Definitive Interconnection System Impact Study for Generation Interconnection Requests

(DISIS-2015-001-3)

Group 6 & GEN-2015-004 Only

September 2017

Generator Interconnection

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.
08/28/2015	SPP	Report Reissued (DISIS-2015-001) to include Group 2, 5, 6, and 7 Interconnection Requests Results
12/23/2015	SPP	Re-Study to account for withdrawn projects
01/6/2016	SPP	Re-posted 12/23/15 issue with cost allocation correction for GEN-2014-074
03/9/2016	SPP	Re-Study to account for withdrawn projects
09/01/2017	SPP	Group 6 and GEN-2015-004 Re-Study to account for withdrawn projects

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 2,535.89 MW of new generation which would be located within the transmission systems of Grand River Dam Authority (GRDA), Kansas City Power and Light Company – Greater Missouri Operations Company (KCPL-GMO), 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. This study represents the "Stand-Alone" analysis for remaining Interconnection Requests in the DISIS-2015-001 analysis.

Power flow analysis has indicated that for the power flow cases studied, 2,535.89 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. 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

[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.

Appendix G-T (Thermal) and Appendix G-V (Voltage). 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 $16,992,980 for Group 6 and GEN-2015-004 Interconnection Customers and $102,714,177 for all DISIS-2015-001 Interconnection Customers. 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. **<u>The in-service date for the DISIS customers will be deferred until the construction of these network upgrades can be completed.</u>** 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 transmission reinforcement for Interconnection Service, but could require Interconnection Customer to reduce generation in operational conditions. These transmission constraints occur when this study's generation is dispatched into the SPP footprint for ERIS or when this study's generation is dispatched into the interconnecting Transmission Owner's (T.O.) area for 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 2,535.89 MW of new generation which would be located within the transmission systems of Grand River Dam Authority (GRDA), Kansas City Power and Light Company – Greater Missouri Operations Company (KCPL-GMO), 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. This study represents the "Stand-Alone" analysis for remaining Interconnection Requests in the DISIS-2015-001 analysis

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 three (3) 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 2015 series Integrated Transmission Planning models (used in the 2016 ITPNT) including the 2016 winter peak (16WP) season, the 2017 spring (17G) and 2017 summer peak (17SP) seasons, the 2020 light load (20L), summer (20SP) and winter peak (20WP) seasons, and the 2025 summer peak (25SP) season were the starting seasonal models for this study.

Dynamic Stability

The 2015 series SPP Model Development Working Group (MDWG) Models for 2016 winter peak (16WP) season, 2017 summer peak (17SP) season, and the 2025 summer peak (25SP) season cases were used as starting points for this study.

Short Circuit

The 2017 and 2025 summer peak stability cases are 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. <u>The DISIS-2015-001 Interconnection Customers Generation Facilities in service dates may need to be delayed until the completion of the following</u>

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, placed in-service in 2016
    - 200Mvar Capacitive and 50Mvar Inductive Static Var Compensator (SVC)
  - Road Runner 115kV Reactive Power Support, placed in-service in 2016
    - 200Mvar Capacitive and 50Mvar Inductive Static Var Compensator (SVC)
  - 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, placed in-service in 2016[5]
- Northwest 345/138/13.8 kV circuit #3 autotransformer, placed in-service in 2015[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
    - 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

[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.

        - 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, placed in-service in 2016

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. 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.

- 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 District EHV Phase Shifting Transformer, placed in-service in 2016
- Upgrades assigned to DISIS-2012-002 Interconnection Customers:
    - Lake Creek – Lone Wolf 69 kV circuit #1 reset CT, placed in-service in 2015
- Upgrades assigned to DISIS-2013-002 Interconnection Customers:
    - Battle Creek – County Line – Neligh East 115kV circuit #1 rebuild, placed in-service in 2017
- Upgrades assigned to DISIS-2014-002 Interconnection Customers:
    - Arnold – Ransom 115kV circuit #1, terminal equipment replacement
    - Tolk – Plant X 230kV circuit #1 and circuit #2 re-conductor
    - Tuco 345/230kV transformer replacement

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 eight (8 active regional groups based on geographical and electrical impacts. These groupings are shown in Appendix C.

To determine interconnection impacts, eight (8) 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 2017 spring, or in the “High VER” summer and winter peaks. To study peaking units’ impacts, the 2016 winter peak, 2017 summer peak, 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 (2017 SP and 2025 SP) are used for this analysis.

Identification of Network Constraints

Thermal Overloads

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

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

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

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

Appropriate transmission support is then determined to mitigate the constraints.

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

Voltage

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

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

SPP Areas (69kV+):

Transmission Owner	Voltage Criteria (System Intact)	Voltage Criteria (Contingency)
AEPW	0.95 – 1.05 pu	0.92 – 1.05 pu
GRDA	0.95 – 1.05 pu	0.90 – 1.05 pu
SWPA	0.95 – 1.05 pu	0.90 – 1.05 pu
OKGE	0.95 – 1.05 pu	0.90 – 1.05 pu
OMPA	0.95 – 1.05 pu	0.90 – 1.05 pu
WFEC	0.95 – 1.05 pu	0.90 – 1.05 pu
SWPS	0.95 – 1.05 pu	0.90 – 1.05 pu
MIDW	0.95 – 1.05 pu	0.90 – 1.05 pu
SUNC	0.95 – 1.05 pu	0.90 – 1.05 pu
KCPL	0.95 – 1.05 pu	0.90 – 1.05 pu

INDN	0.95 – 1.05 pu	0.90 – 1.05 pu
SPRM	0.95 – 1.05 pu	0.90 – 1.05 pu
NPPD	0.95 – 1.05 pu	0.90 – 1.05 pu
WAPA	0.95 – 1.05 pu	0.90 – 1.05 pu
WERE L-V	0.95 – 1.05 pu	0.93 – 1.05 pu
WERE H-V	0.95 – 1.05 pu	0.95 – 1.05 pu
EMDE L-V	0.95 – 1.05 pu	0.90 – 1.05 pu
EMDE H-V	0.95 – 1.05 pu	0.92 – 1.05 pu
LES	0.95 – 1.05 pu	0.90 – 1.05 pu
OPPD	0.95 – 1.05 pu	0.90 – 1.05 pu

SPP Buses with more stringent voltage criteria:

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

Affected System Areas (115kV+):

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

The constraints identified through the voltage scan are then screened for the following for each interconnection request. 1) 3% DF on the contingent element and 2) 2% change in pu voltage. In certain conditions, engineering judgement was used to determine whether or not a generator had impacts to voltage constraints.

Dynamic Stability

Stability issues considered for transmission reinforcement under ERIS. Generators that fail to meet low voltage ride-through requirements (FERC Order #661-A) or SPP's stability criteria for damping or dynamic voltage recovery are assigned upgrades such that these requirements can be met.

Upgrades Assigned

Thermal overloads that require transmission support to mitigate are discussed in Power Flow Results Section and listed in Appendix G-T. Voltage constraints that may require transmission support are discussed in Section 8 and listed in Appendix G-V (Cluster Analysis). Constraints that are identified solely through the stability analysis are discussed in Section 8 and the appropriate appendix for the detailed stability study of that Interconnection Request. All of these upgrades are cost assigned in Appendix E and Appendix F.

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 2017 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:

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

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

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

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

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

- 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 2,535.89 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 estimated at $16,992,980 for Group 6 and GEN-2015-004 Interconnection Customers and $102,714,177 for all DISIS-2015-001 Interconnection Customers. 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”. If the one-lines and costs in Appendix D have been updated by the Transmission Owner’s Interconnection Facilities Study, those costs will be noted in the appendix. 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 2016 winter peak (16WP) season, the 2017 spring (17G) and 2017 summer peak (17SP) seasons, the 2020 light load (20L), summer (20SP) and winter peak (20WP) seasons, and the 2025 summer peak (25SP) seasonal 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 ERIS. Certain requests that are also pursuing 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 3,514.70 MW of previously queued generation in the area, 161.0 MW of new interconnection service was studied. This group was not analyzed for this restudy and previously identified results remain valid.

Cluster Group 2 (Hitchland Area)

In addition to the 3,626.2 MW of previously queued generation in the area, 0.0 MW of new interconnection service was studied. All Interconnection Requests in Group 2 have withdrawn from the study. No additional analysis was performed for Group 2.

Cluster Group 3 (Spearville Area)

In addition to the 3,204.8 MW of previously queued generation in the area, 26.13 MW of new interconnection service was studied. This group was not analyzed for this restudy and previously identified results remain valid.

Cluster Group 4 (Northwest Kansas Area)

In addition to the 1,462.2 MW of previously queued generation in the area, 0.0 MW of new interconnection service was studied. This group was not analyzed for this restudy and previously identified results remain valid.

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

In addition to the 4,134.77 MW of previously queued generation in the area, 264.0 MW of new interconnection service was studied.

A low steady state voltage constraint for the outage of Border to Woodward 345kV is observed in this restudy. To mitigate the constraint the need for capacitive reactive power at Oklaunion is required.

Due to the withdrawal of GEN-2014-074, GEN-2015-022's NRIS material modification request will be updated and provided in a separate report.

It should be noted that higher queued assigned network upgrades are considered in this analysis based on higher queued Interconnection Request(s) assignment. If higher queued Interconnection Request(s) withdraw from the SPP GI queue or terminate their Generator Interconnection Agreement (GIA), a restudy will be needed for this group to determine network upgrade need changes.

For Group 6 Cluster analysis cost allocation, please refer to Appendix E and F.

Cluster ERIS Constraints			
MONITORED ELEMENT	**Limiting Rate A/B (MVA)**	**TC%LOADING (% MVA)**	**CONTINGENCY**
Currently none			

Cluster NRIS Constraints			
MONITORED ELEMENT	**Limiting Rate A/B (MVA)**	**TC%LOADING (% MVA)**	**CONTINGENCY**
Currently no Group 6 NRIS requests			

After thermal constraints for transmission reinforcement upgrades were mitigated, the following steady -state voltage violations require mitigation. An additional 50 Mvars at the Oklaunion 345kV capacitor bank(s) will be required to mitigate the steady state voltage observed after contingency.

Cluster ERIS Voltage Constraints				
MONITORED ELEMENT	**TC Voltage (PU)**	**VMIN (PU)**	**VMAX (PU)**	**CONTINGENCY**
OKLAUNION 345KV	0.910262	0.92	1.05	BORDER 7345.00 - WOODWARD DISTRICT EHV 345KV CKT 1
	Mitigation			**Add additional 50Mvars at Oklaunion 345kV**

Group 6 (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
ASGI-2015-002	2	Oklaunion voltage
GEN-2015-014	130	Oklaunion voltage
GEN-2015-022	100	Oklaunion voltage

Cluster Group 7 (Southwestern Oklahoma Area)

In addition to the 1,751.00 MW of previously queued generation in the area, 172.90 MW of new interconnection service was studied. GEN-2015-004 was shown to have impacts on Group 6 Interconnection Request constraints for the outage of the Border-Woodward 345kV line. The mitigation is to add a 345kV capacitor bank at Oklaunion. This upgrade is shared with Group 6 Interconnection Requests. GEN-2015-013 was not re-evaluated for impacts.

Cluster ERIS Voltage Constraints				
MONITORED ELEMENT	TC Voltage (PU)	VMIN (PU)	VMAX (PU)	CONTINGENCY
OKLAUNION 345KV	0.910262	0.92	1.05	BORDER 7345.00 - WOODWARD DISTRICT EHV 345KV CKT 1
	Mitigation			Add additional 50Mvars at Oklaunion 345kV

Group 7 (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-2015-004	47	Oklaunion voltage

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

In addition to the 3,975.0 MW of previously queued generation in the area, 1,251.06 MW of new interconnection service was studied. This group was not analyzed for this restudy and previously identified results remain valid.

Cluster Group 9 (Nebraska Area)

In addition to the 2,467.0 MW of previously queued generation in the area, 460.70 MW of new interconnection service was studied. This group was not analyzed for this restudy and previously identified results remain valid.

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, 0.0 MW of new interconnection service was studied. All Interconnection Requests in Group 12 have withdrawn from the study. No additional analysis was performed for Group 12.

Cluster Group 13 (Northeast Kansas/Northwest Missouri Area)

In addition to the 434.6 MW of previously queued generation in the area, 200.1 MW of new interconnection service was studied. This group was not analyzed for this restudy and previously identified results remain valid.

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 new constraints were found in this area.

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

For this restudy, a stability and short circuit analysis was conducted for Group 6 which had significant changes due to Interconnection Request withdrawals. For those groups, each Interconnection Request was studied using modified versions of the 2015 series SPP Model Development Working Group (MDWG) Models 2016 winter, 2017 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 was not performed again for this restudy. The original analysis in DISIS-2015-001 is still valid.

Cluster Group 2 (Hitchland Area)

No Interconnection Requests remained in Group 2.

Cluster Group 3 (Spearville Area)

The Group 3 stability analysis was not performed again for this restudy. The analysis in DISIS-2015-001-1 is still valid.

Cluster Group 4 (Northwest Kansas)

The Group 4 stability analysis was not performed again for this restudy. The original analysis in DISIS-2015-001 is still valid.

Cluster Group 6 (South Texas Panhandle/New Mexico)

The Group 6 stability analysis for this area was performed by SPP Staff to determine the sensitivity of the withdrawn Interconnection Requests. Stability analysis has determined with all previously assigned Network Upgrades in service, all generators in the monitored areas remained stable and within the pre-contingency, voltage recovery, and post fault voltage recovery criterion of 0.7pu to 1.2pu for the entire modeled disturbances.

[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.

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-2015-014	150.0	Vestas V110 2.0MW	Tap on Cochran – LG Plains 115kV	0.95	0.95
GEN-2015-022	112.0	GE LV5 4.0MW Inverters	Swisher 115kV	0.95	0.95
ASGI-2015-002	2.0	GE 2.0MW	Yuma Interchange 115/69kV	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.

