEN-2015-030	ASGI-2015-004
1	FLT01-3PH	**3 phase fault on the Open Sky (515621) to Ranch Road (515576) 345kV line, near Ranch Road.** a. Apply fault at the Ranch Road 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) bac k into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	X						X	
2	FLT02-3PH	**3 phase fault on the Open Sky (515621) to Rosehill (532794) 345kV line, near Open Sky.** a. Apply fault at the Open Sky 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	X		X		X		X	
3	FLT03-3PH	**3 phase fault on the Ranch Road (515576) to Sooner (514803) 345kV line, near Ranch Road.** a. Apply fault at the Ranch Road 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	X		X		X	X	X	
4	FLT04-3PH	**3 phase fault on the Rosehill (532794) to Benton (532791) 345kV line, near Rosehill.** a. Apply fault at the Rosehill 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	X				X			
5	FLT05-3PH	**3 phase fault on the Rosehill (532794) to Wolf Creek (532797) 345kV line, near Rosehill.** a. Apply fault at the Rosehill 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	X				X		X	
6	FLT06-3PH	**3 phase fault on the Rosehill (532794) to Latham (532800) 345kV line, near Rosehill.** a. Apply fault at the Rosehill 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	X				X		X	
7	FLT07-3PH	**3 phase fault on the Sooner (514803) to Spring Creek (514881) 345kV line, near Sooner.** a. Apply fault at the Sooner 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	X		X				X	

Table 2-3 (Continued)
Case List with Contingency Description

Cont. No.	Cont. Name	Description	GEN-2015-001	GEN-2015-003	GEN-2015-015	GEN-2015-016	GEN-2015-024 GEN-2015-025	GEN-2015-028	GEN-2015-030	ASGI-2015-004
8	FLT08-3PH	**3 phase fault on the Sooner (514803) to Cleveland (512694) 345kV line, near Sooner.** a. Apply fault at the Sooner 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	X		X				X	
9	FLT09-3PH	**3 phase fault on the Sooner (514803) to Woodring (514715) 345kV line, near Sooner.** a. Apply fault at the Sooner 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	X		X		X		X	
10	FLT10-3PH	**3 phase fault on the Renfrow (515543) to Hunter (515476) 345kV line, near Renfrow.** a. Apply fault at the Renfrow 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.		X	X			X		
11	FLT11-3PH	**3 phase fault on the Renfrow (514880) to Viola (532798) 345kV line, near Renfrow.** a. Apply fault at the Renfrow 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.		X			X			
12	FLT12-3PH	**3 phase fault on the Viola (532798) to Wichita (532796) 345kV line, near Viola.** a. Apply fault at the Viola 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	X	X			X		X	
13	FLT13-3PH	**3 phase fault on the Wichita (532796) to Benton (532791) 345kV line, near Wichita.** a. Apply fault at the Wichita 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	X	X			X		X	
14	FLT14-3PH	**3 phase fault on the Wichita (532796) to G14-001 Tap (562476) 345kV line, near Wichita.** a. Apply fault at the Wichita 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	X	X			X			
15	FLT15-3PH	**3 phase fault on the Emporia EC (532768) to G14-001 Tap (562476) 345kV line, near G14-001.** a. Apply fault at the G14-001 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.		X			X			

Table 2-3 (Continued)
Case List with Contingency Description

Cont. No.	Cont. Name	Description	GEN-2015-001	GEN-2015-003	GEN-2015-015	GEN-2015-016	GEN-2015-024 GEN-2015-025	GEN-2015-028	GEN-2015-030	ASGI-2015-004
16	FLT16-3PH	**3 phase fault on the Wichita (532796) to G1524&G1525T (560033) 345kV line circuit 1, near Wichita.** a. Apply fault at the Wichita 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.		X			X			
17	FLT17-3PH 2025 Summer Only	**3 phase fault on the Viola (532798) 345/(533075) 138/(532832) 13.8kV transformer, near Viola 345.** a. Apply fault at the Viola 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.		X			X			
18	FLT18-3PH	**3 phase fault on the Renfrow (515543) 345/(515544) 138/(515545) 13.8kV transformer, near Renfrow 345.** a. Apply fault at the Renfrow 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.		X			X	X		
19	FLT19-3PH	**3 phase fault on the G15-015 Tap (560031) to Medford Tap (515569) 138kV line, near G15-015.** a. Apply fault at the G15-015 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.			X			X		
20	FLT20-3PH	**3 phase fault on the G15-015 Tap (560031) to Coyote (515581) 138kV line, near G15-015.** a. Apply fault at the G15-015 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.			X			X		
21	FLT21-3PH	**3 phase fault on the Kildare (514760) to NewkirkAT (514764) 138kV circuit 1 line, near Stateline.** a. Apply fault at the Kildare 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.			X			X		
22	FLT22-3PH	**3 phase fault on the Kildare (514760) to White Eagle (514761) 138kV circuit 1 line, near Stateline.** a. Apply fault at the Kildare 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.			X			X		
23	FLT23-3PH	**3 phase fault on the Renfrow (515544) to Sand Ridge (520409) 138kV circuit 1 line, near Renfrow.** a. Apply fault at the Renfrow 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.			X			X		
24	FLT24-3PH	**3 phase fault on the G15-016 Tap (560029) to Marmaton (532934) 161kV circuit 1 line, near G15-016.** a. Apply fault at the G15-016 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.				X				

Table 2-3 (Continued)
Case List with Contingency Description

Cont. No.	Cont. Name	Description	GEN-2015-001	GEN-2015-003	GEN-2015-015	GEN-2015-016	GEN-2015-024 GEN-2015-025	GEN-2015-028	GEN-2015-030	ASGI-2015-004
25	FLT25-3PH	**3 phase fault on the G15-016 Tap (560029) to Centerville (543065) 161kV circuit 1 line, near G15-016.** a. Apply fault at the G15-016 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.				X				
26	FLT26-3PH	**3 phase fault on the Marmaton (532934) 161/(533639) 69/(532955) 13.2kV transformer, near Marmaton 161kV.** a. Apply fault at the Marmaton 161kV bus. b. Clear fault after 5 cycles by tripping the faulted line.				X				
27	FLT27-3PH	**3 phase fault on the Franklin (532938) to Litchfield (532932) 161kV circuit 1 line, near Franklin.** a. Apply fault at the Franklin 161kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.				X				
28	FLT28-3PH	**3 phase fault on the Franklin (532938) 161/(533876) 69/(533122) 13.2kV transformer, near Franklin 161kV.** a. Apply fault at the Franklin 161kV bus. b. Clear fault after 5 cycles by tripping the faulted line.				X				
29	FLT29-3PH	**3 phase fault on the Neosho (532937) to Marmaton (532934) 161kV circuit 1 line, near Neosho.** a. Apply fault at the Neosho 161kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.				X				
30	FLT30-3PH	**3 phase fault on the Neosho (532937) to Baker (532926) 161kV circuit 1 line, near Neosho.** a. Apply fault at the Neosho 161kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.				X				
31	FLT31-3PH	**3 phase fault on the Neosho (532793) to Lacygne (542981) 345kV circuit 1 line, near Neosho.** a. Apply fault at the Neosho 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.				X	X			
32	FLT32-3PH	**3 phase fault on the Centennial (543067) to Paola (543069) 161kV circuit 1 line, near Centerville.** a. Apply fault at the Centennial 161kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.				X				

Table 2-3 (Continued)
Case List with Contingency Description

Cont. No.	Cont. Name	Description	GEN-2015-001	GEN-2015-003	GEN-2015-015	GEN-2015-016	GEN-2015-024 GEN-2015-025	GEN-2015-028	GEN-2015-030	ASGI-2015-004
33	FLT33-3PH	**3 phase fault on the Reno (532771) to Wichita (532796) 345kV circuit 1 line, near Wichita.** a. Apply fault at the Wichita 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.		X			X			
34	FLT34-3PH	**3 phase fault on the Wichita (532796) 345/Evans (533040) 138/(532829) 13.8kV transformer circuit 1, near Wichita 345kV.** a. Apply fault at the Wichita 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.					X			
35	FLT35-3PH	**3 phase fault on the Lang (532769) to Emporia EC (532768) 345kV circuit 1 line, near Emporia EC.** a. Apply fault at the Emporia EC 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.					X			
36	FLT36-3PH	**3 phase fault on the Morris (532770) to Emporia EC (532768) 345kV circuit 1 line, near Emporia EC.** a. Apply fault at the Emporia EC 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.					X			
37	FLT37-3PH	**3 phase fault on the Swissvale (532774) to Emporia EC (532768) 345kV circuit 1 line, near Emporia EC.** a. Apply fault at the Emporia EC 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.					X			
38	FLT38-3PH	**3 phase fault on the Reno (532771) to Summit (532773) 345kV circuit 1 line, near Reno.** a. Apply fault at the Reno 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.					X			
39	FLT39-3PH	**3 phase fault on the Rosehill 345kV (532794) to Rosehill (533062) 138kV/(532831) 13.8kV transformer, near the 345kV bus.** a. Apply fault at the Rosehill 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.					X			
40	FLT40-3PH	**3 phase fault on the Nardins (515528) to Deer Creek (514741) 69kV circuit 1 line, near Nardins.** a. Apply fault at the Nardins 69kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6.5 cycles, then trip the line in (b) and remove fault.						X		

Table 2-3 (Continued)
Case List with Contingency Description

Cont. No.	Cont. Name	Description	GEN-2015-001	GEN-2015-003	GEN-2015-015	GEN-2015-016	GEN-2015-024	GEN-2015-025	GEN-2015-028	GEN-2015-030	ASGI-2015-004
41	FLT41-3PH	**3 phase fault on the Nardins (515528) to Sinclair Blackwell Tap (515509) 69kV circuit 1 line, near Nardins.** a. Apply fault at the Nardins 69kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6.5 cycles, then trip the line in (b) and remove fault.							X		
42	FLT42-3PH	**3 phase fault on the Grant Co (515547) to Clyde (514719) 69kV circuit 1 line, near Grant Co.** a. Apply fault at the Grant Co 69kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6.5 cycles, then trip the line in (b) and remove fault.							X		
43	FLT43-3PH	**3 phase fault on the Grant Co (515546) 138/ (515547) 69/ (515548) 13.8kV circuit 1 transformer, near Grant Co 69kV.** a. Apply fault at the Grant Co 69kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.							X		
44	FLT44-3PH	**3 phase fault on the Chikaskia (514756) to Blackwell (514755) 69kV circuit 1 line, near Chikaskia.** a. Apply fault at the Chikaskia 69kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6.5 cycles, then trip the line in (b) and remove fault.							X		
45	FLT45-3PH	**3 phase fault on the Chikaskia (514756) to Braman (514750) 69kV circuit 1 line, near Chikaskia.** a. Apply fault at the Chikaskia 69kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6.5 cycles, then trip the line in (b) and remove fault.							X		
46	FLT46-3PH	**3 phase fault on the Chikaskia (514757) 138/ (514756) 69/ (515713) 13.8kV circuit 1 transformer, near Chikaskia 69kV.** a. Apply fault at the Chikaskia 69kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.							X		
47	FLT47-3PH	**3 phase fault on the Woodring (514715) to Mathewson (515497) 345kV circuit 1 line, near Woodring.** a. Apply fault at the Woodring 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.								X	
48	FLT48-3PH	**3 phase fault on the Woodring (514715) 345/ (514714) 138/ (515770) 13.8kV circuit 1 transformer, near Woodring 345kV.** a. Apply fault at the Woodring 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.								X	
49	FLT49-3PH	**3 phase fault on the Sooner (514803) 345/ (514802) 138/ (515760) 13.8kV circuit 1 transformer, near Sooner 345kV.** a. Apply fault at the Sooner 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.								X	

Table 2-3 (Continued)
Case List with Contingency Description

Cont. No.	Cont. Name	Description	GEN-2015-001	GEN-2015-003	GEN-2015-015	GEN-2015-016	GEN-2015-024	GEN-2015-025	GEN-2015-028	GEN-2015-030	ASGI-2015-004
50	FLT50-3PH	**3 phase fault on the Coffeyville Farmland (512734) 138/ Coffeyville City (512735) 69/ (512740) 13.8kV circuit 1 transformer, near Coffeyville City 69kV.** a. Apply fault at the Coffeyville City 69kV bus. b. Clear fault after 5 cycles by tripping the faulted line.									X
51	FLT51-3PH	**3 phase fault on the Coffeyville Farmland (512734) to Delaware (510379) 138kV circuit 1 line, near Coffeyville Farmland.** a. Apply fault at the Coffeyville Farmland 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.									X
52	FLT52-3PH	**3 phase fault on the Coffeyville Farmland (512734) to South Coffeyville City (510378) 138kV circuit 1 line, near Coffeyville Farmland.** a. Apply fault at the Coffeyville Farmland 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.									X
53	FLT53-3PH	**3 phase fault on the South Coffeyville Tap (510422) to Dearing (533002) 138kV circuit 1 line, near South Coffeyville Tap.** a. Apply fault at the South Coffeyville Tap 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.									X
54	FLT54-3PH	**3 phase fault on the South Coffeyville Tap (510422) to North Bartlesville (510386) 138kV circuit 1 line, near South Coffeyville Tap.** a. Apply fault at the South Coffeyville Tap 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.									X
55	FLT55-3PH	**3 phase fault on the Dearing (533002) to Montgomery (533004) 138kV circuit 1 line, near Dearing.** a. Apply fault at the Dearing 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.									X
56	FLT56-3PH	**3 phase fault on the Delaware (510380) to NES (510406) 345kV circuit 1 line, near Delaware.** a. Apply fault at the Delaware 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.									X
57	FLT57-3PH	**3 phase fault on the Delaware (510380) to Neosho (532793) 345kV circuit 1 line, near Delaware.** a. Apply fault at the Delaware 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.									X

Table 2-3 (Continued)
Case List with Contingency Description

Cont. No.	Cont. Name	Description	GEN-2015-001	GEN-2015-003	GEN-2015-015	GEN-2015-016	GEN-2015-024 GEN-2015-025	GEN-2015-028	GEN-2015-030	ASGI-2015-004
58	FLT58-3PH	**Prior outage on the Sooner (514803) – Cleveland (512694) 345kV line** 3 phase fault on the Sooner (514803) to Woodring (514715) 345kV line, near Sooner. a. Apply fault at the Sooner 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	X						X	
59	FLT59-3PH	**Prior outage on the Sooner (514803) – Spring Creek (514881) 345kV line** 3 phase fault on the Sooner (514803) to Woodring (514715) 345kV line, near Sooner. **a. Apply fault at the Sooner 345kV bus.** b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	X						X	
60	FLT60-3PH	**Prior outage on the Rosehill (532794) – Wolf Creek (532797) 345kV line** **3 phase fault on the Rosehill (532794) to Benton (532791) 345kV line, near Rosehill.** a. Apply fault at the Rosehill 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	X				X		X	
61	FLT61-3PH	**Prior outage on the Caney River (532780) – Neosho (532793) 345kV line** **3 phase fault on the Rosehill (532794) to Benton (532791) 345kV line, near Caney River.** a. Apply fault at the Rosehill 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	X				X		X	
62	FLT62-3PH	**Prior outage on the Caney River (532780) – Neosho (532793) 345kV line** **3 phase fault on the Wichita (532796) to Benton (532791) 345kV line, near Wichita.** a. Apply fault at the Wichita 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	X	X			X		X	
63	FLT63-3PH	**Prior outage on the Renfrow (515543) 345/ (515544) 138/ (515545) 13.8kV transformer** **3 phase fault on the Renfrow (515543) to Viola (532798) 345kV line, near Renfrow.** a. Apply fault at the Renfrow 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.		X			X			

Table 2-3 (Continued)
Case List with Contingency Description

Cont. No.	Cont. Name	Description	GEN-2015-001	GEN-2015-003	GEN-2015-015	GEN-2015-016	GEN-2015-024 GEN-2015-025	GEN-2015-028	GEN-2015-030	ASGI-2015-004
64	FLT64-3PH	**Prior outage on the Renfrow (515543) 345/ (515544) 138/ (515545) 13.8kV transformer** **3 phase fault on the Renfrow (515543) to Hunter (515476) 345kV line, near Renfrow.** a. Apply fault at the Renfrow 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.		X	X		X			
65	FLT65-3PH	**Prior outage on the Renfrow (515543) 345/ (515544) 138/ (515545) 13.8kV transformer** **3 phase fault on the Viola (532798) to Wichita (532796) 345kV line, near Viola.** a. Apply fault at the Viola 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.		X			X			
66	FLT66-3PH	**Prior outage on the Wichita (532796) – Benton (532791) 345kV line** **3 phase fault on the Hunter (515476) to Woodring (514715) 345kV line, near Hunter.** a. Apply fault at the Hunter 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.		X	X		X		X	
67	FLT67-3PH	**Prior outage on the Renfrow (515544) – Sand Ridge (520409) 138kV line** **3 phase fault on the Renfrow (515544) to Grant Co (515546) 138kV line, near Renfrow.** a. Apply fault at the Renfrow 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.			X			X		
68	FLT68-3PH	**Prior outage on the Chikaskia (514757) 138/ (514756) 69/ (515713) 13.2kV transformer** **3 phase fault on the Kildare (514760) to Chikaskia (514757) 138kV line, near Chikaskia.** a. Apply fault at the Chikaskia 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.			X			X		
69	FLT69-3PH	**Prior outage on the Marmaton (532934) 161/ (533639) 69/ (532955) 13.2kV transformer** **3 phase fault on the Marmaton (532934) to Franklin (532938) 161kV line, near Marmaton.** a. Apply fault at the Marmaton 161kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.				X				

Table 2-3 (Continued)
Case List with Contingency Description

Cont. No.	Cont. Name	Description	GEN-2015-001	GEN-2015-003	GEN-2015-015	GEN-2015-016	GEN-2015-024 GEN-2015-025	GEN-2015-028	GEN-2015-030	ASGI-2015-004
70	FLT70-3PH	**Prior outage on the Marmaton (532934) 161/ (533639) 69/ (532955) 13.2kV transformer** **3 phase fault on the Marmaton (532934) to Neosho (532937) 161kV line, near Marmaton.** a. Apply fault at the Marmaton 161kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.				X				
71	FLT71-3PH	**Prior outage on the S Ottawa (543066) – SE Ottawa (543055) 161kV line** **3 phase fault on the Paola (543069) to Centennial (543067) 161kV line, near Paola.** a. Apply fault at the Paola 161kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.				X				
72	FLT72-3PH	**Prior outage on the Neosho (532937) – Baker (532926) 161kV line** **3 phase fault on the Neosho (532937) to Riverton (547469) 161kV line, near Neosho.** a. Apply fault at the Neosho 161kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.				X				
73	FLT73-3PH	**Prior outage on the Wichita (532796) – Benton (532791) 345kV line** **3 phase fault on the G14-01 Tap (562476) to Emporia EC (532768) 345kV line, near G14-01.** a. Apply fault at the G14-01 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.		X			X			
74	FLT74-3PH	**Prior outage on the Wichita (532796) – Benton (532791) 345kV line** **3 phase fault on the Wichita (532796) to Viola (532798) 345kV line, near Wichita.** a. Apply fault at the Wichita 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.		X			X			
75	FLT75-3PH	**Prior outage on the Wichita (532796) – G1524&G1525T (560033) 345kV circuit 1 line** **3 phase fault on the Wichita (532796) to G1524&G1525T (560033) 345kV circuit 2 line, near Wichita.** a. Apply fault at the Wichita 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.		X			X			

Table 2-3 (Continued)
Case List with Contingency Description

Cont. No.	Cont. Name	Description	GEN-2015-001	GEN-2015-003	GEN-2015-015	GEN-2015-016	GEN-2015-024 GEN-2015-025	GEN-2015-028	GEN-2015-030	ASGI-2015-004
76	FLT76-3PH	**Prior outage on the Viola (532798) – Renfrow (515543) 345kV line** **3 phase fault on the Rosehill (532794) to Open Sky (515621) 345kV line, near Rosehill.** a. Apply fault at the Rosehill 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	X	X			X		X	
77	FLT77-3PH	**Prior Outage on the Chikaskia (514757) 138/ (514756) 69/ (515713) 13.2kV transformer** **3 phase fault on the Chikaskia (514756) to Blackwell (514755) 69kV line, near Chikaskia.** a. Apply fault at the Chikaskia 69kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.						X		
78	FLT78-3PH	**Prior Outage on the Grant Co (515546) 138/ (515547) 69/ (515548) 13.8kV transformer** **3 phase fault on the Grant Co (515547) to Clyde (514719) 69kV line, near Grant Co.** a. Apply fault at the Grant Co 69kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.						X		
79	FLT79-3PH	**Prior outage on the Woodring (514715) – Hunters (515476) 345kV line** **3 phase fault on the Woodring (514715) to Sooner (514803) 345kV line, near Woodring.** a. Apply fault at the Woodring 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	X						X	
80	FLT80-3PH	**Prior outage on the Sooner (514803) – Cleveland (512694) 345kV line** **3 phase fault on the Sooner (514803) to Spring Creek (514881) 345kV line, near Sooner.** a. Apply fault at the Sooner 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	X						X	
81	FLT81-3PH	**Prior outage on the Sooner (514803) – Cleveland (512694) 345kV line** **3 phase fault on the Sooner (514803) to Ranch Road (515576) 345kV line, near Sooner.** a. Apply fault at the Sooner 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.							X	

Table 2-3 (Continued)
Case List with Contingency Description

Cont. No.	Cont. Name	Description	GEN-2015-001	GEN-2015-003	GEN-2015-015	GEN-2015-016	GEN-2015-024	GEN-2015-025	GEN-2015-028	GEN-2015-030	ASGI-2015-004
82	FLT82-3PH	**Prior outage on the Sooner (514803) – Woodring (514715) 345kV line** **3 phase fault on the Sooner (514803) to Spring Creek (514881) 345kV line, near Sooner.** a. Apply fault at the Sooner 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	X							X	
83	FLT83-3PH	**Prior outage on the Coffeyville Farmland (512734) 138/ Coffeyville City (512735) 69/ (512740) 13.8kV circuit 1 transformer, near Coffeyville City 69kV.** **3 phase fault on the Coffeyville Farmland (512734) to South Coffeyville City (510378) 138kV line, near Coffeyville Farmland.** a. Apply fault at the Coffeyville Farmland 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.									X
84	FLT84-3PH	**Prior outage on the Coffeyville Farmland (512734) 138/ Coffeyville City (512735) 69/ (512740) 13.8kV circuit 1 transformer, near Coffeyville City 69kV.** **3 phase fault on the Coffeyville Farmland (512734) to Delaware (510379) 138kV line, near Coffeyville Farmland.** a. Apply fault at the Coffeyville Farmland 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.									X
85	FLT85-1PH	**Stuck Breaker on Riverton – Neosho 161kv line** a. Apply single-phase fault at Riverton (547469) 161kV bus on the Riverton – Neosho 161kV line b. After 20 cycles, trip the Riverton (547469) 161/69 (547541)/12.5 (547725) kV transformer c. Trip the Riverton (547469) to Neosho (532937) line, and remove the fault									
86	FLT86-1PH	**Ranch Road 345kV Single Phase Fault** a. Apply single-phase fault on the Ranch Road (515576) – Open Sky (515621) 345kV line, near Ranch Road. b. Clear fault after 5 cycles by tripping the line in (a). c. Wait 20 cycles, and then re-close the line in (a) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (a) and remove fault.	X								
87	FLT87-1PH	**Ranch Road 345kV Single Phase Fault** a. Apply single-phase fault on the Ranch Road (515576) – Sooner (514803) 345kV line, near Ranch Road. b. Clear fault after 5 cycles by tripping the line in (a). c. Wait 20 cycles, and then re-close the line in (a) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (a) and remove fault.	X								

Table 2-3 (Continued)
Case List with Contingency Description

Cont. No.	Cont. Name	Description	GEN-2015-001	GEN-2015-003	GEN-2015-015	GEN-2015-016	GEN-2015-024 GEN-2015-025	GEN-2015-028	GEN-2015-030	ASGI-2015-004
88	FLT88-1PH	**Stuck Breaker on Renfrow – Viola 345kV circuit 1 line** a. Apply single-phase fault at Renfrow (515543) on the 345kV bus. b. After 20 cycles, trip the Renfrow 345/ (515544) 138/(515545) 13.8kV transformer c. Trip the Renfrow – Viola (532798) 345 kV circuit 1 line, and remove the fault		X						
89	FLT89-1PH	**Stuck Breaker on Renfrow – Hunter 345kV circuit 1 line** a. Apply single-phase fault at Renfrow (515543) on the 345kV bus. b. After 20 cycles, trip the Renfrow 345/ (515544) 138/(515545) 13.8kV transformer c. Trip the Renfrow – Hunter (515476) 345 kV circuit 1 line, and remove the fault		X						
90	FLT90-1PH	**G15-015 Tap 138kV Single Phase Fault** a. Apply single-phase fault on the G15-015 Tap (560031) – Coyote (515581) 138kV line, near G15-015 Tap. b. Clear fault after 6.5 cycles by tripping the line in (a). c. Wait 20 cycles, and then re-close the line in (a) back into the fault. d. Leave fault on for 6.5 cycles, then trip the line in (a) and remove fault.			X					
91	FLT91-1PH	**G15-015 Tap 138kV Single Phase Fault** a. Apply single-phase fault on the G15-015 Tap (560031) – Medford Tap (515569) 138kV line, near G15-015 Tap. b. Clear fault after 6.5 cycles by tripping the line in (a). c. Wait 20 cycles, and then re-close the line in (a) back into the fault. d. Leave fault on for 6.5 cycles, then trip the line in (a) and remove fault.			X					
92	FLT92-1PH	**G15-016 Tap 161kV Single Phase Fault** a. Apply single-phase fault on the G15-016 Tap (560029) – Centerville (543065) 161kV line, near G15-016 Tap. b. Clear fault after 6.5 cycles by tripping the line in (a). c. Wait 20 cycles, and then re-close the line in (a) back into the fault. d. Leave fault on for 6.5 cycles, then trip the line in (a) and remove fault.				X				
93	FLT93-1PH	**G15-016 Tap 161kV Single Phase Fault** a. Apply single-phase fault on the G15-016 Tap (560029) – Marmaton (532934) line, near G15-016 Tap. b. Clear fault after 6.5 cycles by tripping the line in (a). c. Wait 20 cycles, and then re-close the line in (a) back into the fault. d. Leave fault on for 6.5 cycles, then trip the line in (a) and remove fault.				X				
94	FLT94-1PH	**Stuck Breaker on Wichita – G1524&G1525T 345kV circuit 1 line** a. Apply single-phase fault at Wichita (532796) on the 345kV bus. b. After 20 cycles, trip the Wichita 345/ (533040) 138/(532830) 13.8kV transformer circuit 1 c. Trip the Wichita –G1524&G1525T (560033) 345 kV circuit 1 line, and remove the fault					X			
95	FLT95-1PH	**Stuck Breaker on Wichita – G1524&G1525T 345kV circuit 1 line** a. Apply single-phase fault at Wichita (532796) on the 345kV bus. b. After 20 cycles, trip the Wichita - Viola (532798) 345kV line circuit 1 c. Trip the Wichita – Thistle (539801) 345 kV circuit 1 line, and remove the fault					X			

Table 2-3 (Continued)
Case List with Contingency Description

Cont. No.	Cont. Name	Description	GEN-2015-001	GEN-2015-003	GEN-2015-015	GEN-2015-016	GEN-2015-024 GEN-2015-025	GEN-2015-028	GEN-2015-030	ASGI-2015-004
96	FLT96-1PH	**Stuck Breaker on Wichita – G14-001 Tap 345kV circuit 1 line** a. Apply single-phase fault at Wichita (532796) on the 345kV bus. b. After 20 cycles, trip the Wichita 345/ (533040) 138/(532829) 13.8kV transformer circuit 1 c. Trip the Wichita – G14-001 Tap (562476) 345 kV line, and remove the fault					X			
97	FLT97-1PH	**Stuck Breaker on Wichita – Reno 345kV circuit 1 line** a. Apply single-phase fault at Wichita (532796) on the 345kV bus. b. After 20 cycles, trip the Wichita – Benton (532791) 345kV line circuit 1 c. Trip the Wichita – Reno (532771) 345 kV line, and remove the fault					X			
98	FLT98-1PH	**Nardin 69kV Single Phase Fault** a. Apply single-phase fault on the Nardin (515528) – Sinclair Blackwell Tap (515509) line, near Nardin. b. Clear fault after 8 cycles by tripping the line in (a). c. Wait 20 cycles, and then re-close the line in (a) back into the fault. d. Leave fault on for 8 cycles, then trip the line in (a) and remove fault.						X		
99	FLT99-1PH	**Nardin 69kV Single Phase Fault** a. Apply single-phase fault on the Nardin (515528) – Deer Creek (514741) line, near Nardin. b. Clear fault after 8 cycles by tripping the line in (a). c. Wait 20 cycles, and then re-close the line in (a) back into the fault. d. Leave fault on for 8 cycles, then trip the line in (a) and remove fault.						X		
100	FLT100-1PH	**Stuck Breaker on Rosehill 345/138/13.8kV circuit 1 transformer** a. Apply single-phase fault at Rosehill (532794) on the 345kV bus. b. After 20 cycles, trip the Rosehill (532794) – Benton (532791) 345kV line c. Trip the Rosehill 345/(533062) 138/(532831) 13.8kV transformer circuit 1, and remove the fault	X						X	
101	FLT101-1PH	**Stuck Breaker on Rosehill 345/138/13.8kV circuit 3 transformer** a. Apply single-phase fault at Rosehill (532794) on the 345kV bus. b. After 20 cycles, trip the Rosehill (532794) – Wolf Creek (532797) 345kV line c. Trip the Rosehill 345/(533062) 138/(532827) 13.8kV transformer circuit 3, and remove the fault	X						X	
102	FLT102-1PH	**Stuck Breaker on Sooner – Ranch Road 345kV line** a. Apply single-phase fault at Sooner (514803) 345kV bus on the Sooner – Ranch Road 345kV line b. After 20 cycles, trip the Sooner (514803) – Woodring 345kV line c. Trip the Sooner– Ranch Road (515576) line, and remove the fault	X						X	
103	FLT103-1PH	**Stuck Breaker on Sooner – Cleveland 345kV line** a. Apply single-phase fault at Sooner (514803) 345kV bus on the Sooner – Cleveland 345kV line b. After 20 cycles, trip the Sooner (514803) 345/ (514802) 138/ (515760) 13.8kV transformer c. Trip the Sooner– Cleveland (512694) line, and remove the fault	X						X	

Table 2-3 (Continued)
Case List with Contingency Description

Cont. No.	Cont. Name	Description	GEN-2015-001	GEN-2015-003	GEN-2015-015	GEN-2015-016	GEN-2015-024	GEN-2015-025	GEN-2015-028	GEN-2015-030	ASGI-2015-004
104	FLT104-1PH	**Stuck Breaker on Coffeyville Farmland – South Coffeyville City 138kV line** a. Apply single-phase fault at Coffeyville Farmland (512734) 138kV bus on the Coffeyville Farmland – South Coffeyville City 138kV line b. After 20 cycles, trip the Coffeyville Farmland (512734) 138/ Coffeyville City (512735) 69/ (512740) 13.8kV transformer c. Trip the Coffeyville Farmland – South Coffeyville City (510378) line, and remove the fault									X
105	FLT105-1PH	**Stuck Breaker on Coffeyville Farmland – Delaware 138kV line** a. Apply single-phase fault at Coffeyville Farmland (512734) 138kV bus on the Coffeyville Farmland – Delaware138kV line b. After 20 cycles, trip the Coffeyville Farmland (512734) 138/ Coffeyville City (512735) 69/ (512740) 13.8kV transformer c. Trip the Coffeyville Farmland – Delaware (510379) line, and remove the fault									X

SECTION 3: STABILITY ANALYSIS

The objective of the Stability Analysis was to determine the impacts of the generator interconnections on the stability and voltage recovery on the SPP transmission system. If problems with stability or voltage recovery were identified the need for reactive compensation or system upgrades were investigated.

3.1 Approach

SPP provided MEPPI with the following three power flow cases:

- 2015 Summer Peak
- 2015 Winter Peak
- 2025 Summer Peak

Each case was examined prior to the Stability Analysis to ensure the case contained the proposed study projects and any previously queued projects listed in Tables 2-2 and 2-3 respectively. There was no suspect power flow data in the study area. The dynamic datasets were also verified and stable initial system conditions (i.e., “flat lines”) were achieved. Three-phase and single phase-to-ground faults listed in Table 2-3 were examined. Single-phase fault impedances were calculated for each season to result in a voltage of approximately 60% of the pre-fault voltage. Refer to Table 3-1 for a list of the calculated single-phase fault impedances used for the Cluster

Scenario. Refer to Tables 3-2 through 3-9 for single-phase fault impedances used for each Stand Alone Scenario.

Table 3-1
Calculated Single-Phase Fault Impedances for Cluster Scenario

Cont. No.*	Cont. Name	Single-Phase Fault Impedance (MVA)		
		2015 Summer	2015 Winter	2025 Summer
85	FLT85-1PH	-4234.4	-4031.3	-4234.4
86	FLT86-1PH	-5250.0	-5046.9	-5250.0
87	FLT87-1PH	-5250.0	-5046.9	-5250.0
88	FLT88-1PH	-4437.5	-4437.5	-4843.8
89	FLT89-1PH	-4437.5	-4437.5	-4843.8
90	FLT90-1PH	-1375.0	-1375.0	-1375.0
91	FLT91-1PH	-1375.0	-1375.0	-1375.0
92	FLT92-1PH	-1375.0	-1375.0	-1375.0
93	FLT93-1PH	-1375.0	-1375.0	-1375.0
94	FLT94-1PH	-9312.5	-7687.5	-10125.0
95	FLT95-1PH	-9312.5	-7687.5	-10125.0
96	FLT96-1PH	-9312.5	-7687.5	-10125.0
97	FLT97-1PH	-9312.5	-7687.5	-10125.0
98	FLT98-1PH	-500.0	-468.8	-468.8
99	FLT99-1PH	-500.0	-468.8	-468.8
100	FLT100-1PH	-7281.3	-6468.8	-7281.3
101	FLT101-1PH	-7281.3	-6468.8	-7281.3
102	FLT102-1PH	-9312.5	-8500.0	-9312.5
103	FLT103-1PH	-9312.5	-8500.0	-9312.5
104	FLT104-1PH	-1250.0	-1250.0	-1250.0
105	FLT105-1PH	-1250.0	-1250.0	-1250.0

*Refer to Table 2-3 for a description of the contingency scenerio

Table 3-2
Calculated Single-Phase Fault Impedances for Stand Alone Scenario: GEN-2015-001

Cont. No.*	Cont. Name	Single-Phase Fault Impedance (MVA)		
		2015 Summer	2015 Winter	2025 Summer
86	FLT86-1PH	-5250.0	-4843.8	-5250.0
87	FLT87-1PH	-5250.0	-4843.8	-5250.0
100	FLT100-1PH	-7281.3	-6062.5	-7281.3
101	FLT101-1PH	-7281.3	-6062.5	-7281.3
102	FLT102-1PH	-8906.3	-8500.0	-9312.5
103	FLT103-1PH	-8906.3	-8500.0	-9312.5

*Refer to Table 2-3 for a description of the contingency scenerio

Table 3-3
Calculated Single-Phase Fault Impedances for Stand Alone Scenario: GEN-2015-003

Cont. No.*	Cont. Name	Single-Phase Fault Impedance (MVA)		
		2015 Summer	2015 Winter	2025 Summer
88	FLT88-1PH	-4437.5	-4234.4	-4843.8
89	FLT89-1PH	-4437.5	-4234.4	-4843.8

*Refer to Table 2-3 for a description of the contingency scenerio

Table 3-4
Calculated Single-Phase Fault Impedances for Stand Alone Scenario: GEN-2015-015

Cont. No.*	Cont. Name	Single-Phase Fault Impedance (MVA)		
		2015 Summer	2015 Winter	2025 Summer
90	FLT90-1PH	-1375.0	-1375.0	-1375.0
91	FLT91-1PH	-1375.0	-1375.0	-1375.0

*Refer to Table 2-3 for a description of the contingency scenerio

Table 3-5
Calculated Single-Phase Fault Impedances for Stand Alone Scenario: GEN-2015-016

Cont. No.*	Cont. Name	Single-Phase Fault Impedance (MVA)		
		2015 Summer	2015 Winter	2025 Summer
92	FLT92-1PH	-1375.0	-1375.0	-1375.0
93	FLT93-1PH	-1375.0	-1375.0	-1375.0

*Refer to Table 2-3 for a description of the contingency scenerio

Table 3-6
Calculated Single-Phase Fault Impedances for Stand Alone Scenario: GEN-2015-024 and GEN-2015-025

Cont. No.*	Cont. Name	Single-Phase Fault Impedance (MVA)		
		2015 Summer	2015 Winter	2025 Summer
94	FLT94-1PH	-9312.5	-7687.5	-10125.0
95	FLT95-1PH	-9312.5	-7687.5	-10125.0
96	FLT96-1PH	-9312.5	-7687.5	-10125.0
97	FLT97-1PH	-9312.5	-7687.5	-10125.0

*Refer to Table 2-3 for a description of the contingency scenerio

Table 3-7
Calculated Single-Phase Fault Impedances for Stand Alone Scenario: GEN-2015-028

Cont. No.*	Cont. Name	Single-Phase Fault Impedance (MVA)		
		2015 Summer	2015 Winter	2025 Summer
98	FLT98-1PH	-500.0	-468.8	-468.8
99	FLT99-1PH	-500.0	-468.8	-468.8

*Refer to Table 2-3 for a description of the contingency scenerio

Table 3-8
Calculated Single-Phase Fault Impedances for Stand Alone Scenario: GEN-2015-030

Cont. No.*	Cont. Name	Single-Phase Fault Impedance (MVA)		
		2015 Summer	2015 Winter	2025 Summer
100	FLT100-1PH	-7281.3	-6062.5	-7281.3
101	FLT101-1PH	-7281.3	-6062.5	-7281.3
102	FLT102-1PH	-8906.3	-8500.0	-9312.5
103	FLT103-1PH	-8906.3	-8500.0	-9312.5

*Refer to Table 2-3 for a description of the contingency scenerio

Table 3-9
Calculated Single-Phase Fault Impedances for Stand Alone Scenario: ASGI-2015-004

Cont. No.*	Cont. Name	Single-Phase Fault Impedance (MVA)		
		2015 Summer	2015 Winter	2025 Summer
104	FLT104-1PH	-1250.0	-1250.0	-1312.5
105	FLT105-1PH	-1250.0	-1250.0	-1312.5

*Refer to Table 2-3 for a description of the contingency scenerio

Bus voltages, machine rotor angles, and previously queued generation in the study area were monitored in addition to bus voltages and machine rotor angles in the following areas:

- 520 AEPW
- 524 OKGE
- 525 WFEC
- 526 SPS
- 531 MIDW
- 534 SUNC
- 536 WERE
- 540 GMO
- 541 ETEC

Requested and previously queued generation outside the above study area was also monitored.

The results of the analysis determined if reactive compensation or system upgrades were required to obtain acceptable system performance. If additional reactive compensation was required, the size, type, and location were determined. The proposed reactive reinforcements would ensure the wind or solar farm meets FERC Order 661A low voltage requirements and return the wind or solar farm to its pre-disturbance operating voltage. If the results indicated the need for fast responding reactive support, dynamic support such as an SVC or STATCOM was investigated. If tripping of the prior queued projects was observed during the stability analysis (for under/over voltage or under/over frequency) the simulations were re-ran with the prior queued project's voltage and frequency tripping disabled.

3.2 Cluster Scenario Stability Analysis Results

The Stability Analysis determined that there were no contingencies that resulted in system instability, generation tripping offline, or voltage violations for the 2015 Summer Peak, 2015 Winter Peak, and 2025 Summer peak conditions when all generation interconnection requests were at 100% output.

Refer to Table 3-10 for a summary of the Stability Analysis results for the contingencies listed in Table 2-3. Table 3-10 is a summary of the stability results for the 2015 Summer Peak, 2015 Winter Peak, and 2025 Summer Peak conditions and states whether the system remained stable or generation tripped offline and if acceptable voltage recovery was observed after the fault was cleared. Voltage recovery criteria includes ensuring that the transient voltage recovery is between 0.7 p.u. and 1.2 p.u. and ending in a steady-state voltage (for N-1 contingencies) at the pre-contingent level or at least 0.9 p.u. If high or low voltages were observed the number of buses failing the voltage criteria was listed.

Note contingencies, FLT01-3PH and FLT03-3PH, required the "LVRT extreme UV limit" value in the "VWVRP7" dynamic model of GEN-2015-001 to be changed from 0.05 p.u. to 0.0 p.u. in order for GEN-2015-001 to remain online, as discussed with SPP. The dynamic file modification was used to complete the analysis.

Several voltage buses consistently fell outside of the 0.95 p.u. to 1.05 p.u. range. All instances were observed for pre-fault conditions and since all voltages returned to pre-fault conditions, no mitigation was required.

Refer to Appendix B, Appendix C, and Appendix D for a complete set of plots for all contingencies for 2015 Summer Peak, 2015 Winter Peak, and 2025 Summer Peak conditions, respectively.

Table 3-10
Cluster Scenario: Stability Analysis Summary of Results for 2015 Summer, 2015 Winter, and 2025 Summer Peak Conditions

Cont. No.	Cont. Name	2015 Summer Peak			2015 Winter Peak			2025 Summer Peak		
		Recovers between 0.70 and 1.20 p.u.		Stable?	Recovers between 0.70 and 1.20 p.u.?		Stable?	Recovers between 0.70 and 1.20 p.u.?		Stable?
		Less than 0.70 p.u.	Greater than 1.20 p.u.		Less than 0.70 p.u.	Greater than 1.20 p.u.		Less than 0.70 p.u.	Greater than 1.20 p.u.	
1	FLT01-3PH	No	No	Yes	No	No	Yes	No	No	Yes
2	FLT02-3PH	No	No	Yes	No	No	Yes	No	No	Yes
3	FLT03-3PH	No	No	Yes	No	No	Yes	No	No	Yes
4	FLT04-3PH	No	No	Yes	No	No	Yes	No	No	Yes
5	FLT05-3PH	No	No	Yes	No	No	Yes	No	No	Yes
6	FLT06-3PH	No	No	Yes	No	No	Yes	No	No	Yes
7	FLT07-3PH	No	No	Yes	No	No	Yes	No	No	Yes
8	FLT08-3PH	No	No	Yes	No	No	Yes	No	No	Yes
9	FLT09-3PH	No	No	Yes	No	No	Yes	No	No	Yes
10	FLT10-3PH	No	No	Yes	No	No	Yes	No	No	Yes
11	FLT11-3PH	No	No	Yes	No	No	Yes	No	No	Yes
12	FLT12-3PH	No	No	Yes	No	No	Yes	No	No	Yes
13	FLT13-3PH	No	No	Yes	No	No	Yes	No	No	Yes
14	FLT14-3PH	No	No	Yes	No	No	Yes	No	No	Yes
15	FLT15-3PH	No	No	Yes	No	No	Yes	No	No	Yes
16	FLT16-3PH	No	No	Yes	No	No	Yes	No	No	Yes
17	FLT17-3PH	N/A			N/A			No	No	Yes
18	FLT18-3PH	No	No	Yes	No	No	Yes	No	No	Yes
19	FLT19-3PH	No	No	Yes	No	No	Yes	No	No	Yes
20	FLT20-3PH	No	No	Yes	No	No	Yes	No	No	Yes
21	FLT21-3PH	No	No	Yes	No	No	Yes	No	No	Yes
22	FLT22-3PH	No	No	Yes	No	No	Yes	No	No	Yes
23	FLT23-3PH	No	No	Yes	No	No	Yes	No	No	Yes
24	FLT24-3PH	No	No	Yes	No	No	Yes	No	No	Yes
25	FLT25-3PH	No	No	Yes	No	No	Yes	No	No	Yes
26	FLT26-3PH	No	No	Yes	No	No	Yes	No	No	Yes
27	FLT27-3PH	No	No	Yes	No	No	Yes	No	No	Yes
28	FLT28-3PH	No	No	Yes	No	No	Yes	No	No	Yes
29	FLT29-3PH	No	No	Yes	No	No	Yes	No	No	Yes
30	FLT30-3PH	No	No	Yes	No	No	Yes	No	No	Yes
31	FLT31-3PH	No	No	Yes	No	No	Yes	No	No	Yes
32	FLT32-3PH	No	No	Yes	No	No	Yes	No	No	Yes
33	FLT33-3PH	No	No	Yes	No	No	Yes	No	No	Yes
34	FLT34-3PH	No	No	Yes	No	No	Yes	No	No	Yes
35	FLT35-3PH	No	No	Yes	No	No	Yes	No	No	Yes
36	FLT36-3PH	No	No	Yes	No	No	Yes	No	No	Yes
37	FLT37-3PH	No	No	Yes	No	No	Yes	No	No	Yes
38	FLT38-3PH	No	No	Yes	No	No	Yes	No	No	Yes
39	FLT39-3PH	No	No	Yes	No	No	Yes	No	No	Yes
40	FLT40-3PH	No	No	Yes	No	No	Yes	No	No	Yes
41	FLT41-3PH	No	No	Yes	No	No	Yes	No	No	Yes
42	FLT42-3PH	No	No	Yes	No	No	Yes	No	No	Yes
43	FLT43-3PH	No	No	Yes	No	No	Yes	No	No	Yes
44	FLT44-3PH	No	No	Yes	No	No	Yes	No	No	Yes
45	FLT45-3PH	No	No	Yes	No	No	Yes	No	No	Yes
46	FLT46-3PH	No	No	Yes	No	No	Yes	No	No	Yes
47	FLT47-3PH	No	No	Yes	No	No	Yes	No	No	Yes
48	FLT48-3PH	No	No	Yes	No	No	Yes	No	No	Yes
49	FLT49-3PH	No	No	Yes	No	No	Yes	No	No	Yes
50	FLT50-3PH	No	No	Yes	No	No	Yes	No	No	Yes
51	FLT51-3PH	No	No	Yes	No	No	Yes	No	No	Yes
52	FLT52-3PH	No	No	Yes	No	No	Yes	No	No	Yes
53	FLT53-3PH	No	No	Yes	No	No	Yes	No	No	Yes

Table 3-10 (Continued)
Cluster Scenario: Stability Analysis Summary of Results for 2015 Winter, 2015 Summer, and 2025 Summer Peak Conditions

Cont. No.	Cont. Name	2015 Summer Peak			2015 Winter Peak			2025 Summer Peak		
		Recovers between 0.70 and 1.20 p.u.		Stable?	Recovers between 0.70 and 1.20 p.u.?		Stable?	Recovers between 0.70 and 1.20 p.u.?		Stable?
		Less than 0.70 p.u.	Greater than 1.20 p.u.		Less than 0.70 p.u.	Greater than 1.20 p.u.		Less than 0.70 p.u.	Greater than 1.20 p.u.	
54	FLT54-3PH	No	No	Yes	No	No	Yes	No	No	Yes
55	FLT55-3PH	No	No	Yes	No	No	Yes	No	No	Yes
56	FLT56-3PH	No	No	Yes	No	No	Yes	No	No	Yes
57	FLT57-3PH	No	No	Yes	No	No	Yes	No	No	Yes
58	FLT58-3PH	No	No	Yes	No	No	Yes	No	No	Yes
59	FLT59-3PH	No	No	Yes	No	No	Yes	No	No	Yes
60	FLT60-3PH	No	No	Yes	No	No	Yes	No	No	Yes
61	FLT61-3PH	No	No	Yes	No	No	Yes	No	No	Yes
62	FLT62-3PH	No	No	Yes	No	No	Yes	No	No	Yes
63	FLT63-3PH	No	No	Yes	No	No	Yes	No	No	Yes
64	FLT64-3PH	No	No	Yes	No	No	Yes	No	No	Yes
65	FLT65-3Ph	No	No	Yes	No	No	Yes	No	No	Yes
66	FLT66-3PH	No	No	Yes	No	No	Yes	No	No	Yes
67	FLT67-3PH	No	No	Yes	No	No	Yes	No	No	Yes
68	FLT68-3PH	No	No	Yes	No	No	Yes	No	No	Yes
69	FLT69-3PH	No	No	Yes	No	No	Yes	No	No	Yes
70	FLT70-3PH	No	No	Yes	No	No	Yes	No	No	Yes
71	FLT71-3PH	No	No	Yes	No	No	Yes	No	No	Yes
72	FLT72-3PH	No	No	Yes	No	No	Yes	No	No	Yes
73	FLT73-3PH	No	No	Yes	No	No	Yes	No	No	Yes
74	FLT74-3PH	No	No	Yes	No	No	Yes	No	No	Yes
75	FLT75-3PH	No	No	Yes	No	No	Yes	No	No	Yes
76	FLT76-3PH	No	No	Yes	No	No	Yes	No	No	Yes
77	FLT77-3PH	No	No	Yes	No	No	Yes	No	No	Yes
78	FLT78-3PH	No	No	Yes	No	No	Yes	No	No	Yes
79	FLT79-3PH	No	No	Yes	No	No	Yes	No	No	Yes
80	FLT80-3PH	No	No	Yes	No	No	Yes	No	No	Yes
81	FLT81-3PH	No	No	Yes	No	No	Yes	No	No	Yes
82	FLT82-3PH	No	No	Yes	No	No	Yes	No	No	Yes
83	FLT83-3PH	No	No	Yes	No	No	Yes	No	No	Yes
84	FLT84-3PH	No	No	Yes	No	No	Yes	No	No	Yes
85	FLT85-1PH	No	No	Yes	No	No	Yes	No	No	Yes
86	FLT86-1PH	No	No	Yes	No	No	Yes	No	No	Yes
87	FLT87-1PH	No	No	Yes	No	No	Yes	No	No	Yes
88	FLT88-1PH	No	No	Yes	No	No	Yes	No	No	Yes
89	FLT89-1PH	No	No	Yes	No	No	Yes	No	No	Yes
90	FLT90-1PH	No	No	Yes	No	No	Yes	No	No	Yes
91	FLT91-1PH	No	No	Yes	No	No	Yes	No	No	Yes
92	FLT92-1PH	No	No	Yes	No	No	Yes	No	No	Yes
93	FLT93-1PH	No	No	Yes	No	No	Yes	No	No	Yes
94	FLT94-1PH	No	No	Yes	No	No	Yes	No	No	Yes
95	FLT95-1PH	No	No	Yes	No	No	Yes	No	No	Yes
96	FLT96-1PH	No	No	Yes	No	No	Yes	No	No	Yes
97	FLT97-1PH	No	No	Yes	No	No	Yes	No	No	Yes
98	FLT98-1PH	No	No	Yes	No	No	Yes	No	No	Yes
99	FLT99-1PH	No	No	Yes	No	No	Yes	No	No	Yes
100	FLT100-1PH	No	No	Yes	No	No	Yes	No	No	Yes
101	FLT101-1PH	No	No	Yes	No	No	Yes	No	No	Yes
102	FLT102-1PH	No	No	Yes	No	No	Yes	No	No	Yes
103	FLT103-1PH	No	No	Yes	No	No	Yes	No	No	Yes
104	FLT104-1PH	No	No	Yes	No	No	Yes	No	No	Yes
105	FLT105-1PH	No	No	Yes	No	No	Yes	No	No	Yes

3.3 Stand Alone Scenario Stability Analysis Results: GEN-2015-001

The Stability Analysis determined that there were no contingencies that resulted in system instability, generation tripping offline, or voltage violations for 2015 Summer Peak, 2015 Winter Peak, and 2025 Summer Peak conditions when GEN-2015-001 was at 100% output.

Refer to Table 3-11 for a summary of the Stability Analysis results for the contingencies listed in Table 2-3 that correspond to the GEN-2015-001 Stand Alone Analysis. Table 3-11 is a summary of the stability results for the 2015 Summer Peak, 2015 Winter Peak, and 2025 Summer Peak conditions and states whether the system remained stable or generation tripped offline and if acceptable voltage recovery was observed after the fault was cleared. Voltage recovery criteria includes ensuring that the transient voltage recovery is between 0.7 p.u. and 1.2 p.u. and ending in a steady state voltage (for N-1 contingencies) at the pre-contingent level or at least 0.9 p.u. If high or low voltages were observed the number of buses failing the voltage criteria was listed.

Note contingencies, FLT01-3PH and FLT03-3PH, required the “LVRT extreme UV limit” value in the “VWVRP7” dynamic model of GEN-2015-001 to be changed from 0.05 p.u. to 0.0 p.u. in order for GEN-2015-001 to remain online, as discussed with SPP. The dynamic file modification was used to complete the analysis.

Several voltage buses consistently fell outside of the 0.95 p.u. to 1.05 p.u. range. All instances were observed for pre-fault conditions and since all voltages returned to pre-fault conditions, no mitigation was required.

Refer to Appendix E for a complete set of plots for all the GEN-2015-001 Stand Alone Analysis contingencies for 2015 Summer Peak, 2015 Winter Peak, and 2025 Summer Peak conditions.

Table 3-11
Stand Alone Scenario GEN-2015-001: Stability Analysis Summary of Results for 2015 Winter, 2015 Summer, and 2025 Summer Peak Conditions

Cont. No.	Cont. Name	2015 Summer Peak			2015 Winter Peak			2025 Summer Peak		
		Recovers between 0.70 and 1.20 p.u.		Stable?	Recovers between 0.70 and 1.20 p.u.?		Stable?	Recovers between 0.70 and 1.20 p.u.?		Stable?
		Less than 0.70 p.u.	Greater than 1.20 p.u.		Less than 0.70 p.u.	Greater than 1.20 p.u.		Less than 0.70 p.u.	Greater than 1.20 p.u.	
1	FLT01-3PH	No	No	Yes	No	No	Yes	No	No	Yes
2	FLT02-3PH	No	No	Yes	No	No	Yes	No	No	Yes
3	FLT03-3PH	No	No	Yes	No	No	Yes	No	No	Yes
4	FLT04-3PH	No	No	Yes	No	No	Yes	No	No	Yes
5	FLT05-3PH	No	No	Yes	No	No	Yes	No	No	Yes
6	FLT06-3PH	No	No	Yes	No	No	Yes	No	No	Yes
7	FLT07-3PH	No	No	Yes	No	No	Yes	No	No	Yes
8	FLT08-3PH	No	No	Yes	No	No	Yes	No	No	Yes
9	FLT09-3PH	No	No	Yes	No	No	Yes	No	No	Yes
12	FLT12-3PH	No	No	Yes	No	No	Yes	No	No	Yes
13	FLT13-3PH	No	No	Yes	No	No	Yes	No	No	Yes
58	FLT58-3PH	No	No	Yes	No	No	Yes	No	No	Yes
59	FLT59-3PH	No	No	Yes	No	No	Yes	No	No	Yes
60	FLT60-3PH	No	No	Yes	No	No	Yes	No	No	Yes
61	FLT61-3PH	No	No	Yes	No	No	Yes	No	No	Yes
62	FLT62-3PH	No	No	Yes	No	No	Yes	No	No	Yes
76	FLT76-3PH	No	No	Yes	No	No	Yes	No	No	Yes
79	FLT79-3PH	No	No	Yes	No	No	Yes	No	No	Yes
80	FLT80-3PH	No	No	Yes	No	No	Yes	No	No	Yes
82	FLT82-3PH	No	No	Yes	No	No	Yes	No	No	Yes
86	FLT86-1PH	No	No	Yes	No	No	Yes	No	No	Yes
87	FLT87-1PH	No	No	Yes	No	No	Yes	No	No	Yes
100	FLT100-1PH	No	No	Yes	No	No	Yes	No	No	Yes
101	FLT101-1PH	No	No	Yes	No	No	Yes	No	No	Yes
102	FLT102-1PH	No	No	Yes	No	No	Yes	No	No	Yes
103	FLT103-1PH	No	No	Yes	No	No	Yes	No	No	Yes

3.4 Stand Alone Scenario Stability Analysis Results: GEN-2015-003

The Stability Analysis determined that there were no contingencies that resulted in system instability, generation tripping offline, or voltage violations for the 2015 Summer Peak, 2015 Winter Peak, and 2025 Summer peak conditions when GEN-2015-003 was at 100% output.

Refer to Table 3-12 for a summary of the Stability Analysis results for the contingencies listed in Table 2-3 that corresponds to the GEN-2015-003 Stand Alone Analysis. Table 3-12 is a summary of the stability results for the 2015 Summer Peak, 2015 Winter Peak, and 2025 Summer Peak conditions and states whether the system remained stable or generation tripped offline and if acceptable voltage recovery was observed after the fault was cleared. Voltage recovery criteria includes ensuring that the transient voltage recovery is between 0.7 p.u. and 1.2 p.u. and ending in a steady state voltage (for N-1 contingencies) at the pre-contingent level or at least 0.9 p.u. If high or low voltages were observed the number of buses failing the voltage criteria was listed.

Several voltage buses consistently fell outside of the 0.95 p.u. to 1.05 p.u. range. All instances were observed for pre-fault condition and since all voltages restored to pre-fault conditions, no mitigation was required.

Refer to Appendix F for a complete set of plots for all the GEN-2015-003 Stand Alone Scenario contingencies for 2015 Summer Peak, 2015 Winter Peak, and 2025 Summer Peak conditions.

Table 3-12
Stand Alone Scenario GEN-2015-003: Stability Analysis Summary of Results for 2015 Winter, 2015 Summer, and 2025 Summer Peak Conditions

Cont. No.	Cont. Name	2015 Summer Peak			2015 Winter Peak			2025 Summer Peak		
		Recovers between 0.70 and 1.20 p.u.		Stable?	Recovers between 0.70 and 1.20 p.u.?		Stable?	Recovers between 0.70 and 1.20 p.u.?		Stable?
		Less than 0.70 p.u.	Greater than 1.20 p.u.		Less than 0.70 p.u.	Greater than 1.20 p.u.		Less than 0.70 p.u.	Greater than 1.20 p.u.	
10	FLT10-3PH	No	No	Yes	No	No	Yes	No	No	Yes
11	FLT11-3PH	No	No	Yes	No	No	Yes	No	No	Yes
12	FLT12-3PH	No	No	Yes	No	No	Yes	No	No	Yes
13	FLT13-3PH	No	No	Yes	No	No	Yes	No	No	Yes
14	FLT14-3PH	No	No	Yes	No	No	Yes	No	No	Yes
15	FLT15-3PH	No	No	Yes	No	No	Yes	No	No	Yes
16	FLT16-3PH	No	No	Yes	No	No	Yes	No	No	Yes
17	FLT17-3PH	N/A			N/A			No	No	Yes
18	FLT18-3PH	No	No	Yes	No	No	Yes	No	No	Yes
33	FLT33-3PH	No	No	Yes	No	No	Yes	No	No	Yes
62	FLT62-3PH	No	No	Yes	No	No	Yes	No	No	Yes
63	FLT63-3PH	No	No	Yes	No	No	Yes	No	No	Yes
64	FLT64-3PH	No	No	Yes	No	No	Yes	No	No	Yes
65	FLT65-3PH	No	No	Yes	No	No	Yes	No	No	Yes
66	FLT66-3PH	No	No	Yes	No	No	Yes	No	No	Yes
73	FLT73-3PH	No	No	Yes	No	No	Yes	No	No	Yes
74	FLT74-3PH	No	No	Yes	No	No	Yes	No	No	Yes
75	FLT75-3PH	No	No	Yes	No	No	Yes	No	No	Yes
76	FLT76-3PH	No	No	Yes	No	No	Yes	No	No	Yes
88	FLT88-1PH	No	No	Yes	No	No	Yes	No	No	Yes
89	FLT89-1PH	No	No	Yes	No	No	Yes	No	No	Yes

3.5 Stand Alone Scenario Stability Analysis Results: GEN-2015-015

The Stability Analysis determined that there were no contingencies that resulted in system instability, generation tripping offline, or voltage violations for the 2015 Summer Peak, 2015 Winter Peak, and 2025 Summer peak conditions when GEN-2015-015 was at 100% output.

Refer to Table 3-13 for a summary of the Stability Analysis results for the contingencies listed in Table 2-3 that corresponds to the GEN-2015-015 Stand Alone Analysis. Table 3-13 is a summary of the stability results for the 2015 Summer Peak, 2015 Winter Peak, and 2025 Summer Peak conditions and states whether the system remained stable or generation tripped offline and if acceptable voltage recovery was observed after the fault was cleared. Voltage recovery criteria includes ensuring that the transient voltage recovery is between 0.7 p.u. and 1.2 p.u. and ending in a steady state voltage (for N-1 contingencies) at the pre-contingent level or at least 0.9 p.u. If high or low voltages were observed the number of buses failing the voltage criteria was listed.

Several voltage buses consistently fell outside of the 0.95 p.u. to 1.05 p.u. range. All instances were observed for pre-fault conditions and since all voltages returned to pre-fault conditions, no mitigation was required.

Refer to Appendix G for a complete set of plots for all the GEN-2015-015 Stand Alone Scenario contingencies for 2015 Summer Peak, 2015 Winter Peak, and 2025 Summer Peak conditions.

Table 3-13
Stand Alone Scenario GEN-2015-015: Stability Analysis Summary of Results for 2015 Winter, 2015 Summer, and 2025 Summer Peak Conditions

Cont. No.	Cont. Name	2015 Summer Peak			2015 Winter Peak			2025 Summer Peak		
		Recovers between 0.70 and 1.20 p.u.		Stable?	Recovers between 0.70 and 1.20 p.u.?		Stable?	Recovers between 0.70 and 1.20 p.u.?		Stable?
		Less than 0.70 p.u.	Greater than 1.20 p.u.		Less than 0.70 p.u.	Greater than 1.20 p.u.		Less than 0.70 p.u.	Greater than 1.20 p.u.	
2	FLT02-3PH	No	No	Yes	No	No	Yes	No	No	Yes
3	FLT03-3PH	No	No	Yes	No	No	Yes	No	No	Yes
7	FLT07-3PH	No	No	Yes	No	No	Yes	No	No	Yes
8	FLT08-3PH	No	No	Yes	No	No	Yes	No	No	Yes
9	FLT09-3PH	No	No	Yes	No	No	Yes	No	No	Yes
10	FLT10-3PH	No	No	Yes	No	No	Yes	No	No	Yes
19	FLT19-3PH	No	No	Yes	No	No	Yes	No	No	Yes
20	FLT20-3PH	No	No	Yes	No	No	Yes	No	No	Yes
21	FLT21-3PH	No	No	Yes	No	No	Yes	No	No	Yes
22	FLT22-3PH	No	No	Yes	No	No	Yes	No	No	Yes
23	FLT23-3PH	No	No	Yes	No	No	Yes	No	No	Yes
64	FLT64-3PH	No	No	Yes	No	No	Yes	No	No	Yes
66	FLT66-3PH	No	No	Yes	No	No	Yes	No	No	Yes
67	FLT67-3PH	No	No	Yes	No	No	Yes	No	No	Yes
68	FLT68-3PH	No	No	Yes	No	No	Yes	No	No	Yes
90	FLT90-1PH	No	No	Yes	No	No	Yes	No	No	Yes
91	FLT91-1PH	No	No	Yes	No	No	Yes	No	No	Yes

3.6 Stand Alone Scenario Stability Analysis Results: GEN-2015-016

The Stability Analysis determined that there were no contingencies that resulted in system instability, generation tripping offline, or voltage violations for the 2015 Summer Peak, 2015 Winter Peak, and 2025 Summer peak conditions when GEN-2015-016 was at 100% output.

Refer to Table 3-14 for a summary of the Stability Analysis results for the contingencies listed in Table 2-3 that corresponds to the GEN-2105-016 Stand Alone Analysis. Table 3-14 is a summary of the stability results for the 2015 Summer Peak, 2015 Winter Peak, and 2025 Summer Peak conditions and states whether the system remained stable or generation tripped offline and if acceptable voltage recovery was observed after the fault was cleared. Voltage recovery criteria includes ensuring that the transient voltage recovery is between 0.7 p.u. and 1.2

p.u. and ending in a steady state voltage (for N-1 contingencies) at the pre-contingent level or at least 0.9 p.u. If high or low voltages were observed the number of buses failing the voltage criteria was listed.

Several voltage buses consistently fell outside of the 0.95 p.u. to 1.05 p.u. range. All instances were observed for pre-fault conditions and since all voltages returned to pre-fault conditions, no mitigation was required.

Refer to Appendix H for a complete set of plots for all the GEN-2015-016 Stand Alone Scenario contingencies for 2015 Summer Peak, 2015 Winter Peak, and 2025 Summer Peak conditions.

Table 3-14
Stand Alone Scenario GEN-2015-016: Stability Analysis Summary of Results for 2015 Winter, 2015 Summer, and 2025 Summer Peak Conditions

Cont. No.	Cont. Name	2015 Summer Peak			2015 Winter Peak			2025 Summer Peak		
		Recovers between 0.70 and 1.20 p.u.		Stable?	Recovers between 0.70 and 1.20 p.u.?		Stable?	Recovers between 0.70 and 1.20 p.u.?		Stable?
		Less than 0.70 p.u.	Greater than 1.20 p.u.		Less than 0.70 p.u.	Greater than 1.20 p.u.		Less than 0.70 p.u.	Greater than 1.20 p.u.	
24	FLT24-3PH	No	No	Yes	No	No	Yes	No	No	Yes
25	FLT25-3PH	No	No	Yes	No	No	Yes	No	No	Yes
26	FLT26-3PH	No	No	Yes	No	No	Yes	No	No	Yes
27	FLT27-3PH	No	No	Yes	No	No	Yes	No	No	Yes
28	FLT28-3PH	No	No	Yes	No	No	Yes	No	No	Yes
29	FLT29-3PH	No	No	Yes	No	No	Yes	No	No	Yes
30	FLT30-3PH	No	No	Yes	No	No	Yes	No	No	Yes
31	FLT31-3PH	No	No	Yes	No	No	Yes	No	No	Yes
32	FLT32-3PH	No	No	Yes	No	No	Yes	No	No	Yes
69	FLT69-3PH	No	No	Yes	No	No	Yes	No	No	Yes
70	FLT70-3PH	No	No	Yes	No	No	Yes	No	No	Yes
71	FLT71-3PH	No	No	Yes	No	No	Yes	No	No	Yes
72	FLT72-3PH	No	No	Yes	No	No	Yes	No	No	Yes
92	FLT92-1PH	No	No	Yes	No	No	Yes	No	No	Yes
93	FLT93-1PH	No	No	Yes	No	No	Yes	No	No	Yes

3.7 Stand Alone Scenario Stability Analysis Results: GEN-2015-024 and GEN-2015-025 (Tap Wichita – Thistle circuits 1&2)

The Stability Analysis determined that there were no contingencies that resulted in system instability, generation tripping offline, or voltage violations for the 2015 Summer Peak, 2015 Winter Peak, and 2025 Summer peak conditions when GEN-2015-024 and GEN-2015-025 were at 100% output.

Refer to Table 3-15 for a summary of the Stability Analysis results for the contingencies listed in Table 2-3 that corresponds to the GEN-2015-024 and GEN-2015-025 Stand Alone Analysis. Table 3-15 is a summary of the stability results for the 2015 Summer Peak, 2015 Winter Peak, and 2025 Summer Peak conditions and states whether the system remained stable or generation tripped offline and if acceptable voltage recovery was observed after the fault was cleared.

Voltage recovery criteria includes ensuring that the transient voltage recovery is between 0.7 p.u. and 1.2 p.u. and ending in a steady state voltage (for N-1 contingencies) at the pre-contingent level or at least 0.9 p.u. If high or low voltages were observed the number of buses failing the voltage criteria was listed.

Several voltage buses consistently fell outside of the 0.95 p.u. to 1.05 p.u. range. All instances were observed for pre-fault conditions and since all voltages returned to pre-fault conditions, no mitigation was required.

Refer to Appendix I for a complete set of plots for all the GEN-2015-024 and GEN-2015-025 Stand Alone Scenario contingencies for 2015 Summer Peak, 2015 Winter Peak, and 2025 Summer Peak conditions.

Table 3-15
Stand Alone Scenario GEN-2015-024 and GEN-2015-025: Stability Analysis Summary of Results for 2015 Winter, 2015 Summer, and 2025 Summer Peak Conditions

Cont. No.	Cont. Name	2015 Summer Peak			2015 Winter Peak			2025 Summer Peak		
		Recovers between 0.70 and 1.20 p.u.		Stable?	Recovers between 0.70 and 1.20 p.u.?		Stable?	Recovers between 0.70 and 1.20 p.u.?		Stable?
		Less than 0.70 p.u.	Greater than 1.20 p.u.		Less than 0.70 p.u.	Greater than 1.20 p.u.		Less than 0.70 p.u.	Greater than 1.20 p.u.	
2	FLT02-3PH	No	No	Yes	No	No	Yes	No	No	Yes
3	FLT03-3PH	No	No	Yes	No	No	Yes	No	No	Yes
4	FLT04-3PH	No	No	Yes	No	No	Yes	No	No	Yes
5	FLT05-3PH	No	No	Yes	No	No	Yes	No	No	Yes
6	FLT06-3PH	No	No	Yes	No	No	Yes	No	No	Yes
9	FLT09-3PH	No	No	Yes	No	No	Yes	No	No	Yes
11	FLT11-3PH	No	No	Yes	No	No	Yes	No	No	Yes
12	FLT12-3PH	No	No	Yes	No	No	Yes	No	No	Yes
13	FLT13-3PH	No	No	Yes	No	No	Yes	No	No	Yes
14	FLT14-3PH	No	No	Yes	No	No	Yes	No	No	Yes
15	FLT15-3PH	No	No	Yes	No	No	Yes	No	No	Yes
16	FLT16-3PH	No	No	Yes	No	No	Yes	No	No	Yes
17	FLT17-3PH	N/A			N/A			No	No	Yes
18	FLT18-3PH	No	No	Yes	No	No	Yes	No	No	Yes
31	FLT31-3PH	No	No	Yes	No	No	Yes	No	No	Yes
33	FLT33-3PH	No	No	Yes	No	No	Yes	No	No	Yes
34	FLT34-3PH	No	No	Yes	No	No	Yes	No	No	Yes
35	FLT35-3PH	No	No	Yes	No	No	Yes	No	No	Yes
36	FLT36-3PH	No	No	Yes	No	No	Yes	No	No	Yes
37	FLT37-3PH	No	No	Yes	No	No	Yes	No	No	Yes
38	FLT38-3PH	No	No	Yes	No	No	Yes	No	No	Yes
39	FLT39-3PH	No	No	Yes	No	No	Yes	No	No	Yes
60	FLT60-3PH	No	No	Yes	No	No	Yes	No	No	Yes
61	FLT61-3PH	No	No	Yes	No	No	Yes	No	No	Yes
62	FLT62-3PH	No	No	Yes	No	No	Yes	No	No	Yes
63	FLT63-3PH	No	No	Yes	No	No	Yes	No	No	Yes
64	FLT64-3PH	No	No	Yes	No	No	Yes	No	No	Yes
65	FLT65-3PH	No	No	Yes	No	No	Yes	No	No	Yes
66	FLT66-3PH	No	No	Yes	No	No	Yes	No	No	Yes
73	FLT73-3PH	No	No	Yes	No	No	Yes	No	No	Yes
74	FLT74-3PH	No	No	Yes	No	No	Yes	No	No	Yes
75	FLT75-3PH	No	No	Yes	No	No	Yes	No	No	Yes
76	FLT76-3PH	No	No	Yes	No	No	Yes	No	No	Yes
94	FLT94-1PH	No	No	Yes	No	No	Yes	No	No	Yes
95	FLT95-1PH	No	No	Yes	No	No	Yes	No	No	Yes
96	FLT96-1PH	No	No	Yes	No	No	Yes	No	No	Yes
97	FLT97-1PH	No	No	Yes	No	No	Yes	No	No	Yes

3.8 Stand Alone Scenario Stability Analysis Results: GEN-2015-028

The Stability Analysis determined that there were no contingencies that resulted in system instability, generation tripping offline, or voltage violations for the 2015 Summer Peak, 2015 Winter Peak, and 2025 Summer peak conditions when GEN-2015-028 was at 100% output.

Refer to Table 3-16 for a summary of the Stability Analysis results for the contingencies listed in Table 2-3 that corresponds to the GEN-2015-028 Stand Alone Analysis. Table 3-16 is a summary of the stability results for the 2015 Summer Peak, 2015 Winter Peak, and 2025

Summer Peak conditions and states whether the system remained stable or generation tripped offline and if acceptable voltage recovery was observed after the fault was cleared. Voltage recovery criteria includes ensuring that the transient voltage recovery is between 0.7 p.u. and 1.2 p.u. and ending in a steady state voltage (for N-1 contingencies) at the pre-contingent level or at least 0.9 p.u. If high or low voltages were observed the number of buses failing the voltage criteria was listed.

Several voltage buses consistently fell outside of the 0.95 p.u. to 1.05 p.u. range. All instances were observed for pre-fault conditions and since all voltages returned to pre-fault conditions, no mitigation was required.

Refer to Appendix J for a complete set of plots for all the GEN-2015-028 Stand Alone Scenario contingencies for 2015 Summer Peak, 2015 Winter Peak, and 2025 Summer Peak conditions.

Table 3-16
Stand Alone Scenario GEN-2015-028: Stability Analysis Summary of Results for 2015 Winter, 2015 Summer, and 2025 Summer Peak Conditions

Cont. No.	Cont. Name	2015 Summer Peak			2015 Winter Peak			2025 Summer Peak		
		Recovers between 0.70 and 1.20 p.u.		Stable?	Recovers between 0.70 and 1.20 p.u.?		Stable?	Recovers between 0.70 and 1.20 p.u.?		Stable?
		Less than 0.70 p.u.	Greater than 1.20 p.u.		Less than 0.70 p.u.	Greater than 1.20 p.u.		Less than 0.70 p.u.	Greater than 1.20 p.u.	
3	FLT03-3PH	No	No	Yes	No	No	Yes	No	No	Yes
10	FLT10-3PH	No	No	Yes	No	No	Yes	No	No	Yes
18	FLT18-3PH	No	No	Yes	No	No	Yes	No	No	Yes
19	FLT19-3PH	No	No	Yes	No	No	Yes	No	No	Yes
20	FLT20-3PH	No	No	Yes	No	No	Yes	No	No	Yes
21	FLT21-3PH	No	No	Yes	No	No	Yes	No	No	Yes
22	FLT22-3PH	No	No	Yes	No	No	Yes	No	No	Yes
23	FLT23-3PH	No	No	Yes	No	No	Yes	No	No	Yes
40	FLT40-3PH	No	No	Yes	No	No	Yes	No	No	Yes
41	FLT41-3PH	No	No	Yes	No	No	Yes	No	No	Yes
42	FLT42-3PH	No	No	Yes	No	No	Yes	No	No	Yes
43	FLT43-3PH	No	No	Yes	No	No	Yes	No	No	Yes
44	FLT44-3PH	No	No	Yes	No	No	Yes	No	No	Yes
45	FLT45-3PH	No	No	Yes	No	No	Yes	No	No	Yes
46	FLT46-3PH	No	No	Yes	No	No	Yes	No	No	Yes
67	FLT67-3PH	No	No	Yes	No	No	Yes	No	No	Yes
68	FLT68-3PH	No	No	Yes	No	No	Yes	No	No	Yes
77	FLT77-3PH	No	No	Yes	No	No	Yes	No	No	Yes
78	FLT78-3PH	No	No	Yes	No	No	Yes	No	No	Yes
98	FLT98-1PH	No	No	Yes	No	No	Yes	No	No	Yes
99	FLT99-1PH	No	No	Yes	No	No	Yes	No	No	Yes

3.9 Stand Alone Scenario Stability Analysis Results: GEN-2015-030

The Stability Analysis determined that there were no contingencies that resulted in system instability, generation tripping offline, or voltage violations for the 2015 Summer Peak, 2015 Winter Peak, and 2025 Summer peak conditions when GEN-2015-030 was at 100% output.

Refer to Table 3-17 for a summary of the Stability Analysis results for the contingencies listed in Table 2-3 that corresponds to the GEN-2015-030 Stand Alone Analysis. Table 3-17 is a summary of the stability results for the 2015 Summer Peak, 2015 Winter Peak, and 2025 Summer Peak conditions and states whether the system remained stable or generation tripped offline and if acceptable voltage recovery was observed after the fault was cleared. Voltage recovery criteria includes ensuring that the transient voltage recovery is between 0.7 p.u. and 1.2 p.u. and ending in a steady state voltage (for N-1 contingencies) at the pre-contingent level or at least 0.9 p.u. If high or low voltages were observed the number of buses failing the voltage criteria was listed.

Several voltage buses consistently fell outside of the 0.95 p.u. to 1.05 p.u. range. All instances were observed for pre-fault conditions and since all voltages returned to pre-fault conditions, no mitigation was required.

Refer to Appendix K for a complete set of plots for all the GEN-2015-030 Stand Alone Scenario contingencies for 2015 Summer Peak, 2015 Winter Peak, and 2025 Summer Peak conditions.

Table 3-17
Stand Alone Scenario GEN-2015-030: Stability Analysis Summary of Results for 2015 Winter, 2015 Summer, and 2025 Summer Peak Conditions

Cont. No.	Cont. Name	2015 Summer Peak			2015 Winter Peak			2025 Summer Peak		
		Recovers between 0.70 and 1.20 p.u.		Stable?	Recovers between 0.70 and 1.20 p.u.?		Stable?	Recovers between 0.70 and 1.20 p.u.?		Stable?
		Less than 0.70 p.u.	Greater than 1.20 p.u.		Less than 0.70 p.u.	Greater than 1.20 p.u.		Less than 0.70 p.u.	Greater than 1.20 p.u.	
1	FLT01-3PH	No	No	Yes	No	No	Yes	No	No	Yes
2	FLT02-3PH	No	No	Yes	No	No	Yes	No	No	Yes
3	FLT03-3PH	No	No	Yes	No	No	Yes	No	No	Yes
5	FLT05-3PH	No	No	Yes	No	No	Yes	No	No	Yes
6	FLT06-3PH	No	No	Yes	No	No	Yes	No	No	Yes
7	FLT07-3PH	No	No	Yes	No	No	Yes	No	No	Yes
8	FLT08-3PH	No	No	Yes	No	No	Yes	No	No	Yes
9	FLT09-3PH	No	No	Yes	No	No	Yes	No	No	Yes
12	FLT12-3PH	No	No	Yes	No	No	Yes	No	No	Yes
13	FLT13-3PH	No	No	Yes	No	No	Yes	No	No	Yes
47	FLT47-3PH	No	No	Yes	No	No	Yes	No	No	Yes
48	FLT48-3PH	No	No	Yes	No	No	Yes	No	No	Yes
49	FLT49-3PH	No	No	Yes	No	No	Yes	No	No	Yes
58	FLT58-3PH	No	No	Yes	No	No	Yes	No	No	Yes
59	FLT59-3PH	No	No	Yes	No	No	Yes	No	No	Yes
60	FLT60-3PH	No	No	Yes	No	No	Yes	No	No	Yes
61	FLT61-3PH	No	No	Yes	No	No	Yes	No	No	Yes
62	FLT62-3PH	No	No	Yes	No	No	Yes	No	No	Yes
66	FLT66-3PH	No	No	Yes	No	No	Yes	No	No	Yes
76	FLT76-3PH	No	No	Yes	No	No	Yes	No	No	Yes
79	FLT79-3PH	No	No	Yes	No	No	Yes	No	No	Yes
80	FLT80-3PH	No	No	Yes	No	No	Yes	No	No	Yes
81	FLT81-3PH	No	No	Yes	No	No	Yes	No	No	Yes
82	FLT82-3PH	No	No	Yes	No	No	Yes	No	No	Yes
100	FLT100-1PH	No	No	Yes	No	No	Yes	No	No	Yes
101	FLT101-1PH	No	No	Yes	No	No	Yes	No	No	Yes
102	FLT102-1PH	No	No	Yes	No	No	Yes	No	No	Yes
103	FLT103-1PH	No	No	Yes	No	No	Yes	No	No	Yes

3.10 Stand Alone Scenario Stability Analysis Results: ASGI-2015-004

The Stability Analysis determined that there were no contingencies that resulted in system instability, generation tripping offline, or voltage violations for the 2015 Summer Peak, 2015 Winter Peak, and 2025 Summer peak conditions when ASGI-2015-004 was at 100% output.

Refer to Table 3-18 for a summary of the Stability Analysis results for the contingencies listed in Table 2-3 that corresponds to the ASGI-2015-004 Stand Alone Analysis. Table 3-18 is a summary of the stability results for the 2015 Summer Peak, 2015 Winter Peak, and 2025 Summer Peak conditions and states whether the system remained stable or generation tripped offline and if acceptable voltage recovery was observed after the fault was cleared. Voltage recovery criteria includes ensuring that the transient voltage recovery is between 0.7 p.u. and 1.2 p.u. and ending in a steady state voltage (for N-1 contingencies) at the pre-contingent level or at least 0.9 p.u. If high or low voltages were observed the number of buses failing the voltage criteria was listed.

Several voltage buses consistently fell outside of the 0.95 p.u. to 1.05 p.u. range. All instances were observed for pre-fault conditions and since all voltages returned to pre-fault conditions, no mitigation was required.

Refer to Appendix L for a complete set of plots for all the ASGI-2015-004 Stand Alone Scenario contingencies for 2015 Summer Peak, 2015 Winter Peak, and 2025 Summer Peak conditions.

Table 3-18
Stand Alone Scenario ASGI-2015-004: Stability Analysis Summary of Results for 2015 Winter, 2015 Summer, and 2025 Summer Peak Conditions

Cont. No.	Cont. Name	2015 Summer Peak			2015 Winter Peak			2025 Summer Peak		
		Recovers between 0.70 and 1.20 p.u.		Stable?	Recovers between 0.70 and 1.20 p.u.?		Stable?	Recovers between 0.70 and 1.20 p.u.?		Stable?
		Less than 0.70 p.u.	Greater than 1.20 p.u.		Less than 0.70 p.u.	Greater than 1.20 p.u.		Less than 0.70 p.u.	Greater than 1.20 p.u.	
50	FLT50-3PH	No	No	Yes	No	No	Yes	No	No	Yes
51	FLT51-3PH	No	No	Yes	No	No	Yes	No	No	Yes
52	FLT52-SB	No	No	Yes	No	No	Yes	No	No	Yes
53	FLT53-3PH	No	No	Yes	No	No	Yes	No	No	Yes
54	FLT54-SB	No	No	Yes	No	No	Yes	No	No	Yes
55	FLT55-3PH	No	No	Yes	No	No	Yes	No	No	Yes
56	FLT56-3PH	No	No	Yes	No	No	Yes	No	No	Yes
57	FLT57-3PH	No	No	Yes	No	No	Yes	No	No	Yes
83	FLT83-3PH	No	No	Yes	No	No	Yes	No	No	Yes
84	FLT84-3PH	No	No	Yes	No	No	Yes	No	No	Yes
104	FLT104-1PH	No	No	Yes	No	No	Yes	No	No	Yes
105	FLT105-1PH	No	No	Yes	No	No	Yes	No	No	Yes

SECTION 4: SHORT CIRCUIT ANALYSIS

The objective of this task is to quantify the three-phase to ground fault currents for the 2025 Summer Peak season for each interconnecting generator.

4.1 Approach

The short-circuit analysis will assess breaker adequacy and fault duties for the generator interconnection bus and five buses away from the point of interconnection. MEPPI will assume no outages to find maximum short-circuit currents that flow through the breaker. The Automatic Sequencing Fault Calculation (ASCC) function in PSS/E was utilized to perform this task. FLAT conditions were applied to pre-fault conditions and the following adjustments were utilized:

- All synchronous and asynchronous machine P and Q output was set to zero
- All transformer tap ratios were set to 1.0 p.u. and all phase shift angles were set to zero
- All generator reactance’s were fixed to the subtransient reactance
- All line charging was set to zero
- All shunts were set to zero

- All loads were set to zero
- All pre-fault bus voltages were set to 1.0 p.u. and a phase shift angle of zero

4.2 Short Circuit Results

The maximum fault current for each bus is provided for the 2025 Summer Peak condition. The following tables show the short circuit results for the study generators:

- Table 4-1: Short Circuit Analysis for GEN-2015-001
- Table 4-2: Short Circuit Analysis for GEN-2015-003
- Table 4-3: Short Circuit Analysis for GEN-2015-015
- Table 4-4: Short Circuit Analysis for GEN-2015-016
- Table 4-5: Short Circuit Analysis for the GEN-2015-024 and GEN-2015-025
- Table 4-6: Short Circuit Analysis for GEN-2015-028
- Table 4-7: Short Circuit Analysis for GEN-2015-030
- Table 4-8: Short Circuit Analysis for ASGI-2015-004

Table 4-1
Short Circuit Analysis for Study Project GEN-2015-001

Study Generator GEN-2015-001											
Bus Number	Bus Name	Bus Voltage (kV)	Fault Current 3-LG (kA)	Bus Number	Bus Name	Bus Voltage (kV)	Fault Current 3-LG (kA)	Bus Number	Bus Name	Bus Voltage (kV)	Fault Current 3-LG (kA)
533024	29TH 4	138	19.42	533042	FARBER 4	138	16.00	514707	PERRY 4	138	10.86
301430	2CLEVLNDXFMR	69	9.72	514709	FRMNTAP4	138	16.42	515576	RANCHRD7	345	12.91
300943	2SILVCTY	69	10.12	515610	FSHRTAP7	345	15.94	514909	REDBUD 7	345	24.18
300137	4BRISTOW	138	7.16	579253	G07-21&14-02	345	13.58	515544	RENFROW4	138	14.00
301429	4CLEVELNDXFMR	138	16.44	579268	G07-44&14-03	345	9.13	515543	RENFROW7	345	12.87
300138	4CLEVLND	138	16.44	562075	G11-051-TAP	345	16.71	532771	RENO 7	345	12.20
300139	4FAIRFAX	138	7.49	562423	G13-028-TAP	345	25.84	533062	ROSEHIL4	138	31.02
300131	4FISHERTP	138	14.45	562476	G14-001-TAP	345	10.53	532794	ROSEHIL7	345	18.30
301425	4GLENCOE	138	9.20	560033	G1524&G1525T	345	19.53	509870	SAPLPRD7	345	20.75
300996	4JAVINE	138	6.52	572091	GEN-2008-098	345	12.59	515045	SEMINOL7	345	28.12
301339	4SFORKKTP	138	6.81	583490	GEN-2012-041	345	11.42	512726	SILVCTYGR4	138	15.40
300140	4SILVCTY	138	15.55	583740	GEN-2013-028	345	25.84	514799	SNRPMP 4	138	11.22
300141	4STILWTR	138	11.52	583750	GEN-2013-029	345	11.31	514798	SNRPMPT4	138	20.29
533029	59TH ST4	138	18.60	584170	GEN-2014-064	138	9.33	514731	SO4TH 4	138	14.10
533066	64TH 4	138	14.25	584450	GEN-2015-001	345	12.91	514802	SOONER 4	138	31.30
533026	ANDOVER4	138	17.64	584470	GEN-2015-003	345	9.49	514803	SOONER 7	345	22.77
514907	ARCADIA4	138	40.30	584700	GEN-2015-029	345	9.77	514881	SPRNGCK7	345	21.36
514908	ARCADIA7	345	24.98	584690	GEN-2015-030	345	17.67	533067	SPRNGDL4	138	14.39
532988	BELAIRE4	138	18.65	512650	GRDA1 7	345	26.28	515512	SPVALLY4	138	8.38
532986	BENTON 4	138	28.12	515476	HUNTERS7	345	12.54	514758	STDBEAR4	138	13.86
532791	BENTON 7	345	19.01	514825	KAYWIND7	345	11.56	533068	STEARMN4	138	19.68
533030	BOEING 4	138	17.09	514828	KETCHTP4	138	25.47	515011	STILWTR4	138	12.45
514854	BRADEN 4	138	30.07	542981	LACYGNE7	345	24.67	509895	T.NO.2-4	138	34.10
533032	BU11PON4	138	15.00	532800	LATHAMS7	345	10.37	509817	T.NO.--4	138	34.16
533626	BURLJCT2	69	4.90	514873	LNEOAK 4	138	25.96	509852	T.NO.--7	345	23.17
532780	CANEYRV7	345	9.82	514770	MARLNDT4	138	10.81	532993	TALLGRS4	138	10.04
532781	CANEYWF7	345	9.56	521006	MARSHAL4	138	7.66	515407	TATONGA7	345	16.41
533629	CC2SHAR2	69	4.58	514733	MARSHL 4	138	7.69	515181	UNVRSTY4	138	12.43
533035	CHISHLM4	138	22.34	515497	MATHWSN7	345	28.60	532798	VIOLA 7	345	13.64
515477	CHSHLMV7	345	12.52	532990	MIDIAN 4	138	10.17	514710	WAUKOMI4	138	9.34
514898	CIMARON4	138	40.88	514704	MILLERT4	138	20.24	514711	WAUKOTP4	138	14.53
514901	CIMARON7	345	30.05	514801	MINCO 7	345	15.97	532799	WAVERLY7	345	14.77
512694	CLEVLND7	345	14.51	515447	MORISNT4	138	13.36	533604	WEAVER 2	69	11.63
514705	COWCRK 2	69	4.04	515006	MORRISN4	138	13.33	532991	WEAVER 4	138	21.91
514706	COWCRK 4	138	11.15	510406	N.E.S.-7	345	18.42	510376	WEBBTAP4	138	8.06
515448	CRSRDSW7	345	11.58	532793	NEOSHO 7	345	16.22	509757	WEKIWA-4	138	31.10
514827	CTNWOOD4	138	16.19	514879	NORTWST4	138	41.57	509755	WEKIWA-7	345	18.41
510380	DELWARE7	345	11.37	514880	NORTWST7	345	29.44	514761	WHEAGLE4	138	15.67
515400	DMANCRK4	138	8.04	515471	NW164TH4	138	34.21	532796	WICHITA7	345	24.56
515412	DMNCRKT4	138	13.68	509807	ONETA--7	345	26.11	533653	WOLFCRK2	69	5.91
514934	DRAPER 7	345	20.97	515621	OPENSKY7	345	11.59	532797	WOLFCRK7	345	15.97
532801	ELKRVR17	345	9.17	514743	OSAGE 4	138	16.56	514714	WOODRNG4	138	17.74
533793	ELPASO 2	69	11.81	514742	OSGE 2	69	17.57	514715	WOODRNG7	345	16.68
533039	ELPASO 4	138	25.04	514737	OTOE 4	138	16.16	514713	WRVALLY4	138	8.60
533040	EVANS N4	138	41.45	514708	OTTER 4	138	9.40				
514703	FAIRMNT4	138	10.53	512749	PAWNSW4	138	9.73				

Table 4-2
Short Circuit Analysis for Study Projects GEN-2015-003

Study Generator GEN-2015-003											
Bus Number	Bus Name	Bus Voltage (kV)	Fault Current 3-LG (kA)	Bus Number	Bus Name	Bus Voltage (kV)	Fault Current 3-LG (kA)	Bus Number	Bus Name	Bus Voltage (kV)	Fault Current 3-LG (kA)
533024	29TH 4	138	19.42	583490	GEN-2012-041	345	11.42	514708	OTTER 4	138	9.40
533074	45TH ST4	138	28.05	583750	GEN-2013-029	345	11.31	533830	PECK 2	69	6.51
300138	4CLEVLND	138	16.44	583850	GEN-2014-001	345	7.03	514707	PERRY 4	138	10.86
514736	4CORNER2	69	4.08	583990	GEN-2014-049	345	7.88	515576	RANCHRD7	345	12.91
533029	59TH ST4	138	18.60	584170	GEN-2014-064	138	9.33	515544	RENFROW4	138	14.00
514908	ARCADIA7	345	24.98	584450	GEN-2015-001	345	12.91	515543	RENFROW7	345	12.87
533850	BASICCH2	69	20.33	584470	GEN-2015-003	345	9.49	533416	RENO 3	115	29.75
532988	BELAIRE4	138	18.65	584570	GEN-2015-015	138	5.87	532771	RENO 7	345	12.20
533015	BENTLEY4	138	12.28	584700	GEN-2015-029	345	9.77	533062	ROSEHIL4	138	31.02
532986	BENTON 4	138	28.12	584690	GEN-2015-030	345	17.67	532794	ROSEHIL7	345	18.30
532791	BENTON 7	345	19.01	533795	GILL E 2	69	33.33	520409	SAND RDG_138	138	10.18
520203	BYRON_138	138	4.18	533044	GILL E 4	138	27.15	520204	SANDY_CN_138	138	5.45
514757	CHIKASI4	138	9.14	533046	GILL S 4	138	27.15	533063	SC10BEL4	138	9.57
533035	CHISHLM4	138	22.34	533796	GILL W 2	69	33.33	533065	SG12COL4	138	22.62
515477	CHSHLMV7	345	12.52	533045	GILL W 4	138	27.15	514798	SNRPMPT4	138	20.29
514898	CIMARON4	138	40.88	533798	GILLJCT2	69	21.80	514731	SO4TH 4	138	14.10
514901	CIMARON7	345	30.05	515547	GRANTCO2	69	7.53	514802	SOONER 4	138	31.30
533413	CIRCLE 3	115	29.31	515546	GRANTCO4	138	6.78	514803	SOONER 7	345	22.77
539800	CLARKCOUNTY7	345	12.54	539668	HARPER 4	138	5.56	514881	SPRNGCK7	345	21.36
533036	CLEARWT4	138	17.07	533804	HAYSVLJ2	69	14.21	532873	SUMMIT 6	230	13.61
512694	CLEVLND7	345	14.51	520938	HAZLTNJ2	69	2.71	532773	SUMMIT 7	345	11.00
514719	CLYDE 2	69	4.58	515476	HUNTERS7	345	12.54	532984	SUMNER 4	138	9.90
515581	COYOTE 4	138	8.37	533053	LAKERDG4	138	19.03	532774	SWISVAL7	345	16.10
532981	CRESWLN4	138	8.05	532769	LANG 7	345	16.59	509852	T.NO.--7	345	23.17
515448	CRSRDSW7	345	11.58	532800	LATHAMS7	345	10.37	515407	TATONGA7	345	16.41
514827	CTNWOOD4	138	16.19	533812	LIN 2	69	9.69	532985	TCROCK 4	138	5.25
533415	DAVIS 3	115	9.15	533813	MACARTH2	69	22.53	539804	THISTLE4	138	16.48
514934	DRAPER 7	345	20.97	533054	MAIZE 4	138	23.27	539801	THISTLE7	345	15.97
539805	ELMCREEK7	345	5.72	533390	MAIZEW 4	138	27.67	533558	TIMBJCT2	69	8.01
533039	ELPASO 4	138	25.04	521006	MARSHAL4	138	7.66	532992	TIMBJCT4	138	5.61
532768	EMPEC 7	345	16.79	514733	MARSHL 4	138	7.69	532798	VIOLA 7	345	13.64
533040	EVANS N4	138	41.45	515497	MATHWSN7	345	28.60	533075	VIOLA 4	138	20.63
533041	EVANS S4	138	41.45	515569	MDFRDTP4	138	11.66	521085	WAKITA 2	69	5.21
514703	FAIRMNT4	138	10.53	514739	MEDFORD2	69	5.45	520205	WAKITA_138	138	5.53
533042	FARBER 4	138	16.00	532990	MIDIAN 4	138	10.17	514710	WAUKOMI4	138	9.34
532792	FR2EAST7	345	6.41	539676	MILAN 4	138	3.51	514711	WAUKOTP4	138	14.53
532795	FR2WEST7	345	5.16	539675	MILANTP4	138	6.55	532799	WAVERLY7	345	14.77
514709	FRMNTAP4	138	16.42	514704	MILLERT4	138	20.24	532796	WICHITA7	345	24.56
515610	FSHRTAP7	345	15.94	514801	MINCO 7	345	15.97	533438	WMCPHER3	115	15.91
579253	G07-21&14-02	345	13.58	515447	MORISNT4	138	13.36	533653	WOLFCRK2	69	5.91
579268	G07-44&14-03	345	9.13	532770	MORRIS 7	345	12.55	532797	WOLFCRK7	345	15.97
562075	G11-051-TAP	345	16.71	533429	MOUNDRG3	115	9.75	514714	WOODRNG4	138	17.74
562476	G14-001-TAP	345	10.53	521008	NASH 2	69	2.65	514715	WOODRNG7	345	16.68
560031	G15-015-TAP	138	8.51	514879	NORTWST4	138	41.57	514713	WRVALLY4	138	8.60
584660	G1524&G1525	345	5.11	514880	NORTWST7	345	29.44	515375	WWRDEHV7	345	20.32
560033	G1524&G1525T	345	19.53	514740	NUMAOGE2	69	4.58				
532767	GEARY 7	345	9.84	515621	OPENSKY7	345	11.59				

Table 4-3
Short Circuit Analysis for Study Project GEN-2015-015

Study Generator GEN-2015-015											
Bus Number	Bus Name	Bus Voltage (kV)	Fault Current 3-LG (kA)	Bus Number	Bus Name	Bus Voltage (kV)	Fault Current 3-LG (kA)	Bus Number	Bus Name	Bus Voltage (kV)	Fault Current 3-LG (kA)
514755	BLACKWL2	69	8.52	584570	GEN-2015-015	138	5.87	515544	RENFROW4	138	14.00
520871	BRAMAN 2	69	8.95	515547	GRANTCO2	69	7.53	515543	RENFROW7	345	12.87
514750	BRMAN 2	69	8.95	515546	GRANTCO4	138	6.78	520409	SAND RDG_138	138	10.18
514756	CHIKASI2	69	10.21	515476	HUNTERS7	345	12.54	520204	SANDY_CN_138	138	5.45
514757	CHIKASI4	138	9.14	514754	KAYCOOP2	69	5.83	514728	SINCBLK2	69	7.17
515477	CHSHLMV7	345	12.52	514760	KILDARE4	138	10.78	515509	SNCBLKT2	69	7.19
514719	CLYDE 2	69	4.58	515569	MDFRDTP4	138	11.66	532798	VIOLA 7	345	13.64
514748	CONTEMP4	138	13.47	514739	MEDFORD2	69	5.45	533075	VIOLA 4	138	20.63
515581	COYOTE 4	138	8.37	515528	NARDINS2	69	5.52	521085	WAKITA 2	69	5.21
515412	DMNCRKT4	138	13.68	514759	NEWKIRK4	138	8.94	520205	WAKITA_138	138	5.53
532792	FR2EAST7	345	6.41	514751	NEWKRKT2	69	5.59	514761	WHEAGLE4	138	15.67
560031	G15-015-TAP	138	8.51	514764	NWKRKAT4	138	10.45	532796	WICHITA7	345	24.56
583750	GEN-2013-029	345	11.31	529255	OMBLKWL2	69	8.22	514715	WOODRNG7	345	16.68
584470	GEN-2015-003	345	9.49	514743	OSAGE 4	138	16.56				

Table 4-4
Short Circuit Analysis for Study Projects GEN-2015-016

Study Generator GEN-2015-016											
Bus Number	Bus Name	Bus Voltage (kV)	Fault Current 3-LG (kA)	Bus Number	Bus Name	Bus Voltage (kV)	Fault Current 3-LG (kA)	Bus Number	Bus Name	Bus Voltage (kV)	Fault Current 3-LG (kA)
300739	7BLACKBERRY	345	12.25	547523	JOP 59 TX	69	9.60	543069	PAOLA 5	161	9.71
300949	7JASPER	345	10.65	547470	JOP145 5	161	17.23	533769	PITNAC 2	69	11.05
300740	7SPORTSMAN	345	23.75	547483	JOP389 5	161	19.47	543077	PLSTVAL5	161	9.17
533621	ALLEN 2	69	5.67	533696	LABETTS2	69	7.04	547491	PUR421 5	161	9.82
533756	AQUARS 2	69	7.66	542981	LACYGNE7	345	24.67	547541	RIV167 2	69	17.91
547476	ASB349 5	161	12.93	532800	LATHAMS7	345	10.37	547502	RIV167 5	161	21.69
532926	BAKER 5	161	8.43	533003	LIBERTY4	138	7.14	547602	RIV406 2	69	15.78
543057	BUCYRUS5	161	18.93	533765	LITCH 2	69	12.65	547469	RIV4525	161	23.37
532780	CANEYRV7	345	9.82	532932	LITCH 5	161	11.09	547503	RIV452T 5	161	22.97
532781	CANEYWF7	345	9.56	533639	MARMATN2	69	8.34	547501	RIV453 5	161	22.17
543067	CENTENL5	161	9.72	532934	MARMTNE5	161	7.94	533771	ROUSE 2	69	9.04
547477	CJ 366 5	161	12.62	533640	MCKEE 2	69	4.16	543066	S.OTTWA5	161	6.43
543065	CNTRVIL5	161	6.09	512631	MIAMI 5	161	9.10	533644	SE4DEVO2	69	3.67
547530	COL 94 2	69	6.31	533767	MULBERY2	69	7.09	533773	SE8CLEM2	69	4.44
533758	CRAWFOR2	69	6.71	510406	N.E.S.-7	345	18.42	533645	SE9HIAT2	69	3.73
510379	DELWARE4	138	10.88	533768	NEOSHO 2	69	18.72	543055	SEOTTWA5	161	6.52
510380	DELWARE7	345	11.37	533021	NEOSHO 4	138	23.17	542968	STILWEL7	345	23.67
547490	FIR417 5	161	14.28	532937	NEOSHO 5	161	22.10	547498	STL439 5	161	24.04
533876	FRANKLIN2	69	8.58	532793	NEOSHO 7	345	16.22	533008	TV1MNDV4	138	6.82
532938	FRANKLIN5	161	8.62	533022	NEOSHON4	138	23.17	533647	UN1ELSM2	69	7.45
560029	G15-016-TAP	161	7.26	533020	NEOSHOS4	138	23.17	533650	UN8HUMB2	69	4.07
547555	GAL278 2	69	15.82	533005	NEPARSN4	138	11.95	542965	W.GRDNR7	345	23.99
584580	GEN-2015-016	161	6.43	547494	OAK432 5	161	17.21	543068	WAGSTAF5	161	13.20
547690	GLF339 2	69	8.97	533703	ORDNJCT2	69	8.73	532799	WAVERLY7	345	14.77
547601	HOC404 2	69	9.38	547534	ORO110 2	69	17.47	533654	ZILAJCT2	69	5.63
547486	HOC404 4	138	6.42	547467	ORO110 5	161	19.04				
547487	HOC404 5	161	12.83	543112	OSAWAT 5	161	9.34				

Table 4-5
Short Circuit Analysis for Study Project GEN-2015-024 and GEN-2015-025
(Tap Wichita – Thistle circuit 1&2)

Study Generators GEN-2015-025, GEN-2015-025											
Bus Number	Bus Name	Bus Voltage (kV)	Fault Current 3-LG (kA)	Bus Number	Bus Name	Bus Voltage (kV)	Fault Current 3-LG (kA)	Bus Number	Bus Name	Bus Voltage (kV)	Fault Current 3-LG (kA)
533840	17TH 2	69	27.63	532767	GEARY 7	345	9.84	533505	NCTYSVC2	69	4.04
533064	17TH 4	138	17.92	562701	GEN-2006-006	345	14.41	532793	NEOSHO 7	345	16.22
533024	29TH 4	138	19.42	579351	GEN-2007-062	345	8.58	532865	NMANHT6	230	8.91
533440	43LORAN	115	16.29	572091	GEN-2008-098	345	12.59	533822	NOEASTE2	69	22.97
533074	45TH ST4	138	28.05	579480	GEN-2008-124	230	20.12	533060	NOEASTE4	138	20.14
533029	59TH ST4	138	18.60	582008	GEN-2011-008	345	10.06	533371	NORTHVW3	115	11.74
533066	64TH 4	138	14.25	581112	GEN-2011-014	345	10.57	533373	NPHILPJ3	115	11.87
533001	ALTOONA4	138	7.80	582016	GEN-2011-016	345	7.72	515621	OPENSKY7	345	11.59
533026	ANDOVER4	138	17.64	582019	GEN-2011-019	345	20.32	515398	OUSPRT 4	138	9.60
533411	ARKVAL 3	115	9.98	582020	GEN-2011-020	345	20.32	533830	PECK 2	69	6.51
533412	ARKVALJ3	115	10.17	583110	GEN-2011-051	345	16.71	533372	PHILIPS3	115	12.65
532851	AUBURN 6	230	13.44	583370	GEN-2012-024	345	9.95	533608	POTWNTP2	69	5.24
539674	BARBER 4	138	8.02	583490	GEN-2012-041	345	11.42	533307	PRAIRIE3	115	9.24
533850	BASICCH2	69	20.33	583750	GEN-2013-029	345	11.31	515576	RANCHRD7	345	12.91
532988	BELAIRE4	138	18.65	583850	GEN-2014-001	345	7.03	533306	READING3	115	6.38
533015	BENTLEY4	138	12.28	583990	GEN-2014-049	345	7.88	533427	REFINRY3	115	14.77
532986	BENTON 4	138	28.12	584010	GEN-2014-051	345	8.41	515544	RENFROW4	138	14.00
532791	BENTON 7	345	19.01	584450	GEN-2015-001	345	12.91	515543	RENFROW7	345	12.87
533030	BOEING 4	138	17.09	584470	GEN-2015-003	345	9.49	533416	RENO 3	115	29.75
515458	BORDER 7	345	5.11	533795	GILL E 2	69	33.33	532771	RENO 7	345	12.20
533032	BU11PON4	138	15.00	533044	GILL E 4	138	27.15	530686	RICE 6	230	5.01
531501	BUCKNER7	345	10.70	533046	GILL S 4	138	27.15	533832	RIPLEYM2	69	19.51
533626	BURLJCT2	69	4.90	533796	GILL W 2	69	33.33	533062	ROSEHIL4	138	31.02
533031	BURNSTP4	138	4.49	533045	GILL W 4	138	27.15	532794	ROSEHIL7	345	18.30
533583	BUTLER 2	69	12.75	533798	GILLJCT2	69	21.80	533434	SALTCRK3	115	9.64
532987	BUTLER 4	138	10.00	533799	GRANT 2	69	10.39	520409	SAND RDG_138	138	10.18
532989	BUTLERS4	138	10.00	515547	GRANTCO2	69	7.53	533063	SC10BEL4	138	9.57
515554	BVRCNTY7	345	16.00	515546	GRANTCO4	138	6.78	533377	SCHILNG3	115	10.65
532780	CANEYRV7	345	9.82	539679	GRTBEND6	230	8.39	533065	SG12COL4	138	22.62
532781	CANEYWF7	345	9.56	533011	HALSTDN4	138	9.47	530593	SMKYP1 6	230	6.05
533629	CC2SHAR2	69	4.58	533012	HALSTDS4	138	9.47	530599	SMKYP2 6	230	6.47
533630	CC3WEST2	69	4.49	533736	HALSTED2	69	10.65	530592	SMOKYHL6	230	6.97
533034	CENTENN4	138	16.29	539668	HARPER 4	138	5.56	533379	SO GATE3	115	10.80
533362	CHAPMAN3	115	10.45	533804	HAYSVLJ2	69	14.21	514803	SOONER 7	345	22.77
533587	CHASJCT2	69	9.89	533513	HEC 2	69	11.54	539695	SPEARVL6	230	12.81
533589	CHESNEY2	69	8.40	533419	HEC 3	115	26.74	531469	SPERVIL7	345	14.41
533786	CHISHLM2	69	17.73	533421	HEC GT 3	115	28.40	533380	SPRGCRK3	115	3.92
533035	CHISHLM4	138	22.34	533422	HEC U4 3	115	27.59	533067	SPRNGDL4	138	14.39
515477	CHSHLMV7	345	12.52	533369	HILSBOR3	115	2.59	539759	SPRVL 3	115	11.71
533413	CIRCLE 3	115	29.31	533805	HOOVERN2	69	32.33	533068	STEARMN4	138	19.68
532871	CIRCLE 6	230	10.64	533049	HOOVERN4	138	18.85	542968	STILWEL7	345	23.67
533414	CITIES 3	115	9.10	533050	HOOVERS4	138	18.85	533381	SUMMIT 3	115	17.66
539800	CLARKCOUNTY7	345	12.54	532765	HOYT 7	345	15.41	532873	SUMMIT 6	230	13.61
533036	CLEARWT4	138	17.07	515476	HUNTERS7	345	12.54	532773	SUMMIT 7	345	11.00
533037	COMOTAR4	138	18.35	530618	HUNTSVL3	115	4.05	532984	SUMNER 4	138	9.90
539658	CONCRD6	230	5.80	514796	IODINE-4	138	7.09	532856	SWISVAL6	230	21.38
533788	COWSKIN2	69	16.48	539809	IRONWOOD 1 7	345	13.93	532774	SWISVAL7	345	16.10
533038	COWSKIN4	138	19.51	539803	IRONWOOD7	345	13.93	532993	TALLGRS4	138	10.04
542977	CRAIG 7	345	20.77	532852	JEC 6	230	24.72	515407	TATONGA7	345	16.41
532981	CRESWLN4	138	8.05	532766	JEC N 7	345	23.67	533069	TCBURNS4	138	3.25
533506	DAVIS 2	69	7.70	514825	KAYWIND7	345	11.56	532985	TCROCK 4	138	5.25
533415	DAVIS 3	115	9.15	515394	KEENAN 4	138	9.05	532857	TECHILL6	230	11.23
533301	EAST ST3	115	9.19	530558	KNOLL 6	230	10.96	539804	THISTLE4	138	16.48
532801	ELKRVR17	345	9.17	542981	LACYGNE7	345	24.67	539801	THISTLE7	345	15.97
539805	ELMCREEK7	345	5.72	533053	LAKERDG4	138	19.03	533558	TIMBJCT2	69	8.01
539639	ELMCREK6	230	8.21	533304	LANG 3	115	14.37	532992	TIMBJCT4	138	5.61
533793	ELPASO 2	69	11.81	532769	LANG 7	345	16.59	533607	TOWTAPE2	69	5.68
533039	ELPASO 4	138	25.04	532800	LATHAMS7	345	10.37	525832	TUCO_INT 7	345	12.05
533417	EMCPHER3	115	15.33	532853	LAWHILL6	230	13.51	533455	TWR 33 3	115	12.63
532872	EMCPHER6	230	9.46	533812	LIN 2	69	9.69	533359	UNIONRG3	115	3.63
532768	EMPEC 7	345	16.79	533813	MACARTH2	69	22.53	532874	UNIONRG6	230	7.32
533040	EVANS N4	138	41.45	533054	MAIZE 4	138	23.27	532798	VIOLA 7	345	13.64
533041	EVANS S4	138	41.45	533391	MAIZEE 4	138	21.80	533075	VIOLA 4	138	20.63
533368	EXIDE J3	115	12.60	533390	MAIZEW 4	138	27.67	542965	W.GRDNR7	345	23.99

Table 4-5 (Continued)
Short Circuit Analysis for Study Project GEN-2015-024 and GEN-2015-025
(Tap Wichita – Thistle circuit 1&2)

Study Generators GEN-2015-025, GEN-2015-025											
Bus Number	Bus Name	Bus Voltage (kV)	Fault Current 3-LG (kA)	Bus Number	Bus Name	Bus Voltage (kV)	Fault Current 3-LG (kA)	Bus Number	Bus Name	Bus Voltage (kV)	Fault Current 3-LG (kA)
533042	FARBER 4	138	16.00	533426	MANVILE3	115	11.77	520205	WAKITA_138	138	5.53
539638	FLATRDG3	138	14.80	533516	MAPLE J2	69	7.39	532799	WAVERLY7	345	14.77
539631	FLATRWD3	138	9.76	515497	MATHWSN7	345	28.60	533604	WEAVER 2	69	11.63
533366	FLORENC3	115	3.39	533335	MCDOWEL3	115	17.78	532991	WEAVER 4	138	21.91
533043	FOWLER 4	138	16.42	532862	MCDOWEL6	230	6.86	542966	WGARDNR5	161	22.12
532792	FR2EAST7	345	6.41	533428	MCPHER 3	115	15.87	533439	WHEATLD3	115	8.96
532795	FR2WEST7	345	5.16	515569	MDFRDTP4	138	11.66	532796	WICHITA7	345	24.56
533328	FT JCT 3	115	14.64	533597	MIDIAN 2	69	12.34	533183	WM BROS3	115	10.13
579358	G07-062-HV-2	345	6.54	532990	MIDIAN 4	138	10.17	533438	WMCPHER3	115	15.91
560242	G11-017-TAP	345	10.15	539676	MILAN 4	138	3.51	533653	WOLFCRK2	69	5.91
562075	G11-051-TAP	345	16.71	539675	MILANTP4	138	6.55	532797	WOLFCRK7	345	15.97
560000	G11-14-TAP	345	14.39	533305	MORRIS 3	115	12.27	514714	WOODRNG4	138	17.74
583090	G1149&G1504	345	4.67	532863	MORRIS 6	230	13.36	514715	WOODRNG7	345	16.68
562476	G14-001-TAP	345	10.53	532770	MORRIS 7	345	12.55	514785	WOODWRD4	138	20.72
560031	G15-015-TAP	138	8.51	533742	MOUND 2	69	7.47	515376	WWRDEHV4	138	25.46
584660	G1524&G1525	345	5.11	533013	MOUND 4	138	7.94	515375	WWRDEHV7	345	20.32
560033	G1524&G1525T	345	19.53	533429	MOUNDRG3	115	9.75	533016	WWUPLNT4	138	8.96
582708	G-2011-008-1	345	9.00	539637	MRWYP16	230	7.58				
533336	GEARY 3	115	17.16	533529	MWIRNJ22	69	6.71				

Table 4-6
Short Circuit Analysis for Study Project GEN-2015-028

Study Generators GEN-2015-028											
Bus Number	Bus Name	Bus Voltage (kV)	Fault Current 3-LG (kA)	Bus Number	Bus Name	Bus Voltage (kV)	Fault Current 3-LG (kA)	Bus Number	Bus Name	Bus Voltage (kV)	Fault Current 3-LG (kA)
520837	BLACKWE2	69	5.82	514741	DEERCK 2	69	4.54	521013	NUMA 2	69	4.58
514755	BLACKWL2	69	8.52	560031	G15-015-TAP	138	8.51	514740	NUMAOGE2	69	4.58
515478	BLKWLWD2	69	4.89	515547	GRANTCO2	69	7.53	514764	NWKRKAT4	138	10.45
520871	BRAMAN 2	69	8.95	515546	GRANTCO4	138	6.78	529255	OMBLKWL2	69	8.22
514750	BRMAN 2	69	8.95	514754	KAYCOOP2	69	5.83	514728	SINCBLK2	69	7.17
514756	CHIKASI2	69	10.21	514760	KILDARE4	138	10.78	515509	SNCBLKT2	69	7.19
514757	CHIKASI4	138	9.14	514739	MEDFORD2	69	5.45	514752	TONKAWA2	69	4.86
514744	CHILOCO2	69	11.15	515528	NARDINS2	69	5.52	514761	WHEAGLE4	138	15.67
514719	CLYDE 2	69	4.58	521012	NEWKIRK2	69	5.59				
515581	COYOTE 4	138	8.37	514751	NEWKRKT2	69	5.59				

Table 4-7
Short Circuit Analysis for Study Project GEN-2015-030

Study Generator GEN-2015-030											
Bus Number	Bus Name	Bus Voltage (kV)	Fault Current 3-LG (kA)	Bus Number	Bus Name	Bus Voltage (kV)	Fault Current 3-LG (kA)	Bus Number	Bus Name	Bus Voltage (kV)	Fault Current 3-LG (kA)
300889	2BRIISTOW	69	9.36	579253	G07-21&14-02	345	13.58	509844	OWASOTP4	138	14.89
300927	2CLEVLND	69	9.72	579268	G07-44&14-03	345	9.13	509851	P&P WTP4	138	14.89
301430	2CLEVLNDXFMR	69	9.72	579272	G0744&1403HV	345	9.13	512749	PAWNSW4	138	9.73
300928	2DIXIE	69	5.35	562075	G11-051-TAP	345	16.71	515039	PAYNESB4	138	7.42
300929	2FAIRFAX	69	4.84	562423	G13-028-TAP	345	25.84	514707	PERRY 4	138	10.86
300936	2MANFORD	69	6.21	560389	GEN-2010-055	138	31.10	514864	PIEDMNT4	138	21.69
300943	2SILVCTY	69	10.12	583110	GEN-2011-051	345	16.71	514829	PINE ST4	138	11.49
301413	2WILLIAMS	69	11.60	583490	GEN-2012-041	345	11.42	510907	PITTSB-7	345	13.21
300945	2YALE	69	5.14	583740	GEN-2013-028	345	25.84	509863	PPTAP 4	138	10.27
509837	46ST--E4	138	14.00	583750	GEN-2013-029	345	11.31	514851	QUAILCK4	138	28.13
300137	4BRISTOW	138	7.16	584170	GEN-2014-064	138	9.33	509782	R.S.S.-7	345	29.76
300138	4CLEVLND	138	16.44	584450	GEN-2015-001	345	12.91	515576	RANCHRD7	345	12.91
301429	4CLEVLNDXFMR	138	16.44	584470	GEN-2015-003	345	9.49	514909	REDBUD 7	345	24.18
300139	4FAIRFAX	138	7.49	584700	GEN-2015-029	345	9.77	515544	RENFROW4	138	14.00
300145	4FISHER	138	12.23	584690	GEN-2015-030	345	17.67	515543	RENFROW7	345	12.87
300131	4FISHERTP	138	14.45	515800	GRACMNT7	345	14.47	515461	RNDBARN4	138	38.35
301425	4GLENCOE	138	9.20	515546	GRANTCO4	138	6.78	533062	ROSEHIL4	138	31.02
300996	4JAVINE	138	6.52	512656	GRDA1 5	161	41.53	532794	ROSEHIL7	345	18.30
300844	4RAMSEY	138	9.64	512650	GRDA1 7	345	26.28	520409	SAND RDG_138	138	10.18
301369	4REMNGTON	138	7.86	514863	HAYMAKR4	138	25.30	509871	SAPLPRD4	138	32.04
300165	4SFORKK	138	4.34	514774	HENESEY4	138	7.15	509870	SAPLPRD7	345	20.75
301339	4SFORKKTP	138	6.81	515476	HUNTERS7	345	12.54	514895	SARA 4	138	18.41
300140	4SILVCTY	138	15.55	514790	IMO 4	138	10.72	515044	SEMINOL4	138	57.59
300146	4SKIAETP	138	6.90	514820	JENSENT4	138	14.92	515045	SEMINOL7	345	28.12
300141	4STILWTR	138	11.52	514906	JNSKAMO4	138	20.14	509812	SHEFFD-4	138	25.22
300686	4WOODY	138	7.61	514825	KAYWIND7	345	11.56	510432	SHIDWFC4	138	5.62
300740	7SPORTSMAN	345	23.75	514834	KETCH 4	138	25.90	512726	SILVCTYGR4	138	15.40
514907	ARCADIA4	138	40.30	514828	KETCHTP4	138	25.47	509884	SKIATOK4	138	10.41
514908	ARCADIA7	345	24.98	505610	KEYSTON4	138	21.27	514852	SLVRLAK4	138	31.14
532986	BENTON 4	138	28.12	514760	KILDARE4	138	10.78	514799	SNRPMP 4	138	11.22
532791	BENTON 7	345	19.01	515600	KNGFSHR7	345	11.02	514798	SNRPMPT4	138	20.29
514854	BRADEN 4	138	30.07	515514	KNIPE 4	138	4.92	514730	SO4TH 2	69	13.10
514815	BRECKNR4	138	9.96	532800	LATHAMS7	345	10.37	514731	SO4TH 4	138	14.10
515605	CANADN7	345	11.32	515373	LBRTYLK4	138	13.34	514802	SOONER 4	138	31.30
532780	CANEYRV7	345	9.82	515465	LGARBER4	138	20.77	514803	SOONER 7	345	22.77
509839	CDC-ET 4	138	18.48	514873	LNEOAK 4	138	25.96	514881	SPRNGCK7	345	21.36
509842	CDC-WT 4	138	19.20	514770	MARLNDT4	138	10.81	515512	SPVALLY4	138	8.38
515477	CHSHLMV7	345	12.52	521006	MARSHAL4	138	7.66	514758	STDBEAR4	138	13.86
514898	CIMARON4	138	40.88	514733	MARSHL 4	138	7.69	533068	STEARMN4	138	19.68
514901	CIMARON7	345	30.05	515497	MATHWSN7	345	28.60	515011	STILWTR4	138	12.45
509745	CLARKSV7	345	19.71	515009	MCELROY4	138	12.47	509895	T.NO.2-4	138	34.10
512694	CLEVLND7	345	14.51	515444	MCNOWND7	345	15.92	509817	T.NO.--4	138	34.16
515402	CONBLKT2	69	15.58	515569	MDFRDTP4	138	11.66	509852	T.NO.--7	345	23.17
514753	CONORTH4	138	13.52	514704	MILLERT4	138	20.24	515407	TATONGA7	345	16.41
514748	CONTEMP4	138	13.47	514801	MINCO 7	345	15.97	512750	TONECE7	345	15.86
514705	COWCRK 2	69	4.04	515466	MITCHSB4	138	20.71	511425	TUTCONT4	138	10.63
514706	COWCRK 4	138	11.15	515549	MNCWND37	345	11.08	515181	UNVRSTY4	138	12.43
515377	CRESENT4	138	7.06	515447	MORISNT4	138	13.36	532798	VIOLA 7	345	13.64
515448	CRSRDSW7	345	11.58	515006	MORRISN4	138	13.33	533075	VIOLA 4	138	20.63
514827	CTNWOOD4	138	16.19	515224	MUSKOGE7	345	28.52	521100	WARREN 4	138	8.60
515542	CWBOYHT4	138	7.84	510396	N.E.S.-4	138	35.42	514710	WAUKOMI4	138	9.34
514894	CZECHAL4	138	25.97	510406	N.E.S.-7	345	18.42	514711	WAUKOTP4	138	14.53
510379	DELWARE4	138	10.88	532793	NEOSHO 7	345	16.22	532799	WAVERLY7	345	14.77
510380	DELWARE7	345	11.37	512731	NORTHTP4	138	9.89	532991	WEAVER 4	138	21.91
515400	DMANCRK4	138	8.04	514879	NORTWST4	138	41.57	510376	WEBBTAP4	138	8.06
515412	DMNCRKT4	138	13.68	514880	NORTWST7	345	29.44	509823	WED-TAP4	138	18.86
514933	DRAPER 4	138	39.13	515471	NW164TH4	138	34.21	509757	WEKIWA-4	138	31.10
514934	DRAPER 7	345	20.97	509836	OEC 7	345	25.82	509755	WEKIWA-7	345	18.41
532801	ELKRVR17	345	9.17	529241	OMMORANT	69	12.32	514768	WF KAY 2	69	2.95
533039	ELPASO 4	138	25.04	529249	OMWW	69	13.35	514761	WHEAGLE4	138	15.67
514819	EL-RENO4	138	15.08	509806	ONETA--4	138	46.96	532796	WICHITA7	345	24.56

Table 4-7 (Continued)
Short Circuit Analysis for Study Project GEN-2015-030

Study Generator GEN-2015-030											
Bus Number	Bus Name	Bus Voltage (kV)	Fault Current 3-LG (kA)	Bus Number	Bus Name	Bus Voltage (kV)	Fault Current 3-LG (kA)	Bus Number	Bus Name	Bus Voltage (kV)	Fault Current 3-LG (kA)
510377	FAIRFXT4	138	8.10	509807	ONETA--7	345	26.11	533653	WOLFCRK2	69	5.91
514703	FAIRMNT4	138	10.53	515621	OPENSKY7	345	11.59	532797	WOLFCRK7	345	15.97
514712	FAIRMON4	138	8.21	514743	OSAGE 4	138	16.56	514714	WOODRNG4	138	17.74
532792	FR2EAST7	345	6.41	514742	OSGE 2	69	17.57	514715	WOODRNG7	345	16.68
514709	FRMNTAP4	138	16.42	514737	OTOE 4	138	16.16	514713	WRVALLY4	138	8.60
515610	FSHRTAP7	345	15.94	514708	OTTER 4	138	9.40	515375	WWRDEHV7	345	20.32

Table 4-8
Short Circuit Analysis for Study Project ASGI-2015-004

Study Generator ASGI-2015-004											
Bus Number	Bus Name	Bus Voltage (kV)	Fault Current 3-LG (kA)	Bus Number	Bus Name	Bus Voltage (kV)	Fault Current 3-LG (kA)	Bus Number	Bus Name	Bus Voltage (kV)	Fault Current 3-LG (kA)
300739	7BLACKBERRY	345	12.25	510379	DELWARE4	138	10.88	533021	NEOSHO 4	138	23.17
584740	ASGI2015-004	69	8.59	510380	DELWARE7	345	11.37	532937	NEOSHO 5	161	22.10
510391	BV-SE--4	138	12.02	512734	FARML 4	138	7.98	532793	NEOSHO 7	345	16.22
532780	CANEYRV7	345	9.82	542981	LACYGNE7	345	24.67	509807	ONETA--7	345	26.11
512735	COFCTY2	69	8.59	533003	LIBERTY4	138	7.14	510378	SCOFCTY4	138	8.35
510422	COFFEYT4	138	9.63	533004	MONTGOM4	138	6.65	509852	T.NO.--7	345	23.17
533688	DEARING2	69	7.38	510406	N.E.S.-7	345	18.42				
533002	DEARING4	138	8.98	510386	NBVILLE4	138	9.22				

SECTION 5: POWER FACTOR ANALYSIS

The objective of this task is to quantify the power factor at the point of interconnection for the wind farms during base case and system contingencies. SPP transmission planning practice requires interconnecting generation projects to maintain the power factor (pf) at the Point of Interconnection (POI) within +/- 0.95 pf for system intact conditions and for post-contingency conditions. This is analyzed by having the wind farm maintain a prescribed voltage schedule at the point of interconnection of 1.0 p.u. voltage, or if the pre-project voltage is higher than 1.0 p.u., to maintain the pre-project voltage schedule.