Cluster Group 7 (Southwest Oklahoma)

The Group 7 stability analysis was not performed again for this restudy. The original analysis in DISIS-2015-001 is still valid.

Cluster Group 8 (South Central Kansas/North Oklahoma)

The Group 8 stability analysis was not performed again for this restudy. The original analysis in DISIS-2015-001-1 is still valid.

Cluster Group 9 (Nebraska)

The Group 9 stability analysis was not performed again for this restudy. The analysis in DISIS-2015-001-1 is still valid.

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)

No remaining Interconnection Requests in Group 12.

Cluster Group 13 (Northwest Missouri Area)

The Group 13 stability analysis was not performed again for this restudy. The original analysis in DISIS-2015-001 is still valid.

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 2,765.79 MW of new generation interconnection requests included in this Definitive Interconnection System Impact Study is estimated at $16,992,980 for Group 6 as listed in listed in Appendix E and F and GEN-2015-004 Interconnection Customers and $102,714,177 for all DISIS-2015-001 Interconnection Customers. 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-duty 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.

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-2015-004	56.36	ER	GRDA	Coffeyville City 69kV	Coffeyville City 69kV		TBD
GEN-2015-001	200.00	ER	OKGE	Ranch Road 345kV	Ranch Road 345kV	12/31/2016	TBD
GEN-2015-004	52.90	ER	OKGE	Border 345kV	Border 345kV	5/15/2017	TBD
GEN-2015-005	200.10	ER	KCPL	Tap Nebraska City - Sibley 345kV	Tap Nebraska City - Sibley 345kV	12/31/2017	TBD
GEN-2015-007	160.00	ER	NPPD	Hoskins 345kV	Hoskins 345kV	12/31/2016	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-2015-021	20.00	ER/NR	SUNCMKEC	Johnson Corner 115kV	Johnson Corner 115kV	12/31/2016	TBD
GEN-2015-022	112.00	ER	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-2015-029	161.00	ER	OKGE	Tatonga 345kV	Tatonga 345kV	12/1/2016	TBD
GEN-2015-030	200.10	ER	OKGE	Sooner 345kV	Sooner 345kV	12/1/2017	TBD
Total:	2,535.89						

*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	Remington 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 69kV	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-2014-014	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	Weatherford 138kV	On-Line
GEN-2004-014	154.50	SUNCMKEC	Spearville 230kV	On-Line at 100MW
GEN-2004-020	27.00	AEPW	Weatherford 138kV	On-Line
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

Request	Amount	Area	Requested/Proposed Point of Interconnection	Status or In-Service Date
GEN-2005-013	201.00	WERE	Caney River 345kV	On-Line
GEN-2006-002	101.00	AEPW	Sweetwater 230kV	On-Line
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-2007-017IS	166.00	WAPA	Ft Thompson-Grand Island 345kV	On Schedule
GEN-2007-018IS	234.00	WAPA	Ft Thompson-Grand Island 345kV	On Schedule
GEN-2007-021	201.00	OKGE	Tatonga 345kV	On-Line
GEN-2007-025	300.00	WERE	Viola 345kV	On-Line
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-Line
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	425.00	OKGE	Woodward EHV 345kV	On-Line for 225MW, On Schedule 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-2008-018	250.00	SPS	Finney 345kV	On-Line
GEN-2008-021	42.00	WERE	Wolf Creek 345kV	On-Line
GEN-2008-022	300.00	SPS	Crossroads 345kV	On-Line
GEN-2008-023	150.00	AEPW	Hobart Junction 138kV	On-Line
GEN-2008-037	101.00	WFEC	Slick Hills 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	200.60	MIDW	Post Rock 230kV	On-Line
GEN-2008-098	100.80	WERE	Waverly 345kV	On-Line
GEN-2008-119O	60.00	OPPD	S1399 161kV	On-Line
GEN-2008-123N	89.70	NPPD	Tap Pauline - Guide Rock (Rosemont) 115kV	On Schedule for 2016
GEN-2008-124	200.10	SUNCMKEC	Ironwood 345kV	On Schedule for 2016
GEN-2008-129	80.00	KCPL	Pleasant Hill 161kV	On-Line
GEN-2009-008	199.50	MIDW	South Hays 230kV	On-Line
GEN-2009-020	48.30	MIDW	Walnut Creek 69kV	On-Line

Request	Amount	Area	Requested/Proposed Point of Interconnection	Status or In-Service Date
GEN-2009-025	59.80	OKGE	Nardins 69kV	On-Line
GEN-2009-040	73.80	WERE	Marshall 115kV	On-Line
GEN-2010-001	300.00	OKGE	Beaver County 345kV	On-Line
GEN-2010-003	100.80	WERE	Waverly 345kV	On-Line
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 Schedule for 2018
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 Suspension
GEN-2010-046	56.00	SPS	TUCO Interchange 230kV	On Schedule for 2016
GEN-2010-051	200.00	NPPD	Tap Hoskins - Twin Church (Dixon County) 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-Line
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-Line
GEN-2011-016	200.10	SUNCMKEC	Ironwood 345kV	On Suspension
GEN-2011-018	73.60	NPPD	Steele City 115kV	On-Line
GEN-2011-019	175.00	OKGE	Woodward 345kV	On Schedule for 2017
GEN-2011-020	165.60	OKGE	Woodward 345kV	On Schedule for 2017
GEN-2011-022	299.00	SPS	Hitchland 345kV	On Schedule for 2016 (150MW) and 2017 (149MW)
GEN-2011-025	80.00	SPS	Tap Floyd County - Crosby County 115kV	On Schedule for 2016
GEN-2011-027	120.00	NPPD	Tap Hoskins - Twin Church (Dixon County) 230kV	On Schedule for 2018
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-Line
GEN-2011-054	300.00	OKGE	Cimarron 345kV	On-Line
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-Line
GEN-2012-001	61.20	SPS	Cirrus Tap 230kV	On-Line
GEN-2012-004	41.40	OKGE	Carter County 138kV	On-Line
GEN-2012-007	120.00	SUNCMKEC	Rubart 115kV	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-2012-028	74.80	WFEC	Gotebo 69kV	On-Line
GEN-2012-032	300.00	OKGE	Open Sky 345kV	On-Line

Request	Amount	Area	Requested/Proposed Point of Interconnection	Status or In-Service Date
GEN-2012-033	98.10	OKGE	Tap and Tie South 4th - Bunch Creek & Enid Tap - Fairmont (GEN-2012-033T) 138kV	On-Line
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-2012-041	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 Suspension
GEN-2013-007	100.30	OKGE	Tap Prices Falls - Carter 138kV	On-Line
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	On Suspension
GEN-2013-011	30.00	AEPW	Turk 138kV	On-Line
GEN-2013-012	147.00	OKGE	Redbud 345kV	On-Line
GEN-2013-016	203.00	SPS	TUCO 345kV	On Schedule for 2017
GEN-2013-019	73.60	LES	Tap Sheldon - Folsom & Pleasant Hill (GEN-2013-002 Tap) 115kV CKT 2	On Suspension
GEN-2013-022	25.00	SPS	Norton 115kV	On-Line
GEN-2013-027	150.00	SPS	Tap Tolk - Yoakum 230kV	On Schedule for 2018
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-Line for 151.6MW
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	Knoll 115kV	On-Line
GEN-2014-001	200.60	WERE	Tap Wichita - Emporia Energy Center (GEN-2014-001 Tap) 345kV	On Suspension
GEN-2014-002	10.50	OKGE	Tatonga 345kV (GEN-2007-021 POI)	On Schedule for 2015
GEN-2014-003	15.80	OKGE	Tatonga 345kV (GEN-2007-044 POI)	On Schedule for 2015
GEN-2014-004	4.00	NPPD	Steele City 115kV (GEN-2011-018 POI)	On-Line
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	On Suspension
GEN-2014-013	73.50	NPPD	Meadow Grove (GEN-2008-086N2 Sub) 230kV	On-Line
GEN-2014-020	100.00	AEPW	Tuttle 138kV	On Schedule for 2017
GEN-2014-021	300.00	KCPL	Tap Nebraska City - Mullin Creek 345kV	On Schedule for 2016
GEN-2014-025	2.40	MIDW	Walnut Creek 69kV	On-Line
GEN-2014-028	35.00	EMDE	Riverton 161kV	On-Line
GEN-2014-031	35.80	NPPD	Meadow Grove 230kV	On-Line
GEN-2014-032	10.20	NPPD	Meadow Grove 230kV	On Schedule for 2016
GEN-2014-033	70.00	SPS	Chaves County 115kV	On-Line
GEN-2014-034	70.00	SPS	Chaves County 115kV	On-Line
GEN-2014-035	30.00	SPS	Chaves County 115kV	On Schedule for 2018
GEN-2014-039	73.40	NPPD	Friend 115kV	On Schedule for 2017
GEN-2014-040	320.40	SPS	Castro 115kV	On-Line
GEN-2014-041	120.80	SUNCMKEC	Arnold 115kV	On Suspension
GEN-2014-047	40.00	SPS	Crossroads 345kV	On Schedule for 2017
GEN-2014-056	250.00	OKGE	Minco 345kV	On Schedule for 2016
GEN-2014-057	250.00	AEPW	Tap Lawton - Sunnyside (Terry Road) 345kV	On-Line
GEN-2014-064	248.40	OKGE	Otter 138kV	On Suspension
Gray County Wind (Montezuma)	110.00	SUNCMKEC	Gray County Tap 115kV	On-Line

Request	Amount	Area	Requested/Proposed Point of Interconnection	Status or In-Service Date
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 (Carson)	10.00	SPS	Martin 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:	**25,212.8**			

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	425.00	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	175.00	OKGE	Woodward 345kV
GEN-2011-020	165.60	OKGE	Woodward 345kV
GEN-2011-054	300.00	OKGE	Cimarron 345kV
GEN-2014-002	10.50	OKGE	Tatonga 345kV (GEN-2007-021 POI)
GEN-2014-003	15.80	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	**3,514.70**		
GEN-2015-029	161.00	OKGE	Tatonga 345kV
CURRENT CLUSTER SUBTOTAL	**161.00**		
AREA TOTAL	**3,675.70**		

GROUP 2: HITCHLAND AREA

Request	Capacity	Area	Proposed Point of Interconnection
ASGI-2011-002	20.00	SPS	Herring 115kV
ASGI-2013-001	11.50	SPS	PanTex South 115kV
GEN-2002-008	240.00	SPS	Hitchland 345kV
GEN-2002-009	80.00	SPS	Hansford 115kV
GEN-2002-022	240.00	SPS	Bushland 230kV
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-2008-051	322.00	SPS	Potter 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
Llano Estacado (White Deer)	80.00	SPS	Llano Wind 115kV
SPS Distributed (Carson)	10.00	SPS	Martin 115kV
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	**3,626.20**		
AREA TOTAL	**3,626.20**		

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-2006-021	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	Ironwood 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
Gray County Wind (Montezuma)	110.00	SUNCMKEC	Gray County Tap 115kV
PRIOR QUEUED SUBTOTAL	**3,204.80**		
ASGI-2015-001	6.13	SUNCMKEC	Ninnescah 115kV
GEN-2015-021	20.00	SUNCMKEC	Johnson Corner 115kV
CURRENT CLUSTER SUBTOTAL	**26.13**		
AREA TOTAL	**3,230.93**		

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-2008-092	200.60	MIDW	Post Rock 230kV
GEN-2009-008	199.50	MIDW	South Hays 230kV
GEN-2009-020	48.30	MIDW	Walnut Creek 69kV
GEN-2010-057	201.00	MIDW	Rice County 230kV
GEN-2013-033	28.00	MIDW	Knoll 115kV
GEN-2014-025	2.40	MIDW	Walnut Creek 69kV
GEN-2014-041	120.80	SUNCMKEC	Arnold 115kV
PRIOR QUEUED SUBTOTAL	**1,462.20**		
AREA TOTAL	**1,462.20**		

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 69kV
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
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	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-2012-020	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-2014-040	320.40	SPS	Castro 115kV
GEN-2014-047	40.00	SPS	Crossroads 345kV
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	**4,134.77**		
ASGI-2015-002	2.00	SPS	SP-Yuma 69kV
GEN-2015-014	150.00	SPS	Tap Cochran - Lehman 115kV
GEN-2015-022	112.00	SPS	Swisher 115kV
CURRENT CLUSTER SUBTOTAL	**264.00**		
AREA TOTAL	**4,398.77**		

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	Weatherford 138kV
GEN-2004-020	27.00	AEPW	Weatherford 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-2007-052	150.00	WFEC	Anadarko 138kV
GEN-2008-023	150.00	AEPW	Hobart Junction 138kV
GEN-2008-037	101.00	WFEC	Slick Hills 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	**1,751.00**		
GEN-2015-004	52.90	OKGE	Border 345kV
GEN-2015-013	120.00	WFEC	Synder 138kV
CURRENT CLUSTER SUBTOTAL	**172.90**		
AREA TOTAL	**1,923.90**		

GROUP 8: NORTH OKLAHOMA/SOUTH CENTRAL KANSAS AREA

Request	Capacity	Area	Proposed Point of Interconnection
ASGI-2010-006	150.00	AECI	Remington 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-2012-032	300.00	OKGE	Open Sky 345kV
GEN-2012-033	98.10	OKGE	Tap and Tie South 4th - Bunch Creek & Enid Tap - Fairmont (GEN-2012-033T) 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 (GEN-2014-001 Tap) 345kV
GEN-2014-028	35.00	EMDE	Riverton 161kV
GEN-2014-064	248.40	OKGE	Otter 138kV
PRIOR QUEUED SUBTOTAL	**3,975.00**		
ASGI-2015-004	56.36	GRDA	Coffeyville City 69kV
GEN-2015-001	200.00	OKGE	Ranch Road 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-2015-030	200.10	OKGE	Sooner 345kV
CURRENT CLUSTER SUBTOTAL	**1,251.06**		
AREA TOTAL	**5,226.06**		