The 2015 Summer Peak, 2015 Winter Peak, and 2025 Summer Peak power flows provided by SPP were examined prior to the Power Factor Analysis to ensure they contained the proposed study project modeled at 100% of the nameplate rating and any previously queued projects listed in Table 2-2. There was no suspect power flow data in the study area. The proposed study project and any previously queued projects at the same point of interconnection were turned off during the power factor analysis. The wind farm(s) were then replaced by a generator modeled at the high side bus with the same real power (MW) capability as the wind farm(s) and open limits for the reactive power set points (Mvar). The generator was set to hold the POI scheduled bus voltage. All N-1, three-phase fault contingencies from Table 2-3 were then applied and the reactive power required to maintain the bus voltage was recorded.

5.1 Approach

GEN-2015-001 and GEN-2012-041 were disabled and the generators were placed at the study project's point of interconnect bus. The generators were modeled with PGEN = 200.0 MW for GEN-2015-001, PGEN = 85.269 MW for GEN-2012-041 during Summer Peak conditions, and PGEN=121.488 MW for GEN-2012-041 during Winter Peak conditions. QMin = -9999 Mvar and QMax = 9999 Mvar for both generator for both conditions. All buses and transformers connected from the study project's POI bus to the generators were disabled. The scheduled voltage was set to 1.01 p.u. for the 2015 Summer Peak and 2025 Summer Peak conditions and to 1.00 p.u. for the 2015 Winter Peak conditions.

GEN-2015-003, GEN-2013-029 Unit 1, and GEN-2013-029 Unit 2 were disabled and the generators were placed at the study project's point of interconnect bus. The generators were modeled with PGEN = 200.0 MW for GEN-2015-003, PGEN = 151.8 MW for GEN-2013-029 Unit 1, and PGEN = 148.0 MW for GEN-2013-029 Unit 2. QMin = -9999 Mvar and QMax = 9999 Mvar for all generators. All buses and transformers connected from the study project's POI bus to the generators were disabled. The scheduled voltage was set to 1.00 p.u. for all study years.

GEN-2015-015 was disabled and a generator was placed at the study project's point of interconnect bus. The generator was modeled with PGEN = 154.6 MW, QMin = -9999 Mvar, and QMax = 9999 Mvar. All buses and transformers connected from the study project's POI bus to GEN-2015-015 were disabled. The scheduled voltage was set to 1.00 p.u. for all study years.

GEN-2015-016 was disabled and a generator was placed at the study project's point of interconnect bus. The generator was modeled with PGEN = 200.0 MW, QMin = -9999 Mvar, and QMax = 9999 Mvar. All buses and transformers connected from the study project's POI bus to GEN-2015-016 were disabled. The scheduled voltage was set to 1.00 p.u. for all study years.

GEN-2015-024 and GEN-2015-025 were disabled and the generators were placed at the study project's point of interconnect bus. The generators were modeled with PGEN=220.0 MW, QMin = -9999 Mvar, and QMax = 9999 Mvar. All buses and transformers connected from the study project's POI bus to the generators were disabled. The scheduled voltage was set to 1.01 p.u. for the 2015 Summer Peak and 2025 Summer Peak conditions and to 1.00 p.u. for the 2015 Winter Peak conditions.

GEN-2015-028 was disabled and a generator was placed at the study project's point of interconnect bus. The generator was modeled with PGEN = 62.79 MW, QMin = -9999 Mvar, and QMax = 9999 Mvar. All buses and transformers connected from the study project's POI bus to GEN-2015-028 were disabled. The scheduled voltage was set to 1.03 p.u. for the 2015

Summer Peak conditions and 1.02 p.u. for the 2015 Winter Peak and 2025 Summer Peak conditions.

GEN-2015-030 was disabled and the generator was placed at the study project's point of interconnect bus. The generator was modeled with PGEN = 200.1 MW, QMin = -9999 Mvar, and QMax = 9999 Mvar. All buses and transformers connected from the study project's POI bus to GEN-2015-030 were disabled. The scheduled voltage was set to 1.01 p.u. for all study years.

5.2 Power Factor Analysis Results

The power factor was calculated for the 2015 Summer Peak, 2015 Winter Peak, and 2025 Summer Peak condition. The following tables show the power factor results for the study generators:

- Table 5-1: Power Factor Analysis for GEN-2015-001
- Table 5-2: Power Factor Analysis for GEN-2015-003
- Table 5-3: Power Factor Analysis for GEN-2015-015
- Table 5-4: Power Factor Analysis for GEN-2015-016
- Table 5-5: Power Factor Analysis for GEN-2015-024
- Table 5-6: Power Factor Analysis for GEN-2015-025
- Table 5-7: Power Factor Analysis for GEN-2015-028
- Table 5-8: Power Factor Analysis for GEN-2015-030

Note that a positive Q (Mvar) output illustrates that the generator is absorbing reactive power from the system, implying a leading power factor; a negative Q (Mvar) illustrates that the generator is supplying reactive power to the system, implying a lagging power factor.

Table 5-1
Power Factor Analysis: GEN-2015-001

Cont. No.	Case	2015 Summer Peak			2015 Winter Peak			2025 Summer Peak		
		Power Factor		Q (MVAR)	Power Factor		Q (MVAR)	Power Factor		Q (MVAR)
0	Base	0.975	Leading	45.51	0.990	Leading	28.64	0.989	Leading	29.97
1	FLT01-3PH	0.996	Leading	16.85	0.981	Leading	39.98	0.996	Leading	18.81
2	FLT02-3PH	0.999	Leading	6.36	0.986	Leading	34.31	0.999	Leading	8.68
3	FLT03-3PH	0.975	Leading	45.51	0.990	Leading	28.64	0.989	Leading	29.97
4	FLT04-3PH	0.968	Leading	52.13	0.980	Leading	40.68	0.987	Leading	31.99
5	FLT05-3PH	0.981	Leading	39.98	0.997	Leading	16.09	0.994	Leading	21.91
6	FLT06-3PH	0.975	Leading	45.51	0.993	Leading	23.40	0.990	Leading	28.36
7	FLT07-3PH	0.975	Leading	45.51	0.990	Leading	28.64	0.989	Leading	29.97
8	FLT08-3PH	0.982	Leading	38.65	0.993	Leading	24.34	0.993	Leading	24.04
9	FLT09-3PH	0.976	Leading	45.10	0.990	Leading	28.17	0.989	Leading	29.69
10	FLT10-3PH	0.979	Leading	41.53	0.994	Leading	22.52	0.991	Leading	26.90
11	FLT11-3PH	0.975	Leading	45.14	0.991	Leading	26.59	0.989	Leading	30.07
12	FLT12-3PH	0.980	Leading	40.64	1.000	Leading	3.87	0.989	Leading	29.99
13	FLT13-3PH	0.957	Leading	60.67	0.989	Leading	29.25	0.989	Leading	30.49
14	FLT14-3PH	0.977	Leading	43.76	0.991	Leading	26.75	0.990	Leading	28.35
15	FLT15-3PH	0.977	Leading	43.53	0.991	Leading	26.38	0.990	Leading	28.38
16	FLT16-3PH	0.976	Leading	44.44	0.991	Leading	27.39	0.990	Leading	29.04
17	FLT17-3PH	N/A	N/A	N/A	N/A	N/A	N/A	0.99	Leading	26.04
18	FLT18-3PH	0.976	Leading	44.87	0.990	Leading	28.29	0.989	Leading	29.63
19	FLT19-3PH	0.975	Leading	45.50	0.990	Leading	28.57	0.989	Leading	29.95
20	FLT20-3PH	0.976	Leading	44.95	0.990	Leading	28.41	0.989	Leading	29.62
21	FLT21-3PH	0.976	Leading	44.68	0.990	Leading	27.94	0.989	Leading	29.88
22	FLT22-3PH	0.976	Leading	44.86	0.991	Leading	27.60	0.989	Leading	29.52
23	FLT23-3PH	0.976	Leading	45.05	0.990	Leading	28.15	0.989	Leading	29.66
24	FLT24-3PH	0.976	Leading	45.05	0.990	Leading	28.33	0.989	Leading	29.34
25	FLT25-3PH	0.975	Leading	45.36	0.990	Leading	28.34	0.989	Leading	29.85
26	FLT26-3PH	0.975	Leading	45.14	0.990	Leading	28.78	0.989	Leading	29.72
27	FLT27-3PH	0.975	Leading	45.52	0.990	Leading	28.60	0.989	Leading	29.97
28	FLT28-3PH	0.975	Leading	45.48	0.990	Leading	28.63	0.989	Leading	29.95
29	FLT29-3PH	0.975	Leading	45.63	0.990	Leading	28.73	0.989	Leading	30.11
30	FLT30-3PH	0.975	Leading	46.01	0.990	Leading	28.92	0.989	Leading	30.47
31	FLT31-3PH	0.978	Leading	42.96	0.991	Leading	26.70	0.992	Leading	26.15
32	FLT32-3PH	0.975	Leading	45.69	0.990	Leading	28.78	0.989	Leading	30.12
33	FLT33-3PH	0.977	Leading	43.54	0.992	Leading	25.63	0.992	Leading	25.79
34	FLT34-3PH	0.972	Leading	48.65	0.989	Leading	29.78	0.986	Leading	33.82
35	FLT35-3PH	0.975	Leading	45.44	0.990	Leading	28.87	0.989	Leading	29.94
36	FLT36-3PH	0.975	Leading	45.33	0.990	Leading	28.28	0.989	Leading	29.80
37	FLT37-3PH	0.975	Leading	45.81	0.990	Leading	29.14	0.989	Leading	30.10
38	FLT38-3PH	0.976	Leading	44.30	0.991	Leading	27.07	0.989	Leading	29.29
39	FLT39-3PH	0.977	Leading	43.77	0.989	Leading	30.20	0.990	Leading	29.05
40	FLT40-3PH	0.975	Leading	45.48	0.990	Leading	28.59	0.989	Leading	29.91

Table 5-1 (Continued)
Power Factor Analysis: GEN-2015-001

Cont. No.	Case	2015 Summer Peak			2015 Winter Peak			2025 Summer Peak		
		Power Factor		Q (MVAR)	Power Factor		Q (MVAR)	Power Factor		Q (MVAR)
41	FLT41-3PH	0.975	Leading	45.43	0.990	Leading	28.62	0.989	Leading	29.88
42	FLT42-3PH	0.975	Leading	45.51	0.990	Leading	28.58	0.989	Leading	29.98
43	FLT43-3PH	0.975	Leading	45.48	0.990	Leading	28.62	0.989	Leading	29.98
44	FLT44-3PH	0.975	Leading	45.56	0.990	Leading	28.64	0.989	Leading	30.01
45	FLT45-3PH	0.975	Leading	45.51	0.990	Leading	28.60	0.989	Leading	29.97
46	FLT46-3PH	0.975	Leading	45.56	0.990	Leading	28.74	0.989	Leading	30.13
47	FLT47-3PH	0.977	Leading	43.81	0.995	Leading	19.47	0.990	Leading	28.72
48	FLT48-3PH	0.975	Leading	45.36	0.990	Leading	28.60	0.989	Leading	29.91
49	FLT49-3PH	0.975	Leading	45.51	0.990	Leading	28.64	0.989	Leading	29.97
50	FLT50-3PH	0.975	Leading	45.54	0.990	Leading	28.66	0.989	Leading	30.03
51	FLT51-3PH	0.975	Leading	45.18	0.990	Leading	28.15	0.989	Leading	29.80
52	FLT52-3PH	0.975	Leading	45.18	0.990	Leading	28.15	0.989	Leading	29.80
53	FLT53-3PH	0.977	Leading	44.13	0.991	Leading	27.51	0.990	Leading	28.96
54	FLT54-3PH	0.975	Leading	45.20	0.990	Leading	28.35	0.989	Leading	29.63
55	FLT55-3PH	0.976	Leading	44.99	0.990	Leading	28.25	0.989	Leading	29.57
56	FLT56-3PH	0.977	Leading	43.77	0.991	Leading	27.31	0.989	Leading	29.45
57	FLT57-3PH	0.976	Leading	44.18	0.991	Leading	27.03	0.989	Leading	29.62

Table 5-2
Power Factor Analysis: GEN-2015-003

Cont. No.	Case	2015 Summer Peak			2015 Winter Peak			2025 Summer Peak		
		Power Factor		Q (MVAR)	Power Factor		Q (MVAR)	Power Factor		Q (MVAR)
0	Base	0.990	Leading	27.83	0.992	Lagging	-25.43	0.987	Leading	32.13
1	FLT01-3PH	0.990	Leading	28.12	0.991	Lagging	-26.50	0.987	Leading	32.16
2	FLT02-3PH	0.991	Leading	27.48	0.991	Lagging	-27.69	0.989	Leading	30.39
3	FLT03-3PH	0.990	Leading	27.83	0.992	Lagging	-25.43	0.987	Leading	32.13
4	FLT04-3PH	0.992	Leading	26.12	0.990	Lagging	-28.16	0.988	Leading	31.33
5	FLT05-3PH	0.991	Leading	27.10	0.991	Lagging	-27.11	0.989	Leading	30.50
6	FLT06-3PH	0.991	Leading	27.67	0.992	Lagging	-26.23	0.988	Leading	31.81
7	FLT07-3PH	0.990	Leading	27.83	0.992	Lagging	-25.43	0.987	Leading	32.13
8	FLT08-3PH	0.993	Leading	24.08	0.989	Lagging	-29.28	0.990	Leading	28.08
9	FLT09-3PH	0.996	Leading	17.62	0.984	Lagging	-36.49	0.992	Leading	26.18
10	FLT10-3PH	1.000	Leading	5.02	0.973	Lagging	-47.20	0.999	Leading	8.66
11	FLT11-3PH	0.993	Leading	23.61	0.994	Leading	22.01	0.995	Leading	20.49
12	FLT12-3PH	0.979	Lagging	-41.79	0.898	Lagging	-98.03	1.000	Leading	1.52
13	FLT13-3PH	0.995	Leading	19.08	0.991	Lagging	-27.24	0.989	Leading	29.55
14	FLT14-3PH	0.992	Leading	24.82	0.990	Lagging	-29.14	0.989	Leading	29.73
15	FLT15-3PH	0.993	Leading	23.97	0.989	Lagging	-30.28	0.989	Leading	29.30
16	FLT16-3PH	0.991	Leading	26.49	0.991	Lagging	-27.28	0.988	Leading	30.99
17	FLT17-3PH	N/A	N/A	N/A	N/A	N/A	N/A	0.989	Leading	29.431
18	FLT18-3PH	0.995	Leading	19.99	0.987	Lagging	-32.91	0.988	Leading	31.84
19	FLT19-3PH	0.991	Leading	27.42	0.992	Lagging	-24.67	0.988	Leading	31.85
20	FLT20-3PH	0.994	Leading	21.21	0.988	Lagging	-31.35	0.990	Leading	27.81
21	FLT21-3PH	0.990	Leading	28.80	0.993	Lagging	-24.48	0.987	Leading	32.25
22	FLT22-3PH	0.993	Leading	24.33	0.989	Lagging	-29.95	0.990	Leading	29.08
23	FLT23-3PH	0.994	Leading	21.85	0.987	Lagging	-33.10	0.989	Leading	29.73
24	FLT24-3PH	0.991	Leading	27.66	0.992	Lagging	-25.53	0.987	Leading	31.94
25	FLT25-3PH	0.990	Leading	27.86	0.992	Lagging	-25.47	0.987	Leading	32.14
26	FLT26-3PH	0.990	Leading	27.78	0.992	Lagging	-25.38	0.987	Leading	32.06
27	FLT27-3PH	0.990	Leading	27.83	0.992	Lagging	-25.45	0.987	Leading	32.13
28	FLT28-3PH	0.990	Leading	27.83	0.992	Lagging	-25.43	0.987	Leading	32.13
29	FLT29-3PH	0.990	Leading	27.84	0.992	Lagging	-25.43	0.987	Leading	32.15
30	FLT30-3PH	0.990	Leading	27.87	0.992	Lagging	-25.42	0.987	Leading	32.20
31	FLT31-3PH	0.991	Leading	27.21	0.992	Lagging	-25.84	0.988	Leading	31.21
32	FLT32-3PH	0.990	Leading	27.87	0.992	Lagging	-25.42	0.987	Leading	32.17
33	FLT33-3PH	0.993	Leading	24.49	0.988	Lagging	-30.93	0.992	Leading	25.92
34	FLT34-3PH	0.986	Leading	33.37	0.995	Lagging	-19.94	0.983	Leading	37.59
35	FLT35-3PH	0.990	Leading	27.84	0.992	Lagging	-25.00	0.987	Leading	32.14
36	FLT36-3PH	0.991	Leading	27.56	0.992	Lagging	-26.00	0.988	Leading	31.90
37	FLT37-3PH	0.991	Leading	27.44	0.992	Lagging	-25.42	0.988	Leading	31.67
38	FLT38-3PH	0.992	Leading	25.75	0.990	Lagging	-28.35	0.988	Leading	30.90
39	FLT39-3PH	0.991	Leading	27.63	0.992	Lagging	-25.55	0.988	Leading	31.75
40	FLT40-3PH	0.992	Leading	26.05	0.991	Lagging	-27.06	0.989	Leading	30.06

Table 5-2 (Continued)
Power Factor Analysis: GEN-2015-003

Cont. No.	Case	2015 Summer Peak			2015 Winter Peak			2025 Summer Peak		
		Power Factor		Q (MVAR)	Power Factor		Q (MVAR)	Power Factor		Q (MVAR)
41	FLT41-3PH	0.992	Leading	25.23	0.990	Lagging	-28.29	0.989	Leading	30.09
42	FLT42-3PH	0.990	Leading	28.57	0.992	Lagging	-25.31	0.987	Leading	33.05
43	FLT43-3PH	0.990	Leading	27.95	0.993	Lagging	-24.59	0.987	Leading	33.00
44	FLT44-3PH	0.990	Leading	28.32	0.992	Lagging	-25.27	0.987	Leading	32.60
45	FLT45-3PH	0.990	Leading	27.78	0.992	Lagging	-25.76	0.987	Leading	32.13
46	FLT46-3PH	0.990	Leading	27.89	0.992	Lagging	-24.79	0.987	Leading	33.13
47	FLT47-3PH	0.991	Leading	26.39	0.993	Lagging	-23.85	0.992	Leading	25.58
48	FLT48-3PH	0.990	Leading	28.01	0.991	Lagging	-26.55	0.987	Leading	33.14
49	FLT49-3PH	0.990	Leading	27.83	0.992	Lagging	-25.43	0.987	Leading	32.13
50	FLT50-3PH	0.990	Leading	27.84	0.992	Lagging	-25.43	0.987	Leading	32.15
51	FLT51-3PH	0.990	Leading	27.77	0.992	Lagging	-25.55	0.987	Leading	32.08
52	FLT52-3PH	0.990	Leading	27.77	0.992	Lagging	-25.55	0.987	Leading	32.08
53	FLT53-3PH	0.991	Leading	27.70	0.992	Lagging	-25.58	0.988	Leading	31.91
54	FLT54-3PH	0.990	Leading	27.81	0.992	Lagging	-25.48	0.987	Leading	32.03
55	FLT55-3PH	0.991	Leading	27.76	0.992	Lagging	-25.50	0.987	Leading	32.02
56	FLT56-3PH	0.990	Leading	28.18	0.992	Lagging	-25.25	0.987	Leading	32.21
57	FLT57-3PH	0.990	Leading	28.00	0.992	Lagging	-25.44	0.987	Leading	32.13

Table 5-3
Power Factor Analysis: GEN-2015-015

Cont. No.	Case	2015 Summer Peak			2015 Winter Peak			2025 Summer Peak		
		Power Factor		Q (MVAR)	Power Factor		Q (MVAR)	Power Factor		Q (MVAR)
0	Base	0.996	Leading	14.67	0.999	Leading	6.05	0.997	Leading	12.74
1	FLT01-3PH	0.995	Leading	14.89	0.999	Leading	5.37	0.997	Leading	12.84
2	FLT02-3PH	0.996	Leading	13.66	1.000	Leading	3.76	0.997	Leading	11.34
3	FLT03-3PH	0.996	Leading	14.67	0.999	Leading	6.05	0.997	Leading	12.74
4	FLT04-3PH	0.996	Leading	14.20	0.999	Leading	5.52	0.997	Leading	12.49
5	FLT05-3PH	0.996	Leading	14.06	1.000	Leading	4.65	0.997	Leading	11.87
6	FLT06-3PH	0.996	Leading	14.65	0.999	Leading	5.54	0.997	Leading	12.63
7	FLT07-3PH	0.996	Leading	14.67	0.999	Leading	6.05	0.997	Leading	12.74
8	FLT08-3PH	0.997	Leading	12.83	1.000	Leading	4.82	0.998	Leading	10.80
9	FLT09-3PH	0.998	Leading	10.61	1.000	Leading	0.50	0.998	Leading	10.58
10	FLT10-3PH	1.000	Lagging	-2.80	0.987	Lagging	-25.66	1.000	Lagging	-0.68
11	FLT11-3PH	0.997	Leading	11.67	0.993	Leading	18.90	0.999	Leading	6.68
12	FLT12-3PH	0.946	Lagging	-53.08	0.959	Lagging	-45.62	0.991	Lagging	-20.81
13	FLT13-3PH	0.997	Leading	11.88	0.999	Leading	5.11	0.997	Leading	11.80
14	FLT14-3PH	0.996	Leading	13.55	0.999	Leading	5.19	0.997	Leading	11.90
15	FLT15-3PH	0.996	Leading	13.22	1.000	Leading	4.77	0.997	Leading	11.82
16	FLT16-3PH	0.996	Leading	14.14	0.999	Leading	5.30	0.997	Leading	12.31
17	FLT17-3PH	N/A	N/A	N/A	N/A	N/A	N/A	0.998	Leading	10.57
18	FLT18-3PH	0.997	Leading	12.71	0.991	Leading	21.30	0.999	Lagging	-6.25
19	FLT19-3PH	0.995	Leading	15.01	0.995	Leading	14.83	0.997	Leading	11.70
20	FLT20-3PH	0.999	Leading	8.47	1.000	Lagging	-0.30	0.998	Leading	10.43
21	FLT21-3PH	0.991	Leading	21.44	0.997	Leading	11.49	0.996	Leading	13.76
22	FLT22-3PH	1.000	Leading	1.75	0.997	Lagging	-11.15	1.000	Leading	1.74
23	FLT23-3PH	0.999	Leading	6.18	0.999	Lagging	-4.94	0.998	Leading	9.15
24	FLT24-3PH	0.996	Leading	14.58	0.999	Leading	6.00	0.997	Leading	12.68
25	FLT25-3PH	0.996	Leading	14.67	0.999	Leading	5.99	0.997	Leading	12.71
26	FLT26-3PH	0.996	Leading	14.59	0.999	Leading	6.07	0.997	Leading	12.69
27	FLT27-3PH	0.996	Leading	14.67	0.999	Leading	6.05	0.997	Leading	12.75
28	FLT28-3PH	0.996	Leading	14.66	0.999	Leading	6.05	0.997	Leading	12.74
29	FLT29-3PH	0.996	Leading	14.67	0.999	Leading	6.06	0.997	Leading	12.75
30	FLT30-3PH	0.996	Leading	14.71	0.999	Leading	6.08	0.997	Leading	12.79
31	FLT31-3PH	0.996	Leading	14.34	0.999	Leading	5.81	0.997	Leading	12.39
32	FLT32-3PH	0.996	Leading	14.69	0.999	Leading	6.06	0.997	Leading	12.76
33	FLT33-3PH	0.996	Leading	13.41	1.000	Leading	4.50	0.998	Leading	10.59
34	FLT34-3PH	0.994	Leading	16.62	0.999	Leading	7.44	0.996	Leading	14.67
35	FLT35-3PH	0.996	Leading	14.66	0.999	Leading	6.21	0.997	Leading	12.74
36	FLT36-3PH	0.996	Leading	14.57	0.999	Leading	5.83	0.997	Leading	12.66
37	FLT37-3PH	0.996	Leading	14.49	0.999	Leading	6.10	0.997	Leading	12.68
38	FLT38-3PH	0.996	Leading	13.90	0.999	Leading	4.95	0.997	Leading	12.35
39	FLT39-3PH	0.996	Leading	14.54	0.999	Leading	5.31	0.997	Leading	12.51
40	FLT40-3PH	0.996	Leading	13.55	1.000	Leading	4.88	0.997	Leading	11.22

Table 5-3 (Continued)
Power Factor Analysis: GEN-2015-015

Cont. No.	Case	2015 Summer Peak			2015 Winter Peak			2025 Summer Peak		
		Power Factor		Q (MVAR)	Power Factor		Q (MVAR)	Power Factor		Q (MVAR)
41	FLT41-3PH	0.997	Leading	12.73	1.000	Leading	3.14	0.998	Leading	9.75
42	FLT42-3PH	0.995	Leading	15.74	0.999	Leading	5.77	0.996	Leading	14.05
43	FLT43-3PH	0.996	Leading	13.80	0.999	Leading	5.75	0.997	Leading	12.65
44	FLT44-3PH	0.993	Leading	18.60	0.999	Leading	8.29	0.995	Leading	16.18
45	FLT45-3PH	0.995	Leading	15.64	0.999	Leading	5.66	0.996	Leading	13.55
46	FLT46-3PH	0.993	Leading	18.26	0.996	Leading	14.11	0.988	Leading	24.59
47	FLT47-3PH	0.996	Leading	12.99	1.000	Leading	4.46	0.998	Leading	9.97
48	FLT48-3PH	0.996	Leading	14.34	0.999	Leading	6.49	0.997	Leading	12.57
49	FLT49-3PH	0.996	Leading	14.67	0.999	Leading	6.05	0.997	Leading	12.74
50	FLT50-3PH	0.996	Leading	14.67	0.999	Leading	6.06	0.997	Leading	12.76
51	FLT51-3PH	0.996	Leading	14.55	0.999	Leading	5.84	0.997	Leading	12.66
52	FLT52-3PH	0.996	Leading	14.55	0.999	Leading	5.84	0.997	Leading	12.66
53	FLT53-3PH	0.996	Leading	14.51	0.999	Leading	5.92	0.997	Leading	12.57
54	FLT54-3PH	0.996	Leading	14.55	0.999	Leading	5.98	0.997	Leading	12.57
55	FLT55-3PH	0.996	Leading	14.60	0.999	Leading	5.99	0.997	Leading	12.68
56	FLT56-3PH	0.996	Leading	14.58	0.999	Leading	5.90	0.997	Leading	12.65
57	FLT57-3PH	0.996	Leading	14.60	0.999	Leading	5.86	0.997	Leading	12.69

Table 5-4
Power Factor Analysis: GEN-2015-016

Cont. No.	Case	2015 Summer Peak			2015 Winter Peak			2025 Summer Peak		
		Power Factor		Q (MVAR)	Power Factor		Q (MVAR)	Power Factor		Q (MVAR)
0	Base	0.984	Leading	36.01	0.981	Leading	39.60	0.986	Leading	33.94
1	FLT01-3PH	0.984	Leading	36.08	0.982	Leading	39.00	0.986	Leading	33.70
2	FLT02-3PH	0.983	Leading	37.31	0.981	Leading	39.53	0.985	Leading	34.98
3	FLT03-3PH	0.984	Leading	36.01	0.981	Leading	39.60	0.986	Leading	33.94
4	FLT04-3PH	0.984	Leading	36.47	0.980	Leading	40.21	0.986	Leading	34.04
5	FLT05-3PH	0.985	Leading	34.92	0.982	Leading	38.95	0.987	Leading	32.46
6	FLT06-3PH	0.985	Leading	35.48	0.980	Leading	40.75	0.986	Leading	34.03
7	FLT07-3PH	0.984	Leading	36.01	0.981	Leading	39.60	0.986	Leading	33.94
8	FLT08-3PH	0.985	Leading	34.66	0.982	Leading	38.87	0.987	Leading	32.10
9	FLT09-3PH	0.984	Leading	35.94	0.981	Leading	39.52	0.986	Leading	33.89
10	FLT10-3PH	0.985	Leading	35.35	0.981	Leading	39.05	0.986	Leading	33.25
11	FLT11-3PH	0.984	Leading	35.95	0.981	Leading	39.43	0.986	Leading	34.08
12	FLT12-3PH	0.984	Leading	36.44	0.981	Leading	39.62	0.986	Leading	34.09
13	FLT13-3PH	0.982	Leading	38.80	0.980	Leading	40.36	0.985	Leading	35.09
14	FLT14-3PH	0.985	Leading	35.20	0.982	Leading	38.73	0.986	Leading	33.71
15	FLT15-3PH	0.986	Leading	33.51	0.983	Leading	37.10	0.987	Leading	32.51
16	FLT16-3PH	0.984	Leading	36.04	0.981	Leading	39.58	0.986	Leading	33.94
17	FLT17-3PH	N/A	N/A	N/A	N/A	N/A	N/A	0.99	Leading	34.15
18	FLT18-3PH	0.984	Leading	35.96	0.981	Leading	39.62	0.986	Leading	33.85
19	FLT19-3PH	0.984	Leading	35.99	0.981	Leading	39.56	0.986	Leading	33.93
20	FLT20-3PH	0.984	Leading	36.04	0.981	Leading	39.68	0.986	Leading	33.93
21	FLT21-3PH	0.984	Leading	35.95	0.981	Leading	39.53	0.986	Leading	33.92
22	FLT22-3PH	0.984	Leading	35.87	0.981	Leading	39.48	0.986	Leading	33.82
23	FLT23-3PH	0.984	Leading	35.89	0.981	Leading	39.51	0.986	Leading	33.80
24	FLT24-3PH	0.997	Leading	15.57	0.994	Leading	22.64	0.997	Leading	16.55
25	FLT25-3PH	0.994	Leading	22.15	0.996	Leading	18.59	0.996	Leading	17.23
26	FLT26-3PH	0.981	Leading	39.39	0.968	Leading	51.73	0.980	Leading	40.10
27	FLT27-3PH	0.981	Leading	40.04	0.980	Leading	40.11	0.981	Leading	39.12
28	FLT28-3PH	0.985	Leading	35.24	0.981	Leading	39.32	0.987	Leading	33.09
29	FLT29-3PH	0.991	Leading	27.69	0.990	Leading	29.20	0.993	Leading	24.13
30	FLT30-3PH	0.988	Leading	31.06	0.984	Leading	35.98	0.990	Leading	28.91
31	FLT31-3PH	0.986	Leading	33.74	0.983	Leading	37.10	0.988	Leading	31.32
32	FLT32-3PH	0.971	Leading	49.50	0.968	Leading	52.03	0.975	Leading	45.67
33	FLT33-3PH	0.986	Leading	33.68	0.983	Leading	37.69	0.987	Leading	32.40
34	FLT34-3PH	0.984	Leading	36.42	0.981	Leading	39.94	0.986	Leading	34.31
35	FLT35-3PH	0.984	Leading	35.89	0.981	Leading	39.76	0.986	Leading	33.85
36	FLT36-3PH	0.984	Leading	35.71	0.981	Leading	39.37	0.986	Leading	33.72
37	FLT37-3PH	0.987	Leading	32.47	0.983	Leading	37.89	0.988	Leading	30.84
38	FLT38-3PH	0.985	Leading	35.23	0.982	Leading	38.93	0.987	Leading	33.19
39	FLT39-3PH	0.984	Leading	35.87	0.981	Leading	39.56	0.986	Leading	33.81
40	FLT40-3PH	0.984	Leading	36.00	0.981	Leading	39.59	0.986	Leading	33.93

Table 5-4 (Continued)
Power Factor Analysis: GEN-2015-016

Cont. No.	Case	2015 Summer Peak			2015 Winter Peak			2025 Summer Peak		
		Power Factor		Q (MVAR)	Power Factor		Q (MVAR)	Power Factor		Q (MVAR)
41	FLT41-3PH	0.984	Leading	36.03	0.981	Leading	39.63	0.986	Leading	33.94
42	FLT42-3PH	0.984	Leading	35.99	0.981	Leading	39.59	0.986	Leading	33.91
43	FLT43-3PH	0.984	Leading	36.00	0.981	Leading	39.60	0.986	Leading	33.93
44	FLT44-3PH	0.984	Leading	36.01	0.981	Leading	39.60	0.986	Leading	33.94
45	FLT45-3PH	0.984	Leading	36.01	0.981	Leading	39.60	0.986	Leading	33.93
46	FLT46-3PH	0.984	Leading	36.00	0.981	Leading	39.60	0.986	Leading	33.93
47	FLT47-3PH	0.985	Leading	35.17	0.982	Leading	38.90	0.986	Leading	33.23
48	FLT48-3PH	0.984	Leading	35.97	0.981	Leading	39.60	0.986	Leading	33.89
49	FLT49-3PH	0.984	Leading	36.01	0.981	Leading	39.60	0.986	Leading	33.94
50	FLT50-3PH	0.984	Leading	36.11	0.981	Leading	39.68	0.986	Leading	34.14
51	FLT51-3PH	0.986	Leading	34.42	0.983	Leading	37.11	0.987	Leading	32.99
52	FLT52-3PH	0.986	Leading	34.42	0.983	Leading	37.11	0.987	Leading	32.99
53	FLT53-3PH	0.987	Leading	32.28	0.985	Leading	35.46	0.988	Leading	31.14
54	FLT54-3PH	0.984	Leading	36.20	0.981	Leading	39.10	0.986	Leading	33.82
55	FLT55-3PH	0.986	Leading	34.05	0.983	Leading	37.90	0.987	Leading	32.51
56	FLT56-3PH	0.983	Leading	37.65	0.981	Leading	39.44	0.985	Leading	35.36
57	FLT57-3PH	0.984	Leading	36.24	0.983	Leading	37.70	0.986	Leading	34.10

Table 5-5
Power Factor Analysis: GEN-2015-024

Cont. No.	Case	2015 Summer Peak			2015 Winter Peak			2025 Summer Peak		
		Power Factor		Q (MVAR)	Power Factor		Q (MVAR)	Power Factor		Q (MVAR)
0	Base	0.979	Lagging	-45.57	0.762	Lagging	-187.12	0.981	Lagging	-43.38
1	FLT01-3PH	0.982	Lagging	-42.28	0.746	Lagging	-196.11	0.981	Lagging	-43.00
2	FLT02-3PH	0.972	Lagging	-53.52	0.715	Lagging	-215.20	0.973	Lagging	-52.36
3	FLT03-3PH	0.979	Lagging	-45.57	0.762	Lagging	-187.12	0.981	Lagging	-43.38
4	FLT04-3PH	0.963	Lagging	-61.31	0.731	Lagging	-205.55	0.973	Lagging	-51.96
5	FLT05-3PH	0.971	Lagging	-54.16	0.728	Lagging	-207.33	0.968	Lagging	-56.69
6	FLT06-3PH	0.979	Lagging	-45.90	0.751	Lagging	-193.66	0.980	Lagging	-45.18
7	FLT07-3PH	0.979	Lagging	-45.57	0.762	Lagging	-187.12	0.981	Lagging	-43.38
8	FLT08-3PH	0.967	Lagging	-57.57	0.740	Lagging	-200.02	0.972	Lagging	-53.10
9	FLT09-3PH	0.975	Lagging	-50.44	0.751	Lagging	-193.21	0.979	Lagging	-45.44
10	FLT10-3PH	0.914	Lagging	-97.92	0.655	Lagging	-253.79	0.947	Lagging	-74.89
11	FLT11-3PH	0.976	Lagging	-49.16	0.724	Lagging	-209.32	0.984	Lagging	-39.56
12	FLT12-3PH	1.000	Lagging	-3.92	0.883	Lagging	-117.13	0.995	Lagging	-22.38
13	FLT13-3PH	0.897	Lagging	-108.42	0.780	Lagging	-176.70	0.968	Lagging	-56.74
14	FLT14-3PH	0.952	Lagging	-70.77	0.726	Lagging	-208.62	0.957	Lagging	-67.00
15	FLT15-3PH	0.951	Lagging	-71.81	0.722	Lagging	-210.71	0.957	Lagging	-66.40
16	FLT16-3PH	0.979	Lagging	-45.57	0.762	Lagging	-187.12	0.981	Lagging	-43.38
17	FLT17-3PH	N/A	N/A	N/A	N/A	N/A	N/A	0.960	Lagging	-64.20
18	FLT18-3PH	0.969	Lagging	-56.16	0.745	Lagging	-196.80	0.977	Lagging	-47.79
19	FLT19-3PH	0.980	Lagging	-44.71	0.762	Lagging	-186.91	0.982	Lagging	-42.54
20	FLT20-3PH	0.972	Lagging	-52.99	0.751	Lagging	-193.54	0.978	Lagging	-47.23
21	FLT21-3PH	0.978	Lagging	-46.70	0.759	Lagging	-188.97	0.981	Lagging	-43.47
22	FLT22-3PH	0.977	Lagging	-48.53	0.752	Lagging	-193.04	0.979	Lagging	-45.65
23	FLT23-3PH	0.973	Lagging	-52.56	0.748	Lagging	-194.99	0.978	Lagging	-47.39
24	FLT24-3PH	0.979	Lagging	-45.54	0.762	Lagging	-186.83	0.981	Lagging	-43.83
25	FLT25-3PH	0.978	Lagging	-47.04	0.758	Lagging	-189.46	0.980	Lagging	-44.28
26	FLT26-3PH	0.979	Lagging	-46.10	0.762	Lagging	-186.73	0.981	Lagging	-43.77
27	FLT27-3PH	0.979	Lagging	-45.49	0.762	Lagging	-187.06	0.981	Lagging	-43.31
28	FLT28-3PH	0.979	Lagging	-45.62	0.762	Lagging	-187.14	0.981	Lagging	-43.42
29	FLT29-3PH	0.979	Lagging	-45.56	0.762	Lagging	-187.06	0.981	Lagging	-43.28
30	FLT30-3PH	0.980	Lagging	-44.99	0.763	Lagging	-186.63	0.982	Lagging	-42.75
31	FLT31-3PH	0.977	Lagging	-47.78	0.757	Lagging	-189.63	0.977	Lagging	-47.61
32	FLT32-3PH	0.979	Lagging	-45.56	0.761	Lagging	-187.32	0.981	Lagging	-43.30
33	FLT33-3PH	0.955	Lagging	-68.08	0.702	Lagging	-223.29	0.911	Lagging	-99.54
34	FLT34-3PH	1.000	Leading	3.45	0.831	Lagging	-147.27	0.999	Leading	10.51
35	FLT35-3PH	0.979	Lagging	-45.37	0.770	Lagging	-182.58	0.982	Lagging	-42.76
36	FLT36-3PH	0.977	Lagging	-47.84	0.754	Lagging	-191.80	0.979	Lagging	-45.82
37	FLT37-3PH	0.984	Lagging	-40.10	0.776	Lagging	-179.03	0.983	Lagging	-40.59
38	FLT38-3PH	0.960	Lagging	-63.87	0.723	Lagging	-210.03	0.971	Lagging	-53.99
39	FLT39-3PH	0.977	Lagging	-48.40	0.754	Lagging	-191.83	0.979	Lagging	-45.51
40	FLT40-3PH	0.979	Lagging	-46.03	0.761	Lagging	-187.70	0.981	Lagging	-43.96

Table 5-5 (Continued)
Power Factor Analysis: GEN-2015-024

Cont. No.	Case	2015 Summer Peak			2015 Winter Peak			2025 Summer Peak		
		Power Factor		Q (MVAR)	Power Factor		Q (MVAR)	Power Factor		Q (MVAR)
41	FLT41-3PH	0.978	Lagging	-47.29	0.759	Lagging	-188.77	0.980	Lagging	-44.47
42	FLT42-3PH	0.979	Lagging	-45.88	0.761	Lagging	-187.74	0.981	Lagging	-43.40
43	FLT43-3PH	0.979	Lagging	-46.17	0.761	Lagging	-187.39	0.981	Lagging	-43.39
44	FLT44-3PH	0.979	Lagging	-45.46	0.762	Lagging	-187.19	0.981	Lagging	-43.22
45	FLT45-3PH	0.979	Lagging	-45.75	0.761	Lagging	-187.51	0.981	Lagging	-43.45
46	FLT46-3PH	0.979	Lagging	-45.52	0.763	Lagging	-186.53	0.982	Lagging	-42.76
47	FLT47-3PH	0.964	Lagging	-60.67	0.734	Lagging	-203.64	0.971	Lagging	-54.41
48	FLT48-3PH	0.978	Lagging	-47.13	0.759	Lagging	-188.73	0.981	Lagging	-43.91
49	FLT49-3PH	0.979	Lagging	-45.57	0.762	Lagging	-187.12	0.981	Lagging	-43.38
50	FLT50-3PH	0.979	Lagging	-45.53	0.762	Lagging	-187.07	0.981	Lagging	-43.29
51	FLT51-3PH	0.979	Lagging	-46.18	0.759	Lagging	-188.50	0.981	Lagging	-43.72
52	FLT52-3PH	0.979	Lagging	-46.18	0.759	Lagging	-188.50	0.981	Lagging	-43.72
53	FLT53-3PH	0.977	Lagging	-48.25	0.756	Lagging	-190.57	0.979	Lagging	-45.38
54	FLT54-3PH	0.979	Lagging	-46.37	0.760	Lagging	-188.12	0.980	Lagging	-44.18
55	FLT55-3PH	0.978	Lagging	-46.63	0.760	Lagging	-188.43	0.980	Lagging	-44.24
56	FLT56-3PH	0.976	Lagging	-49.43	0.754	Lagging	-191.41	0.980	Lagging	-44.81
57	FLT57-3PH	0.977	Lagging	-48.30	0.755	Lagging	-191.32	0.980	Lagging	-44.14

Table 5-6
Power Factor Analysis: GEN-2015-025

Cont. No.	Case	2015 Summer Peak			2015 Winter Peak			2025 Summer Peak		
		Power Factor		Q (MVAR)	Power Factor		Q (MVAR)	Power Factor		Q (MVAR)
0	Base	0.979	Lagging	-45.57	0.762	Lagging	-187.12	0.981	Lagging	-43.38
1	FLT01-3PH	0.982	Lagging	-42.28	0.746	Lagging	-196.11	0.981	Lagging	-43.00
2	FLT02-3PH	0.972	Lagging	-53.52	0.715	Lagging	-215.20	0.973	Lagging	-52.36
3	FLT03-3PH	0.979	Lagging	-45.57	0.762	Lagging	-187.12	0.981	Lagging	-43.38
4	FLT04-3PH	0.963	Lagging	-61.31	0.731	Lagging	-205.55	0.973	Lagging	-51.96
5	FLT05-3PH	0.971	Lagging	-54.16	0.728	Lagging	-207.33	0.968	Lagging	-56.69
6	FLT06-3PH	0.979	Lagging	-45.90	0.751	Lagging	-193.66	0.980	Lagging	-45.18
7	FLT07-3PH	0.979	Lagging	-45.57	0.762	Lagging	-187.12	0.981	Lagging	-43.38
8	FLT08-3PH	0.967	Lagging	-57.57	0.740	Lagging	-200.02	0.972	Lagging	-53.10
9	FLT09-3PH	0.975	Lagging	-50.44	0.751	Lagging	-193.21	0.979	Lagging	-45.44
10	FLT10-3PH	0.914	Lagging	-97.92	0.655	Lagging	-253.79	0.947	Lagging	-74.89
11	FLT11-3PH	0.976	Lagging	-49.16	0.724	Lagging	-209.32	0.984	Lagging	-39.56
12	FLT12-3PH	1.000	Lagging	-3.92	0.883	Lagging	-117.13	0.995	Lagging	-22.38
13	FLT13-3PH	0.897	Lagging	-108.42	0.780	Lagging	-176.69	0.968	Lagging	-56.74
14	FLT14-3PH	0.952	Lagging	-70.77	0.726	Lagging	-208.62	0.957	Lagging	-67.00
15	FLT15-3PH	0.951	Lagging	-71.81	0.722	Lagging	-210.71	0.957	Lagging	-66.40
16	FLT16-3PH	0.979	Lagging	-45.57	0.762	Lagging	-187.12	0.981	Lagging	-43.38
17	FLT17-3PH	N/A	N/A	N/A	N/A	N/A	N/A	0.960	Lagging	-64.20
18	FLT18-3PH	0.969	Lagging	-56.16	0.745	Lagging	-196.80	0.977	Lagging	-47.79
19	FLT19-3PH	0.980	Lagging	-44.71	0.762	Lagging	-186.91	0.982	Lagging	-42.54
20	FLT20-3PH	0.972	Lagging	-52.99	0.751	Lagging	-193.54	0.978	Lagging	-47.23
21	FLT21-3PH	0.978	Lagging	-46.70	0.759	Lagging	-188.97	0.981	Lagging	-43.47
22	FLT22-3PH	0.977	Lagging	-48.53	0.752	Lagging	-193.04	0.979	Lagging	-45.65
23	FLT23-3PH	0.973	Lagging	-52.56	0.748	Lagging	-194.99	0.978	Lagging	-47.39
24	FLT24-3PH	0.979	Lagging	-45.54	0.762	Lagging	-186.83	0.981	Lagging	-43.83
25	FLT25-3PH	0.978	Lagging	-47.04	0.758	Lagging	-189.46	0.980	Lagging	-44.28
26	FLT26-3PH	0.979	Lagging	-46.10	0.762	Lagging	-186.73	0.981	Lagging	-43.77
27	FLT27-3PH	0.979	Lagging	-45.49	0.762	Lagging	-187.06	0.981	Lagging	-43.31
28	FLT28-3PH	0.979	Lagging	-45.62	0.762	Lagging	-187.14	0.981	Lagging	-43.42
29	FLT29-3PH	0.979	Lagging	-45.56	0.762	Lagging	-187.06	0.981	Lagging	-43.28
30	FLT30-3PH	0.980	Lagging	-44.99	0.763	Lagging	-186.63	0.982	Lagging	-42.75
31	FLT31-3PH	0.977	Lagging	-47.78	0.757	Lagging	-189.63	0.977	Lagging	-47.61
32	FLT32-3PH	0.979	Lagging	-45.56	0.761	Lagging	-187.32	0.981	Lagging	-43.30
33	FLT33-3PH	0.955	Lagging	-68.08	0.702	Lagging	-223.29	0.911	Lagging	-99.54
34	FLT34-3PH	1.000	Leading	3.45	0.831	Lagging	-147.27	0.999	Leading	10.51
35	FLT35-3PH	0.979	Lagging	-45.37	0.770	Lagging	-182.58	0.982	Lagging	-42.76
36	FLT36-3PH	0.977	Lagging	-47.84	0.754	Lagging	-191.80	0.979	Lagging	-45.82
37	FLT37-3PH	0.984	Lagging	-40.10	0.776	Lagging	-179.03	0.983	Lagging	-40.59
38	FLT38-3PH	0.960	Lagging	-63.87	0.723	Lagging	-210.03	0.971	Lagging	-53.99
39	FLT39-3PH	0.977	Lagging	-48.40	0.754	Lagging	-191.83	0.979	Lagging	-45.51
40	FLT40-3PH	0.979	Lagging	-46.03	0.761	Lagging	-187.70	0.981	Lagging	-43.96

Table 5-6 (Continued)
Power Factor Analysis: GEN-2015-025

Cont. No.	Case	2015 Summer Peak			2015 Winter Peak			2025 Summer Peak		
		Power Factor		Q (MVAR)	Power Factor		Q (MVAR)	Power Factor		Q (MVAR)
41	FLT41-3PH	0.978	Lagging	-47.29	0.759	Lagging	-188.77	0.980	Lagging	-44.47
42	FLT42-3PH	0.979	Lagging	-45.88	0.761	Lagging	-187.74	0.981	Lagging	-43.40
43	FLT43-3PH	0.979	Lagging	-46.17	0.761	Lagging	-187.38	0.981	Lagging	-43.39
44	FLT44-3PH	0.979	Lagging	-45.46	0.762	Lagging	-187.19	0.981	Lagging	-43.22
45	FLT45-3PH	0.979	Lagging	-45.75	0.761	Lagging	-187.51	0.981	Lagging	-43.45
46	FLT46-3PH	0.979	Lagging	-45.52	0.763	Lagging	-186.53	0.982	Lagging	-42.76
47	FLT47-3PH	0.964	Lagging	-60.67	0.734	Lagging	-203.64	0.971	Lagging	-54.41
48	FLT48-3PH	0.978	Lagging	-47.13	0.759	Lagging	-188.73	0.981	Lagging	-43.91
49	FLT49-3PH	0.979	Lagging	-45.57	0.762	Lagging	-187.12	0.981	Lagging	-43.38
50	FLT50-3PH	0.979	Lagging	-45.53	0.762	Lagging	-187.07	0.981	Lagging	-43.29
51	FLT51-3PH	0.979	Lagging	-46.18	0.759	Lagging	-188.50	0.981	Lagging	-43.72
52	FLT52-3PH	0.979	Lagging	-46.18	0.759	Lagging	-188.50	0.981	Lagging	-43.72
53	FLT53-3PH	0.977	Lagging	-48.25	0.756	Lagging	-190.57	0.979	Lagging	-45.38
54	FLT54-3PH	0.979	Lagging	-46.37	0.760	Lagging	-188.12	0.980	Lagging	-44.18
55	FLT55-3PH	0.978	Lagging	-46.63	0.760	Lagging	-188.43	0.980	Lagging	-44.24
56	FLT56-3PH	0.976	Lagging	-49.43	0.754	Lagging	-191.41	0.980	Lagging	-44.81
57	FLT57-3PH	0.977	Lagging	-48.30	0.755	Lagging	-191.32	0.980	Lagging	-44.14

Table 5-7
Power Factor Analysis: GEN-2015-028

Cont. No.	Case	2015 Summer Peak			2015 Winter Peak			2025 Summer Peak		
		Power Factor		Q (MVAR)	Power Factor		Q (MVAR)	Power Factor		Q (MVAR)
0	Base	0.980	Leading	12.74	0.993	Leading	7.57	0.993	Leading	7.40
1	FLT01-3PH	0.980	Leading	12.81	0.993	Leading	7.42	0.993	Leading	7.47
2	FLT02-3PH	0.982	Leading	12.24	0.994	Leading	6.78	0.994	Leading	6.81
3	FLT03-3PH	0.980	Leading	12.74	0.993	Leading	7.57	0.993	Leading	7.40
4	FLT04-3PH	0.980	Leading	12.65	0.993	Leading	7.47	0.993	Leading	7.35
5	FLT05-3PH	0.981	Leading	12.57	0.994	Leading	7.18	0.994	Leading	7.17
6	FLT06-3PH	0.980	Leading	12.75	0.993	Leading	7.44	0.993	Leading	7.39
7	FLT07-3PH	0.980	Leading	12.74	0.993	Leading	7.57	0.993	Leading	7.40
8	FLT08-3PH	0.982	Leading	12.23	0.993	Leading	7.21	0.994	Leading	6.85
9	FLT09-3PH	0.983	Leading	11.70	0.995	Leading	6.12	0.994	Leading	6.83
10	FLT10-3PH	0.989	Leading	9.39	1.000	Leading	0.66	0.997	Leading	5.06
11	FLT11-3PH	0.982	Leading	12.02	0.986	Leading	10.57	0.995	Leading	6.11
12	FLT12-3PH	0.998	Leading	3.63	0.997	Lagging	-4.54	0.997	Leading	5.03
13	FLT13-3PH	0.982	Leading	12.18	0.993	Leading	7.49	0.993	Leading	7.23
14	FLT14-3PH	0.981	Leading	12.50	0.993	Leading	7.39	0.993	Leading	7.22
15	FLT15-3PH	0.981	Leading	12.46	0.993	Leading	7.32	0.993	Leading	7.25
16	FLT16-3PH	0.980	Leading	12.60	0.993	Leading	7.37	0.993	Leading	7.29
17	FLT17-3PH	N/A	N/A	N/A	N/A	N/A	N/A	0.994	Leading	6.91
18	FLT18-3PH	0.986	Leading	10.62	0.986	Leading	10.66	1.000	Leading	0.49
19	FLT19-3PH	0.980	Leading	12.66	0.992	Leading	8.00	0.994	Leading	7.05
20	FLT20-3PH	0.992	Leading	8.00	0.998	Leading	4.06	0.999	Leading	3.20
21	FLT21-3PH	0.973	Leading	14.79	0.990	Leading	9.16	0.993	Leading	7.69
22	FLT22-3PH	0.987	Leading	10.22	0.998	Leading	4.01	0.996	Leading	5.52
23	FLT23-3PH	0.985	Leading	11.14	0.996	Leading	5.32	0.994	Leading	7.05
24	FLT24-3PH	0.980	Leading	12.73	0.993	Leading	7.56	0.993	Leading	7.41
25	FLT25-3PH	0.980	Leading	12.72	0.993	Leading	7.54	0.993	Leading	7.38
26	FLT26-3PH	0.980	Leading	12.72	0.993	Leading	7.57	0.993	Leading	7.39
27	FLT27-3PH	0.980	Leading	12.74	0.993	Leading	7.57	0.993	Leading	7.41
28	FLT28-3PH	0.980	Leading	12.74	0.993	Leading	7.57	0.993	Leading	7.40
29	FLT29-3PH	0.980	Leading	12.74	0.993	Leading	7.57	0.993	Leading	7.40
30	FLT30-3PH	0.980	Leading	12.75	0.993	Leading	7.58	0.993	Leading	7.42
31	FLT31-3PH	0.980	Leading	12.69	0.993	Leading	7.52	0.993	Leading	7.37
32	FLT32-3PH	0.980	Leading	12.74	0.993	Leading	7.57	0.993	Leading	7.40
33	FLT33-3PH	0.981	Leading	12.50	0.993	Leading	7.24	0.994	Leading	6.96
34	FLT34-3PH	0.979	Leading	13.19	0.992	Leading	7.87	0.992	Leading	7.84
35	FLT35-3PH	0.980	Leading	12.74	0.993	Leading	7.60	0.993	Leading	7.40
36	FLT36-3PH	0.980	Leading	12.72	0.993	Leading	7.51	0.993	Leading	7.39
37	FLT37-3PH	0.980	Leading	12.76	0.993	Leading	7.61	0.993	Leading	7.46
38	FLT38-3PH	0.981	Leading	12.58	0.993	Leading	7.45	0.993	Leading	7.34
39	FLT39-3PH	0.980	Leading	12.69	0.993	Leading	7.34	0.993	Leading	7.32
40	FLT40-3PH	0.956	Leading	19.16	0.971	Leading	15.44	0.975	Leading	14.30

Table 5-7 (Continued)
Power Factor Analysis: GEN-2015-028

Cont. No.	Case	2015 Summer Peak			2015 Winter Peak			2025 Summer Peak		
		Power Factor		Q (MVAR)	Power Factor		Q (MVAR)	Power Factor		Q (MVAR)
41	FLT41-3PH	0.999	Leading	3.26	1.000	Leading	1.15	0.999	Leading	2.86
42	FLT42-3PH	0.977	Leading	13.74	0.993	Leading	7.36	0.991	Leading	8.63
43	FLT43-3PH	0.991	Leading	8.51	0.998	Leading	4.40	1.000	Leading	1.76
44	FLT44-3PH	0.969	Leading	15.91	0.989	Leading	9.28	0.987	Leading	10.16
45	FLT45-3PH	0.979	Leading	13.01	0.995	Leading	6.54	0.993	Leading	7.66
46	FLT46-3PH	0.997	Leading	4.95	0.998	Lagging	-3.62	0.990	Lagging	-9.04
47	FLT47-3PH	0.981	Leading	12.45	0.993	Leading	7.23	0.994	Leading	6.87
48	FLT48-3PH	0.980	Leading	12.75	0.992	Leading	7.94	0.993	Leading	7.36
49	FLT49-3PH	0.980	Leading	12.74	0.993	Leading	7.57	0.993	Leading	7.40
50	FLT50-3PH	0.980	Leading	12.74	0.993	Leading	7.57	0.993	Leading	7.41
51	FLT51-3PH	0.980	Leading	12.70	0.993	Leading	7.49	0.993	Leading	7.38
52	FLT52-3PH	0.980	Leading	12.70	0.993	Leading	7.49	0.993	Leading	7.38
53	FLT53-3PH	0.980	Leading	12.67	0.993	Leading	7.52	0.993	Leading	7.33
54	FLT54-3PH	0.980	Leading	12.67	0.993	Leading	7.53	0.993	Leading	7.31
55	FLT55-3PH	0.980	Leading	12.72	0.993	Leading	7.55	0.993	Leading	7.38
56	FLT56-3PH	0.980	Leading	12.65	0.993	Leading	7.49	0.993	Leading	7.33
57	FLT57-3PH	0.980	Leading	12.67	0.993	Leading	7.49	0.993	Leading	7.37

Table 5-8
Power Factor Analysis: GEN-2015-030

Cont. No.	Case	2015 Summer Peak			2015 Winter Peak			2025 Summer Peak		
		Power Factor		Q (MVAR)	Power Factor		Q (MVAR)	Power Factor		Q (MVAR)
0	Base	0.985	Lagging	-34.73	0.973	Lagging	-47.82	0.981	Lagging	-39.76
1	FLT01-3PH	0.970	Lagging	-49.80	0.984	Lagging	-35.69	0.976	Lagging	-45.09
2	FLT02-3PH	0.938	Lagging	-74.26	0.950	Lagging	-65.90	0.945	Lagging	-69.56
3	FLT03-3PH	0.985	Lagging	-34.73	0.973	Lagging	-47.82	0.981	Lagging	-39.76
4	FLT04-3PH	0.988	Lagging	-31.62	0.980	Lagging	-41.13	0.982	Lagging	-38.93
5	FLT05-3PH	0.985	Lagging	-35.16	0.967	Lagging	-52.37	0.979	Lagging	-41.42
6	FLT06-3PH	0.984	Lagging	-36.12	0.968	Lagging	-51.75	0.979	Lagging	-42.02
7	FLT07-3PH	0.985	Lagging	-34.73	0.973	Lagging	-47.82	0.981	Lagging	-39.76
8	FLT08-3PH	0.998	Lagging	-12.62	0.979	Lagging	-41.33	1.000	Lagging	-2.83
9	FLT09-3PH	0.991	Lagging	-26.73	0.992	Lagging	-25.27	0.978	Lagging	-43.06
10	FLT10-3PH	0.996	Lagging	-18.86	0.995	Lagging	-20.36	0.990	Lagging	-28.82
11	FLT11-3PH	0.984	Lagging	-36.62	0.982	Lagging	-38.25	0.974	Lagging	-46.86
12	FLT12-3PH	0.902	Lagging	-95.69	0.857	Lagging	-120.39	0.964	Lagging	-55.29
13	FLT13-3PH	0.989	Lagging	-29.72	0.974	Lagging	-46.47	0.981	Lagging	-39.52
14	FLT14-3PH	0.982	Lagging	-38.01	0.969	Lagging	-51.10	0.979	Lagging	-41.68
15	FLT15-3PH	0.980	Lagging	-40.89	0.965	Lagging	-54.32	0.977	Lagging	-43.96
16	FLT16-3PH	0.985	Lagging	-35.14	0.972	Lagging	-48.46	0.980	Lagging	-40.14
17	FLT17-3PH	0.985	Lagging	-34.73	0.97	Lagging	-47.82	0.98	Lagging	-45.06
18	FLT18-3PH	0.979	Lagging	-41.79	0.966	Lagging	-53.77	0.977	Lagging	-43.82
19	FLT19-3PH	0.986	Lagging	-34.28	0.973	Lagging	-47.91	0.981	Lagging	-39.14
20	FLT20-3PH	0.981	Lagging	-39.29	0.969	Lagging	-51.08	0.978	Lagging	-42.41
21	FLT21-3PH	0.985	Lagging	-34.82	0.973	Lagging	-47.90	0.981	Lagging	-39.78
22	FLT22-3PH	0.983	Lagging	-37.03	0.971	Lagging	-49.69	0.979	Lagging	-41.47
23	FLT23-3PH	0.980	Lagging	-40.25	0.967	Lagging	-52.73	0.976	Lagging	-44.71
24	FLT24-3PH	0.984	Lagging	-35.96	0.971	Lagging	-48.85	0.980	Lagging	-41.13
25	FLT25-3PH	0.986	Lagging	-33.81	0.974	Lagging	-46.95	0.982	Lagging	-39.00
26	FLT26-3PH	0.985	Lagging	-34.90	0.973	Lagging	-47.61	0.981	Lagging	-39.85
27	FLT27-3PH	0.985	Lagging	-34.81	0.972	Lagging	-48.00	0.981	Lagging	-39.86
28	FLT28-3PH	0.985	Lagging	-34.73	0.973	Lagging	-47.82	0.981	Lagging	-39.76
29	FLT29-3PH	0.985	Lagging	-34.63	0.973	Lagging	-47.75	0.981	Lagging	-39.67
30	FLT30-3PH	0.985	Lagging	-34.67	0.973	Lagging	-47.84	0.981	Lagging	-39.66
31	FLT31-3PH	0.982	Lagging	-38.39	0.970	Lagging	-50.33	0.976	Lagging	-45.04
32	FLT32-3PH	0.985	Lagging	-34.45	0.973	Lagging	-47.48	0.981	Lagging	-39.54
33	FLT33-3PH	0.980	Lagging	-40.21	0.966	Lagging	-53.46	0.975	Lagging	-45.67
34	FLT34-3PH	0.988	Lagging	-31.65	0.975	Lagging	-45.59	0.984	Lagging	-36.38
35	FLT35-3PH	0.985	Lagging	-34.82	0.973	Lagging	-47.53	0.981	Lagging	-39.79
36	FLT36-3PH	0.985	Lagging	-35.07	0.972	Lagging	-48.21	0.981	Lagging	-40.00
37	FLT37-3PH	0.982	Lagging	-38.38	0.970	Lagging	-50.32	0.978	Lagging	-42.99
38	FLT38-3PH	0.983	Lagging	-36.98	0.971	Lagging	-49.54	0.979	Lagging	-41.64
39	FLT39-3PH	0.984	Lagging	-35.70	0.973	Lagging	-47.21	0.980	Lagging	-40.39
40	FLT40-3PH	0.985	Lagging	-35.06	0.972	Lagging	-48.25	0.980	Lagging	-40.16

Table 5-8 (Continued)
Power Factor Analysis: GEN-2015-030

Cont. No.	Case	2015 Summer Peak			2015 Winter Peak			2025 Summer Peak		
		Power Factor		Q (MVAR)	Power Factor		Q (MVAR)	Power Factor		Q (MVAR)
41	FLT41-3PH	0.984	Lagging	-35.98	0.972	Lagging	-48.05	0.980	Lagging	-40.64
42	FLT42-3PH	0.984	Lagging	-35.75	0.972	Lagging	-48.64	0.980	Lagging	-40.64
43	FLT43-3PH	0.985	Lagging	-35.27	0.972	Lagging	-48.15	0.981	Lagging	-40.04
44	FLT44-3PH	0.985	Lagging	-34.76	0.972	Lagging	-47.98	0.981	Lagging	-39.76
45	FLT45-3PH	0.985	Lagging	-34.93	0.972	Lagging	-48.11	0.981	Lagging	-39.87
46	FLT46-3PH	0.985	Lagging	-34.81	0.973	Lagging	-47.71	0.981	Lagging	-39.56
47	FLT47-3PH	0.947	Lagging	-67.86	0.917	Lagging	-86.83	0.946	Lagging	-68.89
48	FLT48-3PH	0.983	Lagging	-37.07	0.968	Lagging	-52.19	0.981	Lagging	-39.54
49	FLT49-3PH	0.985	Lagging	-34.73	0.973	Lagging	-47.82	0.981	Lagging	-39.76
50	FLT50-3PH	0.985	Lagging	-34.70	0.973	Lagging	-47.80	0.981	Lagging	-39.71
51	FLT51-3PH	0.985	Lagging	-34.97	0.972	Lagging	-48.25	0.981	Lagging	-39.92
52	FLT52-3PH	0.985	Lagging	-34.97	0.972	Lagging	-48.25	0.981	Lagging	-39.92
53	FLT53-3PH	0.986	Lagging	-34.10	0.973	Lagging	-47.30	0.981	Lagging	-39.20
54	FLT54-3PH	0.986	Lagging	-34.22	0.973	Lagging	-47.46	0.981	Lagging	-39.25
55	FLT55-3PH	0.985	Lagging	-34.67	0.973	Lagging	-47.82	0.981	Lagging	-39.72
56	FLT56-3PH	0.989	Lagging	-30.25	0.976	Lagging	-44.24	0.984	Lagging	-36.48
57	FLT57-3PH	0.987	Lagging	-32.09	0.975	Lagging	-45.89	0.982	Lagging	-38.59

Study Generator GEN-2015-001

The Power Factor Analysis shows that GEN-2015-001 has a power factor range of 0.957 to 0.999 leading (absorbing) for the 2015 Summer Peak conditions, a power factor range of 0.980 leading (absorbing) to 1.00 (unity) for the 2015 Winter Peak conditions, and a power factor range of 0.986 to 0.999 leading (absorbing) for the 2025 Summer Peak conditions.