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-2007-017IS	166.00	WAPA	Ft Thompson-Grand Island 345kV
GEN-2007-018IS	234.00	WAPA	Ft Thompson-Grand Island 345kV
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 - Guide Rock (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 Hoskins - Twin Church (Dixon County) 230kV
GEN-2011-018	73.60	NPPD	Steele City 115kV
GEN-2011-027	120.00	NPPD	Tap Hoskins - Twin Church (Dixon County) 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-2013-019	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	**2,467.00**		
GEN-2015-007	160.00	NPPD	Hoskins 345kV
GEN-2015-023	300.70	NPPD	Holt County 345kV
CURRENT CLUSTER SUBTOTAL	**460.70**		
AREA TOTAL	**2,927.70**		

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**		
AREA TOTAL	**30.00**		

GROUP 13: NORTHWEST MISSOURI AREA

Request	Capacity	Area	Proposed Point of Interconnection
GEN-2008-129	80.00	KCPL	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	KCPL	Tap Nebraska City - Mullin Creek 345kV
PRIOR QUEUED SUBTOTAL	**434.60**		
GEN-2015-005	200.10	KCPL	Tap Nebraska City - Sibley 345kV
CURRENT CLUSTER SUBTOTAL	**200.10**		
AREA TOTAL	**634.70**		

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 (Terry Road) 345kV
PRIOR QUEUED SUBTOTAL	**612.50**		
AREA TOTAL	**612.50**		

GROUP 15: E-SOUTH DAKOTA AREA

Request	Capacity	Area	Proposed Point of Interconnection
AREA TOTAL	0.00		

GROUP 16: W-NORTH DAKOTA AREA

Request	Capacity	Area	Proposed Point of Interconnection
AREA TOTAL	0.00		

GROUP 17: W-SOUTH DAKOTA AREA

Request	Capacity	Area	Proposed Point of Interconnection
AREA TOTAL	0.00		

GROUP 18: E-NORTH DAKOTA AREA

Request	Capacity	Area	Proposed Point of Interconnection
AREA TOTAL	0.00		

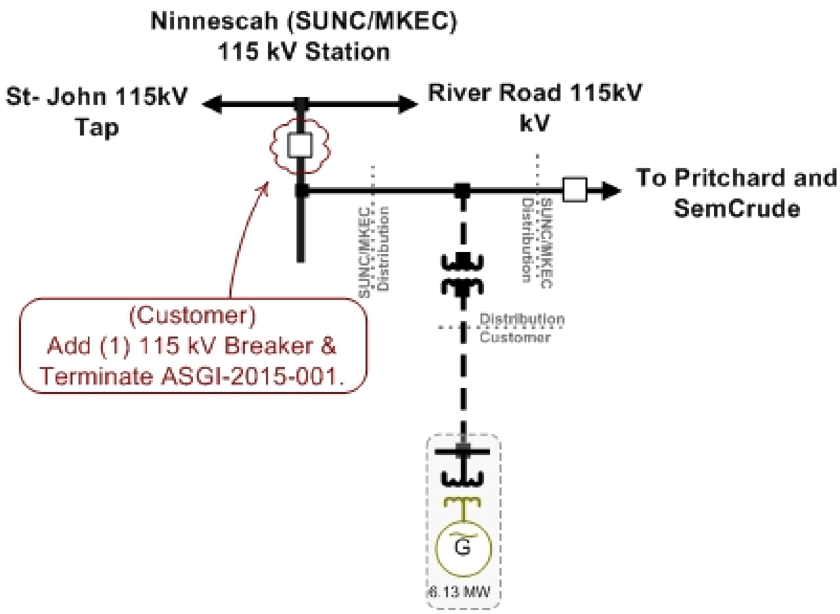
CLUSTER TOTAL (CURRENT STUDY)	2,535.9	MW
PQ TOTAL (PRIOR QUEUED)	25,212.8	MW
CLUSTER TOTAL (INCLUDING PRIOR QUEUED)	27,748.7	MW

D: Proposed Point of Interconnection One Line Diagrams

See next page

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

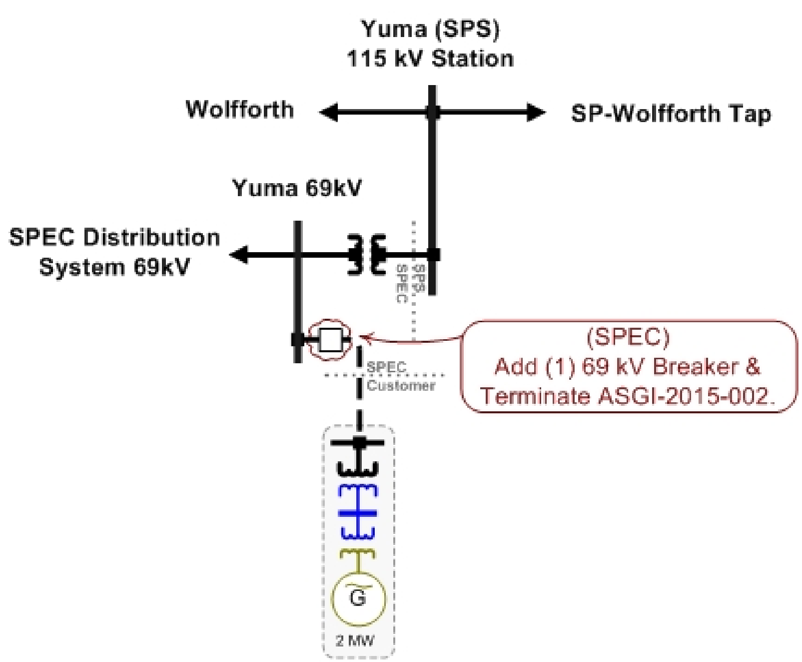
ASGI-2015-001
Estimated Cluster Analysis Interconnection Cost: $3,188,259
Estimated Stand Alone Analysis Interconnection Cost: $3,188,259



ASGI-2015-001

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

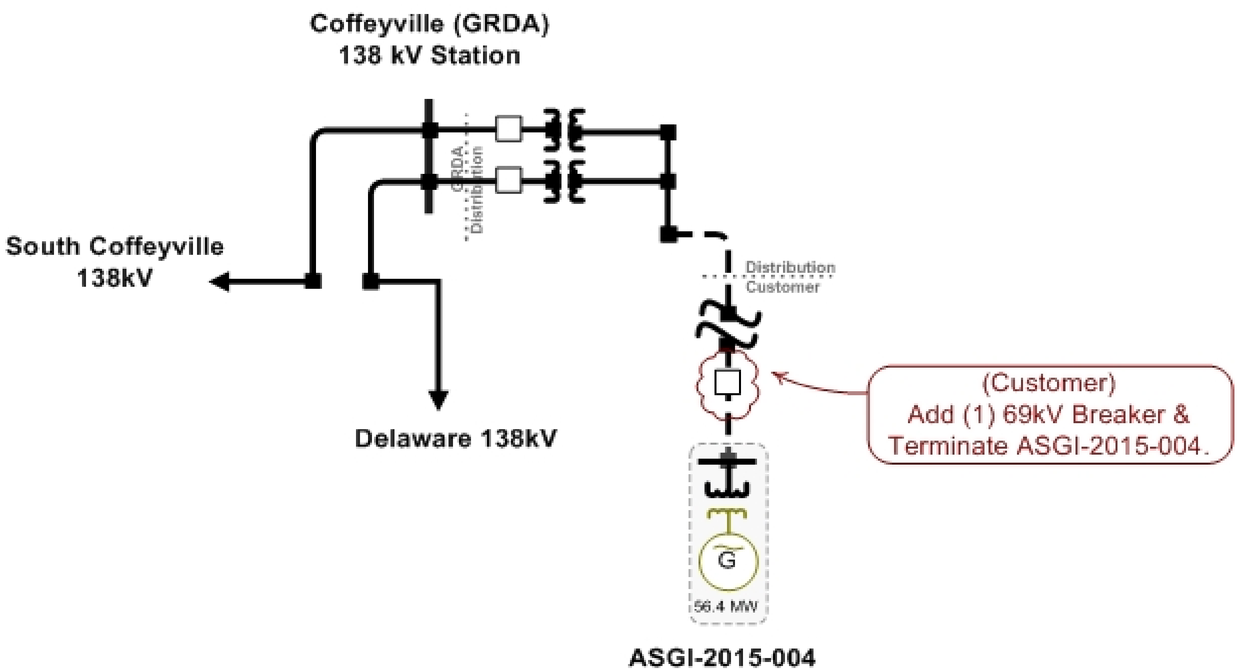
ASGI-2015-002
Estimated Cluster Analysis Interconnection Cost: $0*
Estimated Stand Alone Analysis Interconnection Cost: $0*



ASGI-2015-002

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

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-2015-001

See Posted Interconnection Facilties Study for GEN-2015-001

GEN-2015-004

See Posted Interconnection Facilties Study for GEN-2015-004

GEN-2015-005

See Posted Interconnection Facilties Study for GEN-2015-005

GEN-2015-007

See Posted Interconnection Facilties Study for GEN-2015-007

GEN-2015-013

See Posted Interconnection Facilties Study for GEN-2015-013

GEN-2015-014

See Posted Interconnection Facilties Study for GEN-2015-014

GEN-2015-015

See Posted Interconnection Facilties Study for GEN-2015-015

GEN-2015-016

See Posted Interconnection Facilties Study for GEN-2015-016

GEN-2015-021

See Posted Interconnection Facilties Study for GEN-2015-021

GEN-2015-022

See Posted Interconnection Facilties Study for GEN-2015-022

GEN-2015-023

See Posted Interconnection Facilties Study for GEN-2015-023

GEN-2015-024

See Posted Interconnection Facilties Study for GEN-2015-024

GEN-2015-025

See Posted Interconnection Facilties Study for GEN-2015-025

GEN-2015-029

See Posted Interconnection Facilties Study for GEN-2015-029

GEN-2015-030

See Posted Interconnection Facilties Study for GEN-2015-030

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-2015-002			
ASGI-2015-002 Interconnection Costs See One-Line Diagram.	Current Study	$0	$0
Oklaunion 345kV Reactive Power Install (2)-50Mvar Capacitor Bank(s) at Oklaunion.	Current Study	$43,424	$8,654,413
Amoco Wasson - Oxy Tap 230kV CKT 1 Replace line traps at both terminals	Previously Allocated		$200,000
National Enrichment Plant-Targa 115kV CKT 1 Rebuild approximately 4 miles of 115kV from National Enrichment Plant to Targa per 2015 ITPNT.	Previously Allocated		$2,909,669
Targa-Cardinal 115kV CKT 1 Rebuild approximately 3 miles of 115kV from Targa to Cardinal per 2015 ITPNT.	Previously Allocated		$2,049,062
Tolk - Plant X 230kV CKT 1 & 2 Rebuild circuit 1 and 2 betweek Tolk - Plant X 230kV to 1200 amps each.	Previously Allocated		$9,921,693
	Current Study Total	$43,424	
GEN-2015-004			
GEN-2015-004 Interconnection Costs See One-Line Diagram.	Current Study	$0	$0
Oklaunion 345kV Reactive Power Install (2)-50Mvar Capacitor Bank(s) at Oklaunion.	Current Study	$3,816,914	$8,654,413
	Current Study Total	$3,816,914	
GEN-2015-014			
GEN-2015-014 Interconnection Costs See One-Line Diagram.	Current Study	$4,773,333	$4,773,333
Oklaunion 345kV Reactive Power Install (2)-50Mvar Capacitor Bank(s) at Oklaunion.	Current Study	$2,927,012	$8,654,413
National Enrichment Plant-Targa 115kV CKT 1 Rebuild approximately 4 miles of 115kV from National Enrichment Plant to Targa per 2015 ITPNT.	Previously Allocated		$2,909,669
Tolk - Plant X 230kV CKT 1 & 2 Rebuild circuit 1 and 2 betweek Tolk - Plant X 230kV to 1200 amps each.	Previously Allocated		$9,921,693
	Current Study Total	$7,700,345	

* 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-2015-022			
GEN-2015-022 Interconnection Costs See One-Line Diagram.	Current Study	$3,565,234	$3,565,234
Oklaunion 345kV Reactive Power Install (2)-50Mvar Capacitor Bank(s) at Oklaunion.	Current Study	$1,867,063	$8,654,413
TUCO 345/230/13.2kV CKT 1 Replace existing TUCO 345/230/13.2kV Transformer circuit #1 with 700MVA.	Previously Allocated		$3,347,036
Wolfforth - Terry County 115kV CKT 1 NRIS only required upgrade: Per SPP-NTC-200395	Previously Allocated		$1,461,643
	Current Study Total	$5,432,297	
	TOTAL CURRENT STUDY COSTS:	**$16,992,980**	

* 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-2015-002 Interconnection Costs			**$0**
See One-Line Diagram.			
	ASGI-2015-002	$0	
	Total Allocated Costs	**$0**	
GEN-2015-004 Interconnection Costs			**$0**
See One-Line Diagram.			
	GEN-2015-004	$0	
	Total Allocated Costs	**$0**	
GEN-2015-014 Interconnection Costs			**$4,773,333**
See One-Line Diagram.			
	GEN-2015-014	$4,773,333	
	Total Allocated Costs	**$4,773,333**	
GEN-2015-022 Interconnection Costs			**$3,565,234**
See One-Line Diagram.			
	GEN-2015-022	$3,565,234	
	Total Allocated Costs	**$3,565,234**	
Oklaunion 345kV Reactive Power			**$8,654,413**
Install (2)-50Mvar Capacitor Bank(s) at Oklaunion.			
	ASGI-2015-002	$43,424	
	GEN-2015-004	$3,816,914	
	GEN-2015-014	$2,927,012	
	GEN-2015-022	$1,867,063	
	Total Allocated Costs	**$8,654,413**	

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

G-T: Power Flow Thermal Analysis (Constraints Requiring Transmission Reinforcement)

See next page.

SOLUTION	GROUP	SCENARIO	SEASON	SOURCE	DIRECTION	MONITORED ELEMENT	RATEA (MVA)	RATEB(MVA)	TDF	TC%LOADING (% MVA)	CONTINGENCY
						Currently no thermal constraints for DISIS-2015-001-3 Group 06					

G-V: Power Flow Steady State Voltage Analysis (Constraints Requiring Transmission Reinforcement)

See next page.