Study Generator GEN-2015-003

The Power Factor Analysis shows that GEN-2015-003 has a power factor range of 0.979 lagging (supplying) to 0.986 leading (absorbing) for the 2015 Summer Peak conditions, a power factor range of 0.898 lagging (supplying) to 0.994 leading (absorbing) for the 2015 Winter Peak conditions, and a power factor range of 0.983 leading (supplying) to 1.00 (unity) for the 2025 Summer Peak conditions.

Study Generator GEN-2015-015

The Power Factor Analysis shows that GEN-2015-015 has a power factor range of 0.946 lagging (supplying) to 0.991 leading (absorbing) for the 2015 Summer Peak conditions, a power factor range of 0.959 lagging (supplying) to 0.991 leading (absorbing) for the 2015 Winter Peak conditions, and a power factor range of 0.991 lagging (supplying) to 0.996 leading (absorbing) for the 2025 Summer Peak conditions.

Study Generator GEN-2015-016

The Power Factor Analysis shows that GEN-2015-016 has a power factor range of 0.971 to 0.997 leading (absorbing) for the 2015 Summer Peak conditions, a power factor range of 0.968 to 0.996 leading (absorbing) for the 2015 Winter Peak conditions, and a power factor range of 0.975 to 0.997 leading (absorbing) for the 2025 Summer Peak conditions.

Study Generators GEN-2015-024 and GEN-2015-025 (Tap Wichita – Thistle circuit 1&2)

The Power Factor Analysis shows that the Wichita generation has a power factor range of 0.897 lagging (supplying) to 1.00 (unity) for the 2015 Summer Peak conditions, a power factor range of 0.655 to 0.883 lagging (supplying) for the 2015 Winter Peak conditions, and a power factor range of 0.911 lagging (supplying) to 0.999 leading (absorbing) for the 2025 Summer Peak conditions.

Study Generator GEN-2015-028

The Power Factor Analysis shows that GEN-2015-028 has a power factor range of 0.947 to 0.999 leading (supplying) for the 2015 Summer Peak conditions, a power factor range of 0.997 lagging (supplying) to 0.971 leading (absorbing) for the 2015 Winter Peak conditions, and a power factor range of 0.990 lagging (supplying) to 0.975 leading (absorbing) for the 2025 Summer Peak conditions.

Study Generator GEN-2015-030

The Power Factor Analysis shows that GEN-2015-030 has a power factor range of 0.902 to 0.998 lagging (supplying) for the 2015 Summer Peak conditions, a power factor range of 0.857 to 0.995 lagging (supplying) for the 2015 Winter Peak conditions, and a power factor range of 0.945 lagging (supplying) to 1.00 (unity) for the 2025 Summer Peak conditions.

SECTION 6: LOW WIND/NO WIND ANALYSIS

The objective of this task is to determine the impact of low wind or no wind conditions on wind farms that interconnect to a 345 kV or 230 kV bus. The 2015 Summer Peak, 2015 Winter Peak, and 2025 Summer Peak power flows provided by SPP were examined for this analysis.

6.1 Approach

Low wind or no wind conditions were examined for all 345 kV or 230 kV wind farms. Generators were disabled (independently), but the collector systems remained in-service. In order to maintain generation and load balance in the SPP area, the generation was scaled after disabling the respective generator. The amount of reactive power injected into the transmission network was recorded at the respective point of interconnection. This reactive power comes from the capacitance of the project's transmission lines and collector cables. A shunt reactor was added at the high side bus to bring the Mvar flow into the POI down to approximately zero.

6.2 Low Wind/No Wind Analysis Results

The reactance needed to bring the Mvar flow into the point of interconnect to zero Mvar was recorded for each season for all 345 kV or 230 kV wind farms. Refer to Table 6-1 for the Low Wind/No Wind Analysis results. The table lists the generators examined and the amount of reactive power needed for zero Mvar flow into the POI for each season.

Table 6-1
Low Wind/No Wind Analysis

Request	Size (MW)	Point of Interconnection	15SP	15WP	25SP
GEN-2015-001	200	Ranch Road 345kV	10.0	10.0	10.0
GEN-2015-003	200	Renfrow 345kV	15.2	15.2	15.2
GEN-2015-024	220	Tap Wichita - Thistle 345kV cicruit 1&2	57.1	57.1	57.1
GEN-2015-025	220				
GEN-2015-030	200	Sooner 345kV	9.8	9.8	9.8

SECTION 7: CONCLUSIONS

SUMMARY OF STABILITY ANALYSIS

The Stability Analysis determined that there were no contingencies that resulted in system instability, generation tripping offline, or voltage violations for the 2015 Summer Peak, 2015 Winter Peak, and 2025 Summer Peak conditions when all generation interconnection requests were at 100% output for both the Cluster Scenario study and the Stand Alone Scenario study. Thus, no mitigations or upgrades were required.

Note contingencies, FLT01-3PH and FLT03-3PH, required the "LVRT extreme UV limit" value in the "VWVRP7" dynamic model of GEN-2015-001 to be changed from 0.05 p.u. to 0.0 p.u. in order for GEN-2015-001 to remain online, as discussed with SPP. The dynamic file modification was used to complete the analysis.

Several voltage buses consistently fell outside of the 0.95 p.u. to 1.05 p.u. range. All instances were observed for pre-fault conditions and since all voltages returned to pre-fault conditions, no mitigation was required.

SUMMARY OF THE SHORT CIRCUIT ANALYSIS

The short circuit analysis was performed on the 2025 Summer Peak power flow for all study projects. Refer to Table 7-1 for a list of maximum fault currents observed for each study project.

Table 7-1
List of Maximum Fault Currents Observed for Each Study Project

Study Project	POI Name	Fault Current at POI (kA)	Maximum Fault Current (kA)	Fault Location	Bus Voltage (kV)
GEN-2015-001	Ranch Road 345 kV	12.91	41.57	NORTWST4	138
GEN-2015-003	Renfrow 345 kV	12.87	41.57	NORTWST4	138
GEN-2015-015	Tap Medford - Coyote 138 kV	8.51	24.56	WICHITA7	345
GEN-2015-016	Tap Centerville - Marmaton 161 kV	7.26	24.67	LACYGNE7	345
GEN-2015-024	Tap Witchita - Thistle 345 kV circuit 1	24.56	41.45	EVANS S4	138
GEN-2015-025	Tap Witchita - Thistle 345 kV circuit 2				
GEN-2015-028	Nardins 69 kV	5.52	15.67	WHEAGLE4	138
GEN-2015-030	Sooner 345 kV	22.77	57.59	SEMINOL4	138
ASGI-2015-004	Coffeyville Municipal Light & Power Northern Industrial Park Substation 69 kV	8.59	26.11	ONETA--7	345

SUMMARY OF POWER FACTOR ANALYSIS

<u>Study Generator GEN-2015-001</u>

The Power Factor Analysis shows that GEN-2015-001 has a power factor range of 0.957 to 0.999 leading (absorbing) for the 2015 Summer Peak conditions, a power factor range of 0.980 leading (absorbing) to 1.00 (unity) for the 2015 Winter Peak conditions, and a power factor range of 0.986 to 0.999 leading (absorbing) for the 2025 Summer Peak conditions.

<u>Study Generator GEN-2015-003</u>

The Power Factor Analysis shows that GEN-2015-003 has a power factor range of 0.979 lagging (supplying) to 0.986 leading (absorbing) for the 2015 Summer Peak conditions, a power factor range of 0.898 lagging (supplying) to 0.994 leading (absorbing) for the 2015 Winter Peak conditions, and a power factor range of 0.983 leading (supplying) to 1.00 (unity) for the 2025 Summer Peak conditions.

<u>Study Generator GEN-2015-015</u>

The Power Factor Analysis shows that GEN-2015-015 has a power factor range of 0.946 lagging (supplying) to 0.991 leading (absorbing) for the 2015 Summer Peak conditions, a power factor range of 0.959 lagging (supplying) to 0.991 leading (absorbing) for the 2015 Winter Peak conditions, and a power factor range of 0.991 lagging (supplying) to 0.996 leading (absorbing) for the 2025 Summer Peak conditions.

<u>Study Generator GEN-2015-016</u>

The Power Factor Analysis shows that GEN-2015-016 has a power factor range of 0.971 to 0.997 leading (absorbing) for the 2015 Summer Peak conditions, a power factor range of 0.968 to 0.996 leading (absorbing) for the 2015 Winter Peak conditions, and a power factor range of 0.975 to 0.997 leading (absorbing) for the 2025 Summer Peak conditions.

Study Generators GEN-2015-024 and GEN-2015-025 (Tap Wichita – Thistle circuit 1&2)
The Power Factor Analysis shows that the Wichita generation has a power factor range of 0.897 lagging (supplying) to 1.00 (unity) for the 2015 Summer Peak conditions, a power factor range of 0.655 to 0.883 lagging (supplying) for the 2015 Winter Peak conditions, and a power factor range of 0.911 lagging (supplying) to 0.999 leading (absorbing) for the 2025 Summer Peak conditions.

Study Generator GEN-2015-028
The Power Factor Analysis shows that GEN-2015-028 has a power factor range of 0.947 to 0.999 leading (supplying) for the 2015 Summer Peak conditions, a power factor range of 0.997 lagging (supplying) to 0.971 leading (absorbing) for the 2015 Winter Peak conditions, and a power factor range of 0.990 lagging (supplying) to 0.975 leading (absorbing) for the 2025 Summer Peak conditions.

Study Generator GEN-2015-030
The Power Factor Analysis shows that GEN-2015-030 has a power factor range of 0.902 to 0.998 lagging (supplying) for the 2015 Summer Peak conditions, a power factor range of 0.857 to 0.995 lagging (supplying) for the 2015 Winter Peak conditions, and a power factor range of 0/945 lagging (supplying) to 1.00 (unity) for the 2025 Summer Peak conditions.

SUMMARY OF LOW WIND/NO WIND ANALYSIS

The amount of reactive power injected into the transmission network was recorded at the point of interconnection for GEN-2015-001, GEN-2015-003, GEN-2015-024, GEN-2015-025, and GEN-2015-030 for each season. The maximum reactance needed for zero Mvar flow was 57.1 Mvar for GEN-2015-024 and GEN-2015-025 (Tap Wichita – Thistle circuit 1&2). The minimum reactance needed for zero Mvar flow was 9.8 Mvar for GEN-2015-030 (Sooner 345 kV).

R: Group 9 Dynamic Stability Analysis Report

See S&C study report and SPP addendum on next page

S&C ELECTRIC COMPANY
Excellence Through Innovation

DISIS-2015-001 (GROUP 9)

LITTLE ROCK, AR

SOUTHWEST POWER POOL

DEFINITIVE INTERCONNECTION SYSTEM IMPACT STUDY

S&C PROJECT NUMBER: 9406

DOCUMENT NUMBER: E-857

REVISION: 1

FINAL REPORT

CONFIDENTIAL

JULY 28, 2015

S&C ELECTRIC COMPANY
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REPORT REVISION HISTORY:

REV	DATE	PREPARED BY	REVIEWED BY	APPROVED BY	DESCRIPTION
A	07/16/2015	JT	SK	EHC	Preliminary report issued
0	07/24/2015	JT	SK	EHC	Final report issued
1	07/28/2015	JT	SK	EHC	SPP's comments on high voltages condition added

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1. Executive Summary

S&C Electric Company (S&C) has performed a Definitive Interconnection System Impact Study, DISIS-2015-001 (Group 9), in response to a request through Southwest Power Pool (SPP) Tariff. Group 9 consists of six (6) new interconnection (POI) requests (GEN-2014-023, GEN-2014-059, GEN-2014-060, GEN-2015-007, GEN-2015-008, and GEN-2015-023), all of which are wind farm projects.

S&C has performed dynamic stability analysis for Group 9 under Cluster and Stand-Alone (SA) scenarios. The cluster studies were performed using three (3) cluster base cases (2015 Summer Peak, 2015 Winter Peak, and 2025 Summer Peak) provided by SPP. In the cluster studies, all six new interconnection requests were studied at 100% of nameplate MW capacity. The stand-alone studies were performed using three (3) stand-alone base cases (2015 SP, 2015 WP, and 2025 SP) provided by SPP and by placing an interconnection request into service, one at a time. The in-service interconnection project was dispatched at 100% power and the (5) out of service interconnection projects were set to zero generation or to a defined value if the project is an upgrade to an existing project or facility. The results of dynamics stability analysis for the cluster and stand-alone scenarios indicated that Group 9 required a network upgrade from Holt County to Cherry County to Gentleman 345 kV in 2015 SP and 2015 WP cases for certain contingencies, in order for study projects and nearby generators to ride through and remain stable for all contingencies. Without this necessary upgrade, 2015 SP and 2015 WP cluster base cases and GEN-2015-023 stand-alone base cases exhibit instability for certain contingencies. This issue was discussed with SPP and after the proposed Holt County to Cherry County to Gentleman 345 kV upgrade was added to the base case, the instability issues were eliminated. The dynamics stability studies revealed that Group 9 projects met the SPP transient voltage requirement, though 115 kV Petersbug bus (prior-queued interconnection #640444) in some contingencies reached marginally over the 1.20 p.u. threshold. Such minor voltage excursions were considered acceptable. It was identified that the system intact condition high voltages can be lowered using means such as switching off nearby capacitor banks and adjustment of transformer taps. Lower the system intact voltage conditions will alleviate these voltage recovery violations.

S&C has performed power factor analysis on Group 9 Cluster scenarios. Power factor analysis reported the power factors at the study project POI buses for all N-1 (or N-1-1 for prior-outage contingencies) three-phase contingences and marked the contingency at which the required power factor at the study POI project is beyond the normal required capability (from 0.95 lagging to 0.95 leading) of the studied wind farm. In addition, the maximum leading and lagging reactive power demand and power factor found by the power factor analysis study at the POI buses were given in Section 7.

S&C has performed an analysis of no-wind conditions for the interconnection requests being connected to the 345-kV or 230-kV buses. The no-wind analysis was performed under the Cluster scenarios by taking the interconnection wind generator out of service and determining the Mvar size of a shunt reactor to offset the reactive power that is due to the capacitance of the project's transmission lines and collector cables. The required shunt reactor Mvar ratings are given in Section 8.

S&C has performed a short-circuit analysis for the 2025 Summer Peak under Group 9 Cluster and reported short circuit results at all buses up to five levels away from the study project POIs.

2. INTRODUCTION

S&C has performed a Definitive Interconnection System Impact Study, DISIS-2015-001 (Group 9), in response to a request through the SPP Tariff. Group 9 consist of six (6) new interconnection requests listed in

Table 1, thirty (30) prior-queued projects listed in Table 2, and several adjacent generating units in the WAPA system listed in

Table 3 at 100% of power output.

Table 1: Group 9 Generation Interconnection Requests

Project	Size (MW)	Generator Model	Generator Bus(es)	Point of Interconnection (POI)	POI Bus
GEN-2014-023	79.9	GE	583923	Tap Ft Randall to Meadow Grove 230 kV	560718
GEN-2014-059	160.0	Vestas	584233	Tap Sidney-Ogallala 230 kV	560014
GEN-2014-060	125.8	GE	584113	Tap Pauline-Hildreth 115 kV	560733
GEN-2015-007	160.0	GE	584513	Hoskins 345 kV	640226
GEN-2015-008	150.4	GE	584523	Antelope 115 kV	640521
GEN-2015-023	300.8	GE	584653 and 584656	Holt County 345 kV	640510

Table 2: Prior Queued Projects

Request	Size (MW)	Generator Model	Point of Interconnection
GEN-2003-021N	75	Vestas 1.65 MW (640026)	Tap on the Ainsworth – Calamus 115 kV line (640050)
GEN-2004-023N	75	GENROU (640028)	Columbus 115 kV (640119)
GEN-2006-020N	42	Vestas V90 VCUS 1.8 & 3.0 MW (640421,640441)	Bloomfield 115 kV (640084)
GEN-2006-37N1	75	GE 1.7 MW (640449)	Broken Bow 115 kV (640089)
GEN-2006-038N005	79.5	GE 1.6 MW (640428)	Broken Bow 115 kV (640089)
GEN-2006-038N019	79.5	GE 1.5 MW (640431)	Petersburg 115 kV (640444)
GEN-2006-044N	40.5	GE 1.5 MW (645062)	Petersburg 115 kV (640444)
GEN-2007-011N08	81	Vestas V90 VCRS 3.0 MW (640418)	Bloomfield 115 kV (640084)
GEN-2008-086N02 (replaced by GEN-2014-032)	211.22	GE 100m 1.7 MW (645063, 645063)	Meadow Grove 230 kV (GEN-2008-086N02 POI) (640540)
GEN-2008-119O	60	GE 1.5 MW (645061)	S1399 161kV (646399)
GEN-2008-123N	89.7	GE 100m 1.79 MW, GE 103m 1.72 MW (572054)	Tap on the Pauline – Guide Rock 115 kV (560137)
GEN-2009-040	73.8	Vestas V100 VCSS 2.0 MW (532904)	Marshall 115 kV (533303)

GEN-2010-041	10.5	GE 1.5 MW (580071)	S1399 161kV (646399)
GEN-2010-051	200	GE 100m 1.7 MW (580014, 580017, 580020)	Tap on the Twin Church – Hoskins 230 kV line (560347)
GEN-2011-018 (replaced by GEN-2013-008)	73.6	GE 100m 1.7 MW (640555)	Steele County 115 kV (640426)
GEN-2011-027	120	GE 1.85 MW (580022, 580021, 580023)	Tap Twin Church-Hoskins 230 kV (560347)
GEN-2011-056	3.6 MW increase (Pgen=21.6MW)	GENSAL (640013)	Jeffrey 115 kV (640238)
GEN-2011-056A	3.6 MW increase (Pgen=21.6MW)	GENSAL (640014)	Johnson 1 115 kV (640240)
GEN-2011-056B	4.5 MW increase (Pgen=23.5MW)	GENSAL (640015)	Johnson 2 115 kV (640242)
GEN-2012-021	4.8 MW	GENROU (650010)	84th & Bluff 115 kV (650275)
GEN-2013-002	50.6	Siemens 108m 2.3 MW (583703)	Tap Sheldon - SW7&Bennet - Folsom/Pleasant Hill 115 kV (560746)
GEN-2013-008	1.2MW increase to GEN-2011-018 (Pgen=74.8MW)	GE 100m 1.7 MW (640555)	Steele City (640426) 115 kV
GEN-2013-014	25.5	GE 100m 1.7 MW (583643)	Tap Pauline (640313) – Guide Rock (640206) 115 kV (560137)
GEN-2013-019	73.6	Siemens 108m 2.3 MW (583703)	Tap Sheldon - SW7&Bennet - Folsom/Pleasant Hill 115 kV (560746)
GEN-2013-032	204.0	GE 97.4m 1.7 MW (583783)	Neligh 115 kV (640293)
GEN-2014-004	3.96	GE 97.4m 1.79 MW (640555)	Steele City 115 kV (GEN-2011-018 POI) (640426)
GEN-2014-013	73.5	GE XLE 97.4m (583833)	Meadow Grove 230 kV (GEN-2008-086N02 POI) (640540)
GEN-2014-031	35.8	GE 1.79 MW (583836)	Meadow Grove 230 kV (GEN-2008-086N02 POI) (640540)
GEN-2014-039	73.39	GE 1.79 MW (584093)	Friend 115 kV (640174)
Grand Prairie Wind	400.0	Vestas V110 VCSS 2.0MW (652353/652356)	Holt County – Ft. Thompson 345kV (POI bus #652532)

Table 3: WAPA Generators

Bus #	Bus Name	Pmax (MW)	KV	Unit ID
652546	FTRDL12G	43.0	13.800	1
652546	FTRDL12G	43.0	13.800	2
652547	FTRDL34G	43.0	13.800	3
652547	FTRDL34G	43.0	13.800	4
652548	FTRDL56G	43.0	13.800	5
652548	FTRDL56G	44.0	13.800	6
652549	FTRDL78G	44.0	13.800	7
652549	FTRDL78G	44.0	13.800	8
652575	GAVINS1G	31.0	13.800	1
652576	GAVINS2G	31.0	13.800	2
652577	GAVINS3G	30.0	13.800	3
659116	SPIRI71G	52.0	13.800	1
659117	SPIRI72G	52.0	13.800	2

3. Transmission System and Study Area

The interconnection requests in Group 9 will interconnect into Western Area Power Administration (WAPA, Area #652) and Nebraska Public Power District (NPPD, Area #640).

In addition to Areas #640 and #652, the following areas were monitored also:

- Sunflower Electric Power Corporation (SUNC, Area #534)
- Westar Energy, Inc. (WERE, Area #536)
- Greater Missouri Operations Company (GMO, Area #540)
- Kansas City Power & Light Company (KCP&L, Area #541)
- Omaha Public Power District (OPPD, Area #645)
- Lincoln Electric System (LES, Area #650)
- MidAmerican Energy (MEC, Area #635)

4. Power Flow Base Cases

DISIS-2015-001 (Group 9) and prior-queued projects were modeled as aggregated generating units in the base cases from SPP.

Cluster Scenario Base Cases:

- **MDWG14-15SP_DIS1501_G09.SAV** – 2015 Summer Peak Cluster Base Case for Group 9. New interconnection requests and prior queued projects at 100% output power.
- **MDWG14-15WP_DIS1501_G09.SAV** – 2015 Winter Peak Cluster Base Case for Group 9. New interconnection requests and prior queued projects at 100% output power.
- **MDWG14-25SP_DIS1501_G09.SAV** – 2025 Summer Peak Cluster Base Case for Group 9. New interconnection requests and prior queued projects at 100% output power.

Stand-Alone Scenario Base Cases:

- **MDWG14-15SP_DIS1501_G09-SA.SAV** – 2015 Summer Peak SA Base Case for Group 9. New interconnection requests currently out of service.
- **MDWG14-15WP_DIS1501_G09-SA.SAV** – 2015 Winter Peak SA Base Case for Group 9. New interconnection requests currently out of service.
- **MDWG14-25SP_DIS1501_G09-SA.SAV** – 2025 Summer Peak SA Base Case for Group 9. New interconnection requests currently out of service.

On June 18, 2015, S&C received two additional IDEV files and instructions from SPP, to correct the network parameters in the original base cases, cluster and stand-alone. They are

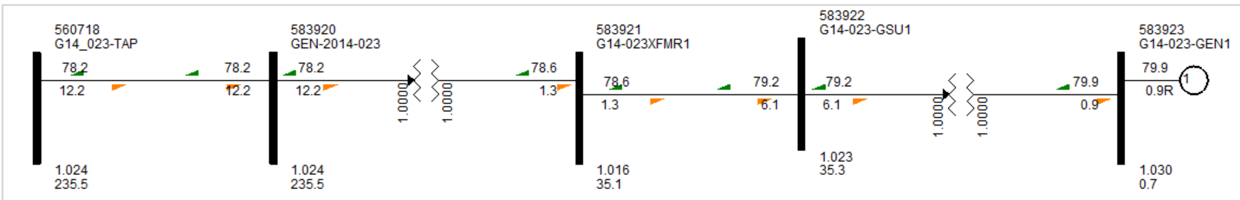
(1) Run "GrandIsland_Holt_GrandPrairie_FtThomp_Line_reactor_corrections.idv" on all three season base cases. This idev makes correction to the line reactors on the Grand Island to Holt to Grand Prairie to Ft. Thompson 345 kV line.

(2) Run "13.DIS-15-1_BUILD_RPLAN-PROJECT[15G 15SP 15WP].idv" on the 2025 Summer Peak case. The idev adds a 345/115 kV transformer (which is missing in this case) at Cherry County 345kV (640500) to Thedford 115kV (640381). The 2015SP and

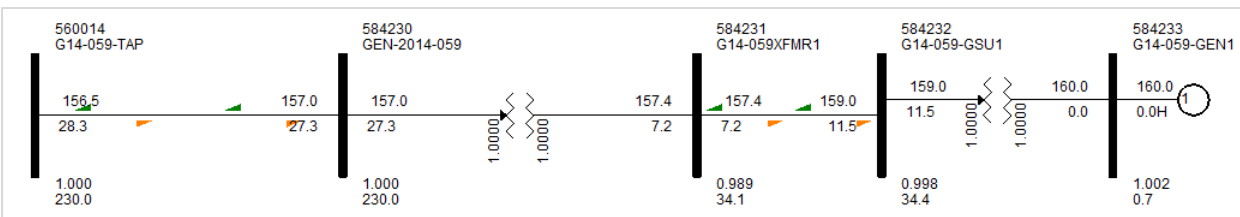
2015WP cases will not have this transformer and the 345kV line from Holt County (640510) to Cherry County (640500) to Gentleman (640183) since these will not go into service until sometime in 2017.

5. Power Flow Model

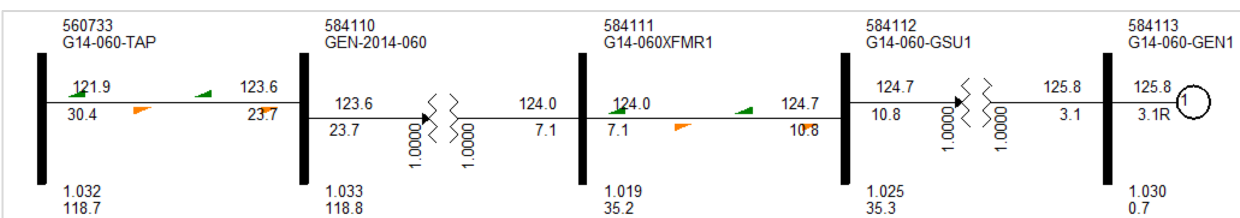
SPP's base case power flow models were built in PSS/E 32.2.2. In PSS/E of the same version, S&C created one-line diagrams depicted in Figure 1 for each interconnection request.



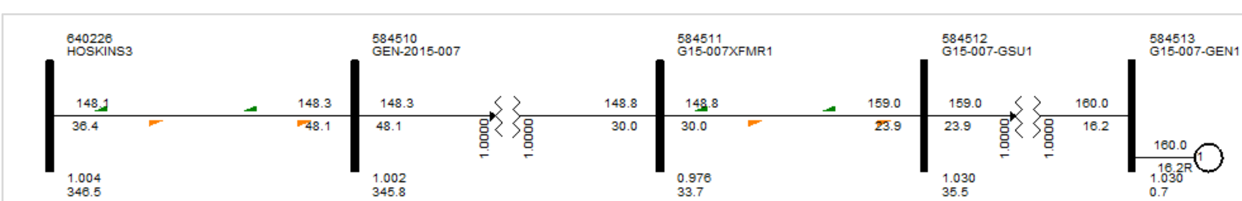
(a) Interconnection request GEN-2014-023



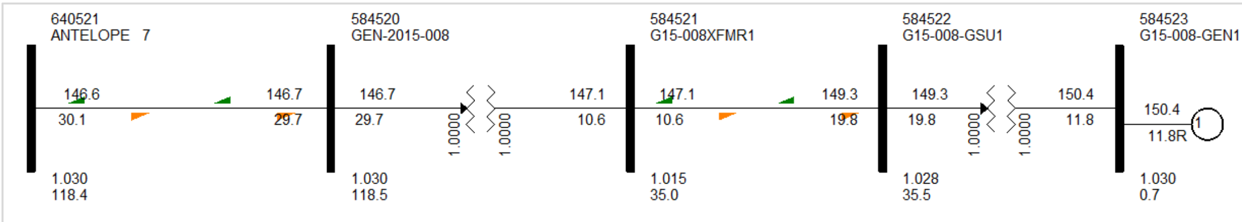
(b) Interconnection request GEN-2014-059



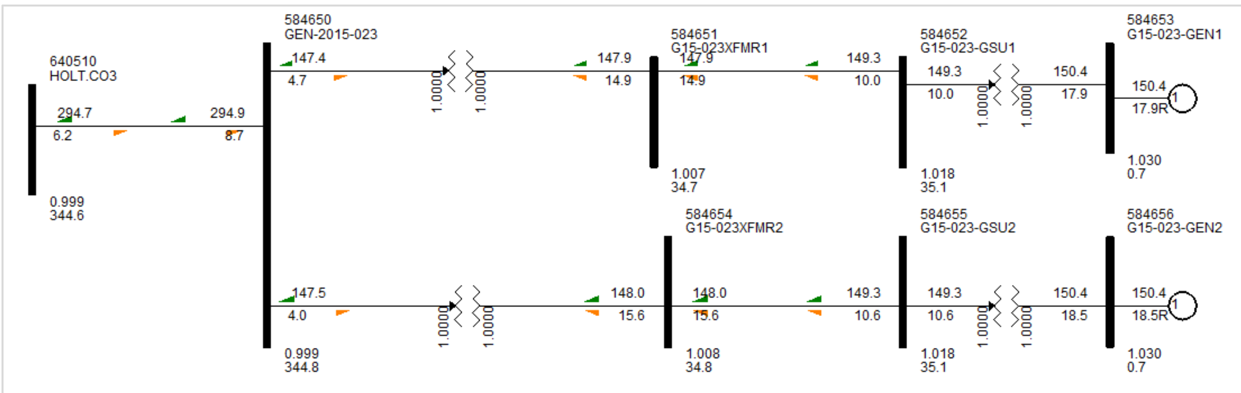
(c) Interconnection request GEN-2014-060



(d) Interconnection request GEN-2015-007



(e) Interconnection request GEN-2015-008



(f) Interconnection request GEN-2015-023

Figure 1. One-line Diagrams of the Interconnection Request Projects

6. Dynamic Stability Analysis

6.1. Assumptions

Dynamic stability analysis was performed for all the SPP contingencies listed in Appendix A. Three phase faults were simulated as bolted faults, while single line-to-ground faults were simulated under the assumption that a single line-to-ground fault will cause a 60% drop in the positive-sequence voltage at the fault location.

6.2. Stability Criteria

Dynamic stability studies were performed to ensure system stability following critical faults on the system. The system is considered stable if the following conditions are met:

(1) Disturbances including three-phase and single-phase to ground faults, should not cause synchronous and asynchronous plants disconnected from the transmission grid.

(2) The angular positions of synchronous machine rotor become constant following an aperiodic system disturbance.

(3) Voltage magnitudes and frequencies at terminals of asynchronous generators should not exceed magnitudes and durations that will cause protection elements to operate. Furthermore, the response after the disturbance needs to be studied at the terminals of the machine to ensure that there are no sustained oscillations in power output, speed, frequency, etc.

(4) Voltage magnitudes and angles after the disturbance should settle to a constant and acceptable operating level. Frequencies should settle to the acceptable range within nominal 60 Hz power frequency.

In addition, performance of the transmission system is measured against the Southwest Power Pool Disturbance Criteria Requirements on Angular oscillations and Transient Voltage Recovery, detailed in Appendix B.

6.3. Dynamic Stability Results

The results of dynamic stability analyses indicated that:

- Machines at bus #584653, #584656, #652353, and #652356 exhibited the stability issues in Contingency #13, #14 and #97 of 2015 SP Cluster. The same stability issues also occurred in Contingency #13, #14 and #97 of 2015 WP Cluster, Contingency #13, #14 and #97 of 2015 SP and 2015 WP stand-alone project GEN-2015-023. Figure 2 show the instability results for Contingency #13 of 2015 SP Cluster.
- In certain contingencies, the maximum transient voltage at the 115 kV Petersbug bus (prior-queued interconnection #640444) was higher than 1.20 p.u. voltage, the upper range by SPP for the transient voltage recovery requirement. For example, 115 kV Petersbug bus voltages reached 1.21 p.u. in Contingency #87 of 2025 SP cluster, 1.21 p.u. in Contingency #88 of 2025 SP cluster, 1.21 p.u. in Contingency #87 and 1.2037 p.u. in Contingency #88 of 2025 SP stand-alone project GEN-2015-008.
- Machines other than discussed above remained stable for all contingencies.
- Bus voltages other than discussed above were all met the SPP transient voltage recovery requirement.

Table 4 below summarized the cluster dynamic stability results for each contingency and each season.

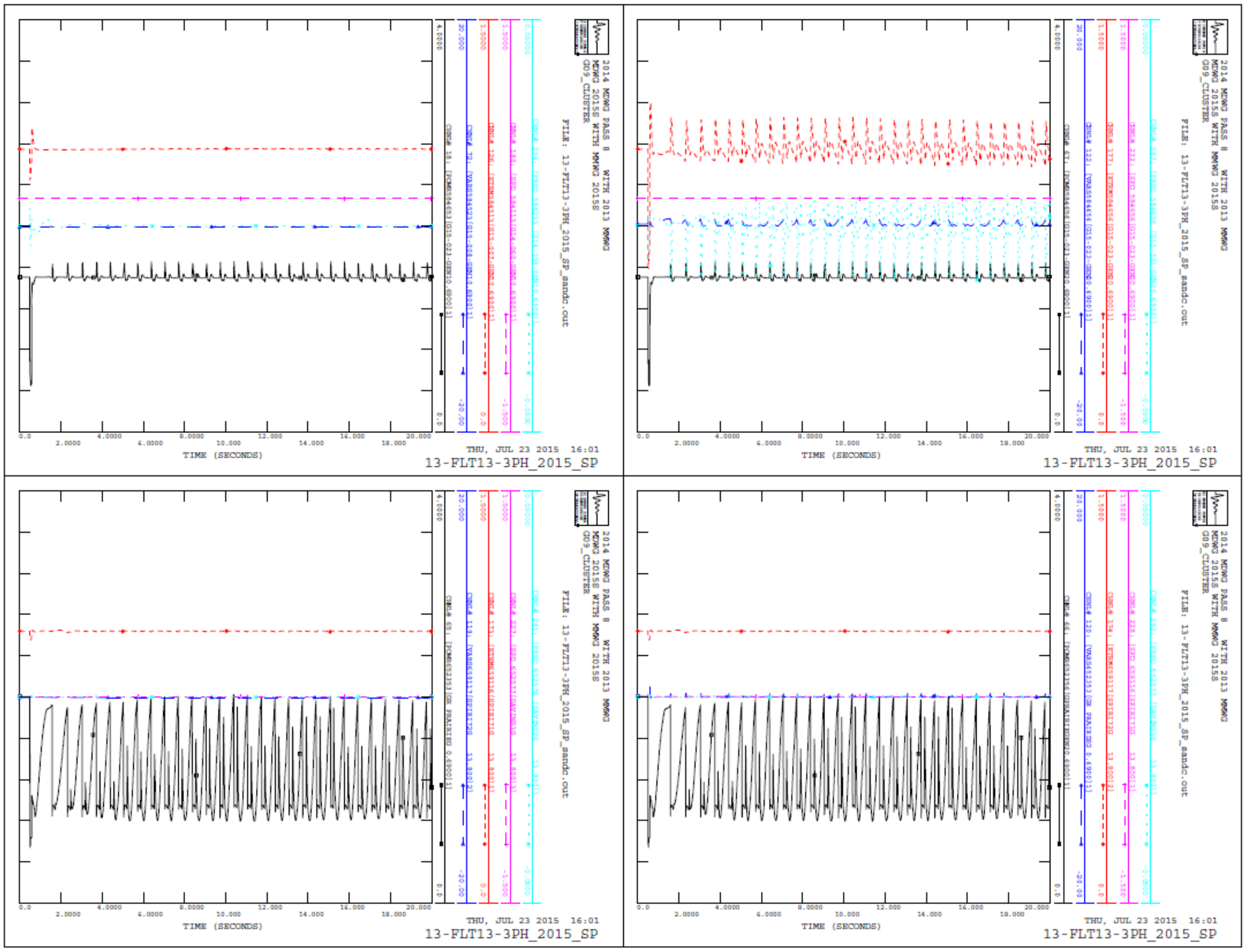


Figure 2. Unstable Machines #584653, #584656, #652353, and #652356 in Contingency #13, 2015 SP Cluster
(Power-Black, Var-Blue, Eterm-Red, SPD-Pink and Freq-Cyan)

Table 4: Group 9 Cluster Dynamic Stability Results

Cont. No.	Cont. Name	2015 Summer Peak	2015 Winter Peak	2025 Summer Peak
1	FLT01-3PH	STABLE	STABLE	STABLE
2	FLT02-3PH	STABLE	STABLE	STABLE
3	FLT03-3PH	STABLE	STABLE	STABLE
4	FLT04-3PH	STABLE	STABLE	STABLE
5	FLT05-3PH	STABLE	STABLE	STABLE
6	FLT06-3PH	STABLE	STABLE	STABLE
7	FLT07-3PH	STABLE	STABLE	STABLE
8	FLT08-3PH	STABLE	STABLE	STABLE
9	FLT08-3PH	STABLE	STABLE	STABLE
10	FLT10-3PH	STABLE	STABLE	STABLE
11	FLT11-3PH 2025SP Only	N/A	N/A	STABLE
12	FLT12-3PH	STABLE	STABLE	STABLE
13	FLT13-3PH	UNSTABLE	UNSTABLE	STABLE
14	FLT14-3PH	UNSTABLE	UNSTABLE	STABLE
15	FLT15-3PH	STABLE	STABLE	STABLE
16	FLT16-3PH	STABLE	STABLE	STABLE
17	FLT17-3PH	STABLE	STABLE	STABLE
18	FLT18-SB	STABLE	STABLE	STABLE
19	FLT19-SB	STABLE	STABLE	STABLE
20	FLT20-PO	STABLE	STABLE	STABLE
21	FLT21-PO	STABLE	STABLE	STABLE
22	FLT22-PO	STABLE	STABLE	STABLE
23	FLT23-SB	STABLE	STABLE	STABLE
24	FLT24-PO	STABLE	STABLE	STABLE
25	FLT25-PO	STABLE	STABLE	STABLE
26	FLT26-PO	STABLE	STABLE	STABLE
27	FLT27-3PH	STABLE	STABLE	STABLE
28	FLT28-3PH	STABLE	STABLE	STABLE
29	FLT29-PO	STABLE	STABLE	STABLE
30	FLT30-PO	STABLE	STABLE	STABLE
31	FLT31-3PH	STABLE	STABLE	STABLE
32	FLT32-1PH	STABLE	STABLE	STABLE
33	FLT33-3PH	STABLE	STABLE	STABLE
34	FLT34-1PH	STABLE	STABLE	STABLE
35	FLT35-3PH	STABLE	STABLE	STABLE
36	FLT36-3PH	STABLE	STABLE	STABLE
37	FLT37-1PH	STABLE	STABLE	STABLE
38	FLT38-3PH	STABLE	STABLE	STABLE
39	FLT39-1PH	STABLE	STABLE	STABLE
40	FLT40-3PH	STABLE	STABLE	STABLE
41	FLT41-1PH	STABLE	STABLE	STABLE
42	FLT42-3PH	STABLE	STABLE	STABLE
43	FLT43-1PH	STABLE	STABLE	STABLE
44	FLT44-3PH	STABLE	STABLE	STABLE
45	FLT45-PO	STABLE	STABLE	STABLE
46	FLT46-PO	STABLE	STABLE	STABLE
47	FLT47-PO	STABLE	STABLE	STABLE
48	FLT48-3PH	STABLE	STABLE	STABLE

Cont. No.	Cont. Name	2015 Summer Peak	2015 Winter Peak	2025 Summer Peak
49	FLT49-1PH	STABLE	STABLE	STABLE
50	FLT50-3PH	STABLE	STABLE	STABLE
51	FLT51-1PH	STABLE	STABLE	STABLE
52	FLT52-PO	STABLE	STABLE	STABLE
53	FLT53-PO	STABLE	STABLE	STABLE
54	FLT54-3PH	STABLE	STABLE	STABLE
55	FLT55-3PH	STABLE	STABLE	STABLE
56	FLT56-3PH	STABLE	STABLE	STABLE
57	FLT57-3PH	STABLE	STABLE	STABLE
58	FLT58-SB	STABLE	STABLE	STABLE
59	FLT59-PO	STABLE	STABLE	STABLE
60	FLT60-PO	STABLE	STABLE	STABLE
61	FLT61-PO	STABLE	STABLE	STABLE
62	FLT62-3PH	STABLE	STABLE	STABLE
63	FLT63-3PH	STABLE	STABLE	STABLE
64	FLT64-PO	STABLE	STABLE	STABLE
65	FLT65-PO	STABLE	STABLE	STABLE
66	FLT66-3PH 2015SP and 2015WP Only	STABLE	STABLE	N/A
67	FLT67-3PH 2025SP Only	N/A	N/A	STABLE
68	FLT68-3PH	STABLE	STABLE	STABLE
69	FLT69-PO	STABLE	STABLE	STABLE
70	FLT70-3PH	STABLE	STABLE	STABLE
71	FLT71-PO	STABLE	STABLE	STABLE
72	FLT72-3PH	STABLE	STABLE	STABLE
73	FLT73-3PH	STABLE	STABLE	STABLE
74	FLT74-3PH	STABLE	STABLE	STABLE
75	FLT75-3PH	STABLE	STABLE	STABLE
76	FLT76-3PH	STABLE	STABLE	STABLE
77	FLT77-PO	STABLE	STABLE	STABLE
78	FLT78-SB	STABLE	STABLE	STABLE
79	FLT79-SB	STABLE	STABLE	STABLE
80	FLT80-SB	STABLE	STABLE	STABLE
81	FLT81-SB 2025SP Only	N/A	N/A	STABLE
82	FLT82-3PH	STABLE	STABLE	STABLE
83	FLT83-3PH	STABLE	STABLE	STABLE
84	FLT84-3PH	STABLE	STABLE	STABLE
85	FLT85-3PH	STABLE	STABLE	STABLE
86	FLT86-PO	STABLE	STABLE	STABLE
87	FLT87-PO 2025SP Only	N/A	N/A	STABLE
88	FLT88-PO 2025SP Only	N/A	N/A	STABLE
89	FLT89-PO 2025SP Only	N/A	N/A	STABLE
90	FLT90-3PH	STABLE	STABLE	STABLE
91	FLT91-3PH	STABLE	STABLE	STABLE
92	FLT92-3PH 2025SP Only	N/A	N/A	STABLE

Cont. No.	Cont. Name	2015 Summer Peak	2015 Winter Peak	2025 Summer Peak
93	FLT93-3PH	STABLE	STABLE	STABLE
94	FLT94-3PH	STABLE	STABLE	STABLE
95	FLT95-3PH	STABLE	STABLE	STABLE
96	FLT96-3PH	STABLE	STABLE	STABLE
97	FLT97-PO	UNSTABLE	UNSTABLE	STABLE
98	FLT98-PO	STABLE	STABLE	STABLE
99	FLT99-PO	STABLE	STABLE	STABLE
100	FLT100-SB	STABLE	STABLE	STABLE
101	FLT101-SB	STABLE	STABLE	STABLE
102	FLT102-SB	STABLE	STABLE	STABLE
103	FLT103-SB Summer 2025SP Only	N/A	N/A	STABLE

Machine stability issues in the cluster dynamic stability simulation were reported to SPP. The resolution from SPP was to add the upgrade from the Holt County to Cherry County to Gentleman 345kV, to the unstable contingencies. Essentially, it required us to apply the second IDEV file "13.DIS-15-1_BUILD_RPLAN-PROJECT[15G 15SP 15WP].idv" to cases in 2015 SP and 2015 WP that exhibited the stability issues. If necessary, the same upgrade can be applied to the stand-alone cases, as indicated by SPP. Tests found that after the Holt County to Cherry County to Gentleman 345 kV upgrade was added to the base case, the stability issues were eliminated. Figure 3 show the results of the upgrade for Contingency #13 of 2015 SP Cluster.

For the voltage recovery violation observed for Fault #87 and #88, it was observed that there were very high voltages in the area of Petersburg for system intact conditions in the 2025 summer peak model. System intact condition voltages can be lowered using means such as switching off nearby capacitor banks and adjustment of transformer taps. Lower the system intact voltage conditions will alleviate these voltage recovery violations.

Plots of cluster dynamic stability results for each contingency and each season are given in Appendix C. Plots of stand-alone dynamic stability results for each contingency and each season are given in Appendix D. Instability results were replaced with the results with the upgrade for the same contingency. In all updated results, there was no generator tripping or disconnection from the transmission grid or unstable machines. Dynamic stability analysis thus concluded that Group 9 successfully rode through all contingencies specified by SPP and the nearby areas retained frequency and voltage stability.

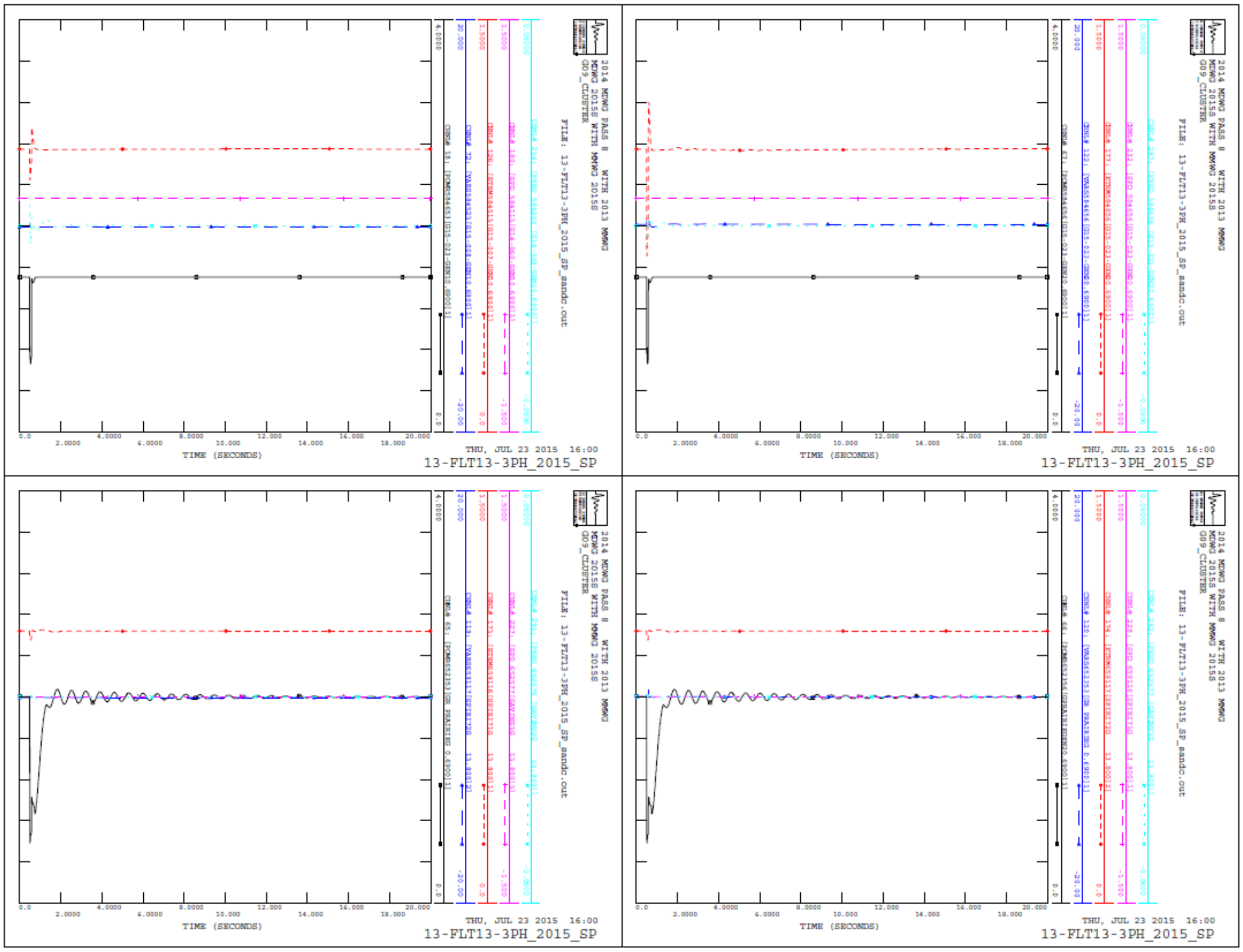


Figure 3. Stable Machines #584653, #584656, #652353, and #652356 in Contingency #13, 2015 SP Cluster after the upgrade
(Power-Black, Var-Blue, Eterm-Red, SPD-Pink and Freq-Cyan)

7. Power Factor Analysis

The power factor analysis was performed under the cluster bases and for all N-1 (N-1-1 for prior-outage contingencies) three-phase contingencies shown in the Fault Definition table in Appendix A. Single-phase contingencies and N-2 contingencies were excluded from the study. Prior to the run, the cluster base cases were slightly altered by turning off the reactive capability of the study project wind farms and by placing a new var generator at each wind farm high voltage bus for supporting the reactive power. The var generators were set to hold the voltage schedule at the interconnection project consistent with the voltage schedules in the provided base case or 1.0 p.u. voltage (whichever is higher).

Table 5 gives the voltage schedule at each interconnection request location in the original cluster base cases. Interconnection requests GEN-2014-059 and GEN-2015-023 having the voltage schedules at 0.9998 p.u. and 0.9988 in the 2015 Summer Peak base case, below 1.0 p.u. voltage, were rescheduled to 1.0 p.u. voltage during the run.

Table 5: Base Case Voltages at the Interconnection Request POI Bus

Request	POI	2015 Summer Peak (p.u.)	2015 Winter Peak (p.u.)	2025 Summer Peak (p.u.)
GEN-2014-023	560718	1.0241	1.0214	1.0276
GEN-2014-059	560014	0.9998	1.0137	1.0073
GEN-2014-060	560733	1.0319	1.0352	1.0192
GEN-2015-007	640226	1.0044	1.0024	1.0128
GEN-2015-008	640521	1.0299	1.0390	1.0316
GEN-2015-023	640510	0.9988	1.0102	1.0099

The power factor analysis results for Group 9 interconnection requests are presented in Appendix E tables. We marked in pink the contingency at which the required power factor at the study POI project is beyond the normal required capability (from 0.95 lagging to 0.95 leading) of the studied wind farm. We also provided a summary table below of the maximum leading/lagging reactive power demand and power factor found by the power factor analysis at the POIs.

Table 6: Summary of Power Factor Analysis at the POI

Request	Capacity	Capacity	Reactive Power/Power Factor at POI	
			Leading (absorbing vars)	Lagging (providing vars)
GEN-2014-023	79.9 MW	560718	-46.9 Mvar / PF = 0.862	73.0 Mvar / PF = 0.738
GEN-2014-059	160.0 MW	560014	-44.8 Mvar / PF = 0.963	99.8 Mvar / PF = 0.848
GEN-2014-060	125.8 MW	560733	-44.1 Mvar / PF = 0.944	30.7 Mvar / PF = 0.971
GEN-2015-007	160.0 MW	640226	-129.4 Mvar / PF = 0.778	66.2 Mvar / PF = 0.924
GEN-2015-008	150.4 MW	640521	-46.5 Mvar / PF = 0.955	10.8 Mvar / PF = 0.997
GEN-2015-023	300.7 MW	640510	-24.0 Mvar / PF = 0.997	161.2 Mvar / PF = 0.881

NOTE: Per the SPP Tariff as reactive power is required for all projects, the final requirement in the GIA will be the pro-forma 0.95 lagging to 0.95 leading at the point of interconnection.

8. No Wind Conditions Analysis

S&C has performed an analysis of no wind conditions for the interconnection requests at the 345-kV or 230-kV bus. The interconnection projects at 115 kV level were excluded from the study. The no-wind analysis was performed under the Cluster scenarios by taking the interconnection wind generator out of service and placing a shunt reactor at the project substation high side to offset the reactive power that comes from the capacitance of the project's transmission lines and collector cables. The size of the shunt reactor was adjusted such that the net Mvar flow into the POI from the studied wind farm was approximately zero. Table 7 gives the shunt reactor Mvar for the studied projects.

Table 7: Shunt Reactor Mvar Determined by No Wind Study

Request	POI	2015 Summer Peak	2015 Winter Peak	2025 Summer Peak
GEN-2014-023	560718	5.6	5.5	5.6
GEN-2014-059	560014	7.5	7.4	7.5
GEN-2015-007	640226	16.7	16.7	16.7
GEN-2015-023	640510	17.2	17.2	17.3

9. SHORT-CIRCUIT STUDY

A short-circuit study has been performed on the power flow models for the 2025 Summer Peak Season for each generator using the Cluster Scenario model. Short-circuit analysis includes applying a 3-phase fault on buses up to 5 levels away from the POI of each interconnection request project. PSS/E "Automatic Sequence Fault Calculation (ASCC)" fault analysis module was used for the purpose of short-circuit analysis. The results of the short-circuit analysis have been recorded for all the buses up to five levels away from the point of interconnection of each interconnection request project. Detailed results of the short-circuit study are provided in Appendix F.

10. Conclusions and Recommendations

- Group 9 dynamic analysis results indicated that 2015 Summer Peak and 2015 Winter Peak Cluster base cases exhibited instabilities in certain contingencies. After the Holt County to Cherry County to Gentleman 345 kV upgrade was added to the base case, the stability issues were eliminated. 2025 Summer Peak cluster base cases that already had these upgrades rode through all contingencies and remained stable.

- Group 9 dynamic analysis results indicated that 2015 Summer Peak and 2015 Winter Peak Stand-Alone GEN-2015-023 base cases exhibited instability in certain contingencies. After the Holt County to Cherry County to Gentleman 345 kV upgrade was added to the base case the stability issues were eliminated. Note that the other (5) stand-alone base cases, in 2015 Summer Peak and 2015 Winter Peak, do not require these upgrades and remain stable during the contingencies. 2025 Summer Peak stand-alone base cases that already had the upgrades rode through all contingencies and remained stable.

- Group 9 dynamic analysis results, for cluster and stand-alone scenarios, indicated that with the necessary upgrade mentioned above, the interconnection request projects are expected to successfully ride through all N-1, N-1-1, and N-2 fault contingency specified by SPP, retaining angular, frequency and voltage stability at the nearby areas and meeting the transient voltage recovery requirement by SPP. It is thus concluded that Group 9 study projects with the required upgrades are expected to successfully interconnect into the transmission system at their desired locations for 100% power outputs.
- For the voltage recovery violation observed for Fault #87 and #88, it was observed that there were very high voltages in the area of Petersburg for system intact conditions in the 2025 summer peak model. System intact condition voltages can be lowered using means such as switching off nearby capacitor banks and adjustment of transformer taps. Lower the system intact voltage conditions will alleviate these voltage recovery violations.

- The results of power factor analysis indicate that all interconnection requests are required to maintain a power factor of 0.95 lagging to 0.95 leading at the POI to meet SPP's requirements.

- The results of no-wind study suggested that to offset the reactive power from the capacitance of the interconnection project's transmission lines and collector cables during the no-wind conditions, a 5.6 Mvar shunt reactor size is required for the GEN-2014-023 high voltage side, 7.5 Mvar for GEN-2014-059, 16.7 Mvar for GEN-2015-007, and 17.3 Mvar for GEN-2015-023.
- A short-circuit study has been performed on the power flow models for the 2025 Summer Peak Season for each generator using the Cluster Scenario model. A 3-phase fault is applied on buses up to 5 levels away from the POI of each interconnection request project and the results of the study have been presented.

APPENDIX A

SPP GROUP 9 FAULT DEFINITIONS (SUBMITTED IN A SEPARATE FILE)

APPENDIX B

SOUTHWEST POWER POOL DISTURBANCE PERFORMANCE REQUIREMENTS (SUBMITTED IN A SEPARATE FILE)

APPENDIX C

DYNAMIC STABILITY PLOTS FOR CLUSTER SCENARIO (SUBMITTED IN SEPARATE FILES FROM APPENDIX C-1 TO C-3)

C-1 Group 9 Cluster Dynamic Stability Plots For 2015 Summer Peak Case

C-2 Group 9 Cluster Dynamic Stability Plots For 2015 Winter Peak Case

C-3 Group 9 Cluster Dynamic Stability Plots For 2025 Summer Peak Case

Each contingency consists of (65) subplots:

- Subplot #1 are the (6) monitor system phase angle channels in the original snapshot file provided by SPP.
- Subplot #2 to Subplot #55 are results for (54) generators in the scope of study.
- Subplots #56 to Subplot #60 are voltages at the POI buses in the scope of study.
- Subplots #61 to Subplot #65 are frequencies at the POI buses in the scope of study.

APPENDIX D

DYNAMIC STABILITY PLOTS FOR STAND-ALONE SCENARIO (SUBMITTED IN SEPARATE FILE FROM APPENDIX D-1 TO D-18)

D-1 Group 9 Stand-Alone "GEN-2014-023" Dynamic Stability Plots For 2015 Summer Peak Case

D-2 Group 9 Stand-Alone "GEN-2014-023" Dynamic Stability Plots For 2015 Winter Peak Case

D-3 Group 9 Stand-Alone "GEN-2014-023" Dynamic Stability Plots For 2025 Summer Peak Case

D-4 Group 9 Stand-Alone "GEN-2014-059" Dynamic Stability Plots For 2015 Summer Peak Case

D-5 Group 9 Stand-Alone "GEN-2014-059" Dynamic Stability Plots For 2015 Winter Peak Case

D-6 Group 9 Stand-Alone "GEN-2014-059" Dynamic Stability Plots For 2025 Summer Peak Case

D-7 Group 9 Stand-Alone "GEN-2014-060" Dynamic Stability Plots For 2015 Summer Peak Case

D-8 Group 9 Stand-Alone "GEN-2014-060" Dynamic Stability Plots For 2015 Winter Peak Case

D-9 Group 9 Stand-Alone "GEN-2014-060" Dynamic Stability Plots For 2025 Summer Peak Case

D-10 Group 9 Stand-Alone "GEN-2015-007" Dynamic Stability Plots For 2015 Summer Peak Case

D-11 Group 9 Stand-Alone “GEN-2015-007” Dynamic Stability Plots For 2015 Winter Peak Case

D-12 Group 9 Stand-Alone “GEN-2015-007” Dynamic Stability Plots For 2025 Summer Peak Case

D-13 Group 9 Stand-Alone “GEN-2015-008” Dynamic Stability Plots For 2015 Summer Peak Case

D-14 Group 9 Stand-Alone “GEN-2015-008” Dynamic Stability Plots For 2015 Winter Peak Case

D-15 Group 9 Stand-Alone “GEN-2015-008” Dynamic Stability Plots For 2025 Summer Peak Case

D-16 Group 9 Stand-Alone “GEN-2015-023” Dynamic Stability Plots For 2015 Summer Peak Case

D-17 Group 9 Stand-Alone “GEN-2015-023” Dynamic Stability Plots For 2015 Winter Peak Case

D-18 Group 9 Stand-Alone “GEN-2015-023” Dynamic Stability Plots For 2025 Summer Peak Case

Each contingency consists of (65) subplots:

- Subplot #1 are the six (6) monitor system phase angle channels in the original snapshot file provided by SPP.
- Subplot #2 to Subplot #55 are results for (54) generators in the scope of study.
- Subplots #56 to Subplot #60 are voltages at the POI buses in the scope of study.
- Subplots #61 to Subplot #65 are frequencies at the POI buses in the scope of study.

APPENDIX E

POWER FACTOR ANALYSIS RESULTS (SUBMITTED IN SEPARATE FILE FROM APPENDIX E-1 TO E-6)

E-1 Group 9 Power Factor Results for Interconnection Request GEN-2014-023 (#560718)

E-2 Group 9 Power Factor Results for Interconnection Request GEN-2014-059 (#560014)

E-3 Group 9 Power Factor Results for Interconnection Request GEN-2014-060 (#560733)

E-4 Group 9 Power Factor Results for Interconnection Request GEN-2015-007 (#640226)

E-5 Group 9 Power Factor Results for Interconnection Request GEN-2015-008 (#640521)

E-6 Group 9 Power Factor Results for Interconnection Request GEN-2015-023 (#640510)

APPENDIX F

SHORT-CIRCUIT STUDY RESULTS (SUBMITTED IN A SEPARATE FILE)

Fault Definitions

Cont. No.	Cont. Name	Description	GEN-2014-023	GEN-2014-059	GEN-2014-060	GEN-2015-007	GEN-2015-008	GEN-2015-023
1	FLT01-3PH	3 phase fault on the G14-023 TAP (560718) to Ft Randall (652509) 230kV line circuit 1, near G14-023 TAP. a. Apply fault at the G14-023 TAP 230kV bus. b. Clear fault after 6 cycles and trip the faulted line and remove fault.	X				X	X
2	FLT02-3PH	3 phase fault on the G14-023 TAP (560718) to Meadow Grove (640540) 230kV line circuit 1, near G14-023 TAP. a. Apply fault at the G14-023 TAP 230kV bus. b. Clear fault after 6 cycles and trip the faulted line and remove fault.	X					
3	FLT03-3PH	3 phase fault on the Meadow Grove (640540) to Columbus (640133) 230kV line circuit 1, near Meadow Grove 230kV. a. Apply fault at the Meadow Grove 230kV bus. b. Clear fault after 6 cycles and trip the faulted line.	X				X	X
4	FLT04-3PH	3 phase fault on the Columbus (640133) to Shell Creek (640343) 230kV line circuit 1, near Columbus. a. Apply fault at the Columbus 230kV bus. b. Clear fault after 6 cycles and trip the faulted line and remove fault.	X					
5	FLT05-3PH	3 phase fault on the Columbus (640133) to Columbus West (640131) 230kV line circuit 1, near Columbus. a. Apply fault at the Columbus 230kV bus. b. Clear fault after 6 cycles and trip the faulted line and remove fault.	X					
6	FLT06-3PH	3 phase fault on the Columbus (640133) to East Columbus (640126) 230kV line circuit 1, near Columbus. a. Apply fault at the Columbus 230kV bus. b. Clear fault after 6 cycles and trip the faulted line and remove fault.	X					
7	FLT07-3PH	3 phase fault on the Columbus (640133) 230/Kelly (640134) 115/(640135) 13.2kV Transformer circuit 1, near Columbus 230kV. a. Apply fault at the Columbus 230kV bus. b. Clear fault after 5.5 cycles, trip the faulted line, and remove the fault.	X					
8	FLT08-3PH	3 phase fault on the Shell Creek (640342) to East Columbus (640125) 345kV line circuit 1, near Shell Creek. a. Apply fault at the Shell Creek 345kV bus. b. Clear fault after 5 cycles and trip the faulted line and remove fault.	X			X		
9	FLT08-3PH	3 phase fault on the Hoskins (640226) to Shell Creek (640342) 345kV line circuit 1, near Hoskins (640226). a. Apply fault at the Hoskins 345kV bus. b. Clear fault after 5 cycles and trip the faulted line and remove fault.	X			X	X	
10	FLT10-3PH	3 phase fault on the Hoskins (640226) to Raun (635200) 345kV line circuit 1, near Hoskins. a. Apply fault at the Hoskins 345kV bus. b. Clear fault after 5 cycles and trip the faulted line and remove fault.	X			X		

Cont. No.	Cont. Name	Description	GEN-2014-023	GEN-2014-059	GEN-2014-060	GEN-2015-007	GEN-2015-008	GEN-2015-023
11	FLT11-3PH 2025SP Only	**ONLY for 6/1/2016 and BEYOND** 3 phase fault on the Hoskins (640226) to Antelope (640520) 345kV line circuit 1, near Hoskins. a. Apply fault at the Hoskins 345kV bus. b. Clear fault after 5 cycles and trip the faulted line and remove fault.	**X**			**X**	**X**	
12	FLT12-3PH	3 phase fault on the Grand Island (652571) to McCool (640271) 345kV line circuit 1, near Grand Island. a. Apply fault at the Grand Island 345kV bus. b. Clear fault after 5 cycles and trip the faulted line and remove fault.	**X**					**X**
13	FLT13-3PH	3 phase fault on the Grand Island (652571) to Holt County (640510) 345kV line circuit 1, near Grand Island. a. Apply fault at the Grand Island 345kV bus. b. Clear fault after 5 cycles and trip the faulted line and remove fault.	**X**					**X**
14	FLT14-3PH	3 phase fault on the Ft. Thompson (652506) to Grand Prairie (652532) 345kV line circuit 1, near Ft. Thompson. a. Apply fault at the Ft. Thompson 345kV bus. b. Clear fault after 5 cycles and trip the faulted line and remove fault.	**X**					**X**
15	FLT15-3PH	3 phase fault on the Ft Thompson (652506) to Leland Olds (659105) 345kV line circuit 1, near Ft Thompson. a. Apply fault at the Ft Thompson 345kV bus. b. Clear fault after 5 cycles and trip the faulted line and remove fault.	**X**					**X**
16	FLT16-3PH	3 phase fault on the Ft Randall (652509) to Utica Junction (652526) 230kV line circuit 1, near Ft Randall. a. Apply fault at the Ft Randall 230kV bus. b. Clear fault after 6 cycles and trip the faulted line and remove fault.	**X**					**X**
17	FLT17-3PH	3 phase fault on the Ft Randall (652509) to Sioux City (652565) 230kV line circuit 1, near Ft Randall. a. Apply fault at the Ft Randall 230kV bus. b. Clear fault after 6 cycles and trip the faulted line and remove fault.	**X**					**X**
18	FLT18-SB	**Ft Randall 230kV Stuck Breaker Scenario 1** a. Apply single phase fault at the Ft Randall (652509) 230kV bus. b. Wait 16 cycles and remove fault. c. Trip Ft Randall (652509) to Utica Junction (652526) 230kV line circuit 1. d. Trip Ft Randall (652509) 230/(652510) 115kV transformer circuit 1.	**X**					
19	FLT19-SB	**Ft Randall 230kV Stuck Breaker Scenario 2** a. Apply single phase fault at the Ft Randall (652509) 230kV bus. b. Wait 16 cycles and remove fault. c. Trip Ft Randall (652509) to Sioux City (652565) 230kV line circuit 1. d. Trip Ft Randall (652509) 230/(652510) 115kV transformer circuit 1.	**X**					

Cont. No.	Cont. Name	Description	GEN-2014-023	GEN-2014-059	GEN-2014-060	GEN-2015-007	GEN-2015-008	GEN-2015-023
20	FLT20-PO	**Ft. Randall Prior Outage Scenario 1** a. Prior Outage: Switch out Ft Randall (652509) to Utica Junction (652526) 230kV circuit 1 and solve. b. Apply 3 phase fault on the Ft Randall (652509) to Sioux City (652565) 230kV line circuit 1, near Ft Randall. c. Clear fault after 6 cycles and trip the faulted line and remove fault.	**X**					
21	FLT21-PO	**Ft. Randall Prior Outage Scenario 2** a. Prior Outage: Switch out Ft Randall (652509) to Utica Junction (652526) 230kV circuit 1 and solve. b. Apply 3 phase fault on the Meadow Grove (640540) to Columbus (640133) 345kV line circuit 1, near Ft Randall. c. Clear fault after 6 cycles and trip the faulted line and remove fault.	**X**					
22	FLT22-PO	**Ft. Randall Prior Outage Scenario 3** a. Prior Outage: Switch out Ft Randall (652509) to Utica Junction (652526) 230kV circuit 1 and solve. b. Apply 3 phase fault on the Ft Randall (652509) 230/(652510) 115kV transformer circuit 1, near Ft Randall 230kV. c. Clear fault after 5.5 cycles and trip the faulted line and remove fault.	**X**					
23	FLT23-SB	**Columbus 230kV Stuck Breaker Scenario 1** a. Apply single phase fault at the Columbus (640133) 230kV bus. b. Wait 16 cycles and remove fault. c. Trip entire Columbus (640133) 230kV bus.	**X**					
24	FLT24-PO	**Columbus Prior Outage Scenario 1** a. Prior Outage: Switch out Columbus (640133) to East Columbus (640126) 230kV circuit 1 and solve. b. Apply 3 phase fault on the Columbus (640133) 230/Kelly (640134) 115/(640135) 13.2kV transformer circuit 1, near Columbus 230kV. c. Clear fault after 5.5 cycles, trip the faulted line, and remove fault.	**X**					
25	FLT25-PO	**Columbus Prior Outage Scenario 2** a. Prior Outage: Switch out Columbus (640133) to East Columbus (640126) 230kV circuit 1 and solve. b. Apply 3 phase fault on the Columbus (640133) to Shell Creek (640343) 230kV circuit 1, near Columbus 230kV. c. Clear fault after 6 cycles, trip the faulted line, and remove fault.	**X**					
26	FLT26-PO	**Utica Junction Prior Outage Scenario 1** a. Prior Outage: Switch out Utica Junction (652526) to Rasmussen (652536) 230kV circuit 1 and solve. b. Apply 3 phase fault on the Utica Junction (652526) to VFODNES4 (652398) 230kV line circuit 1, near Utica Junction. c. Clear fault after 6 cycles and trip the faulted line and remove the fault.	**X**					

Cont. No.	Cont. Name	Description	GEN-2014-023	GEN-2014-059	GEN-2014-060	GEN-2015-007	GEN-2015-008	GEN-2015-023
27	FLT27-3PH	3 phase fault on the Raun (635200) to S3451 (645451) 345kV line circuit 1, near Raun 345kV. a. Apply fault at the Raun 345kV bus. b. Clear fault after 5 cycles and trip the faulted line.	X			X		
28	FLT28-3PH	3 phase fault on the Raun (635200) to Sioux City (652564) 345kV line circuit 1, near Raun 345kV. a. Apply fault at the Raun 345kV bus. b. Clear fault after 5 cycles and trip the faulted line.	X			X		
29	FLT29-PO	**Hoskins 345kV Prior Outage Scenario 1** a. Prior Outage: Switch out Hoskins (640226) to Shell Creek (640342) 345kV circuit 1 and solve. b. Apply 3 phase fault on Hoskins (640226) 345/(640227) 230/(643082) 13.8kV transformer circuit 1, near Hoskins. c. Clear fault after 4.5 cycles and trip the faulted line and remove fault.	X			X	X	
30	FLT30-PO	**Hoskins 345kV Prior Outage Scenario 2** a. Prior Outage: Switch out Hoskins (640226) to Shell Creek (640342) 345kV circuit 1 and solve. b. Apply 3 phase fault on Hoskins (640226) 345/(640228) 115/(640231) 13.8kV transformer circuit 1, near Hoskins. c. Clear fault after 4.5 cycles and trip the faulted line and remove fault.	X			X		
31	FLT31-3PH	3 phase fault on the GEN-2014-059 Tap (560014) to Ogallala (640302) 230kV line circuit 1, near GEN-2014-059 Tap. a. Apply fault at the GEN-2014-059 Tap 230kV bus. b. Clear fault after 6 cycles and trip the faulted line.		X				
32	FLT32-1PH	Single Phase fault like the previous with 16 cycles before breaker action.		X				
33	FLT33-3PH	3 phase fault on the GEN-2014-059 Tap (560014) to Sidney (659134) 230kV line circuit 1, near GEN-2014-059 Tap. a. Apply fault at the GEN-2014-059 Tap 230kV bus. b. Clear fault after 6 cycles and trip the faulted line.		X				
34	FLT34-1PH	Single Phase fault like the previous with 16 cycles before breaker action.		X				
35	FLT35-3PH	3 phase fault on the Ogallala (640302) 230/(659801) 115/(643115) 13.8kV transformer circuit 1, near Ogallala. a. Apply fault at the Ogallala 230kV bus. b. Clear fault after 5.5 cycles and trip the faulted line.		X				
36	FLT36-3PH	3 phase fault on the Ogallala (640302) to Gentleman (640184) 230kV line circuit 1, near Ogallala. a. Apply fault at the Ogallala 230kV bus. b. Clear fault after 6 cycles and trip the faulted line.		X				
37	FLT37-1PH	Single Phase fault like the previous with 16 cycles before breaker action.		X				
38	FLT38-3PH	3 phase fault on the Keystone (640252) to Sidney (659133) 345kV line circuit 1, near Keystone. a. Apply fault at the Keystone 345kV bus. b. Clear fault after 5 cycles and trip the faulted line.		X				

Cont. No.	Cont. Name	Description	GEN-2014-023	GEN-2014-059	GEN-2014-060	GEN-2015-007	GEN-2015-008	GEN-2015-023
39	FLT39-1PH	Single Phase fault like the previous with 14 cycles before breaker action.		X				
40	FLT40-3PH	3 phase fault on the Keystone (640252) to Gentleman (640183) 345kV line circuit 1, near Keystone. a. Apply fault at the Keystone 345kV bus. b. Clear fault after 5 cycles and trip the faulted line.		X				
41	FLT41-1PH	Single Phase fault like the previous with 14 cycles before breaker action.		X				
42	FLT42-3PH	3 phase fault on the Gentleman (640184) to N Platte (640286) 230kV line circuit 1, near Gentleman. a. Apply fault at the Gentleman 230kV bus. b. Clear fault after 5 cycles and trip the faulted line.		X				
43	FLT43-1PH	Single Phase fault like the previous with 16 cycles before breaker action.		X				
44	FLT44-3PH	3 phase fault on the Sidney (659134) 230/(652572) 115/(659803) 13.8kV transformer circuit 1, near Sidney. a. Apply fault at the Sidney 230kV bus. b. Clear fault after 5.5 cycles and trip the faulted line.		X				
45	FLT45-PO	**Sidney 230kV Prior Outage Scenario 1** a. Prior Outage: Switch out Sidney (659133) to Keystone (640252) 345kV circuit 1 and solve. b. Apply 3 phase fault on Sidney (659134) 230/(652572) 115/(659803) 13.8kV transformer circuit 1, near Sidney. c. Clear fault after 6 cycles and trip the faulted line and remove fault.		X				
46	FLT46-PO	**Ogallala 230kV Prior Outage Scenario 1** a. Prior Outage: Switch out Ogallala (640302) 230/(659801) 115/(643115) 13.8kV transformer circuit 1 and solve. b. Apply 3 phase fault on Sidney (659133) to Keystone (640252) 345kV circuit 1, near Sidney. c. Clear fault after 5 cycles and trip the faulted line and remove fault.		X				
47	FLT47-PO	**Gentleman 345kV Prior Outage Scenario 1** a. Prior Outage: Switch out Gentleman (640183) to Sweetwater (640374) 345kV line circuit 1 and solve. b. Apply 3 phase fault on Gentleman (640183) to Sweetwater (640374) 345kV circuit 2, near Gentleman. c. Clear fault after 5 cycles and trip the faulted line and remove fault.		X				X
48	FLT48-3PH	3 phase fault on the GEN-2014-060 Tap (560733) to Hildreth (640222) 115kV line circuit 1, near GEN-2014-060 Tap. a. Apply fault at the Gentleman 230kV bus. b. Clear fault after 5 cycles and trip the faulted line.			X			
49	FLT49-1PH	Single Phase fault like the previous with 19 cycles before breaker action.			X			
50	FLT50-3PH	3 phase fault on the GEN-2014-060 Tap (560733) to Pauline (640313) 115kV line circuit 1, near GEN-2014-060 Tap. a. Apply fault at the Gentleman 230kV bus. b. Clear fault after 5 cycles and trip the faulted line.			X			
51	FLT51-1PH	Single Phase fault like the previous with 19 cycles before breaker action.			X			

Cont. No.	Cont. Name	Description	GEN-2014-023	GEN-2014-059	GEN-2014-060	GEN-2015-007	GEN-2015-008	GEN-2015-023
52	FLT52-PO	**Holdredge 115kV Prior Outage Scenario 1** a. Prior Outage: Switch out Holdredge (640224) to Axtell (640066) 115kV line circuit 1 and solve. b. Apply 3 phase fault on Axtell (640065) to Pauline (640312) 345kV circuit 1, near Axtell. c. Clear fault after 4.5 cycles and trip the faulted line and remove fault.			**X**			
53	FLT53-PO	**Holdredge 115kV Prior Outage Scenario 2** a. Prior Outage: Switch out Holdredge (640224) to Axtell (640066) 115kV line circuit 1 and solve. b. Apply 3 phase fault on Holdredge (640224) to Johnson 2 (640242) 115kV circuit 1, near Holdredge. c. Clear fault after 6.5 cycles and trip the faulted line and remove fault.			**X**			
54	FLT54-3PH	3 phase fault on the Pauline (640313) 115/(640312) 345/(640315) 13.8kV transformer circuit 1, near Pauline. a. Apply fault at the Pauline 115kV bus. b. Clear fault after 5.5 cycles and trip the faulted line.			**X**			
55	FLT55-3PH	3 phase fault on the Hastings (640215) to Hastings City (641088) 115kV line circuit Z1, near Hastings City. a. Apply fault at the Hastings City 115kV bus. b. Clear fault after 6.5 cycles and trip the faulted line.			**X**			
56	FLT56-3PH	3 phase fault on the Pauline (640312) to Moore (640277) 345kV line circuit 1, near Pauline. a. Apply fault at the Pauline 345kV bus. b. Clear fault after 5 cycles and trip the faulted line.			**X**			
57	FLT57-3PH	3 phase fault on the Pauline (640312) to Moore (640277) 345kV line circuit 1, near Pauline. c. Apply fault at the Pauline 345kV bus. d. Clear fault after 5 cycles and trip the faulted line.			**X**			
58	FLT58-SB	**Pauline 115kV Prior Outage Scenario 1** a. Prior Outage: Switch out Pauline (640313) to Hastings (640215) 115kV circuit 1 and solve. b. Apply 3 phase fault on the GEN-2008-123N Tap (560137) to Guide Rock (640206) 115kV line circuit 1, near GEN-2008-123N Tap. c. Clear fault after 6.5 cycles and trip the faulted line and remove fault.			**X**			
59	FLT59-PO	**Pauline 345kV Prior Outage Scenario 1** a. Prior Outage: Switch out Pauline (640312) to Moore (640277) 345kV circuit 1 and solve. b. Apply 3 phase fault on the GEN-2008-123N Tap (560137) to Guide Rock (640206) 115kV line circuit 1, near GEN-2008-123N Tap. c. Clear fault after 6.5 cycles and trip the faulted line and remove fault.			**X**			

Cont. No.	Cont. Name	Description	GEN-2014-023	GEN-2014-059	GEN-2014-060	GEN-2015-007	GEN-2015-008	GEN-2015-023
60	FLT60-PO	**Pauline 115kV Prior Outage Scenario 2** a. Prior Outage: Switch out Pauline (640313) to Hastings (640215) 115kV circuit 1 and solve. b. Apply 3 phase fault on the Pauline (640313) to Hastings (640215) 115kV circuit 2, near Pauline. c. Clear fault after 6.5 cycles and trip the faulted line and remove fault.			**X**			
61	FLT61-PO	**Hastings EC 115kV Prior Outage Scenario 1** a. Prior Outage: Switch out Hastings EC (641087) to Sutton (640372) 115kV circuit 1 and solve. b. Apply 3 phase fault on the Hastings EC (641087) to S 281 7 (641090) 115kV line circuit 1, near Hastings EC. c. Clear fault after 6.5 cycles and trip the faulted line and remove fault.			**X**			
62	FLT62-3PH	3 phase fault on the Hoskins (640226) 345/(640227) 230/(643082) 13.8kV transformer circuit 1, near Hoskins. a. Apply 3 phase fault on Hoskins 345kV. b. Clear fault after 4.5 cycles and trip the faulted line and remove fault.				**X**		
63	FLT63-3PH	3 phase fault on the Hoskins (640226) 345/(640228) 115/(640231) 13.8kV transformer circuit 1, near Hoskins. a. Apply 3 phase fault on Hoskins 345kV. b. Clear fault after 4.5 cycles and trip the faulted line and remove fault.				**X**		
64	FLT64-PO	**Hoskins 345kV Prior Outage Scenario 3** a. Prior Outage: Switch out Hoskins (640226) 345/(640228) 115/(640231) 13.8kV transformer circuit 1 and solve. b. Apply 3 phase fault Hoskins (640226) 345/(640227) 230/(643082) 13.8kV transformer circuit 1, near Hoskins. c. Clear fault after 4.5 cycles and trip the faulted line and remove fault.				**X**		
65	FLT65-PO	**Hoskins 345kV Prior Outage Scenario 4** a. Prior Outage: Switch out Hoskins (640226) 345/(640227) 230/(643082) 13.8kV transformer circuit 1 and solve. b. Apply 3 phase fault Hoskins (640226) 345/(640228) 115/(640231) 13.8kV transformer circuit 1, near Hoskins. c. Clear fault after 4.5 cycles and trip the faulted line and remove fault.				**X**		
66	FLT66-3PH 2015SP and 2015WP Only	**ONLY THROUGH to 6/1/2016** 3 phase fault on the Raun (635200) to Lakefield (631138) 345kV line circuit 1, near Raun 345kV. a. Apply fault at the Raun 345kV bus. b. Clear fault after 5 cycles and trip the faulted line.				**X**		
67	FLT67-3PH 2025SP Only	**ONLY for 6/1/2016 and BEYOND** 3 phase fault on the Raun (635200) to OBrien (635368) 345kV line circuit 1, near Raun 345kV. a. Apply fault at the Raun 345kV bus. b. Clear fault after 5 cycles and trip the faulted line.				**X**		

Cont. No.	Cont. Name	Description	GEN-2014-023	GEN-2014-059	GEN-2014-060	GEN-2015-007	GEN-2015-008	GEN-2015-023
68	FLT68-3PH	3 phase fault on the Raun (635200) to Lehigh (636010) 345kV line circuit 1, near Raun 345kV. a. Apply fault at the Raun 345kV bus. b. Clear fault after 5 cycles and trip the faulted line.				X		
69	FLT69-PO	**Raun 345kV Prior Outage Scenario 1** a. Prior Outage: Switch out Raun (635200) to Lehigh (636010) 345kV line circuit 1 and solve. b. Apply 3 phase fault Raun (635200) to Sioux City (652564) 345kV line circuit 1, near Hoskins. c. Clear fault after 4.5 cycles and trip the faulted line and remove fault.				X		
70	FLT70-3PH	3 phase fault on the Hoskins (640227) to Dixon Co (560347) 230kV line circuit 1, near Hoskins 230kV. a. Apply fault at the Hoskins 230kV bus. b. Clear fault after 6 cycles and trip the faulted line.				X		
71	FLT71-PO	**Hoskins 230kV Prior Outage Scenario 5** a. Prior Outage: Switch out Hoskins (640227) 230/(640228) 115/(643083) 13.8kV transformer circuit 1 and solve. b. Apply 3 phase fault Hoskins (640226) 345/(640228) 115/(640231) 13.8kV transformer circuit 1, near Hoskins. c. Clear fault after 4.5 cycles and trip the faulted line and remove fault.				X		
72	FLT72-3PH	3 phase fault on the Twin Church (640386) to Dixon Co (560347) 230kV line circuit 1, near Twin Church 230kV. a. Apply fault at the Twin Church 230kV bus. b. Clear fault after 6 cycles and trip the faulted line.				X		
73	FLT73-3PH	3 phase fault on the Hoskins (640228) to Norfolk N (640296) 115kV line circuit 1, near Hoskins 115kV. a. Apply fault at the Hoskins 115kV bus. b. Clear fault after 6.5 cycles and trip the faulted line.				X	X	
74	FLT74-3PH	3 phase fault on the Hoskins (640228) to Norfolk (640298) 115kV line circuit 1, near Hoskins 115kV. a. Apply fault at the Hoskins 115kV bus. b. Clear fault after 6.5 cycles and trip the faulted line.				X	X	
75	FLT75-3PH	3 phase fault on the Hoskins (640228) to Stanton N (640363) 115kV line circuit 1, near Hoskins 115kV. a. Apply fault at the Hoskins 115kV bus. b. Clear fault after 6.5 cycles and trip the faulted line.				X	X	
76	FLT76-3PH	3 phase fault on the Hoskins (640228) to Belden (640080) 115kV line circuit 1, near Hoskins 115kV. a. Apply fault at the Hoskins 115kV bus. b. Clear fault after 6.5 cycles and trip the faulted line.				X	X	

Cont. No.	Cont. Name	Description	GEN-2014-023	GEN-2014-059	GEN-2014-060	GEN-2015-007	GEN-2015-008	GEN-2015-023
77	FLT77-PO	**Hoskins 115kV Prior Outage Scenario 6** a. Prior Outage: Switch out Hoskins (640227) 230/(640228) 115/(643083) 13.8kV transformer circuit 1 and solve. b. Apply 3 phase fault Hoskins (640228) to Norfolk N (640296) 115kV line circuit 1, near Hoskins 115kV, near Hoskins. c. Clear fault after 6.5 cycles and trip the faulted line and remove fault.				X	X	
78	FLT78-SB	**Hoskins 345kV Stuck Breaker Scenario 1** a. Apply single phase fault at the Hoskins (640226) 345kV bus. b. Wait 13.5 cycles and remove fault. c. Trip Hoskins (640226) 345/(640227) 230/(643082) 13.8kV transformer circuit 1. d. Trip Hoskins (640226) to Shell Creek (640342) 345kV line circuit 1.				X	X	
79	FLT79-SB	**Hoskins 345kV Stuck Breaker Scenario 2** a. Apply single phase fault at the Hoskins (640226) 345kV bus. b. Wait 13.5 cycles and remove fault. c. Trip Hoskins (640226) 345/(640228) 115/(640231) 13.8kV transformer circuit 1. d. Trip Hoskins (640226) to Raun (635200) 345kV line circuit 1.				X	X	
80	FLT80-SB	**Hoskins 345kV Stuck Breaker Scenario 3** a. Apply single phase fault at the Hoskins (640226) 345kV bus. b. Wait 13.5 cycles and remove fault. c. Trip Hoskins (640226) 345/(640227) 230/(643082) 13.8kV transformer circuit 1. d. Trip Hoskins (640226) to Raun (635200) 345kV line circuit 1.				X		
81	FLT81-SB 2025SP Only	**Hoskins 345kV Stuck Breaker Scenario 4** a. Apply single phase fault at the Hoskins (640226) 345kV bus. b. Wait 13.5 cycles and remove fault. c. Trip Hoskins (640226) 345/(640228) 115/(640231) 13.8kV transformer circuit 1. d. Trip Hoskins (640226) to Neligh East (640520) 345kV line circuit 1.				X		
82	FLT82-3PH	3 phase fault on the Columbus East (640125) 345/(640127) 115/(640129) 13.8kV transformer circuit 1, near Columbus East 345kV. a. Apply fault at the Columbus East 345kV bus. b. Clear fault after 4.5 cycles and trip the faulted line.				X		
83	FLT83-3PH	3 phase fault on the Antelope (640521) to Creighton (640149) 115kV line circuit 1, near Antelope 115kV. a. Apply fault at the Antelope 345kV bus. b. Clear fault after 6.5 cycles and trip the faulted line.					X	
84	FLT84-3PH	3 phase fault on the Antelope (640521) to County Line (640115) 115kV line circuit 1, near Antelope 115kV. a. Apply fault at the Antelope 345kV bus. b. Clear fault after 6.5 cycles and trip the faulted line.					X	

Cont. No.	Cont. Name	Description	GEN-2014-023	GEN-2014-059	GEN-2014-060	GEN-2015-007	GEN-2015-008	GEN-2015-023
85	FLT85-3PH	3 phase fault on the Antelope (640521) to Neligh (640293) 115kV line circuit 1, near Antelope 115kV. a. Apply fault at the Antelope 345kV bus. b. Clear fault after 6.5 cycles and trip the faulted line.					X	
86	FLT86-PO	**Antelope 115kV Prior Outage Scenario 1** a. Prior Outage: Switch out Antelope (640521) 115 to Neligh (640293) 115kV line circuit 1, near Antelope 115kV and solve. b. Apply 3 phase fault Antelope (640521) to Neligh (640293) 115kV line circuit 2, near Hoskins 115kV. c. Clear fault after 6.5 cycles and trip the faulted line and remove fault.					X	
87	FLT87-PO	**ONLY for 6/1/2016 and BEYOND** **Antelope 115kV Prior Outage Scenario 2** a. Prior Outage: Switch out Antelope (640521) 115/(640520) 230/(640524) 13.8kV transformer circuit 1, near Antelope 115kV and solve. b. Apply 3 phase fault Antelope (640521) to County Line (640115) 115kV line circuit 1, near Antelope 115kV. c. Clear fault after 6.5 cycles and trip the faulted line and remove fault.					X	
88	FLT88-PO	**ONLY for 6/1/2016 and BEYOND** **Antelope 115kV Prior Outage Scenario 3** a. Prior Outage: Switch out Antelope (640521) 115/(640520) 230/(640524) 13.8kV transformer circuit 1, near Antelope 115kV and solve. b. Apply 3 phase fault Antelope (640521) to Creighton (640149) 115kV line circuit 1, near Antelope 115kV. c. Clear fault after 6.5 cycles and trip the faulted line and remove fault.					X	
89	FLT89-PO	**ONLY for 6/1/2016 and BEYOND** **Antelope 115kV Prior Outage Scenario 4** a. Prior Outage: Switch out Antelope (640521) 115/(640520) 230/(640524) 13.8kV transformer circuit 1, near Antelope 115kV and solve. b. Apply 3 phase fault Antelope (640521) to Neligh (640293) 115kV line circuit 1, near Antelope 115kV. c. Clear fault after 6.5 cycles and trip the faulted line and remove fault.					X	
90	FLT90-3PH	3 phase fault on the Leland Olds (659105) to Groton (659160) 345kV line circuit 1, near Leland Olds 345kV. a. Apply fault at the Leland Olds 345kV bus. b. Clear fault after 5 cycles and trip the faulted line.						X
91	FLT91-3PH	3 phase fault on the Leland Olds (659105) 345/(659106) 230/(659201) 13.8kV transformer circuit 1, near Leland Olds 345kV. a. Apply fault at the Leland Olds 345kV bus. b. Clear fault after 5 cycles and trip the faulted line.						X

Cont. No.	Cont. Name	Description	GEN-2014-023	GEN-2014-059	GEN-2014-060	GEN-2015-007	GEN-2015-008	GEN-2015-023
92	FLT92-3PH 2025SP Only	**ONLY for 6/1/2016 and BEYOND** 3 phase fault on the Holt Co (640510) to Cherry Co (640500) 345kV line circuit 1, near Holt Co 345kV. a. Apply fault at the Holt Co 345kV bus. b. Clear fault after 5 cycles and trip the faulted line.						X
93	FLT93-3PH	3 phase fault on the Grand Island (652571) to Sweetwater (640374) 345kV line circuit 1, near Grand Island 345kV. a. Apply fault at the Grand Island 345kV bus. b. Clear fault after 5 cycles and trip the faulted line.						X
94	FLT94-3PH	3 phase fault on the Gentleman (640183) to Red Willow (640325) 345kV line circuit 1, near Gentleman 345kV. a. Apply fault at the Gentleman 345kV bus. b. Clear fault after 5 cycles and trip the faulted line.						X
95	FLT95-3PH	3 phase fault on the Sweetwater (640374) to Axtell (640065) 345kV line circuit 1, near Sweetwater 345kV. a. Apply fault at the Sweetwater 345kV bus. b. Clear fault after 5 cycles and trip the faulted line.						X
96	FLT96-3PH	3 phase fault on the Grand Island (652571) 345/(640200) 230/(643071) 13.8kV transformer circuit 3, near Grand Island 345kV. a. Apply fault at the Grand Island 345kV bus. b. Clear fault after 4.5 cycles and trip the faulted line.						X
97	FLT97-PO	**Gentleman 345kV Prior Outage Scenario 1** a. Prior Outage: Switch out Gentleman (640183) to Red Willow (640325) 345kV line circuit 1, near Gentleman 345kV and solve. b. Apply 3 phase fault Ft. Thompson (652506) to Grand Prairie (652532) 345kV line circuit 1, near Ft. Thompson 345kV. c. Clear fault after 5 cycles and trip the faulted line and remove fault.						X
98	FLT98-PO	**Grand Island 345kV Prior Outage Scenario 1** a. Prior Outage: Switch out Grand Island (652571) to Holt County (640510) 345kV line circuit 1, near Grand Island 345kV and solve. b. Apply 3 phase fault Leland Olds (659105) to Groton (659160) 345kV line circuit 1, near Leland Olds 345kV. c. Clear fault after 5 cycles and trip the faulted line and remove fault.						X
99	FLT99-PO	**Ft Thompson 230kV Prior Outage Scenario 1** a. Prior Outage: Switch out Ft Thompson (652507) to Wessington (652607) 230kV line circuit 1, near Ft Thompson 230kV and solve. b. Apply 3 phase fault Ft Thompson (652507) to Letcher (652606) 230kV line circuit 1, near Ft Thompson 230kV. c. Clear fault after 6 cycles and trip the faulted line and remove fault.						X

Cont. No.	Cont. Name	Description	GEN-2014-023	GEN-2014-059	GEN-2014-060	GEN-2015-007	GEN-2015-008	GEN-2015-023
100	FLT100-SB	**Grand Island 345kV Stuck Breaker Scenario 1** a. Apply single phase fault at the Grand Island (652571) 345kV bus. b. Wait 13.5 cycles and remove fault. c. Trip Grand Island (652571) 345/(640200) 230/(652316) 13.8kV transformer circuit 2. d. Trip Grand Island (652571) to Sweetwater (640374) 345kV line circuit 1.						**X**
101	FLT101-SB	**Grand Island 345kV Stuck Breaker Scenario 2** a. Apply single phase fault at the Grand Island (652571) 345kV bus. b. Wait 13.5 cycles and remove fault. c. Trip Grand Island (652571) 345/(640200) 230/(652314) 13.8kV transformer circuit 1. d. Trip Grand Island (652571) to McCool (640271) 345kV line circuit 1.						**X**
102	FLT102-SB	**Grand Island 345kV Stuck Breaker Scenario 3** a. Apply single phase fault at the Grand Island (652571) 345kV bus. b. Wait 13.5 cycles and remove fault. c. Trip Grand Island (652571) 345/(640200) 230/(652314) 13.8kV transformer circuit 1. d. Trip Grand Island (652571) 345/(640200) 230/(643071) 13.8kV transformer circuit 3.						**X**
103	FLT103-SB Summer 2025SP Only	**Hoskins 345kV Stuck Breaker Scenario 5** a. Apply single phase fault at the Hoskins (640226) 345kV bus. b. Wait 13.5 cycles and remove fault. c. Trip Hoskins Hoskins (640226) to Shell Creek (640342) 345kV line circuit 1. d. Trip Hoskins (640226) to Neligh East (640520) 345kV line circuit 1.					**X**	

The Southwest Power Pool Disturbance Performance Criteria Requirements provides a basis for evaluating the system response during the initial transient period following a disturbance on the Bulk Electric System by establishing minimum requirements for machine rotor angle damping and transient voltage recovery.

a. Angular Oscillations
    i. For study projects that are synchronous machines, verify that rotor angle oscillations meet the damping requirements described in Appendix.
    ii. For other synchronous machines that are not study projects, but based on engineering judgment have questionable rotor angle oscillation damping, verify that they meet the requirements described in Appendix.
b. Transient Voltage Recovery
    i. For the transient voltage recovery requirement in Appendix, the bus voltages to be included are those at the point of interconnection for each study generator. Other voltages (115kV and higher) in the area should be checked for this requirement if the terminal voltage of other machines in the monitored area appears to have voltage recovery issues.

Southwest Power Pool
Disturbance Performance Requirements

OVERVIEW

These Disturbance Performance Requirements ("Requirements") shall be applicable to the Bulk Electric System within the Southwest Power Pool Planning Area. Utilization of these Requirements applies to all registered entities within the Southwest Power Pool Planning Area. These Requirements shall not be applicable to facilities that are not part of Bulk Electric System. More stringent Requirements are at the sole discretion of each Transmission Owner.

Transient and dynamic stability assessments are generally performed to assure adequate avoidance of loss of generator synchronism and prevention of system voltage collapse within the first 20 seconds after a system disturbance. These Requirements provide a basis for evaluating the system response during the initial transient period following a disturbance on the Bulk Electric System by establishing minimum requirements for machine rotor angle damping and transient voltage recovery.

ROTOR ANGLE DAMPING REQUIREMENT

Machine Rotor Angles shall exhibit well damped angular oscillations [as defined below] and acceptable power swings following a disturbance on the Bulk Electric System for all NERC Category A, B and C events.

Well damped angular oscillations shall meet one of the following two requirements when calculated directly from the rotor angle:

1. Successive Positive Peak Ratio (SPPR) must be less than or equal to 0.95 where SPPR is calculated as follows:

$$SPPR = \frac{\text{Peak Rotor Angle of } 2^{nd} \text{ Positive Swing Peak}}{\text{Peak Rotor Angle of } 1^{st} \text{ Positive Swing Peak}} \leq 0.95$$

-or- Damping Factor % = $(1 - SPPR) \times 100\% \geq 5\%$

The machine rotor angle damping ratio may be determined by appropriate modal analysis (i.e. Prony Analysis) where the following equivalent requirement must be met:

Damping Ratio ≥ 0.0081633

2. Successive Positive Peak Ratio Five (SPPR5) must be less than or equal to 0.774 where SPPR5 is calculated as follows:

$$SPPR5 = \frac{\text{Peak Rotor Angle of } 5^{th} \text{ Positive Swing Peak}}{\text{Peak Rotor Angle of } 1^{st} \text{ Positive Swing Peak}} \leq 0.774$$

-or- Damping Factor % = $(1 - SPPR5) \times 100\% \geq 22.6\%$

The machine rotor angle damping ratio may be determined by appropriate modal analysis (i.e. Prony Analysis) where the following equivalent requirement must be met:

Damping Ratio ≥ 0.0081633

Qualitatively, these Requirements are shown in Figure 1 below.

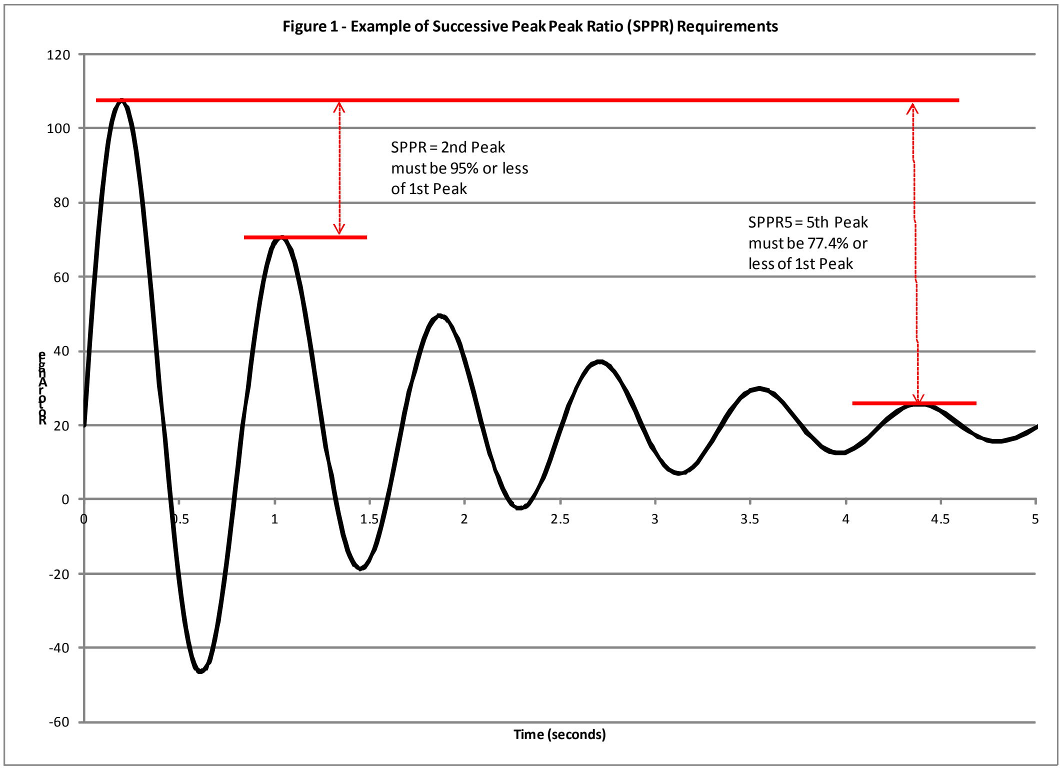


Figure 1 - Example of Successive Peak Peak Ratio (SPPR) Requirements

TRANSIENT VOLTAGE RECOVERY REQUIREMENT

Any time after a disturbance is cleared; bus voltages on the Bulk Electric System shall not swing outside of the bandwidth of 0.70 per unit to 1.20 per unit.

Qualitatively, this Requirement is shown in Figure 2 below.

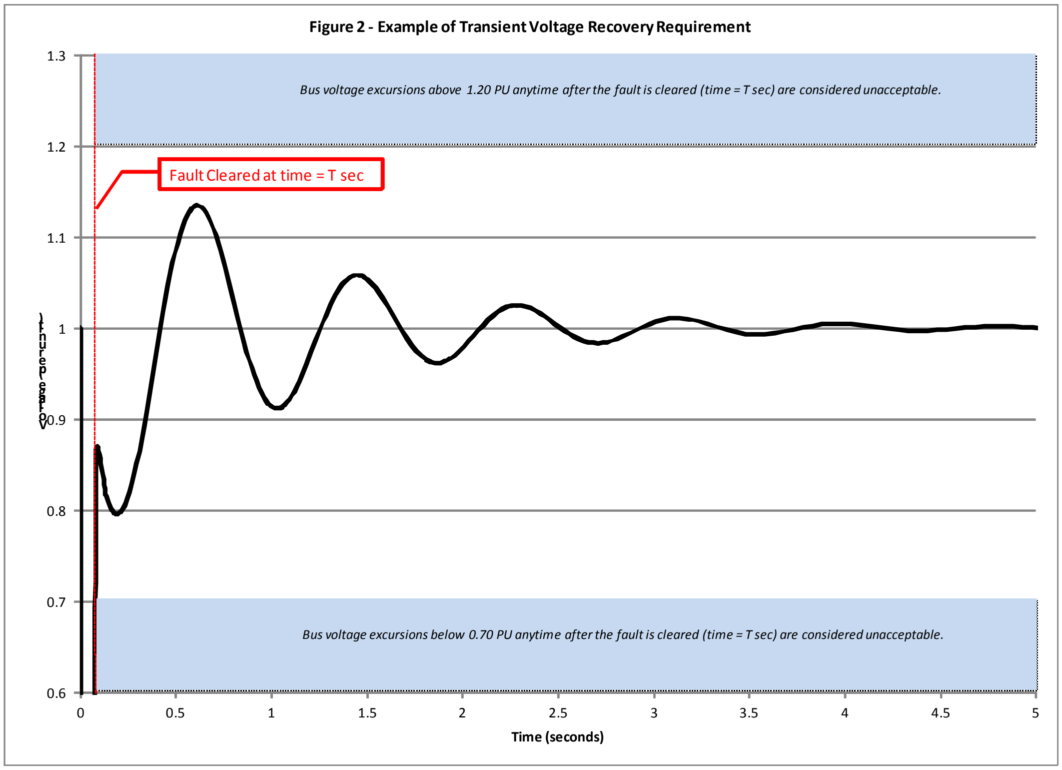


Figure 2 - Example of Transient Voltage Recovery Requirement
Bus voltage excursions above 1.20 PU anytime after the fault is cleared (time = T sec) are considered unacceptable.
Fault Cleared at time = T sec
Bus voltage excursions below 0.70 PU anytime after the fault is cleared (time = T sec) are considered unacceptable.
1.3
1.2
1.1
1
0.9
0.8
0.7
0.6
0
0.5
1
1.5
2
2.5
3
3.5
4
4.5
5
Time (seconds)

Cont. No.	2015 Summer Peak					2015 Winter Peak					2025 Summer Peak				
	P(MW)	Q(MVAR)	Power Factor		V(PU)	P(MW)	Q(MVAR)	Power Factor		V(PU)	P(MW)	Q(MVAR)	Power Factor		V(PU)
0	79.9	-12.1	.989	leading	1.0241	79.9	-11	.991	leading	1.0214	79.9	-13.3	.986	leading	1.0276
1	79.9	35.7	.913	lagging	1.0241	79.9	36.1	.911	lagging	1.0214	79.9	35.6	.913	lagging	1.0276
2	79.9	-46.9	.862	leading	1.0241	79.9	-44.3	.875	leading	1.0214	79.9	-46.2	.866	leading	1.0276
3	79.9	69.3	.755	lagging	1.0241	79.9	68.8	.758	lagging	1.0214	79.9	72.9	.739	lagging	1.0276
4	79.9	0.6	1.000	lagging	1.0241	79.9	2.3	1.000	lagging	1.0214	79.9	0.2	1.000	lagging	1.0276
5	79.9	-13.7	.986	leading	1.0241	79.9	-11.1	.990	leading	1.0214	79.9	-16	.981	leading	1.0276
6	79.9	-14.1	.985	leading	1.0241	79.9	-12.6	.988	leading	1.0214	79.9	-14.5	.984	leading	1.0276
7	79.9	-11.2	.990	leading	1.0241	79.9	-11.1	.990	leading	1.0214	79.9	-11.9	.989	leading	1.0276
8	79.9	-11.3	.990	leading	1.0241	79.9	-10.1	.992	leading	1.0214	79.9	-12.4	.988	leading	1.0276
9	79.9	-9.1	.994	leading	1.0241	79.9	-9.4	.993	leading	1.0214	79.9	-9.5	.993	leading	1.0276
10	79.9	-12.1	.989	leading	1.0241	79.9	-10.5	.991	leading	1.0214	79.9	-13.1	.987	leading	1.0276
11											79.9	-10.2	.992	leading	1.0276
12	79.9	-4.5	.998	leading	1.0241	79.9	-3.3	.999	leading	1.0214	79.9	-6.9	.996	leading	1.0276
13	79.9	19.8	.971	lagging	1.0241	79.9	6.6	.997	lagging	1.0214	79.9	-0.6	1.000	leading	1.0276
14	79.9	-16	.981	leading	1.0241	79.9	-12.5	.988	leading	1.0214	79.9	-14.4	.984	leading	1.0276
15	79.9	-12.4	.988	leading	1.0241	79.9	-10.3	.992	leading	1.0214	79.9	-13.1	.987	leading	1.0276
16	79.9	-10.9	.991	leading	1.0241	79.9	-12.9	.987	leading	1.0214	79.9	-9.4	.993	leading	1.0276
17	79.9	-10.9	.991	leading	1.0241	79.9	-12.9	.987	leading	1.0214	79.9	-11.1	.990	leading	1.0276
20	79.9	-10.9	.991	leading	1.0241	79.9	-12.9	.987	leading	1.0214	79.9	1.1	1.000	lagging	1.0276
21	79.9	69.7	.754	lagging	1.0241	79.9	70	.752	lagging	1.0214	79.9	73	.738	lagging	1.0276
22	79.9	-10.9	.991	leading	1.0241	79.9	-12.9	.987	leading	1.0214	79.9	-9.4	.993	leading	1.0276
24	79.9	-13.7	.986	leading	1.0241	79.9	-14	.985	leading	1.0214	79.9	-13	.987	leading	1.0276
25	79.9	-0.9	1.000	leading	1.0241	79.9	1.8	1.000	lagging	1.0214	79.9	-0.5	1.000	leading	1.0276
26	79.9	-12.5	.988	leading	1.0241	79.9	-12.6	.988	leading	1.0214	79.9	-11.1	.990	leading	1.0276
27	79.9	-12.6	.988	leading	1.0241	79.9	-11.2	.990	leading	1.0214	79.9	-13.5	.986	leading	1.0276
28	79.9	-8.4	.995	leading	1.0241	79.9	-7.6	.996	leading	1.0214	79.9	-9	.994	leading	1.0276
29	79.9	-8.8	.994	leading	1.0241	79.9	-9.2	.993	leading	1.0214	79.9	-8.9	.994	leading	1.0276
30	79.9	-8.6	.994	leading	1.0241	79.9	-8.7	.994	leading	1.0214	79.9	-7.8	.995	leading	1.0276
31	79.9	-11.6	.990	leading	1.0241	79.9	-10.9	.991	leading	1.0214	79.9	-12.8	.987	leading	1.0276
33	79.9	-11.9	.989	leading	1.0241	79.9	-11	.991	leading	1.0214	79.9	-13.2	.987	leading	1.0276
35	79.9	-12.1	.989	leading	1.0241	79.9	-11	.991	leading	1.0214	79.9	-13.2	.987	leading	1.0276
36	79.9	-12.1	.989	leading	1.0241	79.9	-11	.991	leading	1.0214	79.9	-13.3	.986	leading	1.0276
38	79.9	-10.3	.992	leading	1.0241	79.9	-10.7	.991	leading	1.0214	79.9	-12.1	.989	leading	1.0276
40	79.9	-11.1	.990	leading	1.0241	79.9	-10.8	.991	leading	1.0214	79.9	-12.9	.987	leading	1.0276
42	79.9	-12.1	.989	leading	1.0241	79.9	-11	.991	leading	1.0214	79.9	-13.3	.986	leading	1.0276
44	79.9	-12.1	.989	leading	1.0241	79.9	-11	.991	leading	1.0214	79.9	-13.3	.986	leading	1.0276
45	79.9	-10	.992	leading	1.0241	79.9	-10.6	.991	leading	1.0214	79.9	-11.9	.989	leading	1.0276
46	79.9	-10	.992	leading	1.0241	79.9	-10.6	.991	leading	1.0214	79.9	-11.9	.989	leading	1.0276
47	79.9	-7.6	.996	leading	1.0241	79.9	-9	.994	leading	1.0214	79.9	-8.7	.994	leading	1.0276
48	79.9	-12.1	.989	leading	1.0241	79.9	-11	.991	leading	1.0214	79.9	-13.1	.987	leading	1.0276
50	79.9	-12	.989	leading	1.0241	79.9	-10.9	.991	leading	1.0214	79.9	-13.4	.986	leading	1.0276
52	79.9	-11.3	.990	leading	1.0241	79.9	-10	.992	leading	1.0214	79.9	-12.6	.988	leading	1.0276
53	79.9	-12.1	.989	leading	1.0241	79.9	-10.9	.991	leading	1.0214	79.9	-13.4	.986	leading	1.0276
54	79.9	-11.6	.990	leading	1.0241	79.9	-10.6	.991	leading	1.0214	79.9	-12.9	.987	leading	1.0276
55	79.9	-12.1	.989	leading	1.0241	79.9	-11	.991	leading	1.0214	79.9	-13.4	.986	leading	1.0276
56	79.9	-9.9	.992	leading	1.0241	79.9	-7.9	.995	leading	1.0214	79.9	-11.4	.990	leading	1.0276
57	79.9	-9.9	.992	leading	1.0241	79.9	-7.9	.995	leading	1.0214	79.9	-11.4	.990	leading	1.0276
58	79.9	-11.9	.989	leading	1.0241	79.9	-10.8	.991	leading	1.0214	79.9	-13.1	.987	leading	1.0276
59	79.9	-9.1	.994	leading	1.0241	79.9	-7.2	.996	leading	1.0214	79.9	-10.4	.992	leading	1.0276
60	79.9	-12.1	.989	leading	1.0241	79.9	-11	.991	leading	1.0214	79.9	-13.3	.986	leading	1.0276
61	79.9	-11.8	.989	leading	1.0241	79.9	-10.8	.991	leading	1.0214	79.9	-13	.987	leading	1.0276
62	79.9	-11.8	.989	leading	1.0241	79.9	-10.8	.991	leading	1.0214	79.9	-12.8	.987	leading	1.0276
63	79.9	-12.2	.989	leading	1.0241	79.9	-10.9	.991	leading	1.0214	79.9	-13	.987	leading	1.0276
64	79.9	-10.3	.992	leading	1.0241	79.9	-9.4	.993	leading	1.0214	79.9	-9.2	.993	leading	1.0276
65	79.9	-10.1	.992	leading	1.0241	79.9	-8.9	.994	leading	1.0214	79.9	-9.3	.993	leading	1.0276
66	79.9	-12.7	.988	leading	1.0241	79.9	-11.2	.990	leading	1.0214					
67											79.9	-14.2	.985	leading	1.0276
68	79.9	-12.8	.987	leading	1.0241	79.9	-11.6	.990	leading	1.0214	79.9	-14	.985	leading	1.0276
69	79.9	-8.4	.995	leading	1.0241	79.9	-8.1	.995	leading	1.0214	79.9	-9.2	.993	leading	1.0276
70	79.9	-11.7	.989	leading	1.0241	79.9	-10.9	.991	leading	1.0214	79.9	-13	.987	leading	1.0276
71	79.9	-9.2	.993	leading	1.0241	79.9	-7.8	.995	leading	1.0214	79.9	-8.2	.995	leading	1.0276
72	79.9	-11.2	.990	leading	1.0241	79.9	-10.4	.992	leading	1.0214	79.9	-11.8	.989	leading	1.0276
73	79.9	-11.9	.989	leading	1.0241	79.9	-10.7	.991	leading	1.0214	79.9	-13.3	.986	leading	1.0276
74	79.9	-12	.989	leading	1.0241	79.9	-10.8	.991	leading	1.0214	79.9	-13.1	.987	leading	1.0276
75	79.9	-11.9	.989	leading	1.0241	79.9	-10.9	.991	leading	1.0214	79.9	-13.2	.987	leading	1.0276
76	79.9	-11.5	.990	leading	1.0241	79.9	-10.9	.991	leading	1.0214	79.9	-12.6	.988	leading	1.0276
77	79.9	-12	.989	leading	1.0241	79.9	-10.8	.991	leading	1.0214	79.9	-13.2	.987	leading	1.0276
82	79.9	-9.3	.993	leading	1.0241	79.9	-7.8	.995	leading	1.0214	79.9	-10.1	.992	leading	1.0276
83	79.9	-12.2	.989	leading	1.0241	79.9	-11.1	.990	leading	1.0214	79.9	-12.9	.987	leading	1.0276
84	79.9	-6.4	.997	leading	1.0241	79.9	-5.9	.997	leading	1.0214	79.9	-13	.987	leading	1.0276
85	79.9	-12.3	.988	leading	1.0241	79.9	-11.1	.990	leading	1.0214	79.9	-13.7	.986	leading	1.0276
86	79.9	-12.9	.987	leading	1.0241	79.9	-12.1	.989	leading	1.0214	79.9	-14.4	.984	leading	1.0276
87											79.9	-4.6	.998	leading	1.0276
88											79.9	-9.7	.993	leading	1.0276