SOLUTION	GROUP	SCENARIO	SEASON	SOURCE	MONITORED ELEMENT	BC Voltage (PU)	TC Voltage (PU)	Voltage Differ (PU)	VINIT (PU)	VMIN (PU)	VMAX(PU)	TDF	CONTINGENCY	COMMENTS
FDNS	06ALL	0	20L	ASGI_15_02	OKLAUNION 345KV	0.946489	0.910262	0.036227	0.96877	0.92	1.05	0.19094	BORDER 7345.00 - WOODWARD DISTRICT EHV 345KV CKT 1	Current Study Upgrade: Oklaunion capacitor bank addition
FDNS	06ALL	0	20L	G15_004	OKLAUNION 345KV	0.946489	0.910262	0.036227	0.96877	0.92	1.05	0.68279	BORDER 7345.00 - WOODWARD DISTRICT EHV 345KV CKT 1	Current Study Upgrade: Oklaunion capacitor bank addition
FDNS	06ALL	0	20L	G15_014	OKLAUNION 345KV	0.946489	0.910262	0.036227	0.96877	0.92	1.05	0.18183	BORDER 7345.00 - WOODWARD DISTRICT EHV 345KV CKT 1	Current Study Upgrade: Oklaunion capacitor bank addition
FDNS	06ALL	0	20L	G15_022	OKLAUNION 345KV	0.946489	0.910262	0.036227	0.96877	0.92	1.05	0.13881	BORDER 7345.00 - WOODWARD DISTRICT EHV 345KV CKT 1	Current Study Upgrade: Oklaunion capacitor bank addition

H: Power Flow Analysis (Other Constraints Not Requiring Transmission Reinforcement)

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 6 Dynamic Stability Analysis Report

See SPP report next page.

Group 6 Stability Impact Study

DISIS-2015-001-3

September 2017
Generation Interconnection

Southwest Power Pool

Revision History

Date	Author	Change Description
9/1/2017	SPP	DISIS-2015-001-3 Group 6 Stability Report Issued

Southwest Power Pool

Executive Summary

DISIS-2015-001-3 Group 6 Interconnection Customers have requested a Definitive Interconnection System Impact Study detailing the impacts of interconnecting the generation projects shown below.

- GEN-2015-014 – 150.0 MW wind generation facility using seventy-five (75) Vestas V110 2.0 MW wind turbine generators interconnecting to the Southwest Public Service (SPS) transmission system at the existing Lehman 115 kV station.
- GEN-2015-022 – 112.0 MW solar generation facility using twenty-eight (28) GE LV5 4.0 MW inverters interconnecting to the Southwest Public Service (SPS) transmission system at the existing Swisher 115 kV station.
- ASGI-2015-002 – 2.0 MW wind generation facility using one (1) GE 2.0 MW wind turbine generator interconnecting to the South Plains Electric Cooperative (SPEC) transmission system at the existing SPEC Yuma 69 kV station.

A stability cluster impact analysis was performed for the generation project from the DISIS-2015-001-3 Group 6 study. The analysis was performed on five (5) seasonal models including 2016 winter peak (16WP), the 2017 summer peak (17SP), 2020 summer peak (20SP), 2020 winter peak (20WP) and the 2025 summer peak (25SP) cases. These cases are modified versions of the 2015 model series of Model Development Working Group (MDWG) dynamic study models. A total of one-hundred-twenty-one (121) contingencies were evaluated for the five (5) seasonal cases.

Stability analysis has determined with all previously assigned Network Upgrades in service, all generators in the monitored areas remained stable and within the pre-contingency, voltage recovery, and post fault voltage recovery criterion of 0.7pu to 1.2pu for the entire modeled disturbances. Under certain system conditions the interconnection requests may be required to curtail generation output to maintain system reliability.

Power factor analysis for each generation project was performed on the current study 2016 winter peak, 2017 summer peak, 2020 summer peak, 2020 winter pea and 2025 summer peak cases with identified system upgrades. 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.

The reduced generation analysis was conducted for wind farms and solar farms to determine reactor inductive amounts to compensate the capacitive effects on the transmission system during low or reduced generation conditions. The capacitive effect is caused by the interconnecting project's generator lead transmission line and collector systems. Each request may be required to install the following reactors on their facilities: GEN-2015-014 –7.0 Mvar and GEN-2015-022 – 1.8 Mvar.

Short Circuit analysis was conducted using the current study upgrade 2017 summer peak and 2025 summer peak cases.

Nothing in this study should be construed as a guarantee of delivery or transmission service. If the customer wishes to sell power from the facility, a separate request for transmission service must be requested on Southwest Power Pool's OASIS by the Customer.

Table of Contents

1. Introduction

DISIS-2015-001-3 Group 6 Interconnection Customers have requested a Definitive Interconnection System Impact Study detailing the impacts of interconnecting the generation projects shown **Table 1-1** below.

Table 1-1: Group 6 Interconnection Requests

Request	Capacity (MW)	Generator Model	Point of Interconnection
GEN-2015-014	150	Vestas V110 2MW (wind)	Lehman 115kV (560030)
GEN-2015-022	112	GE LV5 4MW (solar)	Swisher 115kV (525212)
ASGI-2015-002	2	GE 2.0MW (wind)	Yuma Interchange 115/69kV (526469)

The previously queued generation projects in the Group 6 area are listed in **Table 1-2** below.

Table 1-2: Prior Queued Projects

Request	Size (MW)	Generator Model	Point of Interconnection
GEN-2001-033	180	Mitsubishi 1000 (524896, 524890)	San Juan Mesa 230kV (524885)
GEN-2001-036	80	Mitsubishi 1000 (583316)	Norton 115kV (524502)
GEN-2006-018	170	GENSAL (525841, 525842, 525843)	TUCOTUCO 230kV (525830)
GEN-2006-026	502	GENROU(527901, 527902, 527903)	Hobbs 115kV (527891) Hobbs 230kV (527894)
GEN-2008-022	300	Vestas V100 VCSS 2.0MW (577100, 577110, 577120)	Crossroads 345kV (Tap on eddy County – Tolk 345kV line) (527656)
GEN-2010-006	180 Summer 205 Winter	GENROU (526333)	Jones_bus2 230kV (526337)
ASGI-2010-010	42	GENSAL (528334)	Lovington 115kV (528334)
ASGI-2010-020	29.9	GE 2.3MW (580088)	Tap on LE-Tatum – LE-Crossroads 69kV line (560360)
ASGI-2010-021	15	Mitsubishi MPS-1000A 1.0MW (580083)	Tap on LE-Saundrtp – LE-Anderson 69kV line (560364)
GEN-2010-046	56	GENSAL (580043)	TUCOTUCO 230kV (525830)
ASGI-2011-001	27.3	Suzlon 2.1 MW (579423)	Lovington 115kV (528334)
ASGI-2011-003	10	Sany 2.0MW (579433)	Hendricks 69kV (525943)
ASGI-2011-004	19.8	Sany 1.8MW (583193, 583196)	Crosby 69kV (525915)
GEN-2011-025	78.76	GE 1.79MW (581140)	Tap on Floyd County – Crosby County 115kV line (562004)
GEN-2011-045	180 Summer 205 Winter	GENROU (526334)	Jones 230kV (526337)
GEN-2011-046	23 Summer 27 Winter	GENROU (524471)	Quay County 115kV (524472)
GEN-2011-048	165 Summer 175 Winter	GENROU (527166)	Mustang 230kV (527151)

Request	Size (MW)	Generator Model	Point of Interconnection
GEN-2012-001	61.2	CCWE 3.6MW (WT4) (599126)	Tap on Grassland – Borden 230kV (526679)
ASGI-2012-002	18.15	Vestas V82 1.65MW (583283)	Clovis 115kV (524808)
GEN-2012-020	477.12	GE 1.68MW (583343, 583346)	TUCOTUCO 230kV (525830)
GEN-2012-034	7MW increase (Pmax = 157MW)	GENROU (527164)	Mustang 230kV (527151)
GEN-2012-035	7MW increase (Pmax = 157MW)	GENROU (527165)	Mustang 230kV (527151)
GEN-2012-036	7MW increase (Pmax = 172MW Summer/182MW Winter)	GENROU (527166)	Mustang 230kV (527151)
GEN-2012-037	196 Summer 203 Winter	GENROU (525844)	TUCOTUCO 345kV (525832)
GEN-2013-016	191 Summer 203 Winter	GENROU (525845)	TUCOTUCO 345kV (525832)
ASGI-2013-002	18.4	Siemens 2.3MW (583613)	Tucumcari 115kV (524509)
ASGI-2013-003	18.4	Siemens 2.3MW (583623)	Clovis 115kV (524808)
ASGI-2013-005	1.65	Vestas V82 1.65MW (583283)	Clovis 115kV (524808)
ASGI-2013-006	2	Gamesa G114 2.0MW (583813)	Erskine 115kV (526109)
GEN-2013-022	24.2	SMA SC-2200-US2.2MW (583313)	Caprock 115kV (524486)
GEN-2013-027	148.35	Vestas V126/V136 GS 3.45MW wind (583843)	Tap on Yoakum to Tolk 230kV (562480)
GEN-2014-012	186 Summer 225 Winter	GENROU (528501)	Tap on Hobbs – Andrews 345kV (operated at 230kV) (528611)
ASGI-2014-001	2.5	GE 107m 2.5 MW (583816)	Erskine 69kV (526109)
GEN-2014-033	70	GE LV5 4MVA& 1MVA 1500V PV and Schneider XC 680 0.68MVA PV Inverter (583953, 583956)	Chaves County 115kV
GEN-2014-034	70	GE LV5 4MVA 1500V PV Inverter (583963)	Chaves County 115kV
GEN-2014-035	30	GE LV5 4MVA 1500V PV Inverter (583973)	Chaves County 115kV
GEN-2014-047	40	AE 500NX 0.5MW PV inverter	Crossroads 345kV

A stability analysis was performed for the addition of the generation projects in Group 6. The analysis was performed on five (5) seasonal models including 2016 winter peak (16WP), the 2017 summer peak (17SP), the 2020 summer peak (20SP), the 2020 winter peak (20WP) and the 2025 summer peak (25SP) cases. These cases are modified versions of the 2015 model series of Model Development Working Group (MDWG) dynamic study models.

The stability analysis determines the impacts of the new interconnecting project on the stability and voltage recovery of the nearby systems and the ability of the interconnecting project to meet FERC Order 661A. If problems with stability or voltage recovery are identified, the need for reactive compensation or system upgrades is investigated. The contingencies listed in **Table 3-1** were used in the stability analysis.

The power factor analysis determines the power factor at the point of interconnection (POI) for the wind interconnection projects for pre-contingency and post-contingency conditions. The contingencies used in the power factor analysis are a subset of the stability analysis contingencies shown in **Table 3-1**.

A reduced generation analysis was conducted for wind farms to determine reactor inductive amounts to compensate the capacitive effects on the transmission system during low or reduced wind conditions cause by the interconnecting project's generator lead transmission line and collector systems. **Table 5-1** displays the minimum reactor inductive amount requirement to compensate capacitive effects from the GEN-2015-014 and GEN-2015-022 facilities.

Short Circuit analysis was conducted using the current study upgrade 2025 summer peak case. The results from the Short circuit analysis are show in Appendix F.

Nothing in this System Impact Study constitutes a request for transmission service or grants the Interconnection Customer any rights to transmission service. If the customer wishes to sell power from the facility, a separate request for transmission service must be requested on Southwest Power Pool's OASIS by the Customer.

2. Facilities

A one-line PSS/E slider drawing from the 16WP case for each of the generation interconnection requests in this study is shown in **Figure 2-1** through **2-3**.