89	[redacted]										79.9	-10.6	.991	leading	1.0276
90	79.9	-10.5	.991	leading	1.0241	79.9	-10.1	.992	leading	1.0214	79.9	-11.9	.989	leading	1.0276
91	79.9	-12.1	.989	leading	1.0241	79.9	-11	.991	leading	1.0214	79.9	-13.2	.987	leading	1.0276
92	[redacted]										79.9	-13.2	.987	leading	1.0276
93	79.9	-11.1	.990	leading	1.0241	79.9	-10.7	.991	leading	1.0214	79.9	-12.1	.989	leading	1.0276
94	79.9	-9.6	.993	leading	1.0241	79.9	-9.1	.994	leading	1.0214	79.9	-10.8	.991	leading	1.0276
95	79.9	-8.8	.994	leading	1.0241	79.9	-8.4	.995	leading	1.0214	79.9	-10.3	.992	leading	1.0276
96	79.9	-11.8	.989	leading	1.0241	79.9	-10.9	.991	leading	1.0214	79.9	-13.1	.987	leading	1.0276
97	79.9	-13.6	.986	leading	1.0241	79.9	-9.6	.993	leading	1.0214	79.9	-12.1	.989	leading	1.0276
98	79.9	23.2	.960	lagging	1.0241	79.9	8.5	.994	lagging	1.0214	79.9	0.6	1.000	lagging	1.0276
99	79.9	-0.9	1.000	leading	1.0241	79.9	-3	.999	leading	1.0214	79.9	-1.4	1.000	leading	1.0276

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Cont. No.	2015 Summer Peak					2015 Winter Peak					2025 Summer Peak				
	P(MW)	Q(MVAR)	Power Factor		V(PU)	P(MW)	Q(MVAR)	Power Factor		V(PU)	P(MW)	Q(MVAR)	Power Factor		V(PU)
0	160	-27.8	.985	leading	1	160	-26.9	.986	leading	1.0137	160	-27.5	.986	leading	1.0073
1	160	-28	.985	leading	1	160	-27.1	.986	leading	1.0137	160	-27.7	.985	leading	1.0073
2	160	-27.5	.986	leading	1	160	-26.7	.986	leading	1.0137	160	-27.3	.986	leading	1.0073
3	160	-25.9	.987	leading	1	160	-25.4	.988	leading	1.0137	160	-26.1	.987	leading	1.0073
4	160	-27.4	.986	leading	1	160	-26.4	.987	leading	1.0137	160	-27.2	.986	leading	1.0073
5	160	-27.6	.985	leading	1	160	-27	.986	leading	1.0137	160	-27.2	.986	leading	1.0073
6	160	-27.8	.985	leading	1	160	-26.9	.986	leading	1.0137	160	-27.5	.986	leading	1.0073
7	160	-27.7	.985	leading	1	160	-26.9	.986	leading	1.0137	160	-27.4	.986	leading	1.0073
8	160	-27.6	.985	leading	1	160	-26.8	.986	leading	1.0137	160	-27.3	.986	leading	1.0073
9	160	-27.5	.986	leading	1	160	-26.9	.986	leading	1.0137	160	-27.2	.986	leading	1.0073
10	160	-27.8	.985	leading	1	160	-26.9	.986	leading	1.0137	160	-27.5	.986	leading	1.0073
11	[redacted]										160	-27.2	.986	leading	1.0073
12	160	-25.5	.988	leading	1	160	-24.7	.988	leading	1.0137	160	-25.2	.988	leading	1.0073
13	160	-21.4	.991	leading	1	160	-22.7	.990	leading	1.0137	160	-17.8	.994	leading	1.0073
14	160	-28.1	.985	leading	1	160	-26.6	.986	leading	1.0137	160	-27.2	.986	leading	1.0073
15	160	-27.8	.985	leading	1	160	-26.8	.986	leading	1.0137	160	-27.5	.986	leading	1.0073
16	160	-27.1	.986	leading	1	160	-26.2	.987	leading	1.0137	160	-26.9	.986	leading	1.0073
17	160	-27.1	.986	leading	1	160	-26.2	.987	leading	1.0137	160	-27	.986	leading	1.0073
20	160	-27.1	.986	leading	1	160	-26.2	.987	leading	1.0137	160	-25.8	.987	leading	1.0073
21	160	-24.6	.988	leading	1	160	-24.4	.989	leading	1.0137	160	-24.9	.988	leading	1.0073
22	160	-27.1	.986	leading	1	160	-26.2	.987	leading	1.0137	160	-26.9	.986	leading	1.0073
24	160	-27.7	.985	leading	1	160	-26.9	.986	leading	1.0137	160	-27.4	.986	leading	1.0073
25	160	-27.3	.986	leading	1	160	-26.4	.987	leading	1.0137	160	-27.1	.986	leading	1.0073
26	160	-27.1	.986	leading	1	160	-26.2	.987	leading	1.0137	160	-27	.986	leading	1.0073
27	160	-26.9	.986	leading	1	160	-26.6	.986	leading	1.0137	160	-27.1	.986	leading	1.0073
28	160	-28.1	.985	leading	1	160	-27.1	.986	leading	1.0137	160	-27.8	.985	leading	1.0073
29	160	-27.5	.986	leading	1	160	-26.9	.986	leading	1.0137	160	-27.2	.986	leading	1.0073
30	160	-27.5	.986	leading	1	160	-26.9	.986	leading	1.0137	160	-27.2	.986	leading	1.0073
31	160	-0.4	1.000	leading	1	160	-0.7	1.000	leading	1.0137	160	-12.5	.997	leading	1.0073
33	160	-29.6	.983	leading	1	160	-24.6	.988	leading	1.0137	160	-14	.996	leading	1.0073
35	160	-42.6	.966	leading	1	160	-31.6	.981	leading	1.0137	160	-44.8	.963	leading	1.0073
36	160	6.7	.999	lagging	1	160	-9.4	.998	leading	1.0137	160	-1.5	1.000	leading	1.0073
38	160	64	.928	lagging	1	160	50.8	.953	lagging	1.0137	160	41	.969	lagging	1.0073
40	160	-0.5	1.000	leading	1	160	-0.8	1.000	leading	1.0137	160	-20.8	.992	leading	1.0073
42	160	-26.1	.987	leading	1	160	-25.4	.988	leading	1.0137	160	-25.9	.987	leading	1.0073
44	160	-20.7	.992	leading	1	160	-23	.990	leading	1.0137	160	-20.7	.992	leading	1.0073
45	160	99.8	.848	lagging	1	160	74.5	.907	lagging	1.0137	160	68.5	.919	lagging	1.0073
46	160	36.2	.975	lagging	1	160	39.9	.970	lagging	1.0137	160	10.9	.998	lagging	1.0073
47	160	-9.1	.998	leading	1	160	-7.6	.999	leading	1.0137	160	-16.1	.995	leading	1.0073
48	160	-27.4	.986	leading	1	160	-26.9	.986	leading	1.0137	160	-26.2	.987	leading	1.0073
50	160	-27.5	.986	leading	1	160	-26.2	.987	leading	1.0137	160	-27.6	.985	leading	1.0073
52	160	-27.4	.986	leading	1	160	-26.8	.986	leading	1.0137	160	-27.3	.986	leading	1.0073
53	160	-28.1	.985	leading	1	160	-26.4	.987	leading	1.0137	160	-28.3	.985	leading	1.0073
54	160	-28.1	.985	leading	1	160	-27.4	.986	leading	1.0137	160	-27.8	.985	leading	1.0073
55	160	-27.8	.985	leading	1	160	-26.9	.986	leading	1.0137	160	-27.5	.986	leading	1.0073
56	160	-27.3	.986	leading	1	160	-26	.987	leading	1.0137	160	-27.1	.986	leading	1.0073
57	160	-27.3	.986	leading	1	160	-26	.987	leading	1.0137	160	-27.1	.986	leading	1.0073
58	160	-27.6	.985	leading	1	160	-26.7	.986	leading	1.0137	160	-27.3	.986	leading	1.0073
59	160	-27.3	.986	leading	1	160	-25.4	.988	leading	1.0137	160	-26.7	.986	leading	1.0073
60	160	-27.8	.985	leading	1	160	-26.8	.986	leading	1.0137	160	-27.5	.986	leading	1.0073
61	160	-27.6	.985	leading	1	160	-26.7	.986	leading	1.0137	160	-27.4	.986	leading	1.0073
62	160	-27.8	.985	leading	1	160	-26.9	.986	leading	1.0137	160	-27.5	.986	leading	1.0073
63	160	-27.8	.985	leading	1	160	-26.9	.986	leading	1.0137	160	-27.5	.986	leading	1.0073
64	160	-27.8	.985	leading	1	160	-26.9	.986	leading	1.0137	160	-27.5	.986	leading	1.0073
65	160	-27.8	.985	leading	1	160	-26.9	.986	leading	1.0137	160	-27.5	.986	leading	1.0073
66	160	-28	.985	leading	1	160	-27.1	.986	leading	1.0137	[redacted]				
67											160	-27.7	.985	leading	1.0073
68	160	-27.2	.986	leading	1	160	-26.5	.987	leading	1.0137	160	-27.3	.986	leading	1.0073
69	160	-27.7	.985	leading	1	160	-26.9	.986	leading	1.0137	160	-27.7	.985	leading	1.0073
70	160	-27.7	.985	leading	1	160	-26.8	.986	leading	1.0137	160	-27.4	.986	leading	1.0073
71	160	-27.7	.985	leading	1	160	-26.7	.986	leading	1.0137	160	-27.4	.986	leading	1.0073
72	160	-28	.985	leading	1	160	-27.1	.986	leading	1.0137	160	-27.7	.985	leading	1.0073
73	160	-27.8	.985	leading	1	160	-26.8	.986	leading	1.0137	160	-27.5	.986	leading	1.0073
74	160	-27.8	.985	leading	1	160	-26.8	.986	leading	1.0137	160	-27.5	.986	leading	1.0073
75	160	-27.8	.985	leading	1	160	-26.8	.986	leading	1.0137	160	-27.5	.986	leading	1.0073
76	160	-27.8	.985	leading	1	160	-26.9	.986	leading	1.0137	160	-27.5	.986	leading	1.0073
77	160	-27.8	.985	leading	1	160	-26.8	.986	leading	1.0137	160	-27.5	.986	leading	1.0073
82	160	-27.7	.985	leading	1	160	-26.8	.986	leading	1.0137	160	-27.4	.986	leading	1.0073
83	160	-27.8	.985	leading	1	160	-26.8	.986	leading	1.0137	160	-27.5	.986	leading	1.0073
84	160	-27.1	.986	leading	1	160	-25.9	.987	leading	1.0137	160	-27.4	.986	leading	1.0073
85	160	-27.8	.985	leading	1	160	-26.9	.986	leading	1.0137	160	-27.5	.986	leading	1.0073
86	160	-28.2	.985	leading	1	160	-27.5	.986	leading	1.0137	160	-27.7	.985	leading	1.0073
87	[redacted]										160	-26.8	.986	leading	1.0073
88											160	-27.2	.986	leading	1.0073

89	[redacted]										160	-27.3	.986	leading	1.0073
90	160	-27.3	.986	leading	1	160	-26.6	.986	leading	1.0137	160	-27.2	.986	leading	1.0073
91	160	-27.8	.985	leading	1	160	-26.9	.986	leading	1.0137	160	-27.5	.986	leading	1.0073
92	[redacted]										160	-27.2	.986	leading	1.0073
93	160	-28.2	.985	leading	1	160	-25.3	.988	leading	1.0137	160	-28.1	.985	leading	1.0073
94	160	-7	.999	leading	1	160	-19.3	.993	leading	1.0137	160	-14.6	.996	leading	1.0073
95	160	-22.2	.991	leading	1	160	-24.1	.989	leading	1.0137	160	-25.1	.988	leading	1.0073
96	160	-27.7	.985	leading	1	160	-26.8	.986	leading	1.0137	160	-27.4	.986	leading	1.0073
97	160	-6.8	.999	leading	1	160	-19.6	.993	leading	1.0137	160	-13.2	.997	leading	1.0073
98	160	-22.7	.990	leading	1	160	-22.3	.990	leading	1.0137	160	-17.1	.994	leading	1.0073
99	160	-25.8	.987	leading	1	160	-25.3	.988	leading	1.0137	160	-25.8	.987	leading	1.0073

	2015 Summer Peak					2015 Winter Peak					2025 Summer Peak				
Cont. No.	P(MW)	Q(MVAR)	Power Factor		V(PU)	P(MW)	Q(MVAR)	Power Factor		V(PU)	P(MW)	Q(MVAR)	Power Factor		V(PU)
0	125.8	-30.8	.971	leading	1.0319	125.8	-32.3	.969	leading	1.0352	125.8	-25	.981	leading	1.0192
1	125.8	-30.6	.972	leading	1.0319	125.8	-32	.969	leading	1.0352	125.8	-24.7	.981	leading	1.0192
2	125.8	-30.5	.972	leading	1.0319	125.8	-31.8	.970	leading	1.0352	125.8	-24.6	.981	leading	1.0192
3	125.8	-30.6	.972	leading	1.0319	125.8	-31.8	.970	leading	1.0352	125.8	-24.8	.981	leading	1.0192
4	125.8	-29.6	.973	leading	1.0319	125.8	-31	.971	leading	1.0352	125.8	-24.1	.982	leading	1.0192
5	125.8	-30.2	.972	leading	1.0319	125.8	-32.1	.969	leading	1.0352	125.8	-24.2	.982	leading	1.0192
6	125.8	-30.7	.971	leading	1.0319	125.8	-32.3	.969	leading	1.0352	125.8	-24.9	.981	leading	1.0192
7	125.8	-30.7	.971	leading	1.0319	125.8	-32.3	.969	leading	1.0352	125.8	-24.9	.981	leading	1.0192
8	125.8	-30.9	.971	leading	1.0319	125.8	-32.6	.968	leading	1.0352	125.8	-25	.981	leading	1.0192
9	125.8	-30.3	.972	leading	1.0319	125.8	-32.1	.969	leading	1.0352	125.8	-24.4	.982	leading	1.0192
10	125.8	-30.8	.971	leading	1.0319	125.8	-32.2	.969	leading	1.0352	125.8	-25	.981	leading	1.0192
11	[redacted]										125.8	-24.6	.981	leading	1.0192
12	125.8	-26.4	.979	leading	1.0319	125.8	-29.3	.974	leading	1.0352	125.8	-22.4	.985	leading	1.0192
13	125.8	-35.8	.962	leading	1.0319	125.8	-36.3	.961	leading	1.0352	125.8	-23.2	.983	leading	1.0192
14	125.8	-29	.974	leading	1.0319	125.8	-28	.976	leading	1.0352	125.8	-23	.984	leading	1.0192
15	125.8	-30.9	.971	leading	1.0319	125.8	-32.2	.969	leading	1.0352	125.8	-25	.981	leading	1.0192
16	125.8	-30	.973	leading	1.0319	125.8	-31.5	.970	leading	1.0352	125.8	-24.4	.982	leading	1.0192
17	125.8	-30	.973	leading	1.0319	125.8	-31.5	.970	leading	1.0352	125.8	-24.5	.982	leading	1.0192
20	125.8	-30	.973	leading	1.0319	125.8	-31.5	.970	leading	1.0352	125.8	-23.3	.983	leading	1.0192
21	125.8	-29.7	.973	leading	1.0319	125.8	-30.8	.971	leading	1.0352	125.8	-24.1	.982	leading	1.0192
22	125.8	-30	.973	leading	1.0319	125.8	-31.5	.970	leading	1.0352	125.8	-24.4	.982	leading	1.0192
24	125.8	-30.5	.972	leading	1.0319	125.8	-32.2	.969	leading	1.0352	125.8	-24.6	.981	leading	1.0192
25	125.8	-29.1	.974	leading	1.0319	125.8	-30.5	.972	leading	1.0352	125.8	-23.7	.983	leading	1.0192
26	125.8	-30.1	.973	leading	1.0319	125.8	-31.4	.970	leading	1.0352	125.8	-24.5	.982	leading	1.0192
27	125.8	-29.7	.973	leading	1.0319	125.8	-32	.969	leading	1.0352	125.8	-24.4	.982	leading	1.0192
28	125.8	-31.1	.971	leading	1.0319	125.8	-32.7	.968	leading	1.0352	125.8	-25.3	.980	leading	1.0192
29	125.8	-30.3	.972	leading	1.0319	125.8	-32.1	.969	leading	1.0352	125.8	-24.4	.982	leading	1.0192
30	125.8	-30.3	.972	leading	1.0319	125.8	-32	.969	leading	1.0352	125.8	-24.3	.982	leading	1.0192
31	125.8	-30.9	.971	leading	1.0319	125.8	-32.5	.968	leading	1.0352	125.8	-24.9	.981	leading	1.0192
33	125.8	-30.8	.971	leading	1.0319	125.8	-32.3	.969	leading	1.0352	125.8	-25.1	.981	leading	1.0192
35	125.8	-30.4	.972	leading	1.0319	125.8	-32.1	.969	leading	1.0352	125.8	-24.5	.982	leading	1.0192
36	125.8	-31.2	.971	leading	1.0319	125.8	-32.5	.968	leading	1.0352	125.8	-25.2	.981	leading	1.0192
38	125.8	-32.3	.969	leading	1.0319	125.8	-33.7	.966	leading	1.0352	125.8	-25.7	.980	leading	1.0192
40	125.8	-31.8	.970	leading	1.0319	125.8	-33.2	.967	leading	1.0352	125.8	-25.5	.980	leading	1.0192
42	125.8	-30.6	.972	leading	1.0319	125.8	-32.3	.969	leading	1.0352	125.8	-24.8	.981	leading	1.0192
44	125.8	-30.8	.971	leading	1.0319	125.8	-32.4	.968	leading	1.0352	125.8	-25	.981	leading	1.0192
45	125.8	-32.6	.968	leading	1.0319	125.8	-34	.965	leading	1.0352	125.8	-25.9	.979	leading	1.0192
46	125.8	-31.7	.970	leading	1.0319	125.8	-33.3	.967	leading	1.0352	125.8	-25.1	.981	leading	1.0192
47	125.8	-24.6	.981	leading	1.0319	125.8	-26.9	.978	leading	1.0352	125.8	-22	.985	leading	1.0192
48	125.8	-31.7	.970	leading	1.0319	125.8	-27.6	.977	leading	1.0352	125.8	-44.1	.944	leading	1.0192
50	125.8	-6.9	.998	leading	1.0319	125.8	-12.1	.995	leading	1.0352	125.8	3.1	1.000	lagging	1.0192
52	125.8	-20.5	.987	leading	1.0319	125.8	-31.3	.970	leading	1.0352	125.8	-7.8	.998	leading	1.0192
53	125.8	-8.5	.998	leading	1.0319	125.8	-32.7	.968	leading	1.0352	125.8	30.7	.971	lagging	1.0192
54	125.8	-20.1	.987	leading	1.0319	125.8	-27.7	.977	leading	1.0352	125.8	-14.6	.993	leading	1.0192
55	125.8	-30.6	.972	leading	1.0319	125.8	-32.2	.969	leading	1.0352	125.8	-24.3	.982	leading	1.0192
56	125.8	-28.2	.976	leading	1.0319	125.8	-31.6	.970	leading	1.0352	125.8	-22.8	.984	leading	1.0192
57	125.8	-28.2	.976	leading	1.0319	125.8	-31.6	.970	leading	1.0352	125.8	-22.8	.984	leading	1.0192
58	125.8	-27.4	.977	leading	1.0319	125.8	-28.4	.975	leading	1.0352	125.8	-23.9	.982	leading	1.0192
59	125.8	-25.4	.980	leading	1.0319	125.8	-28.2	.976	leading	1.0352	125.8	-21.1	.986	leading	1.0192
60	125.8	-31.9	.969	leading	1.0319	125.8	-32	.969	leading	1.0352	125.8	-24.4	.982	leading	1.0192
61	125.8	-29	.974	leading	1.0319	125.8	-30.3	.972	leading	1.0352	125.8	-23.3	.983	leading	1.0192
62	125.8	-30.8	.971	leading	1.0319	125.8	-32.4	.968	leading	1.0352	125.8	-25	.981	leading	1.0192
63	125.8	-30.9	.971	leading	1.0319	125.8	-32.4	.968	leading	1.0352	125.8	-25	.981	leading	1.0192
64	125.8	-30.8	.971	leading	1.0319	125.8	-32.3	.969	leading	1.0352	125.8	-24.9	.981	leading	1.0192
65	125.8	-30.8	.971	leading	1.0319	125.8	-32.3	.969	leading	1.0352	125.8	-24.9	.981	leading	1.0192
66	125.8	-31	.971	leading	1.0319	125.8	-32.7	.968	leading	1.0352	[redacted]				
67	[redacted]										125.8	-25.1	.981	leading	1.0192
68	125.8	-30.1	.973	leading	1.0319	125.8	-31.8	.970	leading	1.0352	125.8	-24.8	.981	leading	1.0192
69	125.8	-30.5	.972	leading	1.0319	125.8	-32.3	.969	leading	1.0352	125.8	-25.1	.981	leading	1.0192
70	125.8	-30.8	.971	leading	1.0319	125.8	-32.3	.969	leading	1.0352	125.8	-25	.981	leading	1.0192
71	125.8	-30.6	.972	leading	1.0319	125.8	-32	.969	leading	1.0352	125.8	-24.7	.981	leading	1.0192
72	125.8	-30.9	.971	leading	1.0319	125.8	-32.4	.968	leading	1.0352	125.8	-25	.981	leading	1.0192
73	125.8	-30.8	.971	leading	1.0319	125.8	-32.2	.969	leading	1.0352	125.8	-25	.981	leading	1.0192
74	125.8	-30.8	.971	leading	1.0319	125.8	-32.3	.969	leading	1.0352	125.8	-25	.981	leading	1.0192
75	125.8	-30.7	.971	leading	1.0319	125.8	-32.3	.969	leading	1.0352	125.8	-25	.981	leading	1.0192
76	125.8	-30.8	.971	leading	1.0319	125.8	-32.3	.969	leading	1.0352	125.8	-25	.981	leading	1.0192
77	125.8	-30.8	.971	leading	1.0319	125.8	-32.2	.969	leading	1.0352	125.8	-25	.981	leading	1.0192
82	125.8	-30.7	.971	leading	1.0319	125.8	-32.2	.969	leading	1.0352	125.8	-25	.981	leading	1.0192
83	125.8	-30.7	.971	leading	1.0319	125.8	-32.1	.969	leading	1.0352	125.8	-25	.981	leading	1.0192
84	125.8	-29.7	.973	leading	1.0319	125.8	-30.9	.971	leading	1.0352	125.8	-24.9	.981	leading	1.0192
85	125.8	-30.9	.971	leading	1.0319	125.8	-32.4	.968	leading	1.0352	125.8	-25.1	.981	leading	1.0192
86	125.8	-31.9	.969	leading	1.0319	125.8	-33.4	.967	leading	1.0352	125.8	-25.6	.980	leading	1.0192
87	[redacted]										125.8	-23.8	.983	leading	1.0192
88											125.8	-24.5	.982	leading	1.0192

89	[redacted]										125.8	-24.6	.981	leading	1.0192
90	125.8	-30.5	.972	leading	1.0319	125.8	-32.1	.969	leading	1.0352	125.8	-24.8	.981	leading	1.0192
91	125.8	-30.8	.971	leading	1.0319	125.8	-32.3	.969	leading	1.0352	125.8	-25	.981	leading	1.0192
92	[redacted]										125.8	-25	.981	leading	1.0192
93	125.8	-29.4	.974	leading	1.0319	125.8	-29.9	.973	leading	1.0352	125.8	-24.5	.982	leading	1.0192
94	125.8	-25.2	.981	leading	1.0319	125.8	-29.3	.974	leading	1.0352	125.8	-23	.984	leading	1.0192
95	125.8	-22.6	.984	leading	1.0319	125.8	-26.9	.978	leading	1.0352	125.8	-20.6	.987	leading	1.0192
96	125.8	-30.6	.972	leading	1.0319	125.8	-32.2	.969	leading	1.0352	125.8	-24.9	.981	leading	1.0192
97	125.8	-25.3	.980	leading	1.0319	125.8	-28	.976	leading	1.0352	125.8	-22.8	.984	leading	1.0192
98	125.8	-35.5	.962	leading	1.0319	125.8	-36.1	.961	leading	1.0352	125.8	-23.3	.983	leading	1.0192
99	125.8	-29.3	.974	leading	1.0319	125.8	-30.8	.971	leading	1.0352	125.8	-23.8	.983	leading	1.0192

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Cont. No.	2015 Summer Peak					2015 Winter Peak					2025 Summer Peak				
	P(MW)	Q(MVAR)	Power Factor		V(PU)	P(MW)	Q(MVAR)	Power Factor		V(PU)	P(MW)	Q(MVAR)	Power Factor		V(PU)
0	160	-36.5	.975	leading	1.0044	160	-34.8	.977	leading	1.0024	160	-42.2	.967	leading	1.0128
1	160	-29.7	.983	leading	1.0044	160	-20	.992	leading	1.0024	160	-28.9	.984	leading	1.0128
2	160	-27	.986	leading	1.0044	160	-18.8	.993	leading	1.0024	160	-27.4	.986	leading	1.0128
3	160	-25.8	.987	leading	1.0044	160	-31.2	.982	leading	1.0024	160	-40.1	.970	leading	1.0128
4	160	-67.2	.922	leading	1.0044	160	-64.9	.927	leading	1.0024	160	-73.6	.908	leading	1.0128
5	160	-41.5	.968	leading	1.0044	160	-34.5	.978	leading	1.0024	160	-50.5	.954	leading	1.0128
6	160	-31.2	.982	leading	1.0044	160	-29.9	.983	leading	1.0024	160	-36.2	.975	leading	1.0128
7	160	-34	.978	leading	1.0044	160	-33.2	.979	leading	1.0024	160	-38.7	.972	leading	1.0128
8	160	-1.5	1.000	leading	1.0044	160	0.9	1.000	lagging	1.0024	160	-10.5	.998	leading	1.0128
9	160	-25	.988	leading	1.0044	160	-18.9	.993	leading	1.0024	160	-34.3	.978	leading	1.0128
10	160	66.2	.924	lagging	1.0044	160	66.2	.924	lagging	1.0024	160	37.2	.974	lagging	1.0128
11	[redacted]										160	14	.996	lagging	1.0128
12	160	-20	.992	leading	1.0044	160	-16.1	.995	leading	1.0024	160	-29	.984	leading	1.0128
13	160	-15.9	.995	leading	1.0044	160	-33.7	.979	leading	1.0024	160	-34.9	.977	leading	1.0128
14	160	-36.4	.975	leading	1.0044	160	-27.9	.985	leading	1.0024	160	-41.2	.968	leading	1.0128
15	160	-37	.974	leading	1.0044	160	-33.9	.978	leading	1.0024	160	-42.2	.967	leading	1.0128
16	160	-28.9	.984	leading	1.0044	160	-25.3	.988	leading	1.0024	160	-34.2	.978	leading	1.0128
17	160	-28.9	.984	leading	1.0044	160	-25.3	.988	leading	1.0024	160	-35	.977	leading	1.0128
20	160	-28.9	.984	leading	1.0044	160	-25.3	.988	leading	1.0024	160	-19.5	.993	leading	1.0128
21	160	-24.6	.988	leading	1.0044	160	-20	.992	leading	1.0024	160	-38.8	.972	leading	1.0128
22	160	-28.9	.984	leading	1.0044	160	-25.3	.988	leading	1.0024	160	-34.2	.978	leading	1.0128
24	160	-24.9	.988	leading	1.0044	160	-20.9	.992	leading	1.0024	160	-28.6	.984	leading	1.0128
25	160	-57.1	.942	leading	1.0044	160	-55.3	.945	leading	1.0024	160	-64.1	.928	leading	1.0128
26	160	-18.2	.994	leading	1.0044	160	-18.5	.993	leading	1.0024	160	-34.1	.978	leading	1.0128
27	160	-28.8	.984	leading	1.0044	160	-34.9	.977	leading	1.0024	160	-38.4	.972	leading	1.0128
28	160	-34.9	.977	leading	1.0044	160	-33.8	.978	leading	1.0024	160	-39.5	.971	leading	1.0128
29	160	-42.2	.967	leading	1.0044	160	-36.5	.975	leading	1.0024	160	-49.8	.955	leading	1.0128
30	160	-28	.985	leading	1.0044	160	-29.3	.984	leading	1.0024	160	-27.1	.986	leading	1.0128
31	160	-36.3	.975	leading	1.0044	160	-35.1	.977	leading	1.0024	160	-41.9	.967	leading	1.0128
33	160	-36.4	.975	leading	1.0044	160	-34.8	.977	leading	1.0024	160	-42.1	.967	leading	1.0128
35	160	-36.2	.975	leading	1.0044	160	-34.6	.977	leading	1.0024	160	-41.8	.968	leading	1.0128
36	160	-36.7	.975	leading	1.0044	160	-34.9	.977	leading	1.0024	160	-42.2	.967	leading	1.0128
38	160	-36.3	.975	leading	1.0044	160	-36.1	.975	leading	1.0024	160	-42.2	.967	leading	1.0128
40	160	-36.5	.975	leading	1.0044	160	-35.6	.976	leading	1.0024	160	-42.4	.967	leading	1.0128
42	160	-36.5	.975	leading	1.0044	160	-34.9	.977	leading	1.0024	160	-42	.967	leading	1.0128
44	160	-36.5	.975	leading	1.0044	160	-34.8	.977	leading	1.0024	160	-42.1	.967	leading	1.0128
45	160	-36.3	.975	leading	1.0044	160	-36.3	.975	leading	1.0024	160	-42.3	.967	leading	1.0128
46	160	-35.8	.976	leading	1.0044	160	-35.8	.976	leading	1.0024	160	-41.9	.967	leading	1.0128
47	160	-26.2	.987	leading	1.0044	160	-26.8	.986	leading	1.0024	160	-34.2	.978	leading	1.0128
48	160	-36.1	.975	leading	1.0044	160	-34.7	.977	leading	1.0024	160	-40	.970	leading	1.0128
50	160	-36.4	.975	leading	1.0044	160	-34.4	.978	leading	1.0024	160	-42.7	.966	leading	1.0128
52	160	-33.3	.979	leading	1.0044	160	-29.3	.984	leading	1.0024	160	-39.5	.971	leading	1.0128
53	160	-36.8	.975	leading	1.0044	160	-34.3	.978	leading	1.0024	160	-43	.966	leading	1.0128
54	160	-35.8	.976	leading	1.0044	160	-35.1	.977	leading	1.0024	160	-41.9	.967	leading	1.0128
55	160	-36.6	.975	leading	1.0044	160	-34.8	.977	leading	1.0024	160	-42.2	.967	leading	1.0128
56	160	-29.4	.984	leading	1.0044	160	-24.3	.989	leading	1.0024	160	-36.4	.975	leading	1.0128
57	160	-29.4	.984	leading	1.0044	160	-24.3	.989	leading	1.0024	160	-36.4	.975	leading	1.0128
58	160	-35.4	.976	leading	1.0044	160	-33.8	.978	leading	1.0024	160	-41.1	.969	leading	1.0128
59	160	-26.3	.987	leading	1.0044	160	-21.6	.991	leading	1.0024	160	-31.7	.981	leading	1.0128
60	160	-36.5	.975	leading	1.0044	160	-34.7	.977	leading	1.0024	160	-42.1	.967	leading	1.0128
61	160	-35	.977	leading	1.0044	160	-33.8	.978	leading	1.0024	160	-40.8	.969	leading	1.0128
62	160	-54.6	.946	leading	1.0044	160	-51.3	.952	leading	1.0024	160	-58.6	.939	leading	1.0128
63	160	-41.2	.968	leading	1.0044	160	-42.9	.966	leading	1.0024	160	-35.3	.977	leading	1.0128
64	160	-125.1	.788	leading	1.0044	160	-129.4	.778	leading	1.0024	160	-117.9	.805	leading	1.0128
65	160	-124.9	.788	leading	1.0044	160	-128.8	.779	leading	1.0024	160	-118	.805	leading	1.0128
66	160	-37.9	.973	leading	1.0044	160	-38.8	.972	leading	1.0024	[redacted]				
67	[redacted]										160	-43	.966	leading	1.0128
68	160	-32.5	.980	leading	1.0044	160	-36.9	.974	leading	1.0024	160	-41.2	.968	leading	1.0128
69	160	-30.7	.982	leading	1.0044	160	-37.3	.974	leading	1.0024	160	-37.9	.973	leading	1.0128
70	160	-22	.991	leading	1.0044	160	-16.2	.995	leading	1.0024	160	-38.2	.973	leading	1.0128
71	160	-89.2	.873	leading	1.0044	160	-101.3	.845	leading	1.0024	160	-75.8	.904	leading	1.0128
72	160	-1.8	1.000	leading	1.0044	160	6.2	.999	lagging	1.0024	160	-9.2	.998	leading	1.0128
73	160	-42.4	.967	leading	1.0044	160	-41.5	.968	leading	1.0024	160	-45.5	.962	leading	1.0128
74	160	-37.7	.973	leading	1.0044	160	-37.1	.974	leading	1.0024	160	-42.5	.966	leading	1.0128
75	160	-36.6	.975	leading	1.0044	160	-31.3	.981	leading	1.0024	160	-45.1	.962	leading	1.0128
76	160	-43.6	.965	leading	1.0044	160	-37.7	.973	leading	1.0024	160	-48.7	.957	leading	1.0128
77	160	-37.1	.974	leading	1.0044	160	-37.3	.974	leading	1.0024	160	-43.3	.965	leading	1.0128
82	160	-40.9	.969	leading	1.0044	160	-41.1	.969	leading	1.0024	160	-42.3	.967	leading	1.0128
83	160	-31.9	.981	leading	1.0044	160	-24.9	.988	leading	1.0024	160	-41	.969	leading	1.0128
84	160	-42.4	.967	leading	1.0044	160	-63.1	.930	leading	1.0024	160	-35.9	.976	leading	1.0128
85	160	-35.4	.976	leading	1.0044	160	-34.3	.978	leading	1.0024	160	-42.3	.967	leading	1.0128
86	160	9.8	.998	lagging	1.0044	160	-3.2	1.000	leading	1.0024	160	-37.8	.973	leading	1.0128
87	[redacted]										160	-21.8	.991	leading	1.0128
88											160	-17	.994	leading	1.0128

89	[redacted]										160	-21.5	.991	leading	1.0128
90	160	-35.6	.976	leading	1.0044	160	-33.6	.979	leading	1.0024	160	-41.4	.968	leading	1.0128
91	160	-36.5	.975	leading	1.0044	160	-34.8	.977	leading	1.0024	160	-42.1	.967	leading	1.0128
92	[redacted]										160	-42	.967	leading	1.0128
93	160	-31.2	.982	leading	1.0044	160	-31.7	.981	leading	1.0024	160	-37.1	.974	leading	1.0128
94	160	-28.3	.985	leading	1.0044	160	-26.4	.987	leading	1.0024	160	-35.5	.976	leading	1.0128
95	160	-27.3	.986	leading	1.0044	160	-24.5	.988	leading	1.0024	160	-34.5	.978	leading	1.0128
96	160	-35.8	.976	leading	1.0044	160	-34.6	.977	leading	1.0024	160	-41.5	.968	leading	1.0128
97	160	-26.7	.986	leading	1.0044	160	-17.2	.994	leading	1.0024	160	-29.7	.983	leading	1.0128
98	160	-14.9	.996	leading	1.0044	160	-32.7	.980	leading	1.0024	160	-34	.978	leading	1.0128
99	160	-32.5	.980	leading	1.0044	160	-28.1	.985	leading	1.0024	160	-38	.973	leading	1.0128

POI-640226

	2015 Summer Peak					2015 Winter Peak					2025 Summer Peak				
Cont. No.	P(MW)	Q(MVAR)	Power Factor		V(PU)	P(MW)	Q(MVAR)	Power Factor		V(PU)	P(MW)	Q(MVAR)	Power Factor		V(PU)
0	150.4	-30.3	.980	leading	1.0299	150.4	-36.8	.971	leading	1.039	150.4	-31.7	.979	leading	1.0316
1	150.4	-31.2	.979	leading	1.0299	150.4	-37.7	.970	leading	1.039	150.4	-33.5	.976	leading	1.0316
2	150.4	-29.2	.982	leading	1.0299	150.4	-36.7	.971	leading	1.039	150.4	-31.4	.979	leading	1.0316
3	150.4	-23.9	.988	leading	1.0299	150.4	-31.7	.979	leading	1.039	150.4	-21.1	.990	leading	1.0316
4	150.4	-29.1	.982	leading	1.0299	150.4	-35.2	.974	leading	1.039	150.4	-29.7	.981	leading	1.0316
5	150.4	-30.5	.980	leading	1.0299	150.4	-36.3	.972	leading	1.039	150.4	-32	.978	leading	1.0316
6	150.4	-30	.981	leading	1.0299	150.4	-36.7	.971	leading	1.039	150.4	-31.8	.978	leading	1.0316
7	150.4	-30.2	.980	leading	1.0299	150.4	-36.4	.972	leading	1.039	150.4	-32.2	.978	leading	1.0316
8	150.4	-31.4	.979	leading	1.0299	150.4	-37.9	.970	leading	1.039	150.4	-34.5	.975	leading	1.0316
9	150.4	-30.6	.980	leading	1.0299	150.4	-35.2	.974	leading	1.039	150.4	-33.5	.976	leading	1.0316
10	150.4	-30.7	.980	leading	1.0299	150.4	-39.4	.967	leading	1.039	150.4	-33.7	.976	leading	1.0316
11	[redacted]										150.4	-46.5	.955	leading	1.0316
12	150.4	-28.5	.983	leading	1.0299	150.4	-33.6	.976	leading	1.039	150.4	-28.4	.983	leading	1.0316
13	150.4	-24.3	.987	leading	1.0299	150.4	-34	.975	leading	1.039	150.4	-24.6	.987	leading	1.0316
14	150.4	-31.3	.979	leading	1.0299	150.4	-36.9	.971	leading	1.039	150.4	-32.4	.978	leading	1.0316
15	150.4	-30.4	.980	leading	1.0299	150.4	-36.7	.971	leading	1.039	150.4	-31.7	.979	leading	1.0316
16	150.4	-27.6	.984	leading	1.0299	150.4	-32.9	.977	leading	1.039	150.4	-27.9	.983	leading	1.0316
17	150.4	-27.6	.984	leading	1.0299	150.4	-32.9	.977	leading	1.039	150.4	-28	.983	leading	1.0316
20	150.4	-27.6	.984	leading	1.0299	150.4	-32.9	.977	leading	1.039	150.4	-22.7	.989	leading	1.0316
21	150.4	-19.8	.991	leading	1.0299	150.4	-27.5	.984	leading	1.039	150.4	-16.5	.994	leading	1.0316
22	150.4	-27.6	.984	leading	1.0299	150.4	-32.9	.977	leading	1.039	150.4	-27.9	.983	leading	1.0316
24	150.4	-29.1	.982	leading	1.0299	150.4	-36	.973	leading	1.039	150.4	-32.1	.978	leading	1.0316
25	150.4	-28.2	.983	leading	1.0299	150.4	-34.4	.975	leading	1.039	150.4	-28.3	.983	leading	1.0316
26	150.4	-29.7	.981	leading	1.0299	150.4	-33.9	.976	leading	1.039	150.4	-26.7	.985	leading	1.0316
27	150.4	-30.3	.980	leading	1.0299	150.4	-37	.971	leading	1.039	150.4	-32.5	.977	leading	1.0316
28	150.4	-30.3	.980	leading	1.0299	150.4	-37.1	.971	leading	1.039	150.4	-32.3	.978	leading	1.0316
29	150.4	-30.3	.980	leading	1.0299	150.4	-34.8	.974	leading	1.039	150.4	-34.6	.975	leading	1.0316
30	150.4	-29.9	.981	leading	1.0299	150.4	-34.3	.975	leading	1.039	150.4	-37.5	.970	leading	1.0316
31	150.4	-30.2	.980	leading	1.0299	150.4	-36.9	.971	leading	1.039	150.4	-31.6	.979	leading	1.0316
33	150.4	-30.3	.980	leading	1.0299	150.4	-36.8	.971	leading	1.039	150.4	-31.7	.979	leading	1.0316
35	150.4	-30.3	.980	leading	1.0299	150.4	-36.8	.971	leading	1.039	150.4	-31.6	.979	leading	1.0316
36	150.4	-30.4	.980	leading	1.0299	150.4	-36.9	.971	leading	1.039	150.4	-31.7	.979	leading	1.0316
38	150.4	-29.7	.981	leading	1.0299	150.4	-36.8	.971	leading	1.039	150.4	-31.3	.979	leading	1.0316
40	150.4	-29.9	.981	leading	1.0299	150.4	-36.5	.972	leading	1.039	150.4	-31.5	.979	leading	1.0316
42	150.4	-30.4	.980	leading	1.0299	150.4	-37	.971	leading	1.039	150.4	-31.8	.978	leading	1.0316
44	150.4	-30.3	.980	leading	1.0299	150.4	-36.9	.971	leading	1.039	150.4	-31.7	.979	leading	1.0316
45	150.4	-29.6	.981	leading	1.0299	150.4	-36.8	.971	leading	1.039	150.4	-31.2	.979	leading	1.0316
46	150.4	-29.6	.981	leading	1.0299	150.4	-36.7	.971	leading	1.039	150.4	-31.2	.979	leading	1.0316
47	150.4	-26.4	.985	leading	1.0299	150.4	-31.2	.979	leading	1.039	150.4	-26.5	.985	leading	1.0316
48	150.4	-30.4	.980	leading	1.0299	150.4	-36.9	.971	leading	1.039	150.4	-31.8	.978	leading	1.0316
50	150.4	-30.3	.980	leading	1.0299	150.4	-36.6	.972	leading	1.039	150.4	-31.7	.979	leading	1.0316
52	150.4	-29.9	.981	leading	1.0299	150.4	-36	.973	leading	1.039	150.4	-31.1	.979	leading	1.0316
53	150.4	-30.3	.980	leading	1.0299	150.4	-36.6	.972	leading	1.039	150.4	-31.6	.979	leading	1.0316
54	150.4	-30.1	.981	leading	1.0299	150.4	-36.6	.972	leading	1.039	150.4	-31.5	.979	leading	1.0316
55	150.4	-30.3	.980	leading	1.0299	150.4	-36.8	.971	leading	1.039	150.4	-31.8	.978	leading	1.0316
56	150.4	-29.3	.982	leading	1.0299	150.4	-34.8	.974	leading	1.039	150.4	-30.1	.981	leading	1.0316
57	150.4	-29.3	.982	leading	1.0299	150.4	-34.8	.974	leading	1.039	150.4	-30.1	.981	leading	1.0316
58	150.4	-30.2	.980	leading	1.0299	150.4	-36.7	.971	leading	1.039	150.4	-31.6	.979	leading	1.0316
59	150.4	-28.9	.982	leading	1.0299	150.4	-34.4	.975	leading	1.039	150.4	-30.1	.981	leading	1.0316
60	150.4	-30.3	.980	leading	1.0299	150.4	-36.8	.971	leading	1.039	150.4	-31.7	.979	leading	1.0316
61	150.4	-30.2	.980	leading	1.0299	150.4	-36.7	.971	leading	1.039	150.4	-31.5	.979	leading	1.0316
62	150.4	-30	.981	leading	1.0299	150.4	-36.3	.972	leading	1.039	150.4	-32.2	.978	leading	1.0316
63	150.4	-29.3	.982	leading	1.0299	150.4	-35.6	.973	leading	1.039	150.4	-34.2	.975	leading	1.0316
64	150.4	-18.6	.992	leading	1.0299	150.4	-23	.989	leading	1.039	150.4	-27.1	.984	leading	1.0316
65	150.4	-17.4	.993	leading	1.0299	150.4	-23.2	.988	leading	1.039	150.4	-27.2	.984	leading	1.0316
66	150.4	-30.8	.980	leading	1.0299	150.4	-37.7	.970	leading	1.039	[redacted]				
67	[redacted]										150.4	-33.5	.976	leading	1.0316
68	150.4	-30.7	.980	leading	1.0299	150.4	-37.6	.970	leading	1.039	150.4	-33	.977	leading	1.0316
69	150.4	-31.2	.979	leading	1.0299	150.4	-38.3	.969	leading	1.039	150.4	-34.1	.975	leading	1.0316
70	150.4	-28.7	.982	leading	1.0299	150.4	-35.2	.974	leading	1.039	150.4	-29.5	.981	leading	1.0316
71	150.4	4.4	1.000	lagging	1.0299	150.4	-4.2	1.000	leading	1.039	150.4	-2.9	1.000	leading	1.0316
72	150.4	-30.8	.980	leading	1.0299	150.4	-38.1	.969	leading	1.039	150.4	-33.8	.976	leading	1.0316
73	150.4	-25.4	.986	leading	1.0299	150.4	-32	.978	leading	1.039	150.4	-27.5	.984	leading	1.0316
74	150.4	-29.2	.982	leading	1.0299	150.4	-35.3	.974	leading	1.039	150.4	-31	.979	leading	1.0316
75	150.4	-30.7	.980	leading	1.0299	150.4	-36.9	.971	leading	1.039	150.4	-31.9	.978	leading	1.0316
76	150.4	-30.3	.980	leading	1.0299	150.4	-36.9	.971	leading	1.039	150.4	-30.8	.980	leading	1.0316
77	150.4	-25.4	.986	leading	1.0299	150.4	-31.6	.979	leading	1.039	150.4	-27.2	.984	leading	1.0316
82	150.4	-30	.981	leading	1.0299	150.4	-36.5	.972	leading	1.039	150.4	-32.5	.977	leading	1.0316
83	150.4	-21.6	.990	leading	1.0299	150.4	-25.6	.986	leading	1.039	150.4	-32.6	.977	leading	1.0316
84	150.4	-12.5	.997	leading	1.0299	150.4	-18.6	.992	leading	1.039	150.4	-23.7	.988	leading	1.0316
85	150.4	-25.1	.986	leading	1.0299	150.4	-31.6	.979	leading	1.039	150.4	-25.4	.986	leading	1.0316
86	150.4	3.4	1.000	lagging	1.0299	150.4	10.2	.998	lagging	1.039	150.4	10.8	.997	lagging	1.0316
87	[redacted]										150.4	-36.3	.972	leading	1.0316
88											150.4	-44.3	.959	leading	1.0316

89	[redacted]										150.4	-38	.970	leading	1.0316
90	150.4	-30	.981	leading	1.0299	150.4	-36.6	.972	leading	1.039	150.4	-31.3	.979	leading	1.0316
91	150.4	-30.3	.980	leading	1.0299	150.4	-36.8	.971	leading	1.039	150.4	-31.7	.979	leading	1.0316
92	[redacted]										150.4	-31.8	.978	leading	1.0316
93	150.4	-29.6	.981	leading	1.0299	150.4	-35.8	.973	leading	1.039	150.4	-31	.979	leading	1.0316
94	150.4	-29.2	.982	leading	1.0299	150.4	-35.4	.973	leading	1.039	150.4	-29.8	.981	leading	1.0316
95	150.4	-28.9	.982	leading	1.0299	150.4	-35	.974	leading	1.039	150.4	-29.5	.981	leading	1.0316
96	150.4	-30.2	.980	leading	1.0299	150.4	-36.8	.971	leading	1.039	150.4	-31.7	.979	leading	1.0316
97	150.4	-30.1	.981	leading	1.0299	150.4	-35.9	.973	leading	1.039	150.4	-31.2	.979	leading	1.0316
98	150.4	-23.8	.988	leading	1.0299	150.4	-33.7	.976	leading	1.039	150.4	-24.1	.987	leading	1.0316
99	150.4	-28.9	.982	leading	1.0299	150.4	-35.3	.974	leading	1.039	150.4	-29.3	.982	leading	1.0316

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Cont. No.	2015 Summer Peak					2015 Winter Peak					2025 Summer Peak				
	P(MW)	Q(MVAR)	Power Factor		V(PU)	P(MW)	Q(MVAR)	Power Factor		V(PU)	P(MW)	Q(MVAR)	Power Factor		V(PU)
0	300.7	-2.4	1.000	leading	1	300.7	-20.9	.998	leading	1.0102	300.7	-21	.998	leading	1.0099
1	300.7	-4.1	1.000	leading	1	300.7	-21.9	.997	leading	1.0102	300.7	-22.1	.997	leading	1.0099
2	300.7	0.7	1.000	lagging	1	300.7	-18.9	.998	leading	1.0102	300.7	-18.7	.998	leading	1.0099
3	300.7	17.9	.998	lagging	1	300.7	-9.7	.999	leading	1.0102	300.7	-5.3	1.000	leading	1.0099
4	300.7	1.8	1.000	lagging	1	300.7	-16.6	.998	leading	1.0102	300.7	-17	.998	leading	1.0099
5	300.7	0.3	1.000	lagging	1	300.7	-23.1	.997	leading	1.0102	300.7	-16.5	.998	leading	1.0099
6	300.7	-2.6	1.000	leading	1	300.7	-21.3	.998	leading	1.0102	300.7	-21.2	.998	leading	1.0099
7	300.7	-2	1.000	leading	1	300.7	-20.8	.998	leading	1.0102	300.7	-20.5	.998	leading	1.0099
8	300.7	-0.6	1.000	leading	1	300.7	-21	.998	leading	1.0102	300.7	-19.7	.998	leading	1.0099
9	300.7	0.6	1.000	lagging	1	300.7	-20.7	.998	leading	1.0102	300.7	-17.8	.998	leading	1.0099
10	300.7	-2.7	1.000	leading	1	300.7	-21.8	.997	leading	1.0102	300.7	-21.5	.997	leading	1.0099
11											300.7	-18.4	.998	leading	1.0099
12	300.7	15.2	.999	lagging	1	300.7	0.3	1.000	lagging	1.0102	300.7	-3.3	1.000	leading	1.0099
13	300.7	112.8	.936	lagging	1	300.7	117.9	.931	lagging	1.0102	300.7	-3.6	1.000	leading	1.0099
14	300.7	139.2	.907	lagging	1	300.7	141.7	.905	lagging	1.0102	300.7	104.7	.944	lagging	1.0099
15	300.7	-2.7	1.000	leading	1	300.7	-16.8	.998	leading	1.0102	300.7	-19.2	.998	leading	1.0099
16	300.7	4.1	1.000	lagging	1	300.7	-16.4	.999	leading	1.0102	300.7	-15.5	.999	leading	1.0099
17	300.7	4.1	1.000	lagging	1	300.7	-16.4	.999	leading	1.0102	300.7	-16.4	.999	leading	1.0099
20	300.7	4.1	1.000	lagging	1	300.7	-16.4	.999	leading	1.0102	300.7	-5.8	1.000	leading	1.0099
21	300.7	32.1	.994	lagging	1	300.7	-0.3	1.000	leading	1.0102	300.7	6.3	1.000	lagging	1.0099
22	300.7	4.1	1.000	lagging	1	300.7	-16.4	.999	leading	1.0102	300.7	-15.5	.999	leading	1.0099
24	300.7	-1.9	1.000	leading	1	300.7	-21.6	.997	leading	1.0102	300.7	-20.4	.998	leading	1.0099
25	300.7	1.8	1.000	lagging	1	300.7	-16.8	.998	leading	1.0102	300.7	-17.3	.998	leading	1.0099
26	300.7	3.2	1.000	lagging	1	300.7	-16.4	.999	leading	1.0102	300.7	-16.9	.998	leading	1.0099
27	300.7	5.1	1.000	lagging	1	300.7	-19.6	.998	leading	1.0102	300.7	-17.5	.998	leading	1.0099
28	300.7	-4.6	1.000	leading	1	300.7	-22	.997	leading	1.0102	300.7	-22.7	.997	leading	1.0099
29	300.7	0.6	1.000	lagging	1	300.7	-20.6	.998	leading	1.0102	300.7	-17.7	.998	leading	1.0099
30	300.7	0.8	1.000	lagging	1	300.7	-20.5	.998	leading	1.0102	300.7	-16.9	.998	leading	1.0099
31	300.7	-0.3	1.000	leading	1	300.7	-20.1	.998	leading	1.0102	300.7	-17.2	.998	leading	1.0099
33	300.7	-1.6	1.000	leading	1	300.7	-20.6	.998	leading	1.0102	300.7	-20.5	.998	leading	1.0099
35	300.7	-1.6	1.000	leading	1	300.7	-20.5	.998	leading	1.0102	300.7	-18.1	.998	leading	1.0099
36	300.7	-2.5	1.000	leading	1	300.7	-20.7	.998	leading	1.0102	300.7	-21.4	.997	leading	1.0099
38	300.7	0.7	1.000	lagging	1	300.7	-21.7	.997	leading	1.0102	300.7	-20.9	.998	leading	1.0099
40	300.7	-1.7	1.000	leading	1	300.7	-22.3	.997	leading	1.0102	300.7	-23.6	.997	leading	1.0099
42	300.7	-1.7	1.000	leading	1	300.7	-20.5	.998	leading	1.0102	300.7	-19.3	.998	leading	1.0099
44	300.7	-2.2	1.000	leading	1	300.7	-20.9	.998	leading	1.0102	300.7	-20.6	.998	leading	1.0099
45	300.7	1.2	1.000	lagging	1	300.7	-22	.997	leading	1.0102	300.7	-21.2	.998	leading	1.0099
46	300.7	2.9	1.000	lagging	1	300.7	-20.8	.998	leading	1.0102	300.7	-16.5	.998	leading	1.0099
47	300.7	32.7	.994	lagging	1	300.7	7.5	1.000	lagging	1.0102	300.7	60.9	.980	lagging	1.0099
48	300.7	-1.4	1.000	leading	1	300.7	-20.7	.998	leading	1.0102	300.7	-16.7	.998	leading	1.0099
50	300.7	-1.9	1.000	leading	1	300.7	-19.5	.998	leading	1.0102	300.7	-21.5	.997	leading	1.0099
52	300.7	0.7	1.000	lagging	1	300.7	-15.7	.999	leading	1.0102	300.7	-17.8	.998	leading	1.0099
53	300.7	-3	1.000	leading	1	300.7	-19.8	.998	leading	1.0102	300.7	-22.6	.997	leading	1.0099
54	300.7	0.5	1.000	lagging	1	300.7	-20.7	.998	leading	1.0102	300.7	-18.8	.998	leading	1.0099
55	300.7	-2.3	1.000	leading	1	300.7	-20.8	.998	leading	1.0102	300.7	-21	.998	leading	1.0099
56	300.7	3.2	1.000	lagging	1	300.7	-7.8	1.000	leading	1.0102	300.7	-12.9	.999	leading	1.0099
57	300.7	3.2	1.000	lagging	1	300.7	-7.8	1.000	leading	1.0102	300.7	-12.9	.999	leading	1.0099
58	300.7	-0.6	1.000	leading	1	300.7	-19.4	.998	leading	1.0102	300.7	-19.1	.998	leading	1.0099
59	300.7	9.2	1.000	lagging	1	300.7	-2.1	1.000	leading	1.0102	300.7	-8.4	1.000	leading	1.0099
60	300.7	-2	1.000	leading	1	300.7	-20.7	.998	leading	1.0102	300.7	-20.8	.998	leading	1.0099
61	300.7	-0.6	1.000	leading	1	300.7	-19.7	.998	leading	1.0102	300.7	-19	.998	leading	1.0099
62	300.7	-2.5	1.000	leading	1	300.7	-21	.998	leading	1.0102	300.7	-21.2	.998	leading	1.0099
63	300.7	-2.7	1.000	leading	1	300.7	-20.9	.998	leading	1.0102	300.7	-21.1	.998	leading	1.0099
64	300.7	-2.8	1.000	leading	1	300.7	-20.8	.998	leading	1.0102	300.7	-21	.998	leading	1.0099
65	300.7	-2.8	1.000	leading	1	300.7	-20.7	.998	leading	1.0102	300.7	-21.1	.998	leading	1.0099
66	300.7	-4.3	1.000	leading	1	300.7	-22.6	.997	leading	1.0102					
67											300.7	-23	.997	leading	1.0099
68	300.7	0.9	1.000	lagging	1	300.7	-19.6	.998	leading	1.0102	300.7	-20.6	.998	leading	1.0099
69	300.7	-2.8	1.000	leading	1	300.7	-21.4	.997	leading	1.0102	300.7	-23	.997	leading	1.0099
70	300.7	-0.9	1.000	leading	1	300.7	-20.3	.998	leading	1.0102	300.7	-20	.998	leading	1.0099
71	300.7	-1.5	1.000	leading	1	300.7	-19.5	.998	leading	1.0102	300.7	-19.4	.998	leading	1.0099
72	300.7	-4.8	1.000	leading	1	300.7	-22.3	.997	leading	1.0102	300.7	-22.6	.997	leading	1.0099
73	300.7	-2.2	1.000	leading	1	300.7	-20.5	.998	leading	1.0102	300.7	-20.9	.998	leading	1.0099
74	300.7	-2.3	1.000	leading	1	300.7	-20.7	.998	leading	1.0102	300.7	-20.8	.998	leading	1.0099
75	300.7	-2.2	1.000	leading	1	300.7	-20.7	.998	leading	1.0102	300.7	-20.8	.998	leading	1.0099
76	300.7	-2.2	1.000	leading	1	300.7	-20.8	.998	leading	1.0102	300.7	-21	.998	leading	1.0099
77	300.7	-2.2	1.000	leading	1	300.7	-20.5	.998	leading	1.0102	300.7	-20.8	.998	leading	1.0099
82	300.7	-1.4	1.000	leading	1	300.7	-19.8	.998	leading	1.0102	300.7	-19.8	.998	leading	1.0099
83	300.7	-2.8	1.000	leading	1	300.7	-20.7	.998	leading	1.0102	300.7	-21.1	.998	leading	1.0099
84	300.7	2	1.000	lagging	1	300.7	-16.1	.999	leading	1.0102	300.7	-20.5	.998	leading	1.0099
85	300.7	-2.5	1.000	leading	1	300.7	-21	.998	leading	1.0102	300.7	-21.2	.998	leading	1.0099
86	300.7	-4.2	1.000	leading	1	300.7	-23.3	.997	leading	1.0102	300.7	-23	.997	leading	1.0099
87											300.7	-14.1	.999	leading	1.0099
88											300.7	-18.5	.998	leading	1.0099

89	[redacted]										300.7	-18.7	.998	leading	1.0099
90	300.7	2	1.000	lagging	1	300.7	-18.7	.998	leading	1.0102	300.7	-17.8	.998	leading	1.0099
91	300.7	-2.4	1.000	leading	1	300.7	-20.9	.998	leading	1.0102	300.7	-20.5	.998	leading	1.0099
92	[redacted]										300.7	3.9	1.000	lagging	1.0099
93	300.7	26.8	.996	lagging	1	300.7	-2.2	1.000	leading	1.0102	300.7	13.9	.999	lagging	1.0099
94	300.7	11.7	.999	lagging	1	300.7	-7.3	1.000	leading	1.0102	300.7	2.2	1.000	lagging	1.0099
95	300.7	12.9	.999	lagging	1	300.7	-3.3	1.000	leading	1.0102	300.7	-3.2	1.000	leading	1.0099
96	300.7	-4.8	1.000	leading	1	300.7	-22.3	.997	leading	1.0102	300.7	-24	.997	leading	1.0099
97	300.7	159.1	.884	lagging	1	300.7	161.2	.881	lagging	1.0102	300.7	136.8	.910	lagging	1.0099
98	300.7	116.7	.932	lagging	1	300.7	119.8	.929	lagging	1.0102	300.7	-2.4	1.000	leading	1.0099
99	300.7	17.5	.998	lagging	1	300.7	-9.9	.999	leading	1.0102	300.7	-6.6	1.000	leading	1.0099

POI-640510

Group 9 System Impact Study Stability Addendum

DISIS-2015-001

July 2015

Generator Interconnection Studies

Executive Summary

Definitive Interconnection System Impact Study (DISIS-2015-001) Interconnection Customers have requested a study detailing the impacts of interconnecting the following requests, included in Group 9, to the transmission system governed by the Southwest Power Pool (SPP) Open Access Transmission Tariff (OATT). While stability analysis for the DISIS-2015-001 was performed by S&C Electric Company in a separate study, additional sensitivities were performed by SPP to determine if any instability occurs as a result of adding the GEN-2014-059 to the stability limited region of western Nebraska.

One of the Group 9 requests, GEN-2014-059, has requested a Point of Interconnection (POI) on the transmission system of Nebraska Public Power District (NPPD) as a proposed tap on the existing Sidney-Ogallala 230kV transmission line. The requested POI is located in the southwestern region of Nebraska adjacent to facilities that comprise the monitored facilities of the Gerald Gentleman Station (GGS) PTDF NERC permanent flowgate. This flowgate serves as a proxy for the GGS Stability Interface, also known as the Western Nebraska Stability Limitation. Since this Interconnection Customer is requesting interconnection into the region of the Western Nebraska Stability Limitation and is impacting the existing proxy flowgate, additional analysis is needed both in DISIS-2015-001 and within the Interconnection Facilities Study phase. This sensitivity study serves as a preliminary analysis for the Interconnection Customer's GEN-2014-059 impact on these stability limitations.

This preliminary stability sensitivity analysis did find that the stated limit for the GGS stability interface would be exceeded for the interconnection of GEN-2014-059, but did not find that instability would occur. However, taking into account all Interconnection Requests in the area including the WAPA GI-1405 Interconnection Request (600MW on the Sidney to Laramie 345kV) would result in instabilities for minimal output of the GI-1405 and GEN-2014-059 requests.

If GEN-2014-059 proceeds into the Interconnection Facilities Study, further analysis will be undertaken by the Transmission Owner, Nebraska Public Power District, to determine if the existing GGS stability limits can be modified or if there are additional scenarios that need to be addressed to protect the transmission system. It may NOT be possible to mitigate the system instability even through the construction of transmission facilities and the installation of fast switching reactive power equipment. However, that will remain unknown until further analysis can be performed by NPPD during the Interconnection Facilities Study phase. If it is determined that it is NOT possible to mitigate this instability, GEN-2014-059 will not be allowed to interconnect into the transmission system as requested.

Revision History

Date	Change Description	Comments
7/30/2015	Posted as Final for DISIS-2015-001	n/a

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Introduction

Background

Definitive Interconnection System Impact Study (DISIS-2015-001) Interconnection Customers have requested a study detailing the impacts of interconnecting the following requests, included in Group 9, to the transmission system governed by the Southwest Power Pool (SPP) Open Access Transmission Tariff (OATT).

Generation Interconnection Requests

Request	Size (MW)	Area	Point of Interconnection
GEN-2014-023	79.9	NPPD	Tap Ft Randall to Meadow Grove 230kV (560718)
GEN-2014-059	160.0	NPPD	Tap Sidney-Ogallala 230kV (560014)
GEN-2014-060	125.8	NPPD	Tap Pauline-Hildreth 115kV (560733)
GEN-2015-007	160.0	NPPD	Hoskins 345kV
GEN-2015-008	150.4	NPPD	Antelope 115kV
GEN-2015-023	300.8	NPPD	Holt County 345kV

Of these requests, GEN-2014-059 has requested interconnection into the western Nebraska region which is limited by specific stability constraints. While stability analysis for the DISIS-2015-001 was performed by S&C Electric Company in a separate study, additional sensitivities were performed by SPP to review the impacts of GEN-2014-059 on the Western Nebraska Stability Limitations as specified within Part 5 “Transmission Planning Assessment Practices” of the FERC Form 715 “Annual Transmission Planning and Evaluation Report” submitted March 28, 2014, by Nebraska Public Power District (NPPD). Although this addendum will show some preliminary results, additional analyses will be required should the Interconnection Customer choose to pursue an Interconnection Facilities Study before interconnecting this generation interconnection request into this region of the NPPD transmission system.

Purpose

GEN-2014-059 is comprised of eighty (80) Vestas VCSS 2.0 MW wind turbine generators for an aggregate power of 160.0MW. The requested Point of Interconnection (POI) is on the transmission system of NPPD as a proposed tap on the existing Sidney-Ogallala 230kV transmission line. The requested POI is located in the southwestern region of Nebraska adjacent to facilities that comprise the monitored facilities of the Gerald Gentleman Station (GGS) PTDF NERC permanent flowgate. This flowgate serves as a proxy for the GGS Stability Interface, also known as the Western Nebraska

Stability Limitation. Since this Interconnection Customer is requesting interconnection into the region of the Western Nebraska Stability Limitation and is impacting the existing proxy flowgate, additional analysis is needed both in DISIS-2015-001 and within the Interconnection Facilities Study phase. This study serves as a preliminary analysis for the Interconnection Customer's GEN-2014-059 impact on these stability limitations.

Because the western Nebraska region is fully subscribed, impacts of interconnecting the GEN-2014-059 project must be studied to determine if unreliable situations that could lead to instability, cascading, and loss of load to the entire western Nebraska area will occur.

Preliminary Analysis

Method

This preliminary analysis will perform sensitivities to initially determine the impacts of interconnecting GEN-2014-059 adjacent to elements of the GGS PTDF Flowgate.

According to the NPPD submitted FERC 715, the GGS is a registered NERC Flowgate and posted stability interface on OASIS (https://www.oasis.oati.com/SWPP/index.html). The PTDF Flowgate definition is consistent with the monitored elements for system intact operation of the GGS Stability Interface. The current system intact Total Transfer Capability (TTC) for this interface is fully subscribed. The maximum system intact stability limit has been approved by MAPP and accommodates all of the current firm capacity rights associated with western Nebraska stability limited resources:

Once the stability cases are constructed to ensure these previously reserved system conditions, GEN-2014-059 is added to the case and faults are taken at the GGS 345 kV and the dynamic stability responses are observed for instability.

Model Preparation

Transient stability analysis was performed using a modified version of the 2014 series of Model Development Working Group (MDWG) dynamic study models. The case was modified to ensure these previously reserved system conditions. The case is then loaded with prior queued interconnection requests and network upgrades assigned to those interconnection requests. Finally, the prior queued and study generation are dispatched into the SPP footprint. The 2015 winter peak cluster scenario was evaluated. An initial simulation was carried out for a no-disturbance run of twenty (20) seconds to verify the numerical stability of the model.

Results

After verifying that the system conditions were stable under steady state conditions, a single phase[1] stuck breaker fault on the Gentleman 345kV was simulated. With GEN-2014-059 added to the system and the stuck breaker fault applied, the system remains stable. The plot in Figure 1 demonstrates that interconnecting GEN-2014-059 did not cause instability. The plot in Figure 2 shows the synchronous machine rotor angles of the Gerald Gentlemen Station Unit # 1 and Unit# 2, and the Laramie River Station Unit# 1 remain stable after the fault is cleared. The plot also shows the voltages of some nearby buses remaining stable.

[1] The single-phase line fault was simulated by applying fault impedance to the positive sequence network at the fault location to represent the effect of the negative and zero sequence networks on the positive sequence network. The fault impedance was computed to give a positive sequence voltage at the specified fault location of approximately 60% of pre-fault voltage. This method is in agreement with SPP current practice.

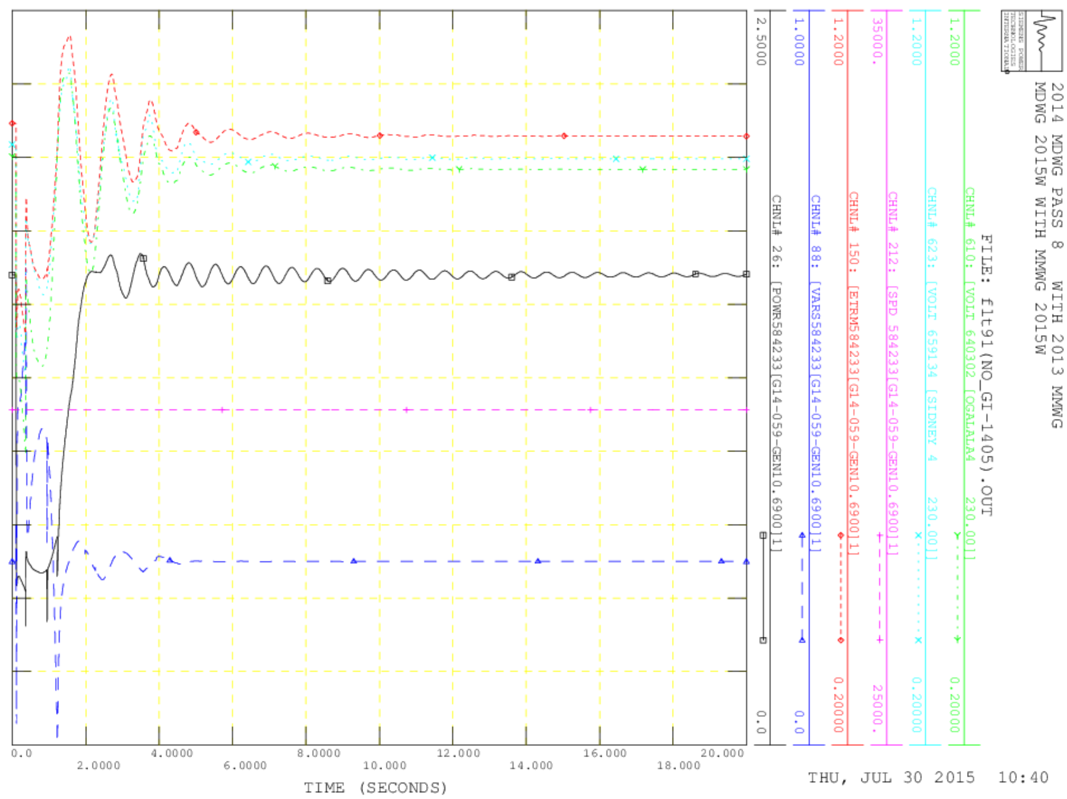

Figure 1: DISIS-2015-001 Group 9 GEN-2014-059 In Service at 160.0MW (Project power, vars,etrm, and speed and voltages on buses either side of project)

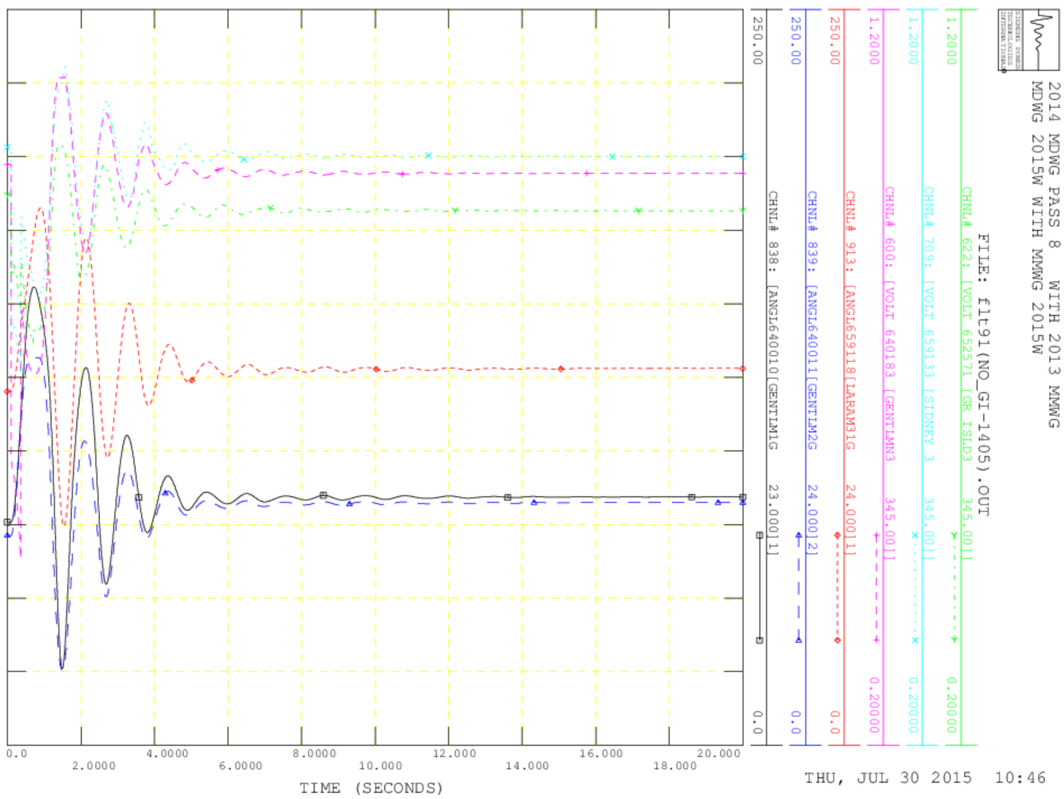

Figure 2: DISIS-2015-001 Group 9 GEN-2014-059 In Service (Some voltages and angles of machines nearby)

Currently, a 600 MW wind project on the Laramie to Sidney 345kV line is being studied by WAPA (GI-1405). A cursory stability analysis was performed by adding the WAPA project to the study case and removing GEN-2014-059 from the case. The GI-1405 project was dispatched at 100MW (a dispatch of 600MW did not allow for a power flow solution to begin analysis). The same stuck breaker fault on the Gentleman 345kV was simulated. The results show that the system becomes unstable. The plot in Figure 3 shows the project power, vars, terminal voltage, and speed are not stable and that the voltages at the buses on either side of the point of interconnection were also not stable. The plot in Figure 4 shows the synchronous machine rotor angles of the Gerald Gentlemen Station Unit # 1 and Unit# 2, and the Laramie River Station Unit# 1 are not stable after the fault is cleared. The plot also shows the oscillatory nature of the voltages of some nearby buses.

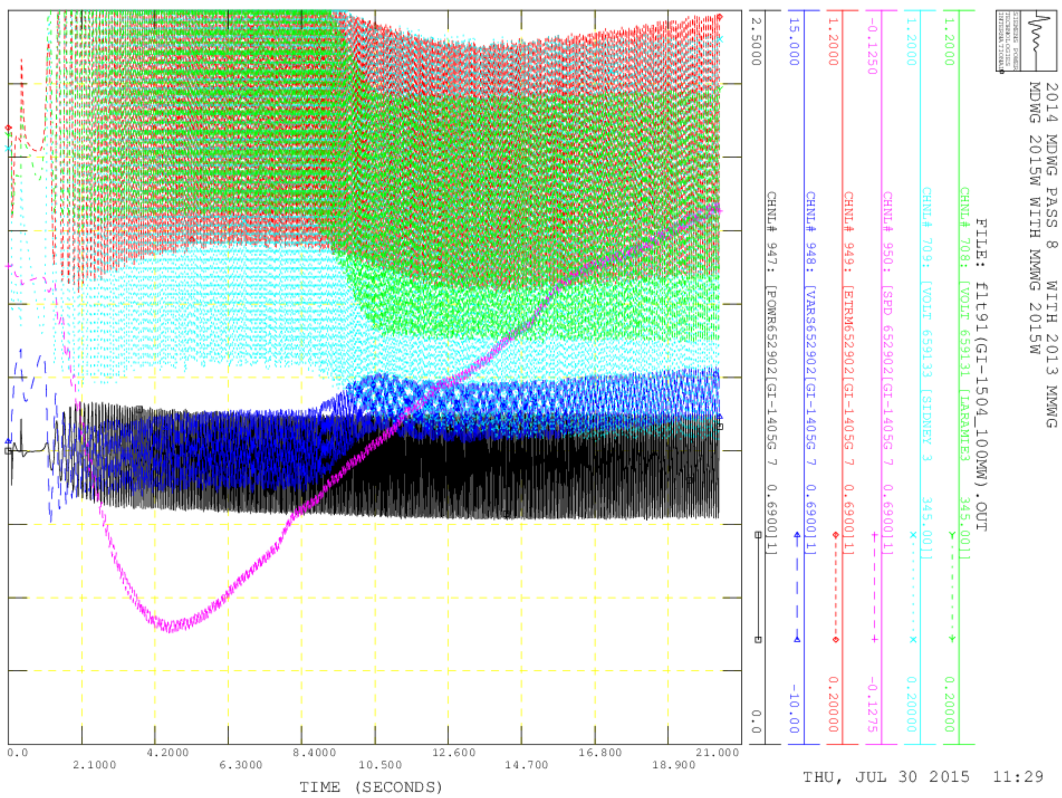

Figure 3: WAPA GI-1405 In Service at 100MW (Project power, vars,etrm, and speed and voltages on buses either side of project)

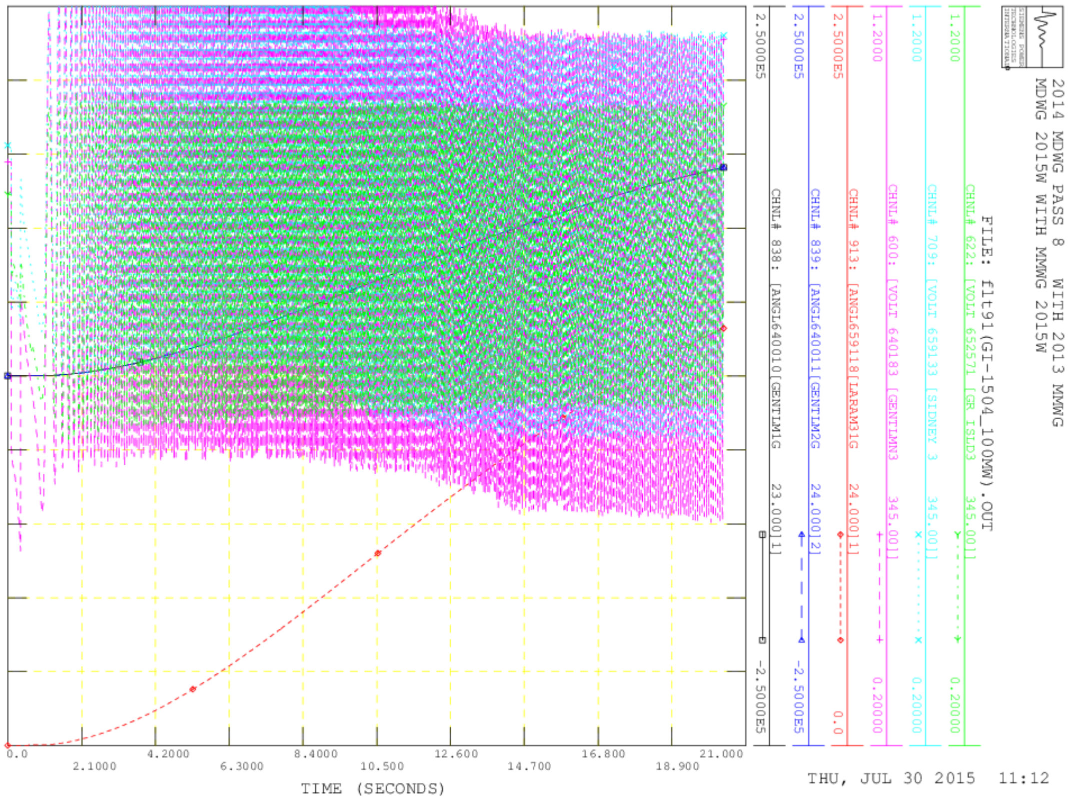

Figure 4: WAPA GI-1405 In Service at 100MW (Some voltages and angles of machines nearby)

Conclusion

Given the results from this preliminary analysis to review the impacts of interconnecting GEN-2014-059 to the stability limited western Nebraska region, SPP must recommend that GEN-2014-059 be studied further in the Interconnection Facilities Study. It should also be noted that it may not be possible to mitigate this instability or may not be possible without the construction or installation of a significant amount of transmission or other related equipment.

S: Group 12 Dynamic Stability Analysis Report

See ABB study report on next page

DEFINITIVE IMPACT STUDY
DISIS-2015-001 (GROUP 12)

FINAL REPORT

July 23, 2015

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Southwest Power Pool	No. 2015-E15797	
Definitive Impact Study DISIS-2015-001 (Group 12)	7/23/2015	# Pages 10

Author(s):	Reviewed by:	Approved by:
Junbiao Han	Shu Liu	Willie Wong

Executive Summary

Southwest Power Pool (SPP) has commissioned ABB Inc., to perform a Definitive Impact Study for DISIS-2015-001 (Group 12) which includes generation interconnection request GEN-2015-019 (60 MW combustion-turbine generator connected at the Fitzhugh 161 kV substation).

The objective of this study is to evaluate the impact of project GEN-2015-019 on system stability and short-circuit performance. The study is performed on three system scenarios provided by SPP:

- 2015 Summer Peak Case
- 2015 Winter Peak Case
- 2025 Summer Peak Case

Results of the stability analysis show that the studied system is stable following all simulated faults with the proposed GEN-2015-019 project in-service. There are no voltage violations in the monitored area and the studied generator shows good damping performance which meets the criteria specified.

System short-circuit current levels at up to five buses away from the point of interconnection were calculated and tabulated for SPP's reference.

Based on the results of stability analysis it can be concluded that **the proposed GEN-2015-019 project does not adversely impact the stability of the SPP system**.

The results of this analysis are based on available data and assumptions made at the time of conducting this study. If any of the data and/or assumptions made in developing the study model change, the results provided in this report may not apply.

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1 INTRODUCTION

Southwest Power Pool (SPP) has commissioned ABB Inc., to perform a Definitive Impact Study for DISIS-2015-001 (Group 12) which includes generation interconnection request GEN-2015-019. This is a 60 MW combustion-turbine generator connected at the Fitzhugh 161 kV substation (Point of Interconnection or POI).

The objective of this study is to evaluate the impact of project GEN-2015-019 on system stability and short-circuit performance. The study is performed on three system scenarios provided by SPP:

- 2015 Summer Peak Case
- 2015 Winter Peak Case
- 2025 Summer Peak Case

SPP provided the study cases for all three system scenarios with GEN-2015-019 included. One line diagrams of the local area for all three seasons are shown in Figure 1-1. The studied generator is circled red.

The three system scenarios supplied by SPP included the following prior queued projects for Group12:

Table 1-1: Group 12 Prior Queued Projects

Request	Size (MW)	Generator Model	Point of Interconnection
GEN-2013-011	30.0 Increase (Pmax=683.0)	GENROU (509416)	Turk 138kV (507454)

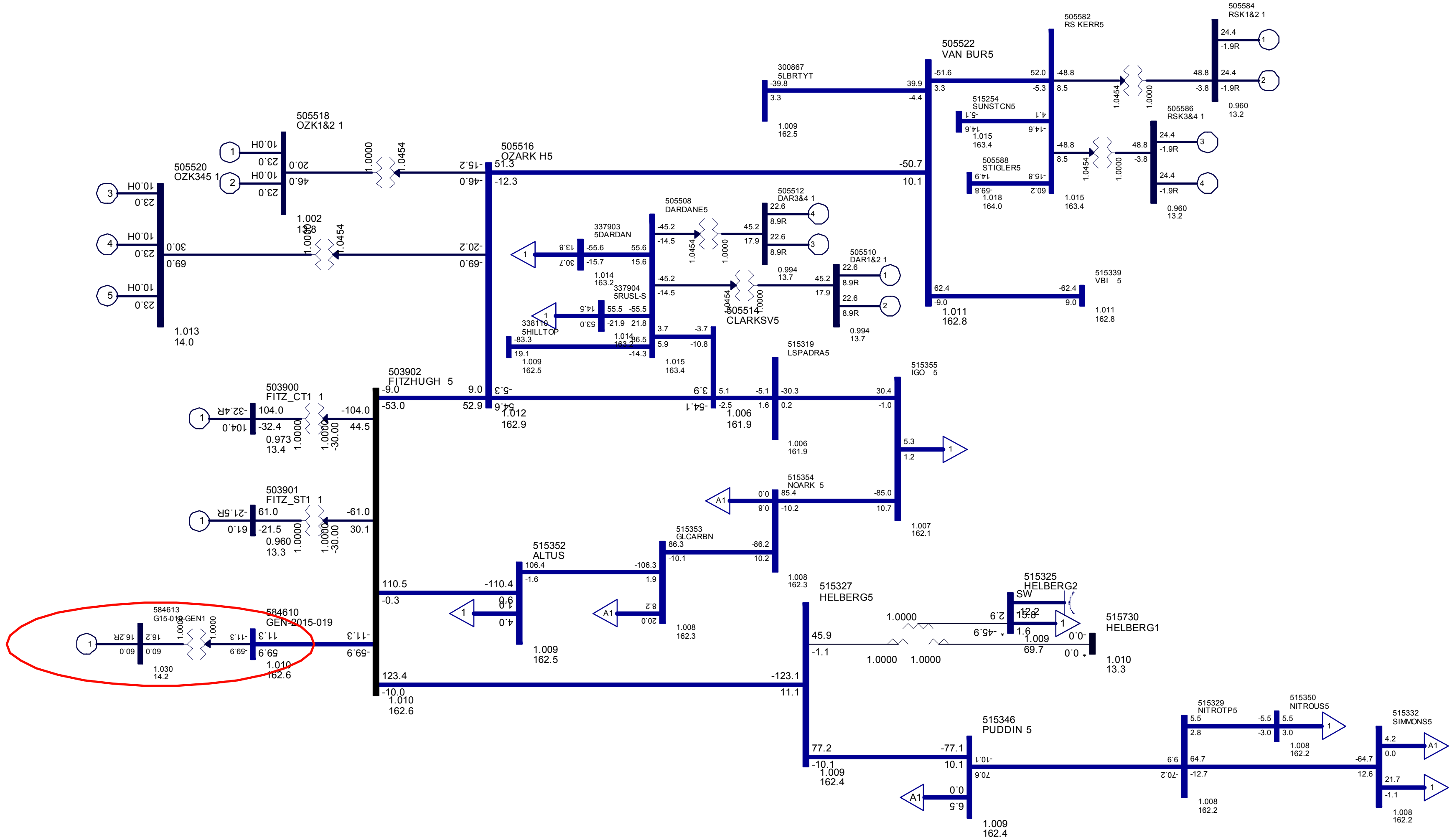


Figure 1-1 (a): One Line Diagram of Fitzhugh Area for 2015 Summer Peak Case

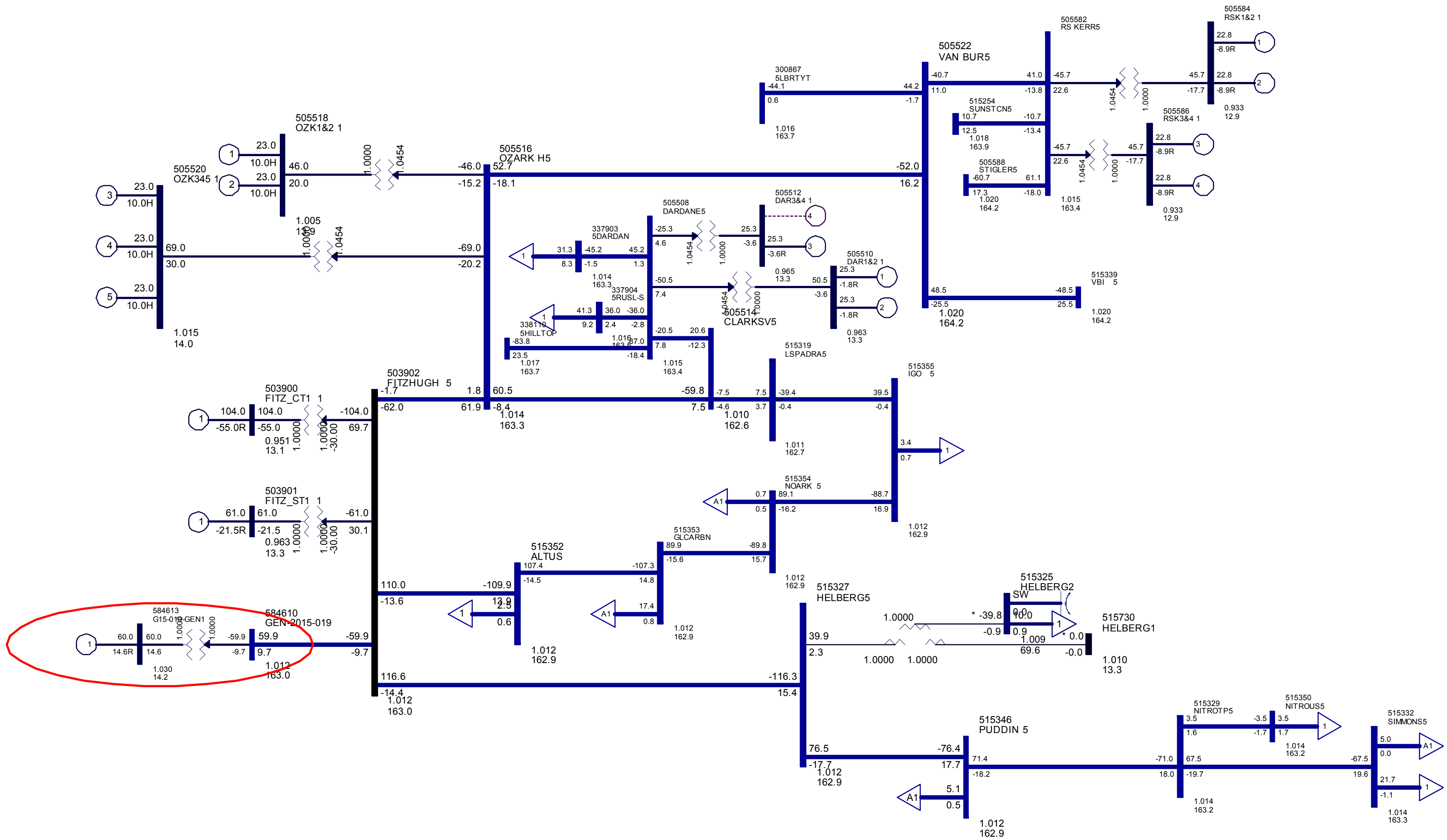


Figure 1-2 (b): One Line Diagram of Fitzhugh Area for 2015 Winter Peak Case

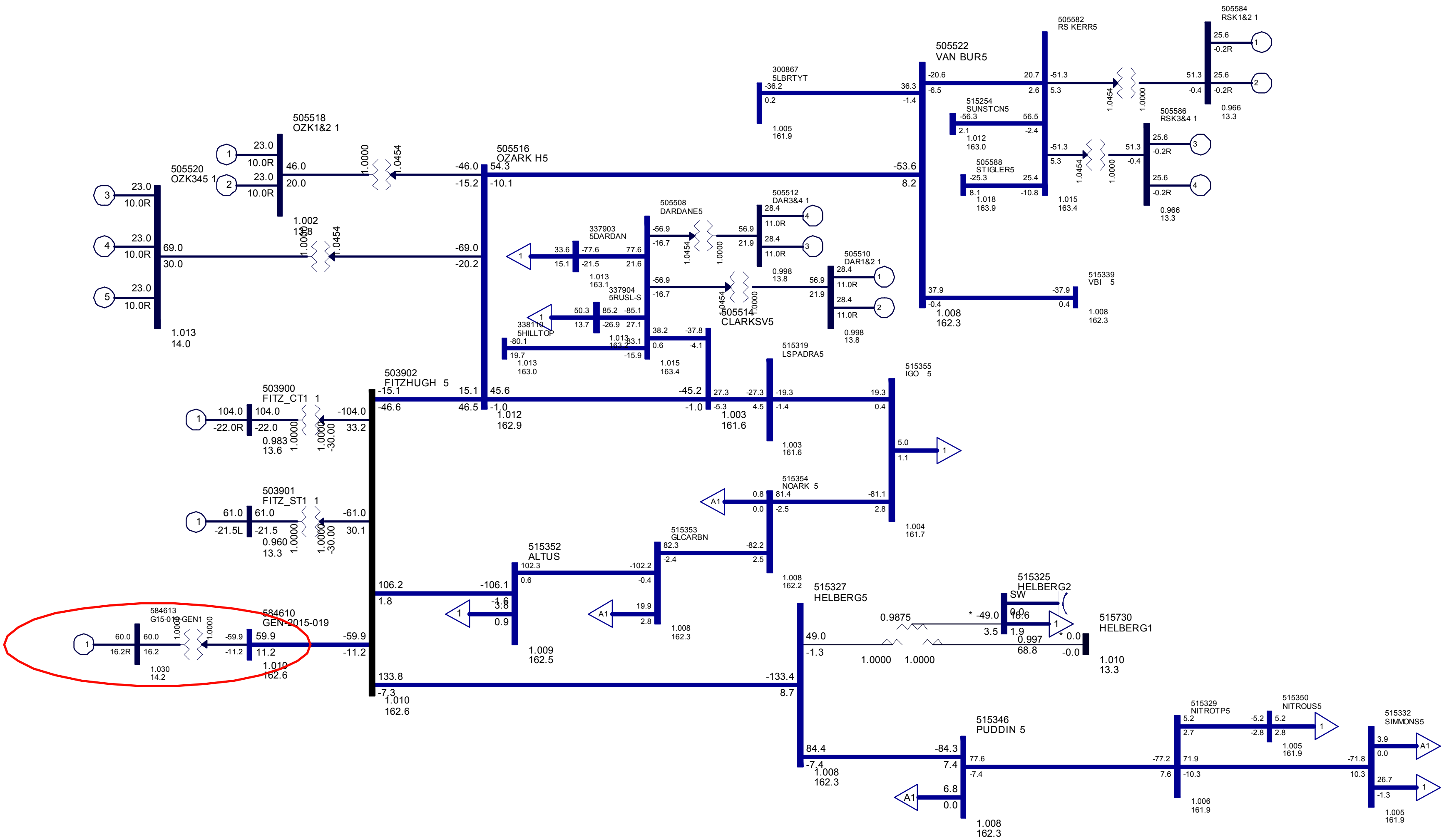


Figure 1-3 (c): One Line Diagram of Fitzhugh Area for 2025 Summer Peak Case

ABB

2 STABILITY ANALYSIS

In this study, ABB investigated the stability of the system for faults in the vicinity of the proposed plant as defined by SPP. The studied faults involve three-phase transformer faults with normal clearing, three-phase line faults with normal clearing and re-closing test, and single-line-to-ground (SLG) faults with stuck breaker.

2.1 STUDY MODEL DEVELOPMENT

SPP provided study models for three seasons:

- 2015 Summer peak
- 2015 Winter Peak
- 2025 Summer Peak

For each study model, the GEN-2015-019 project was already built into the power flow and dynamic cases.

According to SPP's comments, generators on bus OZK1&2 1 [505518] and OZK345 1 [505520] should all be in-service and the power outputs are equal to Pmax for three studied cases; hence, base cases change were made accordingly.

2.2 STABILITY ANALYSIS METHODOLOGY

Stability analysis is performed to determine whether the electric system would meet stability criteria following the addition of the GEN-2015-019 project.

Stability analysis was performed using Siemens-PTI's PSS/E dynamics program V32.1.0.

All the faults listed in Table 2-1 were simulated for 20 seconds.

Table 2-1: List of Faults for Stability Analysis

Cont. No.	Cont. Name	Description
1	FLT01-3PH	3 phase fault on the Fitzhugh (503902) to (OKGE) Altus (515352) 161kV line, near Fitzhugh. a. Apply fault at the Fitzhugh 161kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
2	FLT02-1PH	*Single phase fault and sequence like previous*
3	FLT03-3PH	3 phase fault on the Fitzhugh (503902) to (OKGE) Helberg (515327) 161kV line, near Fitzhugh. a. Apply fault at the Fitzhugh 161kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
4	FLT04-1PH	*Single phase fault and sequence like previous*

Cont. No.	Cont. Name	Description
5	FLT05-3PH	3 phase fault on the Fitzhugh (503902) to (SWPA) Ozark Dam (505516) 161kV line, near Fitzhugh. a. Apply fault at the Fitzhugh 161kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
6	FLT06-1PH	*Single phase fault and sequence like previous*
7	FLT07-3PH	3 phase fault on the (SWPA) Ozark Dam (505516) to (SWPA) Van Buren (505522) 161kV line, near Ozark Dam. a. Apply fault at the Ozark Dam 161kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
8	FLT08-1PH	*Single phase fault and sequence like previous*
9	FLT09-3PH	3 phase fault on the (SWPA) Ozark Dam (505516) to (SWPA) Clarksville (505514) 161kV line, near Ozark Dam. a. Apply fault at the Ozark Dam 161kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
10	FLT10-1PH	*Single phase fault and sequence like previous*
11	FLT11-3PH	3 phase fault on the (OKGE) Helberg (515327) 161kV to Helberg (515325) 69kV/(515730) 13.2kV, near Helburg. a. Apply fault at the Helberg 161kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
12	FLT12-3PH	3 phase fault on the (OKGE) Helberg (515327) to (OKGE) Puddin' Ridge (515346) 161kV line, near Helberg. a. Apply fault at the Helberg 161kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
13	FLT13-1PH	*Single phase fault and sequence like previous*
14	FLT14-PO	**Prior outage** of the Fitzhugh (503902) to (OKGE) Helberg (515327) 161kV line. 3 phase fault on the Fitzhugh (503902) to (OKGE) Altus (515352) 161kV line, near Fitzhugh. a. Prior outage of Fitzhugh – Helberg 161kV. b. Apply fault at the Fitzhugh 161kV bus. c. Clear fault after 5 cycles by tripping the faulted line. d. Wait 20 cycles, and then re-close the line in (c) back into the fault. e. Leave fault on for 5 cycles, then trip the line in (c) and remove fault.
15	FLT15-PO	**Prior outage** of the Fitzhugh (503902) to (SWPA) Ozark Dam (505516) 161kV line, near Fitzhugh. 3 phase fault on the Fitzhugh (503902) to (OKGE) Altus (515352) 161kV line, near Fitzhugh. a. Prior outage of Fitzhugh – Ozark Dam 161kV. b. Apply fault at the Fitzhugh 161kV bus. c. Clear fault after 5 cycles by tripping the faulted line. d. Wait 20 cycles, and then re-close the line in (c) back into the fault. e. Leave fault on for 5 cycles, then trip the line in (c) and remove fault.

Cont. No.	Cont. Name	Description
16	FLT16-PO	**Prior outage** of the Fitzhugh (503902) to (SWPA) Ozark Dam (505516) 161kV line, near Fitzhugh. 3 phase fault on the Fitzhugh (503902) to (OKGE) Helberg (515327) 161kV line, near Fitzhugh. a. Prior outage of Fitzhugh – Ozark Dam 161kV. b. Apply fault at the Fitzhugh 161kV bus. c. Clear fault after 5 cycles by tripping the faulted line. d. Wait 20 cycles, and then re-close the line in (c) back into the fault. e. Leave fault on for 5 cycles, then trip the line in (c) and remove fault.
17	FLT14-PO	**Prior outage** of the the (OKGE) Helberg (515327) to (OKGE) Puddin' Ridge (515346) 161kV line. 3 phase fault on the (OKGE) Helberg (515327) 161kV to Helberg (515325) 69kV/(515730) 13.2kV, near Helburg. a. Prior outage of (OKGE) Helberg to (OKGE) Puddin' Ridge 161kV. b. Apply fault at the (OKGE) Helberg 161kV bus. c. Clear fault after 5 cycles by tripping the faulted transformer.

Single-line-to-ground faults were simulated with the standard method of applying fault impedance to the positive sequence network to represent the effect of the negative and zero sequence networks on the positive sequence network. The SLG fault impedance was computed by assuming a positive sequence voltage at the fault location at approximately 60% of pre-fault voltage, which is a typical value.

The Southwest Pool Disturbance Performance Criteria Requirements in Appendix A were used to evaluate the system response during the initial transient period following a disturbance on the system. Generator response and bus voltages (115 kV and above) in Area 502, 515, 520, 523, 524, 525, and 351 were monitored to ensure the system performance meets criteria requirements. Rotor angles of the studied generator GEN-2015-019 and other nearby synchronous machines were investigated to make sure they maintained synchronism and had adequate damping following system faults.

2.3 STUDY RESULTS

2.3.1 Simulation Results

The results of all studied disturbances show **no** instability problems or voltage violations for all three seasons (see Table 2-2: Summary of Results). All generators in the system stay online without being tripped following all simulated faults. The studied generator GEN-2015-019 shows good damping performance which meets the criteria specified in Appendix A .

Table 2-2 Study Results Summary

Contingency	2015SP	2015WP	2025SP
FLT01-3PH	Stable	Stable	Stable
FLT02-1PH	Stable	Stable	Stable
FLT03-3PH	Stable	Stable	Stable
FLT04-1PH	Stable	Stable	Stable
FLT05-3PH	Stable	Stable	Stable
FLT06-1PH	Stable	Stable	Stable
FLT07-3PH	Stable	Stable	Stable
FLT08-1PH	Stable	Stable	Stable
FLT09-3PH	Stable	Stable	Stable
FLT10-1PH	Stable	Stable	Stable

Contingency	2015SP	2015WP	2025SP
FLT11-3PH	Stable	Stable	Stable
FLT12-3PH	Stable	Stable	Stable
FLT13-1PH	Stable	Stable	Stable
FLT14-PO	Stable	Stable	Stable
FLT15-PO	Stable	Stable	Stable
FLT16-PO	Stable	Stable	Stable
FLT17-PO	Stable	Stable	Stable

Figure 2-1 shows the response of the studied generator following fault FLT01-3PH for 2015 Summer Peak case. The machine speed, active and reactive power output, and terminal voltage are plotted to show the generator response. All the simulation plots are included in Appendix B.

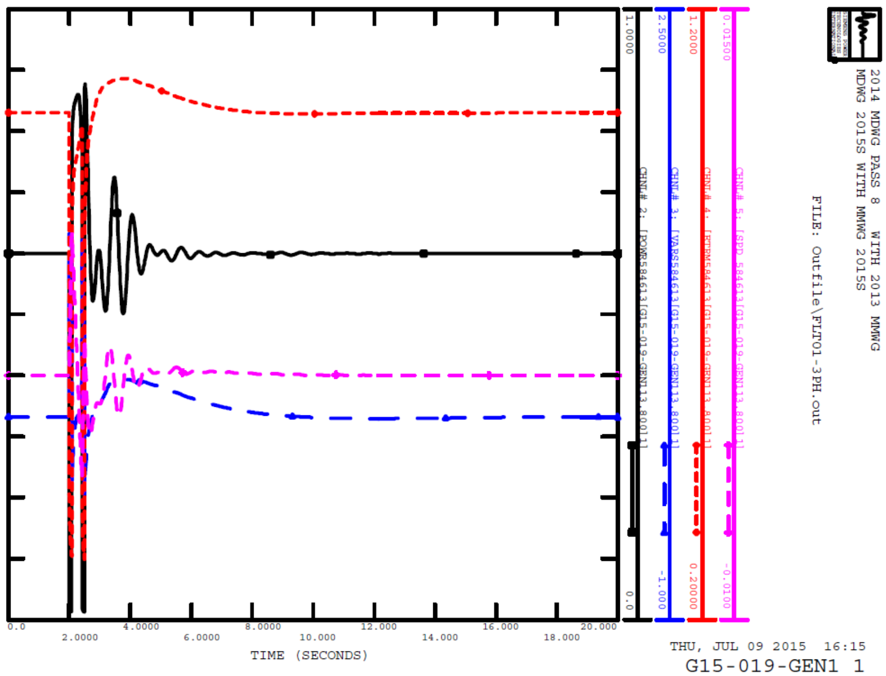


Figure 2-1 GEN-2015-019 Response Following Fault FLT01-3PH for 2015 Summer Peak Case

3 SHORT CIRCUIT ANALYSIS

Short circuit analysis was performed on the 2025 Summer Peak power flow case using the PSS/E program. Since the power flow model does not contain negative and zero sequence data, only three-phase symmetrical fault current levels were calculated at up to five buses away from the point of interconnection.

Table 3-1 tabulates all the three-phase fault current levels, and the calculated values were listed here for SPP's reference.

Table 3-1 Three-Phase Fault Currents

Number	Name	3PH(Amp)	Number	Name	3PH(Amp)
515329	NITROTP5 161.00	8649	505520	OZK345 1 13.800	30249.6
505460	BULL SH5 161.00	13023	505522	VAN BUR5 161.00	17690.1
515332	SIMMONS5 161.00	9095.3	301366	5AKINS 161.00	7495.3
515333	DYER 5 161.00	9628	515769	VBI 1 13.800	11582.8
515335	KLGORE 2 69.000	7058.7	338108	5ST_JOE 161.00	7340.4
515336	VBI 2 69.000	11211.9	338110	5HILLTOP 161.00	8032.7
515337	RUDY 5 161.00	11201.1	515254	SUNSTCN5 161.00	7143.8
515339	VBI 5 161.00	17893.7	515265	SHAD-PT5 161.00	7234.3
515340	OAKGROV5 161.00	14949	300867	5LBRTYT 161.00	8550.3
515341	WHITESD5 161.00	14827.3	515780	LSPADR31 2.3000	12297.6
512655	TAHLQH 5 161.00	10315.4	300869	5LIBRTY 161.00	7983.1
515316	BRANCH 5 161.00	8166.1	505570	EUFAULA5 161.00	7867.9
515346	PUDDIN 5 161.00	9705.1	337905	5RUSL-E 161.00	13633.9
515347	HWY59 5 161.00	15676.5	300877	2STIGLER 69.000	5516.7
515348	NALCOTP5 161.00	15772	515406	ADABELL5 161.00	16031.3
515733	LSPADR41 13.800	2666.7	338517	5MARSHALL# 161.00	6694.9
515350	NITROUS5 161.00	8177.8	505550	SALISAW5 161.00	7512.2
337902	5DANVI 161.00	7003.2	515779	LSPADR21 34.500	2928.7
515352	ALTUS 161.00	10892.5	521124	SUNSTCR5 161.00	7127
515353	GLCARBN 161.00	9988.6	503900	FITZ_CT1 1 13.800	75946.3
515354	NOARK 5 161.00	9407.6	503901	FITZ_ST1 1 13.800	34214.8
515355	IGO 5 161.00	8451.2	503902	FITZHUGH 5 161.00	12023.2
515357	RAZRBAK5 161.00	6778.9	504032	VBI_N 2 69.000	11144.5
515359	MTNBURG5 161.00	4910.1	515298	VBAVEC 2 69.000	8973.2
515360	TWNBRDG5 161.00	13148.6	515708	BRANCH21 13.200	10728.3
505584	RSK1&2 1 13.800	26151.9	515730	HELBERG1 13.200	14011.4
584610	GEN-2015-019161.00	12023.2	505582	RS KERR5 161.00	8289.2
505508	DARDANE5 161.00	12177.8	337903	5DARDAN 161.00	10857.5
584613	G15-019-GEN113.800	44633.8	337904	5RUSL-S 161.00	12340.6

Number	Name	3PH(Amp)	Number	Name	3PH(Amp)
505510	DAR1&2 1 13.800	32868.8	515313	BRANCH 2 69.000	8128.1
505511	CLRKSVL2 69.000	6722.6	505586	RSK3&4 1 13.800	26151.9
505512	DAR3&4 1 13.800	32792.2	505588	STIGLER5 161.00	6571.6
505513	CLK X1 1 12.470	6766.4	515317	PENDER 2 69.000	6710.3
505514	CLARKSV5 161.00	7933.5	515319	LSPADRA5 161.00	7819.1
505515	CLK X2 1 12.470	6766.4	515320	LSPADRA2 69.000	7593.1
505516	OZARK H5 161.00	11607.3	515322	COALHIL2 69.000	6026.8
515314	GRANDPR5 161.00	7539.4	515324	AVECOZK2 69.000	9165.5
505518	OZK1&2 1 13.800	25392.4	515325	HELBERG2 69.000	9868.6
507183	BOONVIL2 69.000	5476.8	515327	HELBERG5 161.00	10209.7

4 CONCLUSIONS

Southwest Power Pool (SPP) has commissioned ABB Inc., to perform a Definitive Impact Study for DISIS-2015-001 (Group 12) which includes generation interconnection request GEN-2015-019 (60 MW combustion-turbine generator connected at the Fitzhugh 161 kV substation).

The objective of this study is to evaluate the impact of project GEN-2015-019 on system stability and short-circuit performance. The study is performed on three system scenarios provided by SPP:

- 2015 Summer Peak Case
- 2015 Winter Peak Case
- 2025 Summer Peak Case

Results of the stability analysis show that the studied system is stable following all simulated faults with the proposed GEN-2015-019 project in-service. There are no voltage violations in the monitored area and the studied generator shows good damping performance which meets the criteria specified.

System short-circuit current levels at up to five buses away from the point of interconnection were calculated and tabulated for SPP's reference.

Based on the results of stability analysis it can be concluded that **the proposed GEN-2015-019 project does not adversely impact the stability of the SPP system**.

The results of this analysis are based on available data and assumptions made at the time of conducting this study. If any of the data and/or assumptions made in developing the study model change, the results provided in this report may not apply.

APPENDIX A SOUTHWEST POWER POOL DISTURBANCE PERFORMANCE CRITERIA REQUIREMENTS

OVERVIEW

These Disturbance Performance Requirements ("Requirements") shall be applicable to the Bulk Electric System within the Southwest Power Pool Planning Area. Utilization of these Requirements applies to all registered entities within the Southwest Power Pool Planning Area. These Requirements shall not be applicable to facilities that are not part of Bulk Electric System. More stringent Requirements are at the sole discretion of each Transmission Owner.

Transient and dynamic stability assessments are generally performed to assure adequate avoidance of loss of generator synchronism and prevention of system voltage collapse within the first 20 seconds after a system disturbance. These Requirements provide a basis for evaluating the system response during the initial transient period following a disturbance on the Bulk Electric System by establishing minimum requirements for machine rotor angle damping and transient voltage recovery.

ROTOR ANGLE DAMPING REQUIREMENT

Machine Rotor Angles shall exhibit well damped angular oscillations [as defined below] and acceptable power swings following a disturbance on the Bulk Electric System for all NERC Category A, B and C events.

Well damped angular oscillations shall meet one of the following two requirements when calculated directly from the rotor angle:

1. Successive Positive Peak Ratio (SPPR) must be less than or equal to 0.95 where SPPR is calculated as follows:

$$\text{SPPR} = \frac{\text{Peak Rotor Angle of } 2^{nd} \text{ Positive Swing Peak}}{\text{Peak Rotor Angle of } 1^{st} \text{ Positive Swing Peak}} \leq 0.95$$

   -or- Damping Factor % = (1 – SPPR) x 100% $\geq$ 5%

   The machine rotor angle damping ratio may be determined by appropriate modal analysis (i.e. Prony Analysis) where the following equivalent requirement must be met:

   Damping Ratio $\geq$ 0.0081633

2. Successive Positive Peak Ratio Five (SPPR5) must be less than or equal to 0.774 where SPPR5 is calculated as follows:

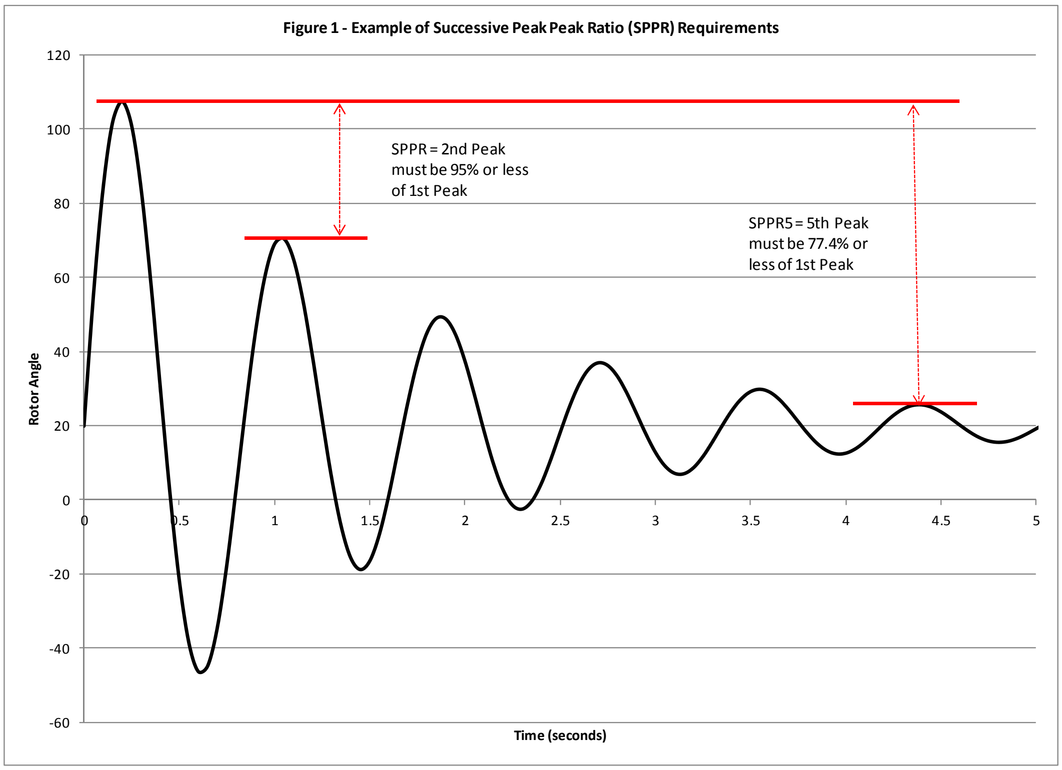
$$\text{SPPR5} = \frac{\text{Peak Rotor Angle of 5}^{\text{th}}\text{ Positive Swing Peak}}{\text{Peak Rotor Angle of 1}^{\text{st}}\text{ Positive Swing Peak}} \leq 0.774$$

-or- Damping Factor % = (1 – SPPR5) x 100% $\geq$ 22.6%

The machine rotor angle damping ratio may be determined by appropriate modal analysis (i.e. Prony Analysis) where the following equivalent requirement must be met:

Damping Ratio $\geq$ 0.0081633

Qualitatively, these Requirements are shown in Figure 1 below.

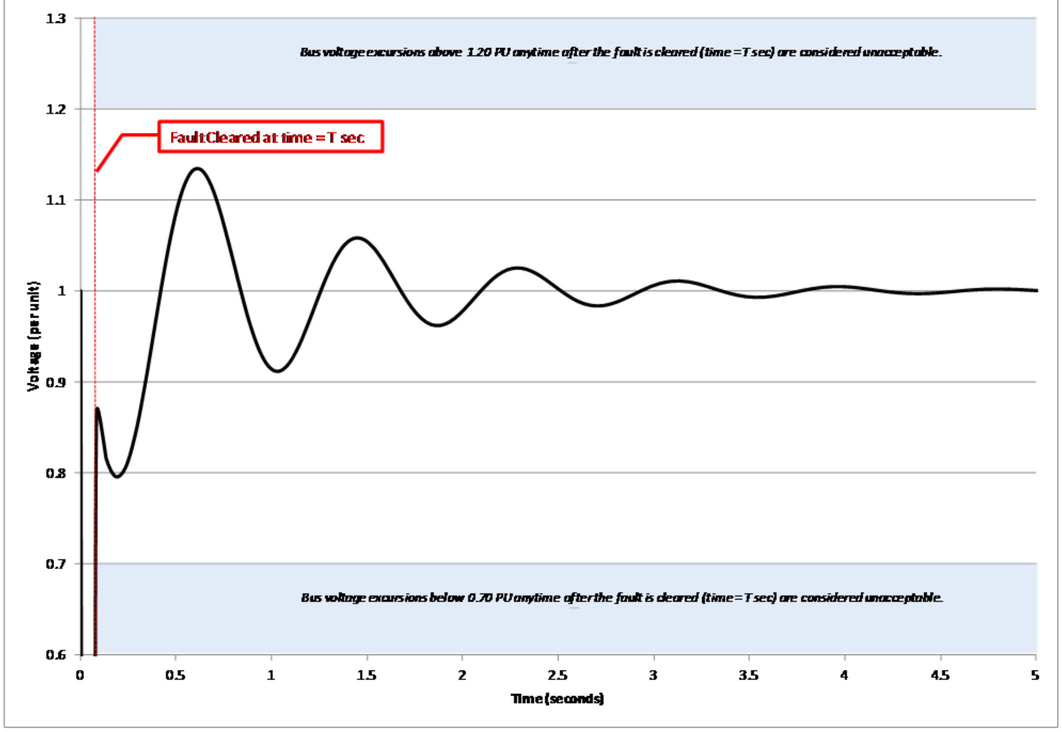


TRANSIENT VOLTAGE RECOVERY REQUIREMENT

Any time after a disturbance is cleared; bus voltages on the Bulk Electric System shall not swing outside of the bandwidth of 0.70 per unit to 1.20 per unit.

Qualitatively, this Requirement is shown in Figure 2 below.

Figure 2 - Example of Transient Voltage Recovery Requirement



APPENDIX B SIMULATION PLOTS FOR STABILITY ANALYSIS

T: Group 13 Dynamic Stability Analysis Report

See Power-tek study report on next page

Southwestern Power Pool Inc. (SPP)

Definitive Impact Study

DISIS-2015-001 (Group 13)

POWER-tek
green inspiration since 1994

Final Report Submitted to
Southwest Power Pool Inc.
July 2015

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TABLE OF CONTENTS

1. Executive Summary

The DISIS-2015-001 (Group 13) Impact Study is a generation interconnection study performed by POWER-tek Global Inc. for Southwest Power Pool (SPP). This report presents the results of impact study comprising of power factor, short circuit, and stability analyses for cluster scenarios of the proposed interconnection projects under DISIS-2015-001 (Group 13) ("The Projects") as described in Table 1.1 below:

Table 1.1: Interconnection Request

Request	Size (MW)	Generator Model	Point of Interconnection (POI)
GEN-2015-005	200.1	GE 1.79MW (9 wind turbines) and GE 2.0MW (92 wind turbines)	Tap on the Nebraska City-Sibley 345kV (bus 560028)

Power factor analysis, short circuit analysis up to 5 Buses away from the point of interconnection (POI), and transient stability simulations were performed for the Projects in service at its full output. SPP provided three base cases for Summer-2015, Winter-2015, and Summer-2025, each comprising of a power flow, sequence data and corresponding dynamics database. The previous queued request projects were already modeled in the base cases. The power factor analysis consists of running all N-1, three phase contingencies shown in the Fault Definitions table (Table 3 in the RFP) in power flow to advise the necessary power factor at the POI for each contingency.

The power factor analysis indicates that interconnection request i.e., GEN-2015-005 is required to provide reactive power as indicated in Tables 3.2.2 through 3.2.4.

Per the SPP OATT, the Interconnection Customer will be required to provide 95% lagging (supplying vars) and 95% leading (absorbing vars) at the POI.

To offset the capacitive effects of the collector system and transmission line of the wind farm under low wind or no wind conditions, the inductive reactive support analysis was performed for summer-2015 scenario. The analysis indicates that at POI (a tap on the Nebraska City-Sibley 345kV) 8.5 MVAR reactor is required at Bus 560028 to maintain zero MVAR flow for GEN-2015-005 generator lead.

The short circuit analysis is performed on the power flow models for the 2025 summer peak season for cluster scenario model. The results are documented for both 3 phase fault as well as single line to ground fault up to 5 buses away from the POI (a tap on the Nebraska City-Sibley 345kV).

There are no impacts on the stability performance of the SPP system during cluster scenario for the contingencies tested on the provided base cases. The study machines stayed on-line and stable for all simulated faults. The Project stability simulations with fifty four (54) specified test disturbances did not show instability problems in the SPP system. Any oscillations were damped out.