Figure 2-1: GEN-2015-014 One-line Diagram

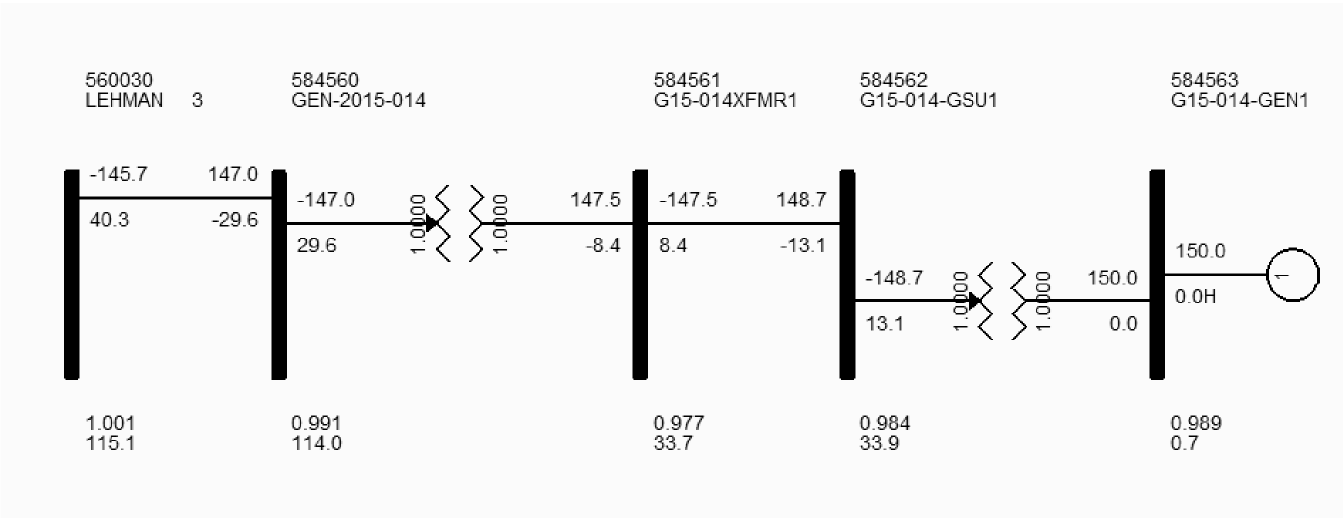


Figure 2-2: GEN-2015-022 One-line Diagram

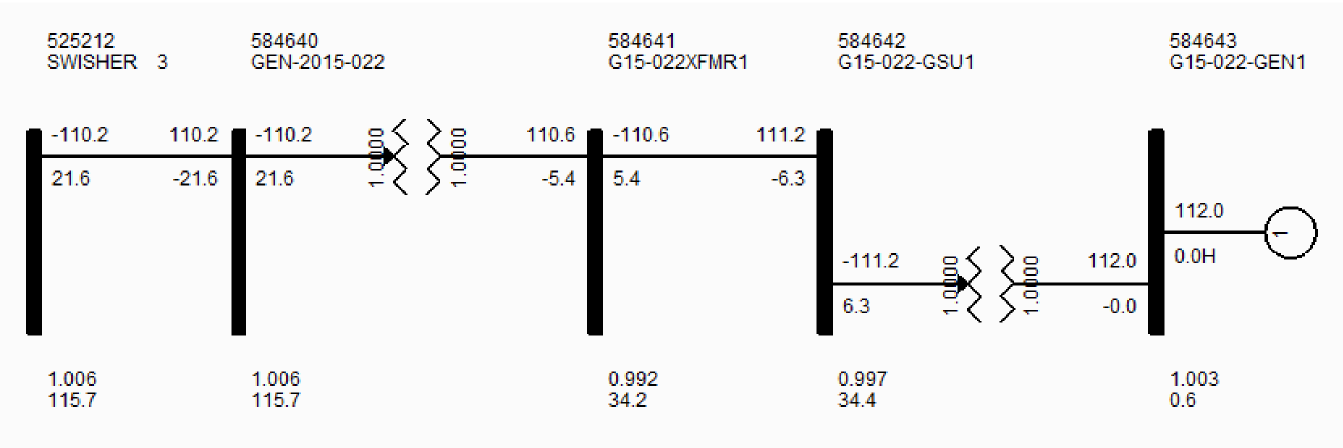
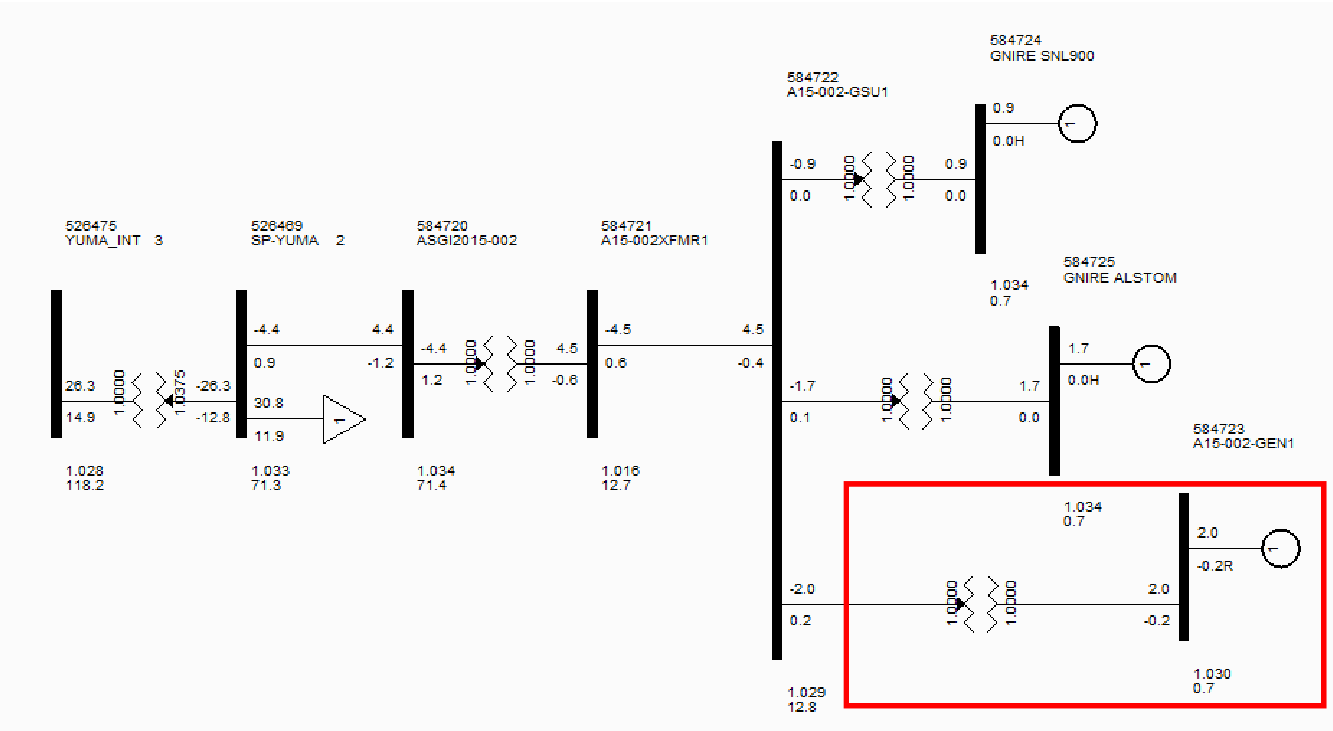


Figure 2-3: ASGI-2015-002 One-line Diagram



3. Stability Analysis

Transient stability analysis is used to determine if the transmission system can maintain angular stability and ensure bus voltages stay within planning criteria bandwidth during and after a disturbance while considering the addition of a generator interconnection request.

Model Preparation

Transient stability analysis was performed using modified versions of the 2015 series of Model Development Working Group (MDWG) dynamic study models including the 2016 winter peak, 2017 summer peak, 2020 summer peak, 2020 winter peak and 2025 summer peak seasonal models. The cases are 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. Initial simulations are then carried out for a no-disturbance run of twenty (20) seconds to verify the numerical stability of the model.

Disturbances

One-hundred-twenty-one (121) contingencies were identified for use in this study and are listed in **Table 3-1**. These contingencies are faults at locations defined by SPP Generation Interconnection Staff. These contingencies include three-phase N-1, single-phase stuck breaker, and three-phase prior outage faults. Single-phase line faults were 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.

Except for transformer faults, the typical sequence of events for a three-phase fault is as follows:

1. apply fault at particular location
2. continue fault for five (5) cycles, clear the fault by tripping the faulted facility
3. after an additional twenty (20) cycles, re-close the previous facility back into the fault
4. continue fault for five (5) additional cycles
5. trip the faulted facility and remove the fault

Transformer faults are typically modeled as three-phase faults, unless otherwise noted. The sequence of events for a transformer fault is as follows:

1. apply fault for five (5) cycles
2. clear the fault by tripping the affected transformer facility (unless otherwise noted there will be no re-closing into a transformer fault)

The SPP areas monitored during the stability analysis were:

- 520: American Electric Power (AEPW)
- 524: Oklahoma Gas and Electric Company (OKGE)
- 526: Southwestern Public Service (SPS)

Table 3-1: Contingencies Evaluated

Cont. No.	Contingency Name	Description
0	FLT_000_NOFAULT	No Fault Conditions
1	FLT_01_TOLKWEST6_PLANTX6_230kV_3PH	3 phase fault on the Tolk West (525531) to Plant X (525481) 230 kV line circuit 1, near Tolk West. a. Apply fault at the Tolk West 230 kV 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	FLT_02_TOLKWEST6_PLANTX6SB_230kV_1PH	**Stuck Breaker on Tolk West – Plant X 230 kV circuit 1 line** a. Apply single-phase fault at Tolk West (525531) on the 230 kV bus. b. After 20 cycles, trip the Tolk West (525531) 230 kV bus and Tolk 2(525562) 230kV bus. c. Trip the Tolk West – Plant X 230 kV circuit 1 line, and remove the fault
3	FLT_03_TOLKWEST6_LAMBCNTY6_230kV_3PH	3 phase fault on the Tolk West (525531) to Lamb County (525637) 230 kV line circuit 1, near Tolk West. a. Apply fault at the Tolk West 230 kV 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	FLT_04_TUCOINT3_TUCOINT6_115_230kV_3PH	3 phase fault on the TUCO (525828) 115 kV/(525830) 230 kV /(525821) 13.2 kV transformer, near TUCO 115 kV. a. Apply fault at the TUCO 115 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
5	FLT_05_TUCOINT7_TUCOINT6_345_230kV_3PH	3 phase fault on the TUCO (525832) 345 kV/(525830) 230 kV /(525824) 13.2 kV transformer, near TUCO 345 kV. a. Apply fault at the TUCO 345 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
6	FLT_06_TUCOINT6_TOLKEAST6_230kV_3PH	3 phase fault on the TUCO (525830) to Tolk East (525524) 345 kV line circuit 1, near TUCO. a. Apply fault at the TUCO 230 kV 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.
7	FLT_07_TUCOINT6_JONES6_230kV_3PH	3 phase fault on the TUCO (525830) to Jones (526337) 345 kV line circuit 1, near TUCO. a. Apply fault at the TUCO 230 kV 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	FLT_10_TUCOINT3_TUCOINT6PO_115_230kV_3PH	**Prior outage on the TUCO (525830) 230kV /(525828) 115 kV/(525819) 13.2kV line circuit 2;** 3 phase fault on the TUCO (525828) 115 kV/(525830) 230 kV /(525821) 13.2 kV transformer, near TUCO 115 kV. a. Apply fault at the TUCO 115 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
9	FLT_11_PLSNTHILL3_ECLOVIS3_115kV_3PH	3 phase fault on the Pleasant Hill (524768) to East Clovis (524773) 115 kV line circuit 1, near Pleasant Hill. a. Apply fault at the Pleasant Hill 115 kV 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	FLT_12_PLSNTHILL3_NCLOVISTP3_115kV_3PH	3 phase fault on the Pleasant Hill (524768) to North Clovis Tap (524773) 345 kV line circuit 1, near Pleasant Hill. a. Apply fault at the Pleasant Hill 115 kV 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.

Table 3-1: Contingencies Evaluated

Cont. No.	Contingency Name	Description
11	FLT_13_PLSNTHILL3_FEHOLLAND3_115kV_3PH	3 phase fault on the Pleasant Hill (524768) to FE-Holland (524831) 345 kV line circuit 1, near Pleasant Hill. a. Apply fault at the Pleasant Hill 115 kV 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.
12	FLT_14_PLSNTHILL6_PLSNTHILL3_230_115kV_3PH	3 phase fault on the Pleasant Hill (524770) 230 kV/(524768) 115 kV /(524767) 13.2 kV transformer, near Pleasant Hill 230 kV. a. Apply fault at the Pleasant Hill 230 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
13	FLT_15_PLSNTHILL6_OASIS6_230kV_3PH	3 phase fault on the Pleasant Hill (524770) to Oasis (524875) 230 kV line circuit 1, near Pleasant Hill. a. Apply fault at the Pleasant Hill 230 kV 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.
14	FLT_16_PLSNTHILL6_ROSEVELTN6_230kV_3PH	3 phase fault on the Pleasant Hill (524770) to Roosevelt North (524909) 345 kV line circuit 1, near Pleasant Hill. a. Apply fault at the Pleasant Hill 230 kV 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.
15	FLT_17_OASIS6_OASIS3_230_115kV_3PH	3 phase fault on the Oasis (524875) 230 kV/(524874) 115 kV /(524872) 13.2 kV transformer, near Oasis 230 kV. a. Apply fault at the Oasis 230 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
16	FLT_18_FECLVSINT3_NCLOVISTP3_115kV_3PH	3 phase fault on the FE-Clovis (524808) to N Clovis Tap (524776) 115 kV line circuit 1, near FE-Clovis. a. Apply fault at the FE-Clovis 115 kV 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.
17	FLT_19_FECLVSINT3_WCLOVIS3_115kV_3PH	3 phase fault on the FE-Clovis (524808) to W Clovis (524784) 115 kV line circuit 1, near FE-Clovis. a. Apply fault at the FE-Clovis 115 kV 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.
18	FLT_20_TUCOINT7_YOAKUM345_345kV_3PH 2020 & 2025 seasons only	3 phase fault on the TUCO (525830) to Yoakum (526936) 345 kV line circuit 1, near TUCO. a. Apply fault at the TUCO 345 kV 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.
19	FLT_21_POTTERCO7_POTTERCO6_345_230kV_3PH	3 phase fault on the Potter (523961) 345 kV / (523959) 230 kV /(523957) 13.2 kV transformer, near Potter 345 kV. a. Apply fault at the ROSEHIL7 345 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
20	FLT_22_BORDER7_TUCOINT7_345kV_3PH	3 phase fault on the Border (515458) to TUCO (525830) 345 kV line circuit 1, near Border. a. Apply fault at the Border 345 kV 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.
21	FLT_23_OASIS3_PERIMETER3_115kV_3PH	3 phase fault on the Oasis (524874) to Perimeter (524797) 115 kV line circuit 1, near Oasis. a. Apply fault at the Oasis 115 kV 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.
22	FLT_24_OASIS3_FECHZPLT3_115kV_3PH	3 phase fault on the Oasis (524874) to FE-CHZPLT (524863) 115 kV line circuit 1, near Oasis. a. Apply fault at the Oasis 115 kV 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.
23	FLT_25_OASIS3_PORTALES3_115kV_3PH	3 phase fault on the Oasis (524874) to Portales (524924) 115 kV line circuit 1, near Oasis. a. Apply fault at the Oasis 115 kV 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.

Table 3-1: Contingencies Evaluated

Cont. No.	Contingency Name	Description
24	FLT_26_PORTALES3_ROOSEVELT3_115kV_3PH	3 phase fault on the Portales (524924) to Roosevelt (524908) 115 kV line circuit 1, near Portales. a. Apply fault at the Portales 115 kV 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.
25	FLT_27_PORTALES3_PORTALES2_115_69kV_3PH	3 phase fault on the Portales (524924) 115 kV/(524923) 69 kV /(524921) 13.2 kV transformer, near Portales 115 kV. a. Apply fault at the Portales 115 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
26	FLT_28_CURRY3_DS#203_115kV_3PH	3 phase fault on the Curry (524822) to DS-#20 (524669) 115 kV line circuit 1, near Curry. a. Apply fault at the Curry 115 kV 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.
27	FLT_29_CURRY3_NORRISTP3_115kV_3PH	3 phase fault on the Curry (524822) to Norris Tap (524764) 115 kV line circuit 1, near Curry. a. Apply fault at the Curry 115 kV 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.
28	FLT_30_CURRY3_ECLOVIS3_115kV_3PH	3 phase fault on the Curry (524822) to East Clovis (524773) 115 kV line circuit 1, near Curry. a. Apply fault at the Curry 115 kV 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.
29	FLT_31_CURRY3_FECLOVIS23_115kV_3PH	3 phase fault on the Curry (524822) to FE-Clovis (524838) 115 kV line circuit 1, near Curry. a. Apply fault at the Curry 115 kV 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.
30	FLT_32_CURRY3_ROOSEVELT3_115kV_3PH	3 phase fault on the Curry (524822) to Roosevelt (524908) 115 kV line circuit 1, near Curry. a. Apply fault at the Curry 115 kV 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.
31	FLT_33_CURRY3_BAILEYCO3_115kV_3PH	3 phase fault on the Curry (524822) to Bailey County (525028) 115 kV line circuit 1, near Curry. a. Apply fault at the Curry 115 kV 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.
32	FLT_34_CURRY3_CURRY2_115_69kV_3PH	3 phase fault on the Curry (524822) 115 kV/(524821) 69 kV /(524819) 13.2 kV transformer, near Curry 115 kV. a. Apply fault at the Curry 115 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
33	FLT_35_EMU&VLYTP3_BAILEYCO3_115kV_3PH	3 phase fault on the EMU&VLY_TP (525019) to Bailey County (525028) 115 kV line circuit 1, near EMU&VLY_TP. a. Apply fault at the EMU&VLY_TP 115 kV 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.
34	FLT_36_EMU&VLYTP3_PLANTX3_115kV_3PH	3 phase fault on the EMU&VLY_TP (525019) to Plant X (525480) 115 kV line circuit 1, near EMU&VLY_TP. a. Apply fault at the EMU&VLY_TP 115 kV 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.
35	FLT_37_OASIS6_SNJUANTAP6_230kV_3PH	3 phase fault on the Oasis (524875) to San Juan Tap (524885) 230 kV line circuit 1, near Oasis. a. Apply fault at the Oasis 230 kV 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.

Table 3-1: Contingencies Evaluated

Cont. No.	Contingency Name	Description
36	FLT_38_OASIS6_SW4K336_230kV_3PH	3 phase fault on the Oasis (524875) to SW_4K33 (524915) 230 kV line circuit 1, near Oasis. a. Apply fault at the Oasis 230 kV 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.
37	FLT_39_ROSEVELTN6_SW4K336_230kV_3PH	3 phase fault on the Roosevelt N (524909) to SW_4K33 (524915) 230 kV line circuit 1, near Roosevelt N. a. Apply fault at the Roosevelt N 230 kV 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.
38	FLT_40_ROSEVELTN6_ROOSEVELT3_230_115kV_3PH	3 phase fault on the Roosevelt N (524909) 230 kV/(524908) 115 kV /(524907) 13.2 kV transformer, near Roosevelt N 230 kV. a. Apply fault at the Roosevelt N 230 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
39	FLT_41_ROSEVELTS6_SW4K336_230kV_3PH	3 phase fault on the Roosevelt N (524911) to SW_4K33 (524915) 230 kV line circuit 1, near Roosevelt S. a. Apply fault at the Roosevelt S 230 kV 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.
40	FLT_42_TOLKWEST6_TOLKTAP6_230kV_3PH	3 phase fault on the Tolk West (525531) to Tolk Tap (525543) 230 kV line circuit 1, near Tolk West. a. Apply fault at the Tolk West 230 kV 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.
41	FLT_43_TOLKEAST6_PLANTX6_230kV_3PH	3 phase fault on the Tolk East (525524) to Plant X (525481) 230 kV line circuit 1, near Tolk East. a. Apply fault at the Tolk East 230 kV 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.
42	FLT_44_TOLKEAST6_TOLKTAP6_230kV_3PH	3 phase fault on the Tolk East (525524) to Tolk Tap (525543) 230 kV line circuit 1, near Tolk East. a. Apply fault at the Tolk East 230 kV 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.
43	FLT_45_SWISHER3_KRESSINT3_115kV_3PH	3 phase fault on the Swisher (525212) to Kress Int (525192) 115 kV line circuit 1, near Swisher. a. Apply fault at the Swisher 115 kV 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.
44	FLT_46_SWISHER3_SWISHER6_115_230kV_3PH	3 phase fault on the Swisher (525212) 115 kV/(525213) 230 kV /(525211) 13.2 kV transformer, near Swisher 115 kV. a. Apply fault at the Swisher 115 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
45	FLT_47_KRESSINT3_TULIATP3_115kV_3PH	3 phase fault on the Kress Int (525192) to Tulia Tap (525179) 115 kV line circuit 1, near Kress Int. a. Apply fault at the Kress Int 115 kV 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.
46	FLT_48_KRESSINT3_KRESSRURAL3_115kV_3PH	3 phase fault on the Kress Int (525192) to Kress Rural (525225) 115 kV line circuit 1, near Kress Int. a. Apply fault at the Kress Int 115 kV 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.
47	FLT_49_KRESSINT3_HALECNTY3_115kV_3PH	3 phase fault on the Kress Int (525192) to Hale County (525454) 115 kV line circuit 1, near Kress Int. a. Apply fault at the Kress Int 115 kV 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.

Table 3-1: Contingencies Evaluated

Cont. No.	Contingency Name	Description
48	FLT_50_KRESSINT3_NEWHART3_115kV_3PH	3 phase fault on the Kress Int (525192) to Newhart (525460) 115 kV line circuit 1, near Kress Int. a. Apply fault at the Kress Int 115 kV 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.
49	FLT_51_RANDALL3_MANHATTAN3_115kV_3PH	3 phase fault on the Randall (524364) to Manhattan (524224) 115 kV line circuit 1, near Randall. a. Apply fault at the Randall 115 kV 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.
50	FLT_52_RANDALL3_GEORGIA3_115kV_3PH	3 phase fault on the Randall (524364) to Georgia (524322) 115 kV line circuit 1, near Randall. a. Apply fault at the Randall 115 kV 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.
51	FLT_54_RANDALL3_CANYONETP3_115kV_3PH	3 phase fault on the Randall (524364) to Canyon East Tap (524522) 115 kV line circuit 1, near Randall. a. Apply fault at the Randall 115 kV 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.
52	FLT_55_RANDALL3_PALODURO3_115kV_3PH	3 phase fault on the Randall (524364) to Palo Duro (524530) 115 kV line circuit 1, near Randall. a. Apply fault at the Randall 115 kV 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.
53	FLT_56_RANDALL3_RANDALL6_115_230kV_3PH	3 phase fault on the Randall (524364) 115 kV/(524365) 230 kV /(524361) 13.2 kV transformer, near Randall 115 kV. a. Apply fault at the Randall 115 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
54	FLT_57_HALECNTY3_COX3_115kV_3PH	3 phase fault on the Hale County (525454) to Cox (525326) 115 kV line circuit 1, near Hale County. a. Apply fault at the Hale County 115 kV 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.
55	FLT_58_HALECNTY3_LAMTON3_115kV_3PH	3 phase fault on the Hale County (525454) to Lamton (525414) 115 kV line circuit 1, near Hale County. a. Apply fault at the Hale County 115 kV 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.
56	FLT_59_HALECNTY3_PLANTX3_115kV_3PH	3 phase fault on the Hale County (525454) to Plant X (525480) 115 kV line circuit 1, near Hale County. a. Apply fault at the Hale County 115 kV 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.
57	FLT_60_HALECNTY3_HALECNTY2_115_69kV_3PH	3 phase fault on the Hale County (525454) 115 kV/(525453) 69 kV /(525451) 13.2 kV transformer, near Hale County 115 kV. a. Apply fault at the Hale County 115 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
58	FLT_61_COX3_KISER3_115kV_3PH	3 phase fault on the Cox (525326) to Kiser (525272) 115 kV line circuit 1, near Cox (. a. Apply fault at the Cox 115 kV 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.
59	FLT_62_COX3_FLOYDCNTY3_115kV_3PH	3 phase fault on the Cox (525326) to Floyd County (525780) 115 kV line circuit 1, near Cox (. a. Apply fault at the Cox 115 kV 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.
60	FLT_63_NEWHART3_CASTROCNTY3_115kV_3PH	3 phase fault on the Newhart (525460) to Castro County (524746) 115 kV line circuit 1, near Newhart. a. Apply fault at the Newhart 115 kV 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.

Table 3-1: Contingencies Evaluated

Cont. No.	Contingency Name	Description
61	FLT_64_NEWHART3_HARTINDUST3_115kV_3PH	3 phase fault on the Newhart (525460) to Hart Industry (525124) 115 kV line circuit 1, near Newhart. a. Apply fault at the Newhart 115 kV 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.
62	FLT_65_NEWHART3_NEWHART6_115_230kV_3PH	3 phase fault on the Newhart (525460) 115 kV/(525461) 230 kV /(525459) 13.2 kV transformer, near Newhart 115 kV. a. Apply fault at the Newhart 115 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
63	FLT_66_SWISHER6_NEWHART6_230kV_3PH	3 phase fault on the Swisher (525213) to Newhart (525460) 115 kV line circuit 1, near Swisher. a. Apply fault at the Swisher 115 kV 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.
64	FLT_67_SWISHER6_TUCOINT6_230kV_3PH	3 phase fault on the Swisher (525213) to TUCO (525830) 115 kV line circuit 1, near Swisher. a. Apply fault at the Swisher 115 kV 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.
65	FLT_68_LEHMAN3_LEHMAN3_115kV_3PH	3 phase fault on the Lehman (560030) to Lehman (526352) 115 kV line circuit 1, near Lehman. a. Apply fault at the Lehman 115 kV 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.
66	FLT_69_LEHMAN3_COCHRAN3_115kV_3PH	3 phase fault on the Lehman (560030) to Cochran (526361) 115 kV line circuit 1, near Lehman. a. Apply fault at the Lehman 115 kV 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.
67	FLT_70_LEHMAN3_LGPLAINS3_115kV_3PH	3 phase fault on the Lehman (560030) to LG Plains (526944) 115 kV line circuit 1, near Lehman. a. Apply fault at the Lehman 115 kV 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.
68	FLT_71_PLAINSINT3_YOAKUM3_115kV_3PH	3 phase fault on the Plains Int (526928) to Yoakum (526934) 115 kV line circuit 1, near Plains Int. a. Apply fault at the Plains Int 115 kV 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.
69	FLT_72_PLAINSINT3_LGPLAINS3_115kV_3PH	3 phase fault on the Plains Int (526928) to LG Plains (526944) 115 kV line circuit 1, near Plains Int. a. Apply fault at the Plains Int 115 kV 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.
70	FLT_73_PLAINSINT3_LEPLNSINT2_115_69kV_3PH	3 phase fault on the Plains Int (526928) 115 kV/(528626) 69 kV transformer, near Plains Int 115 kV. a. Apply fault at the Plains Int 115 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
71	FLT_74_COCHRAN3_PACIFIC3_115kV_3PH	3 phase fault on the Cochran (526361) to Pacific (526424) 115 kV line circuit 1, near Cochran. a. Apply fault at the Cochran 115 kV 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.
72	FLT_75_COCHRAN3_COCHRAN2_115_69kV_3PH	3 phase fault on the Cochran (526361) 115 kV/(526360) 69 kV /(526358) 13.2kV transformer, near Cochran 115 kV. a. Apply fault at the Cochran 115 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
73	FLT_76_SUNDOWN3_LCOPDYKE3_115kV_3PH	3 phase fault on the Sundown (526434) to LC-OPDYKE (526036) 115 kV line circuit 1, near Sundown. a. Apply fault at the Sundown 115 kV 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.

Table 3-1: Contingencies Evaluated

Cont. No.	Contingency Name	Description
74	FLT_77_SUNDOWN3_AMOCOTP3_115kV_3PH	3 phase fault on the Sundown (526434) to Amoco Tap (526445) 115 kV line circuit 1, near Sundown. a. Apply fault at the Sundown 115 kV 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.
75	FLT_78_SUNDOWN3_SUNDOWN6_115_230kV_3PH	3 phase fault on the Sundown (526434) 115 kV/(526435) 230 kV /(526432) 13.2 kV transformer, near Sundown 115 kV. a. Apply fault at the Sundown 115 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
76	FLT_79_SUNDOWN6_PLANTX6_230kV_3PH	3 phase fault on the Sundown (526435) to Plant X (525481) 230 kV line circuit 1, near Sundown. a. Apply fault at the Sundown 230 kV 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.
77	FLT_80_SUNDOWN6_AMOCOSS6_230kV_3PH	3 phase fault on the Sundown (526435) to Amoco (526460) 230 kV line circuit 1, near Sundown. a. Apply fault at the Sundown 230 kV 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.
78	FLT_81_YOAKUM3_PRENTICE3_115kV_3PH	3 phase fault on the Yoakum (526934) to Prentice (526792) 115 kV line circuit 1, near Yoakum. a. Apply fault at the Yoakum 115 kV 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.
79	FLT_82_YOAKUM3_ARCOTP3_115kV_3PH	3 phase fault on the Yoakum (526934) to Arco Tap (527041) 115 kV line circuit 1, near Yoakum. a. Apply fault at the Yoakum 115 kV 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.
80	FLT_83_YOAKUM3_LGPLSHILL3_115kV_3PH	3 phase fault on the Yoakum (526934) to LG-PLSHILL (527194) 115 kV line circuit 1, near Yoakum. a. Apply fault at the Yoakum 115 kV 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.
81	FLT_84_TUCOINT3_LUBBCKEST3_115kV_3PH	3 phase fault on the TUCO (525828) to Lubbock East (526298) 115 kV line circuit 1, near TUCO. a. Apply fault at the TUCO 115 kV 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.
82	FLT_85_CARLISLE3_LPDOUDTP3_115kV_3PH	3 phase fault on the Carlisle (526160) to LP-Doud Tap (526162) 115 kV line circuit 1, near Carlisle. a. Apply fault at the Carlisle 115 kV 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.
83	FLT_86_CARLISLE3_MURPHY3_115kV_3PH	3 phase fault on the Carlisle (526160) to Murphy (526192) 115 kV line circuit 1, near Carlisle. a. Apply fault at the Carlisle 115 kV 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.
84	FLT_87_CARLISLE6_LPMILWAKEE6_230kV_3PH	3 phase fault on the Carlisle (526161) to LP-MILWAKEE (522823) 230 kV line circuit 1, near Carlisle. a. Apply fault at the Carlisle 230 kV 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.
85	FLT_88_CARLISLE6_TUCOINT6_230kV_3PH	3 phase fault on the Carlisle (526161) to TUCO (522823) 230 kV line circuit 1, near Carlisle. a. Apply fault at the Carlisle 230 kV 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.
86	FLT_89_CARLISLE6_WOLFFORTH6_230kV_3PH 2020 & 2025 seasons only	3 phase fault on the Carlisle (526161) to Wolfforth (526525) 230 kV line circuit 1, near Carlisle. a. Apply fault at the Carlisle 230 kV 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.