2. Introduction

2.1. Project Overview and Assumptions

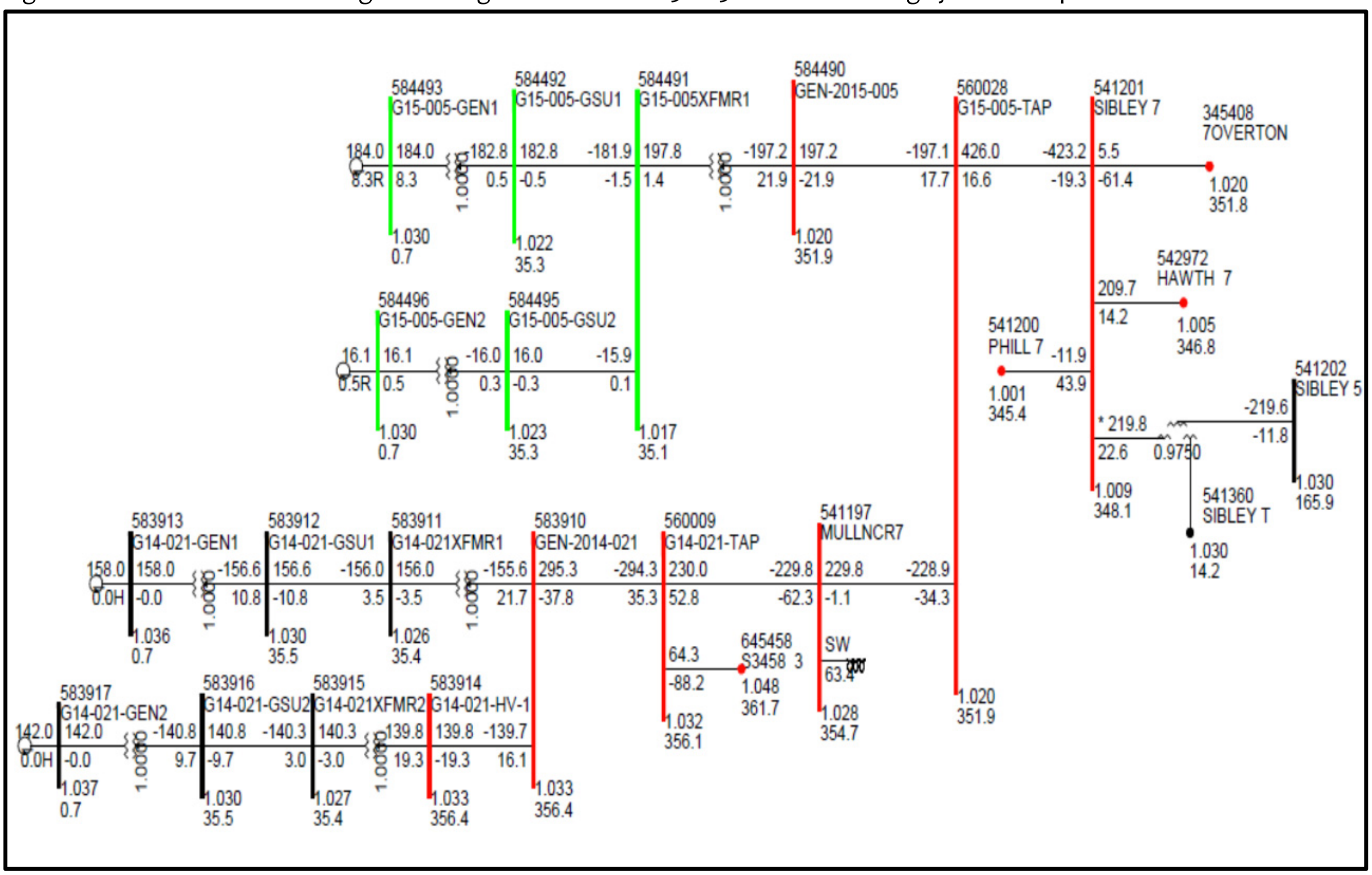
The DISIS-2015-001 (Group 13) Impact Study is a generation interconnection study performed by POWER-tek Global Inc. for SPP. This report presents the results of impact study comprising of power factor, short circuit analysis, and stability analyses for both cluster and stand-alone scenarios of the proposed interconnection projects under DISIS-2015-001 (Group 13) ("The Projects") as described in Table 2.1.1 below:

Table 2.1.1: Interconnection requests

Request	Size (MW)	Wind Turbine Model	Point of Interconnection
GEN-2015-005	200.1	GE 1.79MW (9 wind turbines) and GE 2.0MW (92 wind turbines)	Tap on the Nebraska City-Sibley 345kV (bus 560028)

Figure 2.1.1 show the single line diagram for the interconnection of the Project to present and planned system of SPP. This arrangement was modeled and studied in power flow cases for these projects.

Figure 2.1.1: Power flow single line diagram for GEN-2015-005 and surrounding system components



Appendix-D contains the machines, interconnection, and machines user model parameters.

Table 2.1.2 below shows the list of prior queued projects modeled in the base case.

Table 2.1.2: List of previous queued request projects

Request	Size (MW)	Wind Turbine Model	Point of Interconnection
GEN-2008-129	641/675	Combined Cycle (541163/541164)	Pleasant Hill 161kV (541225)
GEN-2010-036	4.6	GENROU (533264)	6^{th} Street 115kV (533264)
GEN-2011-011	900.0	GENROU (542962)	Iatan 345kV (542982)
ASGI-2013-007	90.0	GE 2.5MW (562454)	Tap Hickory Creek (300087) – Locust Creek (300094) 161kV (562450)
GEN-2014-021	300.0	Vestas V110 2.0MW (583913,583917)	Tap Nebraska City/S3458 (645458) to Mullins Creek (541197) 345kV (560009)
GEN-2014-051	174.0	GE 2.0MW (584013)	JEC N 345kV (532766)

ATC (Available Transfer Capability) studies were not performed as part of this study. These studies will be required at the time transmission service is actually requested. Additional transmission upgrades may be required based on that analysis.

Study assumptions in general have been based on the specific information and data provided by SPP. The accuracy of the conclusions contained within this study is dependent on the assumptions made with respect to other generation additions and transmission improvements planned by other entities. Changes in the assumptions of the timing of other generation additions or transmission improvements may affect this study's conclusions.

2.2. Objectives

The objectives of the study are to conduct power factor analysis and to determine the impact on system stability of interconnecting the proposed wind farms to SPP's transmission system.

2.3. Models and Simulations Tools Used

Version 32 of the Siemens, PSS/E^{TM} power system simulation program was used in this study.

SPP provided its latest stability database cases for summer-2015, winter-2015, and summer-2025 peak seasons. The Project's PSS/E model had been developed prior to this study and was included in the power flow case and the dynamics database. Machines, interconnection and dynamic model data for the Project plants is provided in Appendix D.

Power flow single line diagram of the project in summer 2015 peak condition is shown in Figure 2.1.1. This Figure shows that wind farms model includes representation of the radial transmission line, the substation transformer from transmission voltage (138kV and 345kV) to 34.5V. The remainder of each wind farm is represented by lumped equivalents including a generator, a step-up transformer, and collector system impedance.

No special modeling is required of line relays in these cases, except for the special modeling related to the wind-turbine tripping.

All generators in Areas 536, 540, 541, 542, 544, 545, 545, 640, 645, 650, 652, 635, 330, and 356 were monitored.

3. Power Factor Analysis

3.1. Methodology

Power factor analysis was conducted for the Project using the following methodology:

1. Replace the wind farm by a generator at the high side bus 345 kV, 138 kV, 115kV, or 69 kV bus, as applicable, with the MW of the wind farms at that point of interconnection.
2. Turn off the wind farm as modeled (as well as previous queued projects at the same point of interconnection).
3. Model a var generator at the Project's high voltage side, 345 kV, 138 kV, 115kV, or 69kV bus, as applicable. The var generator is set to hold a voltage schedule at the POI consistent with the voltage schedule in the provided power flow cases for summer and winter or 1.0 pu voltage, whichever is higher.
4. Perform the steady state contingency analysis to determine the power factor necessary at the POI for each contingency.
5. If the required power factor at the POI is beyond the capability of the studied wind turbines to meet (at the POI) capacitor banks may be considered for the stability analysis. The preference is to locate the capacitance banks on the 34.5 kV customer side. Factors to sizing capacitor banks include:
   - 5.1. The ability of the wind farm to meet FERC Order 661A (low voltage ride through) with and without capacitor banks.
   - 5.2. The ability of the wind farm to meet FERC Order 661A (wind farm recovery to pre-fault voltage).
   - 5.3. If wind farms trips on high voltage, power factor lower than unity may be required.

3.2. Analysis

Analysis was performed for the proposed Projects with all prior queued projects in service. A var generator was modeled at the point of interconnection and was set to hold a voltage schedule at the POI consistent with the voltage schedule in the provided power flow cases OR 1 p.u. whichever is higher. The voltages for these Projects are summarized in Table 3.2.1. All upgrades and instructions were made in the base cases. No other changes were made in the base cases provided, other than the addition of the var generators. Contingency analysis was run for provided list of contingencies.

Table 3.2.1: POI voltages for the summer and winter peak cases

Request	Point of Interconnection	Size (MW)	Base Case Voltage (p.u.)		
			Summer 2015 Peak	Winter 2015 Peak	Summer 2025 Peak
GEN-2015-005	Tap on the Nebraska City-Sibley 345kV	200.1	1.02	1.026	1.022

The details of the var requirement during contingencies are highlighted in Table 3.2.2, 3.2.3 and 3.2.4. The highest and the lowest values obtained are highlighted in these tables.

1. For 2015 summer case: The maximum var generator supply is 91.1 MVARs at 0.91 (lagging power factor) for the outage of 645458 [S3458 3 345.00] TO BUS 560009 [G14-021-TAP 345.00] CKT outage. The minimum var requirement is -39.8 MVAR at 0.98 (leading power factor) for outage of 560028 [G15-005-TAP 345.00] TO BUS 541201 [SIBLEY 7 345.00] CKT outage.

Table 3.2.2: Var Generator output in 2015 summer peak case for DISIS-2015-001 (Group 13)

2015 Summer Peak Case Power Factor Study:

Generation Interconnection Request Analysis Rated MW of Wind Farms OR at POI (MW) Rated MVAR of Wind Farms OR at POI (MVAR)						**GEN-2015-005** MW at POI **200.1** MVAR at POI **96.9**	
Cont. Name	**From Bus (# & Name)**		**To Bus (# & Name)**		**ID**	**MVAR at POI**	**P.F at POI**
	Base Case MVAR Flow				N/A	-18.0	1.0
FLT01-3PH	560028	G15-005-TAP 345.00	541201	SIBLEY 7 345.00	CKT 1	-39.8	0.98
FLT02-3PH	560028	G15-005-TAP 345.00	541197	MULLNCR7 345.00	CKT 1	12.9	1.00
FLT03-3PH	541201	SIBLEY 7 345.00	542972	HAWTH 7 345.00	CKT 1	-29.9	0.99
FLT04-3PH	541201	SIBLEY 7 345.00	541200	PHILL 7 345.00	CKT 1	-30.5	0.99
FLT05-3PH	541201	SIBLEY 7 345.00	345408	7OVERTON 345.00	CKT 1	-1.9	1.00
FLT06-3PH	345408	7OVERTON 345.00	345088	7MCCREDIE 345.00	CKT 1	-5.8	1.00
FLT07-3PH	541201	SIBLEY 7 345.00	541202	SIBLEY 5 161.00	T/F	-29.1	0.99
FLT08-3PH	541200	PHILL 7 345.00	541198	PECULR 7 345.00	CKT 1	-22.2	0.99
FLT09-3PH	542972	HAWTH 7 345.00	542973	HAWTHRN5 161.00	T/F	-21.5	0.99
FLT10-3PH	542982	IATAN 7 345.00	542980	NASHUA 7 345.00	CKT 1	-3.0	1.00
FLT11-3PH	542982	IATAN 7 345.00	541350	IATAN5 161.00	T/F	-15.0	1.00
FLT12-3PH	542982	IATAN 7 345.00	532772	STRANGR7 345.00	CKT 1	-16.0	1.00
FLT13-3PH	542982	IATAN 7 345.00	541400	EASTOWN7 345.00	CKT 1	-21.2	0.99
FLT14-3PH	640139	COOPER 3 345.00	541199	ST JOE 3 345.00	CKT 1	-6.4	1.00

Generation Interconnection Request Analysis Rated MW of Wind Farms OR at POI (MW) Rated MVAR of Wind Farms OR at POI (MVAR)						GEN-2015-005 MW at POI **200.1** MVAR at POI **96.9**	
Cont. Name	**From Bus (# & Name)**		**To Bus (# & Name)**		**ID**	**MVAR at POI**	**P.F at POI**
FLT15-3PH	640139	COOPER 3 345.00	300039	7FAIRPT 345.00	CKT 1	-9.0	1.00
FLT16-3PH	635017	ATCHSNT3 345.00	635630	BOONVIL3 345.00	CKT 1	-15.9	1.00
FLT17-3PH	640139	COOPER 3 345.00	640277	MOORE 3 345.00	CKT 1	-18.7	1.00
FLT18-3PH	645458	S3458 3 345.00	640139	COOPER 3 345.00	CKT 1	-10.7	1.00
FLT19-3PH	645458	S3458 3 345.00	645740	S3740 3 345.00	CKT 1	-15.5	1.00
FLT20-3PH	645458	S3458 3 345.00	650189	103&ROKEBY3 345.00	CKT 1	-13.0	1.00
FLT21-3PH	645458	S3458 3 345.00	645456	S3456 3 345.00	CKT 1	-16.4	1.00
FLT22-3PH	645458	S3458 3 345.00	560009	G14-021-TAP 345.00	CKT 1	91.1	0.91
FLT23-3PH	645740	S3740 3 345.00	645455	S3455 3 345.00	CKT 1	-15.7	1.00
FLT24-3PH	635590	FALLOW 3 345.00	635600	GRIMES 3 345.00	CKT 1	-14.9	1.00
FLT25-3PH	645456	S3456 3 345.00	635000	CBLUFFS3 345.00	CKT 1	-20.9	0.99

2. For 2015 winter case: The maximum var generator supply is 90.4 MVARs at 0.91 (lagging power factor) for the outage of 645458 [S3458 3 345.00] TO BUS 560009 [G14-021-TAP 345.00] CKT outage. The minimum var requirement is -40.3 MVAR at 0.98 (leading power factor) for outage of 541201 [SIBLEY 7 345.00] TO BUS 541200 [PHILL 7 345.00] CKT outage.

Table 3.2.3: Var generator output in 2015 winter peak case for DISIS-2015-001 (Group 13)

2015 Winter Peak Case Power Factor Study:

Generation Interconnection Request Analysis Rated MW of Wind Farms OR at POI (MW) Rated MVAR of Wind Farms OR at POI (MVAR)						GEN-2015-005 MW at POI **200.1** MVAR at POI **96.9**	
Cont. Name	**From Bus (# & Name)**		**To Bus (# & Name)**		**ID**	**MVAR at POI**	**P.F at POI**
	Base Case MVAR Flow				N/A	-23.7	0.99
FLT01-3PH	560028	G15-005-TAP 345.00	541201	SIBLEY 7 345.00	CKT 1	-31.4	0.99

Generation Interconnection Request Analysis Rated MW of Wind Farms OR at POI (MW) Rated MVAR of Wind Farms OR at POI (MVAR)						GEN-2015-005 MW at POI **200.1** MVAR at POI **96.9**	
Cont. Name	**From Bus (# & Name)**		**To Bus (# & Name)**		**ID**	**MVAR at POI**	**P.F at POI**
FLT02-3PH	560028	G15-005-TAP 345.00	541197	MULLNCR7 345.00	CKT 1	13.3	1.00
FLT03-3PH	541201	SIBLEY 7 345.00	542972	HAWTH 7 345.00	CKT 1	-34.4	0.99
FLT04-3PH	541201	SIBLEY 7 345.00	541200	PHILL 7 345.00	CKT 1	-40.3	0.98
FLT05-3PH	541201	SIBLEY 7 345.00	345408	7OVERTON 345.00	CKT 1	-8.3	1.00
FLT06-3PH	345408	7OVERTON 345.00	345088	7MCCREDIE 345.00	CKT 1	-13.0	1.00
FLT07-3PH	541201	SIBLEY 7 345.00	541202	SIBLEY 5 161.00	T/F	-29.9	0.99
FLT08-3PH	541200	PHILL 7 345.00	541198	PECULR 7 345.00	CKT 1	-33.2	0.99
FLT09-3PH	542972	HAWTH 7 345.00	542973	HAWTHRN5 161.00	T/F	-25.3	0.99
FLT10-3PH	542982	IATAN 7 345.00	542980	NASHUA 7 345.00	CKT 1	-15.4	1.00
FLT11-3PH	542982	IATAN 7 345.00	541350	IATAN5 161.00	T/F	-21.5	0.99
FLT12-3PH	542982	IATAN 7 345.00	532772	STRANGR7 345.00	CKT 1	-24.0	0.99
FLT13-3PH	542982	IATAN 7 345.00	541400	EASTOWN7 345.00	CKT 1	-25.2	0.99
FLT14-3PH	640139	COOPER 3 345.00	541199	ST JOE 3 345.00	CKT 1	-18.5	1.00
FLT15-3PH	640139	COOPER 3 345.00	300039	7FAIRPT 345.00	CKT 1	-18.9	1.00
FLT16-3PH	635017	ATCHSNT3 345.00	635630	BOONVIL3 345.00	CKT 1	-21.1	0.99
FLT17-3PH	640139	COOPER 3 345.00	640277	MOORE 3 345.00	CKT 1	-23.7	0.99
FLT18-3PH	645458	S3458 3 345.00	640139	COOPER 3 345.00	CKT 1	-23.8	0.99
FLT19-3PH	645458	S3458 3 345.00	645740	S3740 3 345.00	CKT 1	-22.8	0.99
FLT20-3PH	645458	S3458 3 345.00	650189	103&ROKEBY3 345.00	CKT 1	-20.6	0.99
FLT21-3PH	645458	S3458 3 345.00	645456	S3456 3 345.00	CKT 1	-22.9	0.99
FLT22-3PH	645458	S3458 3 345.00	560009	G14-021-TAP 345.00	CKT 1	90.4	0.91
FLT23-3PH	645740	S3740 3 345.00	645455	S3455 3 345.00	CKT 1	-25.2	0.99

Generation Interconnection Request Analysis Rated MW of Wind Farms OR at POI (MW) Rated MVAR of Wind Farms OR at POI (MVAR)						GEN-2015-005 MW at POI **200.1** MVAR at POI **96.9**	
Cont. Name	**From Bus (# & Name)**		**To Bus (# & Name)**		**ID**	**MVAR at POI**	**P.F at POI**
FLT24-3PH	635590	FALLOW 3 345.00	635600	GRIMES 3 345.00	CKT 1	-20.9	0.99
FLT25-3PH	645456	S3456 3 345.00	635000	CBLUFFS3 345.00	CKT 1	-22.4	0.99

3. For 2015 summer case: The maximum var generator supply is 88.7 MVARs at 0.91 (lagging power factor) for the outage of 645458 [S3458 3 345.00] TO BUS 560009 [G14-021-TAP 345.00] CKT outage. The minimum var requirement is -38.2 MVAR at 0.98 (leading power factor) for outage of 560028 [G15-005-TAP 345.00] TO BUS 541201 [SIBLEY 7 345.00] CKT outage.

Table 3.2.3: Var generator output in 2025 summer peak case for DISIS-2015-001 (Group 13)
2025 Summer Peak Case Power Factor Study:

Generation Interconnection Request Analysis Rated MW of Wind Farms OR at POI (MW) Rated MVAR of Wind Farms OR at POI (MVAR)						GEN-2015-005 MW at POI **200.1** MVAR at POI **96.9**	
Cont. Name	**From Bus (# & Name)**		**To Bus (# & Name)**		**ID**	**MVAR at POI**	**P.F at POI**
	Base Case MVAR Flow				N/A	-20.6	0.99
FLT01-3PH	560028	G15-005-TAP 345.00	541201	SIBLEY 7 345.00	CKT 1	-38.2	0.98
FLT02-3PH	560028	G15-005-TAP 345.00	541197	MULLNCR7 345.00	CKT 1	10.9	1.00
FLT03-3PH	541201	SIBLEY 7 345.00	542972	HAWTH 7 345.00	CKT 1	-28.6	0.99
FLT04-3PH	541201	SIBLEY 7 345.00	541200	PHILL 7 345.00	CKT 1	-33.4	0.99
FLT05-3PH	541201	SIBLEY 7 345.00	345408	7OVERTON 345.00	CKT 1	-7.6	1.00
FLT06-3PH	345408	7OVERTON 345.00	345088	7MCCREDIE 345.00	CKT 1	-7.7	1.00
FLT07-3PH	541201	SIBLEY 7 345.00	541202	SIBLEY 5 161.00	T/F	-30.0	0.99
FLT08-3PH	541200	PHILL 7 345.00	541198	PECULR 7 345.00	CKT 1	-25.6	0.99
FLT09-3PH	542972	HAWTH 7 345.00	542973	HAWTHRN5 161.00	T/F	-23.2	0.99
FLT10-3PH	542982	IATAN 7 345.00	542980	NASHUA 7 345.00	CKT 1	-7.3	1.00

Generation Interconnection Request Analysis Rated MW of Wind Farms OR at POI (MW) Rated MVAR of Wind Farms OR at POI (MVAR)						GEN-2015-005 MW at POI **200.1** MVAR at POI **96.9**	
Cont. Name	**From Bus (# & Name)**		**To Bus (# & Name)**		**ID**	**MVAR at POI**	**P.F at POI**
FLT11-3PH	542982	IATAN 7 345.00	541350	IATAN5 161.00	T/F	-17.4	1.00
FLT12-3PH	542982	IATAN 7 345.00	532772	STRANGR7 345.00	CKT 1	-16.8	1.00
FLT13-3PH	542982	IATAN 7 345.00	541400	EASTOWN7 345.00	CKT 1	-23.4	0.99
FLT14-3PH	640139	COOPER 3 345.00	541199	ST JOE 3 345.00	CKT 1	-10.1	1.00
FLT15-3PH	640139	COOPER 3 345.00	300039	7FAIRPT 345.00	CKT 1	-11.8	1.00
FLT16-3PH	635017	ATCHSNT3 345.00	635630	BOONVIL3 345.00	CKT 1	-17.6	1.00
FLT17-3PH	640139	COOPER 3 345.00	640277	MOORE 3 345.00	CKT 1	-21.0	0.99
FLT18-3PH	645458	S3458 3 345.00	640139	COOPER 3 345.00	CKT 1	-13.7	1.00
FLT19-3PH	645458	S3458 3 345.00	645740	S3740 3 345.00	CKT 1	-18.4	1.00
FLT20-3PH	645458	S3458 3 345.00	650189	103&ROKEBY3 345.00	CKT 1	-16.1	1.00
FLT21-3PH	645458	S3458 3 345.00	645456	S3456 3 345.00	CKT 1	-19.4	1.00
FLT22-3PH	645458	S3458 3 345.00	560009	G14-021-TAP 345.00	CKT 1	88.7	0.91
FLT23-3PH	645740	S3740 3 345.00	645455	S3455 3 345.00	CKT 1	-13.3	1.00
FLT24-3PH	635590	FALLOW 3 345.00	635600	GRIMES 3 345.00	CKT 1	-17.5	1.00
FLT25-3PH	645456	S3456 3 345.00	635000	CBLUFFS3 345.00	CKT 1	-19.6	1.00

3.3. Conclusions

The power factor analysis indicates the DISIS-2015-001 (Group 13) interconnection request i.e., GEN-2015-005 is required to maintain the SPP standard power factor at the point of interconnection i.e., (Nebraska City-Sibley 345kV) based on the contingencies studied.

Per the SPP OATT, the Interconnection Customer will be required to provide 95% lagging (supplying vars) and 95% leading (absorbing vars) at the POI.

4. Inductive Reactive Support Analysis

Analysis for low wind /no wind conditions in cluster scenario is performed for the proposed wind generators requests. To offset the capacitive effects of the collector system and transmission line of the wind farm under low wind or no wind conditions, analysis was performed for summer 2015 scenario to calculate the Inductive Reactive Support at point of interconnection for each interconnection request under project DISIS-2015-001 (Group 13) .

Following methodology was adopted as communicated by SPP:

1. Switch the generator and capacitor bank (if installed) out of service with the collector system as modeled remaining in service.
2. Calculate the amount of inductive reactive support required at the 34.5kV collector buses which would result in zero VAR flow at the POI."

The inductive reactive support analysis for wind generator GEN-2015-005 performed for summer 2015 scenario which indicates that at POI (a tap on the Nebraska City-Sibley 345kV) 8.5 MVAR reactor is required at Bus 560028 to maintain zero MVAR flow for GEN-2015-005 generator lead.

Maintaining zero MVar flow at the POI at all times is not possible with static reactor banks. It will be determined on a case by case basis for each generator as to whether additional reactor banks are required for low wind conditions.

The single line diagram for wind generators showing the inductive reactive requirement for Gen-2015-005 is shown in Figure 4.1.1:

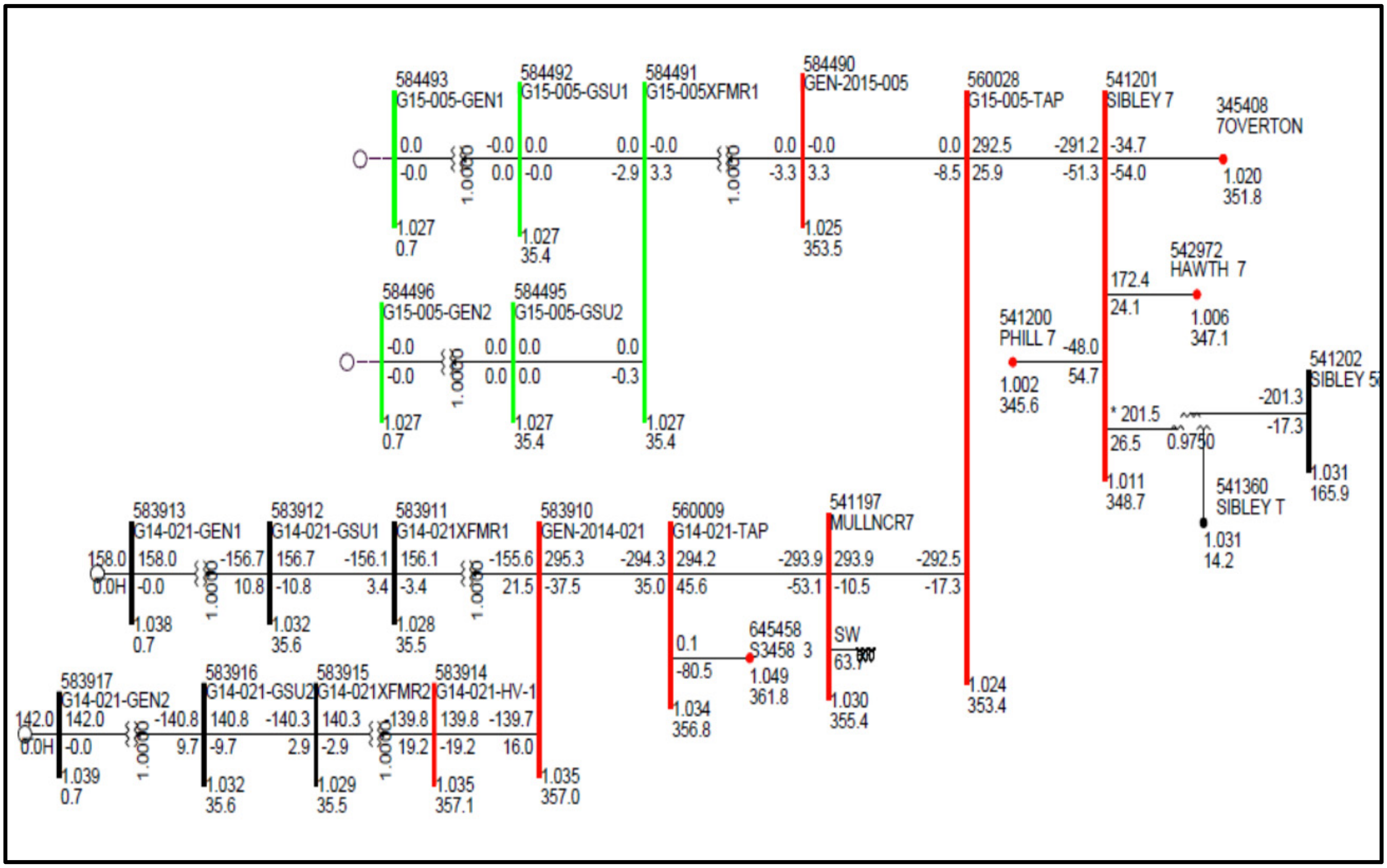


Figure 4.1.1: Inductive reactive requirement for GEN-2015-005

5. Short Circuit Analysis

The short circuit analysis out five buses away was performed for 2025 summer peak case for each interconnection request under project cluster scenario of DISIS-2015-001 (Group 13). No outage was assumed in the system model.

5.1. Short Circuit Result for POI (Tap on the Nebraska City-Sibley 345kV, bus number 560028)

The results of the short circuit analysis for POI i.e., a tap on the Nebraska City-Sibley 345kV (BUS # 560028) are tabulated below in table 5.1.1.

Table 5.1.1: Short circuit results for the POI, a tap on Nebraska City-Sibley 345kV (BUS # 560028)

Bus #	Bus Name	Level Away	Fault Current (Amperes)	
			3 PH	SLG
560028	G15-005-TAP 345.00	0 level	8180.8	5052.7
541197	MULLNCR7 345.00	1 Level	5739.5	3664.2
541201	SIBLEY 7 345.00	1 Level	10061.6	6356.9
584490	GEN-2015-005345.00	1 Level	936.8	714.6
345408	7OVERTON 345.00	2 Level	1783.2	1209.5
541200	PHILL 7 345.00	2 Level	2836.1	1727.4
541202	SIBLEY 5 161.00	2 Level	3938	2976
541360	SIBLEY T 13.800	2 Level	0	0
542972	HAWTH 7 345.00	2 Level	4304	2904
560009	G14-021-TAP 345.00	2 Level	5889	3916.3
584491	G15-005XFMR134.500	2 Level	9367.4	7145.6
345088	7MCCREDIE 345.00	3 Level	1388.9	1069.1
345409	5OVERTON 161.00	3 Level	2124.8	2152.3
541198	PECULR 7 345.00	3 Level	2273.3	1353
541225	PHILL 5 161.00	3 Level	3995.7	3741
541250	SIBLEYPL 161.00	3 Level	4763.9	4318.2
541361	PHILL T 13.800	3 Level	0	0
542973	HAWTHRN5 161.00	3 Level	9481.7	8670.9
542980	NASHUA 7 345.00	3 Level	3375.5	2905.1
543644	HAWT T20 13.800	3 Level	0	0

Bus #	Bus Name	Level Away	Fault Current (Amperes)	
			3 PH	SLG
543645	HAWT T22 13.800	3 Level	0	0
583910	GEN-2014-021345.00	3 Level	1372.1	1043.6
584492	G15-005-GSU134.500	3 Level	8601.4	6546
584495	G15-005-GSU234.500	3 Level	747	569.6
645458	S3458 3 345.00	3 Level	6702.2	5527.4
300044	7MCCRED 345.00	4 Level	920.4	838.8
300500	5HUNTSDL 161.00	4 Level	560.5	552.9
345221	5MOBERLY 161.00	4 Level	1371.9	1366.1
345230	7MONTGMRY 345.00	4 Level	3315.7	3235.4
345411	5OVERTON 2 161.00	4 Level	1427.3	1455.6
541151	SIBLEY#3 22.000	4 Level	16880.8	13052.2
541162	DOGWDSTG 18.000	4 Level	10957.8	10126.6
541163	DOGWDCT1 18.000	4 Level	8147.4	7307
541164	DOGWDCT2 18.000	4 Level	8195.6	7322.6
541199	ST JOE 3 345.00	4 Level	1635.3	1500
541235	DUNCAN 5 161.00	4 Level	989.4	945.7
541239	HSNVL 5 161.00	4 Level	535.5	433.3
541243	LKWINGB5 161.00	4 Level	1359.5	1440.3
541244	ORRICK 5 161.00	4 Level	476.1	482.3
541263	SIBLEY 2 69.000	4 Level	1826.5	1571.9
541280	PHILL 2 69.000	4 Level	774.6	829.6
541313	HARRIS 161.00	4 Level	1243.4	1275.5
541342	PECULR 5 161.00	4 Level	1539.4	1384.6
541346	RTCHFLD5 161.00	4 Level	357.9	283.6
541372	PECULRT 13.800	4 Level	0	0
542951	HAW G5 1 22.000	4 Level	31860.8	29046.4
542961	HAWCT6 1 16.000	4 Level	10144	9085.6
542967	HAW G9 1 13.800	4 Level	10689	9810
542968	STILWEL7 345.00	4 Level	3702	3123.1

Bus #	Bus Name	Level Away	Fault Current (Amperes)	
			3 PH	SLG
542976	LEVEE 5 161.00	4 Level	1808.7	1736.5
542982	IATAN 7 345.00	4 Level	4851.5	4737.8
542997	LEEDS 5 161.00	4 Level	1868	1941.2
543000	BLUEVLY5 161.00	4 Level	826.2	867.6
543011	CHOUTEU5 161.00	4 Level	1521.5	1581.6
543020	BRMGHAM5 161.00	4 Level	463.8	465.4
543027	RANDLPH5 161.00	4 Level	1252.5	1305
543028	NASHUA-5 161.00	4 Level	2277	2523.2
543080	HAWTH 2 69.000	4 Level	321.9	370.1
543640	NASH T11 13.800	4 Level	0	0
548808	ECKLES-161 161.00	4 Level	1128.8	958.3
548814	SUB M-161 161.00	4 Level	630.1	581.9
583911	G14-021XFMR134.500	4 Level	7225	5486.6
583914	G14-021-HV-1345.00	4 Level	644.4	491.6
584493	G15-005-GEN10.6900	4 Level	30069.4	127299.4
584496	G15-005-GEN20.6900	4 Level	37349.6	28481.2
640139	COOPER 3 345.00	4 Level	3474.1	3343
645011	NEBCTY1G 18.000	4 Level	41324.8	40299.4
645012	NEBCTY2G 23.000	4 Level	35775.5	34500.2
645456	S3456 3 345.00	4 Level	2938.5	2776
645740	S3740 3 345.00	4 Level	2211.9	2090.6
650189	103&ROKEBY3 345.00	4 Level	1392.9	1254.7
300039	7FAIRPT 345.00	5 Level	855	843.7
300043	7KINGDM 345.00	5 Level	709.4	726.2
300049	7THOMHL 345.00	5 Level	2235.5	2248.5
300052	7ENON 345.00	5 Level	1293.6	1343.9
300098	5MOCITY 161.00	5 Level	659.4	726.5
300126	5MOBTAP 161.00	5 Level	1462.9	1445.2
300320	5LEVASY 161.00	5 Level	398.1	173.1

Bus #	Bus Name	Level Away	Fault Current (Amperes)	
			3 PH	SLG
300709	2SHARSNV 69.000	5 Level	482.9	510.2
343004	5PERCHE 161.00	5 Level	623	583.1
344224	7CALAWY 1 345.00	5 Level	3876.1	3873.3
344233	5CALIF UE 161.00	5 Level	666.6	626.3
344886	7LABADIE3 345.00	5 Level	3539.7	3546.6
345071	5MCBAIN T 161.00	5 Level	382.8	352.5
345222	2MOBERLY 69.000	5 Level	1864.2	1901.2
345231	5MONTGMRY 161.00	5 Level	1677.6	1692.5
345992	7SPENCER 345.00	5 Level	1480.3	1465.7
532772	STRANGR7 345.00	5 Level	3032.1	3147.1
541150	IATAN 11 13.800	5 Level	0	0
541152	SIBLEY#2 13.200	5 Level	4760	4158.4
541153	SIBLEY#1 13.200	5 Level	4598.8	4103
541203	NASHUA 5 161.00	5 Level	495.6	428.9
541205	BLSPE 5 161.00	5 Level	1288.9	1248.8
541207	ARCHIE 5 161.00	5 Level	999.7	892.2
541215	HLLMRK 5 161.00	5 Level	435.2	332.4
541218	GRNWD 5 161.00	5 Level	1206.8	1291
541230	RNRIDGE5 161.00	5 Level	1502.6	1654.5
541236	RICHMND5 161.00	5 Level	476	475.5
541241	SEDEAST5 161.00	5 Level	456.8	477.8
541248	LBRTYST5 161.00	5 Level	392.3	380.6
541249	HOOKRD 5 161.00	5 Level	1216.8	1287.8
541253	ST JOE 5 161.00	5 Level	1419.9	1438.5
541262	LIBERTY2 69.000	5 Level	530.1	561.4
541279	RGREEN 2 69.000	5 Level	740	792.6
541295	HSNVL 2 69.000	5 Level	503.1	524.2
541340	BELTONS5 161.00	5 Level	1267.1	1331.5
541344	PECULRS5 161.00	5 Level	994.1	791.1

Bus #	Bus Name	Level Away	Fault Current (Amperes)	
			3 PH	SLG
541347	RAYMORE 69.000	5 Level	401.8	423.9
541350	IATAN5 161.00	5 Level	1453.8	1477.6
541370	STJOE 1T 13.800	5 Level	0	0
541371	STJOE 2T 13.800	5 Level	0	0
541400	EASTOWN7 345.00	5 Level	1086.8	1076.3
542957	IAT G1 1 24.000	5 Level	30540.6	30084.2
542962	IAT G2 1 25.000	5 Level	36871.2	35787.2
542963	HAWCT7 1 13.800	5 Level	4404.6	3871
542964	HAWCT8 1 13.800	5 Level	5518.8	4546.8
542965	W.GRDNR7 345.00	5 Level	3397.5	3271.1
542969	STILWEL5 161.00	5 Level	4552.9	4716.6
542981	LACYGNE7 345.00	5 Level	5616.8	5530.6
542985	NEAST 5 161.00	5 Level	3351.2	3799.2
543004	BLUMILS5 161.00	5 Level	323.3	326
543009	WINJT N5 161.00	5 Level	490.3	508.9
543010	WINJT S5 161.00	5 Level	442	446.4
543015	AVONDAL5 161.00	5 Level	1161.5	1239.1
543023	CLAYCM25 161.00	5 Level	0	0
543029	SHOLCRK5 161.00	5 Level	943.9	1020
543062	SALSBRY5 161.00	5 Level	1431.3	1427.3
543091	DUNCNRD2 69.000	5 Level	125.6	147.6
543114	PLUMRRD2 69.000	5 Level	99.7	111.2
543639	LEEDREAC 161.00	5 Level	441.8	448.8
543647	STIL T11 13.800	5 Level	0	0
543648	STIL T22 13.800	5 Level	0	0
548803	SUB F 69.000	5 Level	367	392.5
548807	BLUVLY-161 161.00	5 Level	496.6	456.3
548815	SUB M 69.000	5 Level	816.1	905.8
548820	SUB N-161 161.00	5 Level	519	539

Bus #	Bus Name	Level Away	Fault Current (Amperes)	
			3 PH	SLG
583912	G14-021-GSU134.500	5 Level	7054.2	5379
583915	G14-021XFMR234.500	5 Level	6443	4916.4
635000	CBLUFFS3 345.00	5 Level	5065.9	4988.9
635017	ATCHSNT3 345.00	5 Level	1103.1	1095.4
640009	COOPER1G 22.000	5 Level	44580.9	45789.2
640140	COOPER 5 161.00	5 Level	808.1	824.4
640142	COOPER T2 913.800	5 Level	0	0
640277	MOORE 3 345.00	5 Level	1239.7	1157.9
643172	COOPER T5 913.800	5 Level	0	0
645041	CASS 1G 15.000	5 Level	12043.5	11598
645042	CASS 2G 15.000	5 Level	12058	11607.6
645043	CASS 3X 15.000	5 Level	12043.5	11598
645111	NBAXT1 9 4.2000	5 Level	5460.6	5661.8
645112	NBAXT2 9 4.2000	5 Level	5462	5663.4
645455	S3455 3 345.00	5 Level	2747.8	2774.9
645459	S3459 3 345.00	5 Level	1280.9	1247.3
646206	S1206 5 161.00	5 Level	4558.8	4570.3
648256	S3456T49 13.800	5 Level	0	0
650185	WAGENER 3 345.00	5 Level	1259.8	1229.4

6. Stability Analysis for Cluster Scenario

6.1. Faults Simulated

Fifty Four (54) faults were considered for the transient stability simulations which included three phase faults, as well as single phase line faults, at the locations defined by SPP in the RFP. Single-phase line faults were simulated by applying fault impedance to the positive sequence network at the fault location. As per the SPP current practice to compute the fault levels, the fault impedance was computed to give a positive sequence voltage at the specified fault location of approximately 60% of pre-fault voltage.

Concurrently and previously queued projects as respectively shown in Table-1 and Table-2 of the study request i.e., GEN-2008-129, GEN-2010-036, GEN-2011-011, ASGI-2013-007, GEN-2014-021, GEN-2014-051 as well as areas number 536, 540, 541, 542, 544, 545, 545, 640, 645, 650, 652, 635, 330, and 356 were monitored during all the simulations. Table 6.1.1 shows the list of simulated contingencies. This table also shows the fault clearing time and the time delay before re-closing for all the study contingencies.

Simulations were performed with a 0.1-second steady-state run followed by the appropriate disturbance as described in Table 6.1.1. Simulations were run for minimum 15-second duration to confirm proper machine damping.

Table 6.1.1 summarizes the overall results for all faults simulations of cluster scenario. Complete sets of plots for summer-2015, winter-2015, and summer-2025 peak seasons for each fault are included in Appendices A, B and C respectively.

Table 6.1.1: List of simulated faults for cluster scenario stability analysis

Cont. #	Contingency Name	Description	2015 Summer Results	2015 Winter Results	2025 Summer Results
1	FLT01-3PH	3 phase fault on the G15-005 TAP (560028) to Sibley (541201) 345kV line circuit 1, near G15-005 TAP. a. Apply fault at the G15-005 TAP 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
2	FLT02-3PH	3 phase fault on the G15-005 TAP (560028) to Mullin Creek (541197) 345kV line circuit 1, near G15-005 TAP. a. Apply fault at the G15-005 TAP 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
3	FLT03-3PH	3 phase fault on the Sibley (541201) to Hawthorne (542972) 345kV line circuit 1, near Sibley 345kV. a. Apply fault at the Sibley 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
4	FLT04-3PH	3 phase fault on the Sibley (541201) to Pleasant Hill (541200) 345kV line circuit 1, near Sibley. a. Apply fault at the Sibley 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
5	FLT05-3PH	3 phase fault on the Sibley (541201) to Overton (345408) 345kV line circuit 1, near Sibley. a. Apply fault at the Sibley 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable

Cont. #	Contingency Name	Description	2015 Summer Results	2015 Winter Results	2025 Summer Results
6	FLT06-3PH	3 phase fault on the Overton (345408) to McCredie (345088) 345kV line circuit 1, near Overton. a. Apply fault at the Overton 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
7	FLT07-3PH	3 phase fault on the Sibley (541201) 345/(541202) 161/(541360) 13.8kV Transformer circuit 1, near Sibley 345kV. a. Apply fault at the Sibley 345kV bus. b. Clear fault after 5 cycles, trip the faulted line, and remove the fault.	Stable	Stable	Stable
8	FLT08-3PH	3 phase fault on the Pleasant Hill (541200) to Peculiar (541198) 345kV line circuit 1, near Pleasant Hill. a. Apply fault at the Pleasant Hill 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
9	FLT09-3PH	3 phase fault on the Hawthorne (542972) 345/(542973) 161/(543644) 13.8kV Transformer (Hawt 20) circuit 20, near Hawthorne 345kV. a. Apply fault at the Hawthorne 345kV bus. b. Clear fault after 5 cycles, trip the faulted line, and remove fault.	Stable	Stable	Stable
10	FLT10-3PH	3 phase fault on the Iatan (542982) to Nashua (542980) 345kV line circuit 1, near Iatan. a. Apply fault at the Iatan 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable

Cont. #	Contingency Name	Description	2015 Summer Results	2015 Winter Results	2025 Summer Results
11	FLT11-3PH	3 phase fault on the Iatan (542982) 345/(541350) 161/(541150) 13.8kV Transformer (IATAN 11) circuit 11, near Iatan. a. Apply fault at the Hugo 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
12	FLT12-3PH	3 phase fault on the Iatan (542982) to Stranger (532772) 345kV line circuit 1, near Iatan. a. Apply fault at the Iatan 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
13	FLT13-3PH	3 phase fault on the Iatan (542982) to Eastown (541400) 345kV line circuit 1, near Iatan. a. Apply fault at the Iatan 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
14	FLT14-3PH	3 phase fault on the Cooper (640139) to St Joe (541199) 345kV line circuit 1, near Cooper. a. Apply fault at the Cooper 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
15	FLT15-3PH	3 phase fault on the Cooper (640139) to Fairport (300039) 345kV line circuit 1, near Cooper. a. Apply fault at the Cooper 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable

Cont. #	Contingency Name	Description	2015 Summer Results	2015 Winter Results	2025 Summer Results
16	FLT16-3PH	3 phase fault on the Atchison Tap (635017) to Boonville (635630) 345kV line circuit 1, near Atchison Tap. a. Apply fault at the Atchison Tap 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
17	FLT17-3PH	3 phase fault on the Cooper (640139) to Moore (640277) 345kV line circuit 1, near Cooper. a. Apply fault at the Cooper 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
18	FLT18-3PH	3 phase fault on the Nebraska City/S3458 (645458) to Cooper (640139) 345kV line circuit 1, near Nebraska City/S3458. a. Apply fault at the Nebraska City/S3458 345kV bus. b. Clear fault after 4.5 cycles, trip the faulted line, and remove fault.	Stable	Stable	Stable
19	FLT19-3PH	3 phase fault on the Nebraska City/S3458 (645458) to Cass/S3740 (645740) 345kV line circuit 1, near Nebraska City/S3458. a. Apply fault at the Nebraska City/S3458 345kV bus. b. Clear fault after 4.5 cycles, trip the faulted line, and remove fault.	Stable	Stable	Stable
20	FLT20-3PH	3 phase fault on the Nebraska City/S3458 (645458) to 103&Rokeby (650189) 345kV line circuit 1, near Nebraska City/S3458. a. Apply fault at the Nebraska City/S3458 345kV bus. b. Clear fault after 4.5 cycles, trip the faulted line, and remove fault.	Stable	Stable	Stable
21	FLT21-3PH	3 phase fault on the Nebraska City/S3458 (645458) to Sarpy/S3456 (645456) 345kV line circuit 1, near Nebraska City/S3458. a. Apply fault at the Nebraska City/S3458 345kV bus. b. Clear fault after 4.5 cycles, trip the faulted line, and remove fault.	Stable	Stable	Stable

Cont. #	Contingency Name	Description	2015 Summer Results	2015 Winter Results	2025 Summer Results
22	FLT22-3PH	3 phase fault on the Nebraska City/S3458 (645458) to G14-021 TAP (560009) 345kV line circuit 1, near Nebraska City/S3458 345kV. a. Apply fault at the Nebraska City/S3458 345kV bus. b. Clear fault after 4.5 cycles, trip the faulted line, and remove fault.	Stable	Stable	Stable
23	FLT23-3PH	3 phase fault on the Cass/S3740 (645740) to S3455 (645455) 345kV line circuit 1, near Cass/S3740 345kV. a. Apply fault at the near Cass/S3740 345kV bus. b. Clear fault after 4.5 cycles, trip the faulted line, and remove fault.	Stable	Stable	Stable
24	FLT24-3PH	3 phase fault on the Fallow (635590) to Grimes (635600) 345kV line circuit 1, near Fallow 345kV. a. Apply fault at the Fallow 345kV bus. b. Clear fault after 5 cycles, trip the faulted line, and remove fault.	Stable	Stable	Stable
25	FLT25-3PH	3 phase fault on the Sarpy/S3456 (645456) to Council Bluffs (635000) 345kV line circuit 1, near Sarpy/S3456 345kV. a. Apply fault at the Sarpy/S3456 345kV bus. b. Clear fault after 5 cycles, trip the faulted line, and remove fault.	Stable	Stable	Stable
26	FLT26-3PH	**Sibley 345kV Stuck Breaker Scenario 1** a. Apply single phase fault at the Sibley (541201) 345kV bus. b. Wait 16 cycles and remove fault. c. Trip Sibley (541201) 345/(541202) 161/(541360) 13.8kV transformer circuit 1. d. Trip Sibley (541201) to Hawthorne (542972) 345kV line circuit 1.	Stable	Stable	Stable
27	FLT27-3PH	**Sibley 345kV Stuck Breaker Scenario 2** a. Apply single phase fault at the Sibley (541201) 345kV bus. b. Wait 16 cycles and remove fault. c. Trip Sibley (541201) to Pleasant Hill (541200) 345kV line circuit 1. d. Trip Sibley (541201) to Hawthorne (542972) 345kV line circuit 1.	Stable	Stable	Stable

Cont. #	Contingency Name	Description	2015 Summer Results	2015 Winter Results	2025 Summer Results
28	FLT28-3PH	**Sibley 345kV Stuck Breaker Scenario 3** a. Apply single phase fault at the Sibley (541201) 345kV bus. b. Wait 16 cycles and remove fault. c. Trip Sibley (541201) to Pleasant Hill (541200) 345kV line circuit 1. d. Trip Sibley (541201) to Overton (345408) 345kV line circuit 1.	Stable	Stable	Stable
29	FLT29-SB	**Nebraska City/S3458 345kV Stuck Breaker Scenario 1** a. Apply single phase fault at the Nebraska City/S3458 (645458) end of the Nebraska City/S3458 to Cooper (640139) 345kV line. b. After 4.5 cycles, open remote end of faulted line. c. Wait 9 cycles, remove fault and trip faulted line.	Stable	Stable	Stable
30	FLT30-SB	**Nebraska City/S3458 345kV Stuck Breaker Scenario 2** a. Apply single phase fault at the Nebraska City/S3458 (645458) end of the Nebraska City/S3458 to Cass/S3740 (645740) 345kV line. b. After 4.5 cycles, open remote end of faulted line. c. Wait 9 cycles, remove fault and trip faulted line.	Stable	Stable	Stable
31	FLT31-SB	**Nebraska City/S3458 345kV Stuck Breaker Scenario 3** a. Apply single phase fault at the Nebraska City/S3458 (645458) end of the Nebraska City/S3458 to 103&Rokeby (650189) 345kV line. b. After 4.5 cycles, open remote end of faulted line. c. Wait 9 cycles, remove fault and trip faulted line.	Stable	Stable	Stable
32	FLT32- SB	**Nebraska City/S3458 345kV Stuck Breaker Scenario 4** a. Apply single phase fault at the Nebraska City/S3458 (645458) end of the Nebraska City/S3458 to Sarpy/S3456 (645456) 345kV line. b. After 4.5 cycles, open remote end of faulted line. c. Wait 9 cycles, remove fault and trip faulted line.	Stable	Stable	Stable
33	FLT33-SB	**Nebraska City/S3458 345kV Stuck Breaker Scenario 5** a. Apply single phase fault at the Nebraska City/S3458 (645458) end of the Nebraska City/S3458 to G14-021 TAP (560009) 345kV line. b. After 4.5 cycles, open remote end of faulted line. c. Wait 9 cycles, remove fault and trip faulted line.	Stable	Stable	Stable

Cont. #	Contingency Name	Description	2015 Summer Results	2015 Winter Results	2025 Summer Results
34	FLT34-SB	**Nebraska City/S3458 345kV Stuck Breaker Scenario 6** a. Apply single phase fault at the Nebraska City/S3458 (645458) 345kV bus. b. After 14 cycles, trip Nebraska City/S3458 to Cooper (640139) 345kV line and remove fault.	Stable	Stable	Stable
35	FLT35-SB	**Nebraska City/S3458 345kV Stuck Breaker Scenario 7** a. Apply single phase fault at the Nebraska City/S3458 (645458) 345kV bus. b. After 14.5 cycles, trip Nebraska City/S3458 to Sarpy/S3456 (645456) 345kV line and remove fault.	Stable	Stable	Stable
36	FLT36-SB	**Nebraska City/S3458 345kV Stuck Breaker Scenario 8** a. Apply single phase fault at the Nebraska City/S3458 (645458) 345kV bus. b. After 14.5 cycles, trip Nebraska City/S3458 to Cass/S3740 (645740) 345kV line and remove fault.	Stable	Stable	Stable
37	FLT37-SB	**Nebraska City/S3458 345kV Stuck Breaker Scenario 9** a. Apply single phase fault at the Nebraska City/S3458 (645458) 345kV bus. b. After 14 cycles, trip Nebraska City/S3458 to 103&Rokeby (650189) 345kV line and remove fault.	Stable	Stable	Stable
38	FLT38-SB	**Nebraska City/S3458 345kV Stuck Breaker Scenario 10** a. Apply single phase fault at the Nebraska City/S3458 (645458) 345kV bus. b. After 14 cycles, trip Nebraska City/S3458 to G14-021 TAP (560009) 345kV line and remove fault.	Stable	Stable	Stable
39	FLT39-SB	**Cass/S3470 345kV Stuck Breaker Scenario 1** a. Apply single phase fault at the Cass/S3740 (645740) end of the Cass/S3740 (645740) to the S3455 (645455) 345kV line. b. After 4.5 cycles, open remote end of faulted line. c. Wait 9 cycles, remove fault and trip faulted line.	Stable	Stable	Stable
40	FLT40-SB	**Cass/S3470 345kV Stuck Breaker Scenario 2** a. Apply single phase fault at the Cass/S3740 (645740) 345kV bus. b. After 14.5 cycles, trip Cass/S3740 to S3455 (645455) 345kV line and remove fault.	Stable	Stable	Stable

Cont. #	Contingency Name	Description	2015 Summer Results	2015 Winter Results	2025 Summer Results
41	FLT41-PO	**Sibley Prior Outage Scenario 1** a. Prior Outage: Switch out Sibley (541201) to G15-005 TAP (560028) 345kV circuit 1 and solve. b. Apply 3 phase fault on the Nebraska City/S3458 (645458) to Cooper (640139) 345kV line circuit 1, near Nebraska City/S3458. c. Clear fault after 4.5 cycles and trip the faulted line and remove the fault.	Stable	Stable	Stable
42	FLT42-PO	**Sibley Prior Outage Scenario 2** a. Prior Outage: Switch out Sibley (541201) to G15-005 TAP (560028) 345kV circuit 1 and solve. b. Apply 3 phase fault on the Nebraska City/S3458 (645458) to 103&Rokeby (650189) 345kV line circuit 1, near Nebraska City/S3458. c. Clear fault after 4.5 cycles and trip the faulted line and remove fault.	Stable	Stable	Stable
43	FLT43-PO	**Sibley Prior Outage Scenario 3** a. Prior Outage: Switch out Sibley (541201) to G15-005 TAP (560028) 345kV circuit 1 and solve. b. Apply 3 phase fault on the Cass/S3740 (645740) to S3455 (645455) 345kV line circuit 1, near Cass/S3740. c. Clear fault after 4.5 cycles and trip the faulted line and remove fault.	Stable	Stable	Stable
44	FLT44-PO	**Sibley Prior Outage Scenario 4** a. Prior Outage: Switch out Sibley (541201) to G15-005 TAP (560028) 345kV circuit 1 and solve. b. Apply 3 phase fault on the Nebraska City/S3458 (645458) to Sarpy/S3456 (645456) 345kV line circuit 1, near Nebraska City/S3458. c. Clear fault after 4.5 cycles and trip the faulted line and remove fault.	Stable	Stable	Stable
45	FLT45-PO	**Sibley Prior Outage Scenario 5** a. Prior Outage: Switch out Sibley (541201) to G15-005 TAP (560028) 345kV circuit 1 and solve. b. Apply 3 phase fault on the Nebraska City/S3458 (645458) to Sarpy/S3456 (645456) 345kV line circuit 1, near Nebraska City/S3458. c. Clear fault after 4.5 cycles and trip the faulted line.	Stable	Stable	Stable

Cont. #	Contingency Name	Description	2015 Summer Results	2015 Winter Results	2025 Summer Results
46	FLT46-PO	**St. Joe Prior Outage Scenario 1** a. Prior Outage: Switch out St. Joe (541199) to Nashua (542980) 345kV circuit 1 and solve. b. Apply 3 phase fault on the St. Joe (541199) to Eastown (541400) 345kV line circuit 1, near St. Joe. c. Clear fault after 5 cycles and trip the faulted line. d. Wait 20 cycles, and then re-close the line in (b) back into the fault. e. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
47	FLT47- PO	**Cooper Prior Outage Scenario 1** a. Prior Outage: Switch out Cooper (640139) to Fairport (300039) 345kV circuit 1 and solve. b. Apply 3 phase fault on the Cooper (640139) to St. Joe (541199) 345kV line circuit 1, near Cooper. c. Clear fault after 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
48	FLT48- PO	**Cooper Prior Outage Scenario 2** a. Prior Outage: Switch out Cooper (640139) to the Nebraska City/S3458 (645458) 345kV circuit 1 and solve. b. Apply 3 phase fault on the Cooper (640139) to Moore (640277) 345kV line circuit 1, near Cooper. c. Clear fault after 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
49	FLT49- PO	**Cass/S3740 Prior Outage Scenario 1** a. Prior Outage: Switch out Cass/S3740 (645740) to S3455 (645455) 345kV circuit 1 and solve. b. Apply 3 phase fault on the Nebraska City/S3458 (645458) to Sarpy/S3456 (645456) 345kV line circuit 1, near Nebraska City/S3458. c. Clear fault after 4.5 cycles and trip the faulted line and remove fault.	Stable	Stable	Stable
50	FLT50- PO	**Cass/S3740 Prior Outage Scenario 2** a. Prior Outage: Switch out Cass/S3740 (645740) to S3455 (645455) 345kV circuit 1 and solve. b. Apply 3 phase fault on the S3455 (645455) to Sarpy/S3456 (645456) 345kV line circuit 1, near Cooper. c. Clear fault after 4.5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable

Cont. #	Contingency Name	Description	2015 Summer Results	2015 Winter Results	2025 Summer Results
51	FLT51- PO	**Nebraska City/S3458 Prior Outage Scenario 1** a. Prior Outage: Switch out Nebraska City/S3458 (645458) to G14-021 TAP (560009) 345kV circuit 1 and solve. b. Apply 3 phase fault on Sibley (541201) to Pleasant Hill (541200) 345kV line circuit 1, near Sibley. c. Clear fault after 5 cycles and trip the faulted line. d. Wait 20 cycles, and then re-close the line in (b) back into the fault. e. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
52	FLT52- PO	**Nebraska City/S3458 Prior Outage Scenario 2** a. Prior Outage: Switch out Nebraska City/S3458 (645458) to G14-021 TAP (560009) 345kV circuit 1 and solve. b. Apply 3 phase fault on Sibley (541201) to Hawthorne (542972) 345kV line circuit 1, near Sibley. c. Clear fault after 5 cycles and trip the faulted line. d. Wait 20 cycles, and then re-close the line in (b) back into the fault. e. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
53	FLT53- PO	**Nebraska City/S3458 Prior Outage Scenario 3** a. Prior Outage: Switch out Nebraska City/S3458 (645458) to G14-021 TAP (560009) 345kV circuit 1 and solve. b. Apply 3 phase fault on Sibley (541201) to Overton (345408) 345kV line circuit 1, near Sibley. c. Clear fault after 5 cycles and trip the faulted line. d. Wait 20 cycles, and then re-close the line in (b) back into the fault. e. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable	Stable
54	FLT54- PO	**Nebraska City/S3458 Prior Outage Scenario 4** a. Prior Outage: Switch out Nebraska City/S3458 (645458) to G14-021 TAP (560009) 345kV circuit 1 and solve. b. Apply 3 phase fault on Sibley (541201) 345/(541202) 161/(541360) 13.8kV transformer circuit 1. c. Clear fault after 5 cycles and trip the faulted transformer and remove fault.	Stable	Stable	Stable

6.2. Simulation Results for Cluster Scenario

For cluster scenario, there are no impacts on the stability performance of the SPP system for the contingencies tested on the SPP provided base cases.

7. Conclusions

The findings of the impact study for the proposed interconnection projects under DISIS-2015-001 (Group 13) considered 100% of their proposed installed capacity is as follows:

1. The power factor analysis indicates the DISIS-2015-001 (Group 13) interconnection request i.e., GEN-2015-005 is required to maintain the SPP standard power factor at the point of interconnection i.e., A tap on the Nebraska City-Sibley 345kV based on the contingencies studied. Per the SPP OATT, the Interconnection Customer will be required to provide 95% lagging (supplying vars) and 95% leading (absorbing vars) at the POI.

2. To offset the capacitive effects of the collector system and transmission line of the wind farm under low wind or no wind conditions, analysis was performed for winter-2015 scenario. The analysis indicates that at POI (a tap on the Nebraska City-Sibley 345kV) 8.5 MVAR reactor is required at Bus 560028 to maintain zero MVAR flow for GEN-2015-005 generator lead. Maintaining zero MVar flow at the POI at all times is not possible with static reactor banks. It will be determined on a case by case basis for each generator as to whether additional reactor banks are required for low wind conditions.

3. The short circuit analysis is performed on the power flow models for the 2025 summer peak season for cluster scenario model. The results are documented for both 3 phase fault as well as single line to ground fault up to 5 buses away from the POI (a tap on the Nebraska City-Sibley 345kV).

4. There are no impacts on the stability performance of the SPP system during cluster scenario for the contingencies tested on the provided base cases. The study machines stayed on-line and stable for all simulated faults. The Project stability simulations with fifty four (54) specified test disturbances did not show instability problems in the SPP system. Any oscillations were damped out.

8. Appendix A:2015 Summer Peak Case Stability Run Plots – Cluster

9. Appendix B:2015 Winter Peak Case Stability Run Plots – Cluster

10. Appendix C:2025 Summer Peak Case Stability Run Plots – Cluster

11. Appendix D:Project Model Data