Table 3-1: Contingencies Evaluated

Cont. No.	Contingency Name	Description
87	FLT_90_CARLISLE3_CARLISLE6_115_230kV_3PH	3 phase fault on the Carlisle (526160) 115 kV/(526161) 230 kV /(526157) 13.2 kV transformer, near Carlisle 115 kV. a. Apply fault at the Carlisle 115 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
88	FLT_91_JONES6_LPHOLLY6_230kV_3PH	3 phase fault on the Jones (526337) to LP-Holly (522870) 230 kV line circuit 1, near Jones. a. Apply fault at the Jones 230 kV 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.
89	FLT_92_JONES6_LUBBCKSTH6_230kV_3PH	3 phase fault on the Jones (526337) to Lubbock South (526269) 230 kV line circuit 1, near Jones. a. Apply fault at the Jones 230 kV 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.
90	FLT_93_JONES6_LUBBCKEST6_230kV_3PH	3 phase fault on the Jones (526337) to Lubbock East (526299) 230 kV line circuit 1, near Jones. a. Apply fault at the Jones 230 kV 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.
91	FLT_94_YUMAINT3_SPWOLFTP3_115kV_3PH	3 phase fault on the Yuma Interchange (526475) to SP-Wolf Tap (526481) 115 kV line circuit 1, near Yuma Interchange. a. Apply fault at the Yuma Interchange 115 kV 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.
92	FLT_95_YUMAINT3_WOLFFORTH3_115kV_3PH	3 phase fault on the Yuma Interchange (526475) to Wolfforth (526524) 115 kV line circuit 1, near Yuma Interchange. a. Apply fault at the Yuma Interchange 115 kV 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.
93	FLT_96_SPWOLFTP3_LPDOUDTP3_115kV_3PH	3 phase fault on the SP-Wolf Tap (526481) to LP-Doud Tap (526162) 115 kV line circuit 1, near SP-Wolf Tap. a. Apply fault at the SP-Wolf Tap 115 kV 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.
94	FLT_97_CARLISLE3_CARLISLE2_115_69kV_3PH	3 phase fault on the Carlisle (526160) 115 kV/(526159) 69 kV /(526158) 13.2kV transformer, near Carlisle 115 kV. a. Apply fault at the Carlisle 115 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
95	FLT_98_LUBBCKSTH3_SPWOODROW3_115kV_3PH	3 phase fault on the Lubbock South (526268) to SP_Woodrow (526602) 115 kV line circuit 1, near Lubbock South. a. Apply fault at the Lubbock South 115 kV 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.
96	FLT_99_LUBBCKSTH3_LUBBCKSTH2_115_69kV_3PH	3 phase fault on the Lubbock South (526268) 115 kV/(526267) 69 kV /(526266) 13.2kV transformer, near Lubbock South 115 kV. a. Apply fault at the Lubbock South 115 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
97	FLT_100_LUBBCKSTH3_LUBBCKSTH6_115_230kV_3PH	3 phase fault on the Lubbock South (526268) 115 kV/(526267) 230 kV /(526266) 13.2kV transformer, near Lubbock South 115 kV. a. Apply fault at the Lubbock South 115 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
98	FLT_101_WOLFFORTH3_TERRYCNTY3_115kV_3PH	3 phase fault on the Wolfforth (526524) to Terry County (526736) 115 kV line circuit 1, near Wolfforth. a. Apply fault at the Wolfforth 115 kV 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.
99	FLT_102_WOLFFORTH3_WOLFFORTH6_115_230kV_3PH	3 phase fault on the Wolfforth (526525) 115 kV/(526525) 230 kV /(526522) 13.2kV transformer, near Wolfforth 115 kV. a. Apply fault at the Wolfforth 115 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.

Table 3-1: Contingencies Evaluated

Cont. No.	Contingency Name	Description
100	FLT_103_WOLFFORTH6_LUBBCKSTH6_230kV_3PH	3 phase fault on the Wolfforth (526524) to Lubbock South (526269) 230 kV line circuit 1, near Wolfforth. a. Apply fault at the Wolfforth 230 kV 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.
101	FLT_104_WOLFFORTH6_SUNDOWN6_230kV_3PH	3 phase fault on the Wolfforth (526524) to Sundown (526435) 230 kV line circuit 1, near Wolfforth. a. Apply fault at the Wolfforth 230 kV 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.
102	FLT_105_TERRYCNTY3_LGCLAUENE3_115kV_3PH	3 phase fault on the Terry County (526736) to LG-CLAUENE (526491) 115 kV line circuit 1, near Terry County. a. Apply fault at the Terry County 115 kV 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.
103	FLT_106_TERRYCNTY3_PRENTICE3_115kV_3PH	3 phase fault on the Terry County (526736) to Prentice (526792) 115 kV line circuit 1, near Terry County. a. Apply fault at the Terry County 115 kV 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.
104	FLT_107_TERRYCNTY3_DENVERN3_115kV_3PH	3 phase fault on the Terry County (526736) to Denver N (527130) 115 kV line circuit 1, near Terry County. a. Apply fault at the Terry County 115 kV 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.
105	FLT_108_TERRYCNTY3_SULPHUR3_115kV_3PH	3 phase fault on the Terry County (526736) to Sulphur (527262) 115 kV line circuit 1, near Terry County. a. Apply fault at the Terry County 115 kV 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.
106	FLT_109_TERRYCNTY3_TERRYCNTY2_115_69kV_3PH	3 phase fault on the Terry County (526736) 115 kV/(526735) 69 kV /(526733) 13.2kV transformer, near Terry County 115 kV. a. Apply fault at the Terry County 115 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
107	FLT_110_TOLKTAP6_TOLK7_230_345kV_3PH	3 phase fault on the Tolk Tap (525543) 230 kV/(525549) 69 kV /(525537) 13.2kV transformer, near Tolk Tap 230kV. a. Apply fault at the Tolk Tap 230 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
108	FLT_111_TOLKWEST6_G13027TAP_230kV_3PH	3 phase fault on the Tolk West (525531) to G13-027-TAP (562480) 230 kV line circuit 1, near Tolk West. a. Apply fault at the Tolk West 230 kV 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.
109	FLT_112_G13027TAP_YOAKUM6_230kV_3PH	3 phase fault on the G13-027-TAP (562480) to Yoakum (526935) 230 kV line circuit 1, near G13-027-TAP. a. Apply fault at the G13-027-TAP 230 kV 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.
110	FLT_113_YOAKUM6_G13027TAPSB_230kV_1PH	**Stuck Breaker on Yoakum – G13-027-TAP 230 kV line** a. Apply single-phase fault at Yoakum 230 kV (526935) b. After 20 cycles, trip the Yoakum (526935) to G13-027-TAP (562480) 230 kV line c. Trip the Yoakum (526935) 230 kV/(526934) 115 kV /(526931) 13.2 kV XMFR, and remove the fault
111	FLT_114_YOAKUM6_AMOCOSS6_230kV_3PH	3 phase fault on the Yoakum (526935) to Amoco (526460) 230 kV line circuit 1, near Yoakum. a. Apply fault at the Yoakum 230 kV 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.

Table 3-1: Contingencies Evaluated

Cont. No.	Contingency Name	Description
112	FLT_115_YOAKUM6_OXYBRUTP6_230kV_3PH	3 phase fault on the Yoakum (526935) to OXYBRU Tap (527010) 230 kV line circuit 1, near Yoakum. a. Apply fault at the Yoakum 230 kV 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.
113	FLT_116_YOAKUM6_MUSTANG6_230kV_3PH	3 phase fault on the Yoakum (526935) to Mustang (527149) 230 kV line circuit 1, near Yoakum. a. Apply fault at the Yoakum 230 kV 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.
114	FLT_117_YOAKUM6_HOBBSINT6_230kV_3PH	3 phase fault on the Yoakum (526935) to Hobbs (527894) 230 kV line circuit 1, near Yoakum. a. Apply fault at the Yoakum 230 kV 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.
115	FLT_118_YOAKUM6_YOAKUM3_230_115kV_3PH	3 phase fault on the Yoakum (526935) 230 kV /(526934) 115 kV /(526931) 13.2 kV transformer, near Yoakum 230 kV. a. Apply fault at the Yoakum 230 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
116	FLT_119_YOAKUM6_AMOCOSS6PO_230kV_3PH	**Prior outage on the Yoakum (526935) to Amoco (526460) 230 kV line circuit 1;** 3 phase fault on the Yoakum (526935) 230 kV/(526934) 115 kV/(526931) 13.2 kV line circuit 1, near Yoakum 230 kV. a. Apply fault at the Yoakum 230 kV 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.
117	FLT_120_YOAKUM6_AMOCOSS6SB_230kV_1PH	**Stuck Breaker on Yoakum – Amoco 230 kV line** a. Apply single-phase fault at Yoakum 230 kV (526935) b. After 20 cycles, trip the Yoakum (526935) to Amoco (526460) 230 kV line c. Trip the Yoakum (526935) 230 kVbus, and remove the fault
118	FLT_121_TOLKWEST6_ROSEVELTN6_230kV_3PH	3 phase fault on the Tolk West (525531) to Roosevelt N (524909) 230 kV line circuit 1, near Tolk West. a. Apply fault at the Tolk West 230 kV 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.
119	FLT_122_TOLKWEST6_ROSEVELTN6SB_230kV_1PH	**Stuck Breaker on Tolk West – Roosevelt N 230 kV line** a. Apply single-phase fault at Tolk West (525531) b. After 20 cycles, trip the Tolk West (525531) to Roosevelt N (524909230 kV line c. Trip the Tolk West (525531) 230 kV bus, and remove the fault
120	FLT_123_BORDER7_WWRDEHV7_345kV_3PH	3 phase fault on the Border (526935) to Woodward EHV (515375) 345 kV line, near Border 345 kV. a. Apply fault at the Border 345 kV 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.
121	FLT_124_OKU7_TUCOINT7_345kV_3PH	3 phase fault on the Oklaunion (511456) to TUCO (525832) 345 kV line, near Oklaunion 345 kV. a. Apply fault at the Oklaunion 345 kV 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.

Results

In the 2016 winter peak (16WP), 2017 summer peak (17SP) and 2020 winter peak (20WP), the SLNOS relay on Eddy County – Crossroads 345kV line caused that line to trip for contingencies 1, 3, 40, 41, 42, 107, 108, and 118 (all have three phase faults on Tolk 230kV). A second simulation was run with the SLNOS relay on Eddy County – Crossroads 345kV line turned off and using the problematic contingences. This run was stable with no lines or generators tripping off. A third simulation was run with the problematic contingencies and with the study generators turned off. The result of the third simulation showed that the SLNOS relay tripped the Eddy County – Crossroads 345kV line for each of the problematic contingencies. Therefore, it was determined that this is a pre-existing condition not attributed to the study generators.

A power flow analysis was done as a separate study from the stability analysis. The powerflow analysis showed a need for a 50 Mvar cap bank at OKU to maintain steady state voltages at 0.92pu or higher after certain contingencies. Additional stability runs were completed with that cap bank in place. The 2016 winter peak (16WP) and 2017 summer peak (17SP) seasons showed the same issues with the Eddy County – Crossroads 345kV SLNOS relay. The 2020 winter peak (20WP) season did not.TUCO. As was done previously, runs were completed with the SLNOS relay in question both on and off for those contingencies. The results were similar to those without the cap bank.

The results of the stability analysis are summarized in **Table 3-2**, below. The stability plots will be available upon customer request.

Table 3-2: Stability Results

Contingency Number and Name		DSIS-2015-001-3 G6 Cluster				
		2016WP	2017SP	2020SP	2020WP	2017SP
0	FLT_000_NOFAULT	STABLE	STABLE	STABLE	STABLE	STABLE
1	FLT_01_TOLKWEST6_PLANTX6_230kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
2	FLT_02_TOLKWEST6_PLANTX6SB_230kV_1PH	STABLE	STABLE	STABLE	STABLE	STABLE
3	FLT_03_TOLKWEST6_LAMBCNTY6_230kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
4	FLT_04_TUCOINT3_TUCOINT6_115_230kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
5	FLT_05_TUCOINT7_TUCOINT6_345_230kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
6	FLT_06_TUCOINT6_TOLKEAST6_230kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
7	FLT_07_TUCOINT6_JONES6_230kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
8	FLT_10_TUCOINT3_TUCOINT6PO_115_230kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
9	FLT_11_PLSNTHILL3_ECLOVIS3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
10	FLT_12_PLSNTHILL3_NCLOVISTP3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
11	FLT_13_PLSNTHILL3_FEHOLLAND3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
12	FLT_14_PLSNTHILL6_PLSNTHILL3_230_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
13	FLT_15_PLSNTHILL6_OASIS6_230kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
14	FLT_16_PLSNTHILL6_ROSEVELTN6_230kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
15	FLT_17_OASIS6_OASIS3_230_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
16	FLT_18_FECLVSINT3_NCLOVISTP3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
17	FLT_19_FECLVSINT3_WCLOVIS3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
18	FLT_20_TUCOINT7_YOAKUM345_345kV_3PH 2020 & 2025 seasons only			STABLE	STABLE	STABLE
19	FLT_21_POTTERCO7_POTTERCO6_345_230kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
20	FLT_22_BORDER7_TUCOINT7_345kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
21	FLT_23_OASIS3_PERIMETER3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
22	FLT_24_OASIS3_FECHZPLT3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
23	FLT_25_OASIS3_PORTALES3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
24	FLT_26_PORTALES3_ROOSEVELT3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
25	FLT_27_PORTALES3_PORTALES2_115_69kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE

Contingency Number and Name		DSIS-2015-001-3 G6 Cluster				
		2016WP	2017SP	2020SP	2020WP	2017SP
26	FLT_28_CURRY3_DS#203_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
27	FLT_29_CURRY3_NORRISTP3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
28	FLT_30_CURRY3_ECLOVIS3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
29	FLT_31_CURRY3_FECLOVIS23_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
30	FLT_32_CURRY3_ROOSEVELT3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
31	FLT_33_CURRY3_BAILEYCO3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
32	FLT_34_CURRY3_CURRY2_115_69kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
33	FLT_35_EMU&VLYTP3_BAILEYCO3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
34	FLT_36_EMU&VLYTP3_PLANTX3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
35	FLT_37_OASIS6_SNJUANTAP6_230kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
36	FLT_38_OASIS6_SW4K336_230kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
37	FLT_39_ROSEVELTN6_SW4K336_230kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
38	FLT_40_ROSEVELTN6_ROOSEVELT3_230_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
39	FLT_41_ROSEVELTS6_SW4K336_230kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
40	FLT_42_TOLKWEST6_TOLKTAP6_230kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
41	FLT_43_TOLKEAST6_PLANTX6_230kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
42	FLT_44_TOLKEAST6_TOLKTAP6_230kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
43	FLT_45_SWISHER3_KRESSINT3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
44	FLT_46_SWISHER3_SWISHER6_115_230kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
45	FLT_47_KRESSINT3_TULIATP3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
46	FLT_48_KRESSINT3_KRESSRURAL3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
47	FLT_49_KRESSINT3_HALECNTY3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
48	FLT_50_KRESSINT3_NEWHART3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
49	FLT_51_RANDALL3_MANHATTAN3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
50	FLT_52_RANDALL3_GEORGIA3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
51	FLT_54_RANDALL3_CANYONETP3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
52	FLT_55_RANDALL3_PALODURO3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
53	FLT_56_RANDALL3_RANDALL6_115_230kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
54	FLT_57_HALECNTY3_COX3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
55	FLT_58_HALECNTY3_LAMTON3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
56	FLT_59_HALECNTY3_PLANTX3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
57	FLT_60_HALECNTY3_HALECNTY2_115_69kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
58	FLT_61_COX3_KISER3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
59	FLT_62_COX3_FLOYDCNTY3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
60	FLT_63_NEWHART3_CASTROCNTY3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
61	FLT_64_NEWHART3_HARTINDUST3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
62	FLT_65_NEWHART3_NEWHART6_115_230kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
63	FLT_66_SWISHER6_NEWHART6_230kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
64	FLT_67_SWISHER6_TUCOINT6_230kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
65	FLT_68_LEHMAN3_LEHMAN3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
66	FLT_69_LEHMAN3_COCHRAN3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
67	FLT_70_LEHMAN3_LGPLAINS3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
68	FLT_71_PLAINSINT3_YOAKUM3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
69	FLT_72_PLAINSINT3_LGPLAINS3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
70	FLT_73_PLAINSINT3_LEPLNSINT2_115_69kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
71	FLT_74_COCHRAN3_PACIFIC3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
72	FLT_75_COCHRAN3_COCHRAN2_115_69kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
73	FLT_76_SUNDOWN3_LCOPDYKE3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
74	FLT_77_SUNDOWN3_AMOCOTP3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
75	FLT_78_SUNDOWN3_SUNDOWN6_115_230kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
76	FLT_79_SUNDOWN6_PLANTX6_230kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
77	FLT_80_SUNDOWN6_AMOCOSS6_230kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
78	FLT_81_YOAKUM3_PRENTICE3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
79	FLT_82_YOAKUM3_ARCOTP3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
80	FLT_83_YOAKUM3_LGPLSHILL3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
81	FLT_84_TUCOINT3_LUBBCKEST3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
82	FLT_85_CARLISLE3_LPDOUDTP3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
83	FLT_86_CARLISLE3_MURPHY3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
84	FLT_87_CARLISLE6_LPMILWAKEE6_230kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
85	FLT_88_CARLISLE6_TUCOINT6_230kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
86	FLT_89_CARLISLE6_WOLFFORTH6_230kV_3PH 2020 & 2025 seasons only			STABLE	STABLE	STABLE
87	FLT_90_CARLISLE3_CARLISLE6_115_230kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE

Contingency Number and Name		DSIS-2015-001-3 G6 Cluster				
		2016WP	2017SP	2020SP	2020WP	2017SP
88	FLT_91_JONES6_LPHOLLY6_230kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
89	FLT_92_JONES6_LUBBCKSTH6_230kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
90	FLT_93_JONES6_LUBBCKEST6_230kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
91	FLT_94_YUMAINT3_SPWOLFTP3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
92	FLT_95_YUMAINT3_WOLFFORTH3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
93	FLT_96_SPWOLFTP3_LPDOUDTP3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
94	FLT_97_CARLISLE3_CARLISLE2_115_69kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
95	FLT_98_LUBBCKSTH3_SPWOODROW3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
96	FLT_99_LUBBCKSTH3_LUBBCKSTH2_115_69kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
97	FLT_100_LUBBCKSTH3_LUBBCKSTH6_115_230kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
98	FLT_101_WOLFFORTH3_TERRYCNTY3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
99	FLT_102_WOLFFORTH3_WOLFFORTH6_115_230kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
100	FLT_103_WOLFFORTH6_LUBBCKSTH6_230kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
101	FLT_104_WOLFFORTH6_SUNDOWN6_230kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
102	FLT_105_TERRYCNTY3_LGCLAUENE3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
103	FLT_106_TERRYCNTY3_PRENTICE3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
104	FLT_107_TERRYCNTY3_DENVERN3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
105	FLT_108_TERRYCNTY3_SULPHUR3_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
106	FLT_109_TERRYCNTY3_TERRYCNTY2_115_69kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
107	FLT_110_TOLKTAP6_TOLK7_230_345kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
108	FLT_111_TOLKWEST6_G13027TAP_230kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
109	FLT_112_G13027TAP_YOAKUM6_230kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
110	FLT_113_YOAKUM6_G13027TAPSB_230kV_1PH	STABLE	STABLE	STABLE	STABLE	STABLE
111	FLT_114_YOAKUM6_AMOCOSS6_230kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
112	FLT_115_YOAKUM6_OXYBRUTP6_230kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
113	FLT_116_YOAKUM6_MUSTANG6_230kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
114	FLT_117_YOAKUM6_HOBBSINT6_230kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
115	FLT_118_YOAKUM6_YOAKUM3_230_115kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
116	FLT_119_YOAKUM6_AMOCOSS6PO_230kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
117	FLT_120_YOAKUM6_AMOCOSS6SB_230kV_1PH	STABLE	STABLE	STABLE	STABLE	STABLE
118	FLT_121_TOLKWEST6_ROSEVELTN6_230kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
119	FLT_122_TOLKWEST6_ROSEVELTN6SB_230kV_1PH	STABLE	STABLE	STABLE	STABLE	STABLE
120	FLT_123_BORDER7_WWRDEHV7_345kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE
121	FLT_124_OKU7_TUCOINT7_345kV_3PH	STABLE	STABLE	STABLE	STABLE	STABLE

FERC LVRT Compliance

FERC Order #661A places specific requirements on wind farms through its Low Voltage Ride Through (LVRT) provisions. For Interconnection Agreements signed after December 31, 2006, wind farms shall stay on line for faults at the POI that draw the voltage down at the POI to 0.0 pu. The faults listed below in **Table 3-3** were tested to meet Order 661A LVRT provisions. The results are listed in **Table 3-2**.

Table 3-2: LVRT Contingencies

Contingency Number and Name	Description
FLT_45_SWISHER3_KRESSINT3_115kV_3PH	3 phase fault on the Swisher (525212) to Kress Int (525192) 115 kV line circuit 1, near Swisher. a. Apply fault at the Swisher 115 kV 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.
FLT_46_SWISHER3_SWISHER6_115_230kV_3PH	3 phase fault on the Swisher (525212) 115 kV/(525213) 230 kV /(525211) 13.2 kV transformer, near Swisher 115 kV. a. Apply fault at the Swisher 115 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT_66_SWISHER6_NEWHART6_230kV_3PH	3 phase fault on the Swisher (525213) to Newhart (525460) 115 kV line circuit 1, near Swisher. a. Apply fault at the Swisher 115 kV 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.
FLT_67_SWISHER6_TUCOINT6_230kV_3PH	3 phase fault on the Swisher (525213) to TUCO (525830) 115 kV line circuit 1, near Swisher. a. Apply fault at the Swisher 115 kV 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.
FLT_68_LEHMAN3_LEHMAN3_115kV_3PH	3 phase fault on the Lehman (560030) to Lehman (526352) 115 kV line circuit 1, near Lehman. a. Apply fault at the Lehman 115 kV 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.
FLT_69_LEHMAN3_COCHRAN3_115kV_3PH	3 phase fault on the Lehman (560030) to Cochran (526361) 115 kV line circuit 1, near Lehman. a. Apply fault at the Lehman 115 kV 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.
FLT_70_LEHMAN3_LGPLAINS3_115kV_3PH	3 phase fault on the Lehman (560030) to LG Plains (526944) 115 kV line circuit 1, near Lehman. a. Apply fault at the Lehman 115 kV 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.
FLT_94_YUMAINT3_SPWOLFTP3_115kV_3PH	3 phase fault on the Yuma Interchange (526475) to SP-Wolf Tap (526481) 115 kV line circuit 1, near Yuma Interchange. a. Apply fault at the Yuma Interchange 115 kV 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.
FLT_95_YUMAINT3_WOLFFORTH3_115kV_3PH	3 phase fault on the Yuma Interchange (526475) to Wolfforth (526524) 115 kV line circuit 1, near Yuma Interchange. a. Apply fault at the Yuma Interchange 115 kV 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. Power Factor Analysis

The power factor analysis was performed for each project included in this study and is designed to demonstrate the reactive power requirements at the point of interconnection (POI) using the current study upgrade cases. For all projects that require reactive power, the final requirement in the GIA will be the pro-forma 95% lagging to 95% leading at the POI.

Model Preparation

For each project included in this study, as well as previous queued projects modeled at the same POI, the projects were turned off for the power factor analysis. The projects were replaced by an equivalent generator located at the POI producing the total MW of the project at that POI and 0.0 Mvar capability.

A Mvar generator without limits was modeled at the interconnection project POI to hold a voltage schedule at the POI consistent with the greater of the voltage schedule in the base case or unity (1.0 pu) voltage.

Disturbances

Each N-1 three phase contingency evaluated in the Stability Analysis found in **Table 3-1** was also included in the determination of the power factor requirements.

Results

The power factor ranges are summarized in **Table 4-1** and the resultant ranges are shown in **Tables F-1** to **F-3**, starting here. The analysis showed that reactive power is required for the study projects, the final requirement in the Generation Interconnection Agreement (GIA) for each project will be the pro-forma 95% lagging to 95% leading at the POI.

For analyzing power factor results a positive Q (Mvar) output indicates that the equivalent generator is supplying reactive power to the system, implying a lagging power factor. A negative Q (Mvar) output indicates that the equivalent generator is absorbing reactive power from the system, implying a leading power factor.

Table 4-1: Summary of Power Factor Analysis at the POI

Request	Capacity (MW)	Point of Interconnection (POI)	Fuel	Generator	Lagging (providing Mvars)	Leading (absorbing Mvars)
GEN-2015-014	150	Lehman 115kV (560030)	Wind	Vestas V110 2MW	0.95	0.95
GEN-2015-022	112	Swisher 115kV (525212)	Solar	GE LV5 4MW inverter	0.95	0.95

NOTE: 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.

5. Reduced Wind Generation Analysis

A low wind/low solar irradiance analysis has been performed for the GEN-2015-014 and GEN-2015-022 Interconnection Requests. SPP performed this analysis for excessive capacitive charging current for the addition of the Interconnection Request facilities. The high side of the each Interconnection Customer's transformer will interconnect to The Point of Interconnection (POI).

The project generators and capacitors (if any) were turned off in the base case. The resulting reactive power injection into the transmission network comes from the capacitance of the project's transmission lines and collector cables is shown in **Figure G-1** through **G-4**.

Final shunt reactor requirement for each project with the model information provided to SPP is shown in **Table 5-1**. It is the interconnection customer's responsibility to design and install the reactive compensation equipment necessary to control the reactive power injection at the POI. If an equivalent means of compensation is installed, the reactive power required may vary with system conditions (e.g. a higher compensation amount is required for voltages above unity at the POI and a lower compensation amount is required for voltages below unity at the POI).

Table 5-1*: Summary of Reduced Wind Generation Analysis*

Request	Point of Interconnection (POI)	Reactor Size (Mvar)
GEN-2015-014	Lehman 115kV (560030)	7.0
GEN-2015-022	Swisher 115kV (525212)	1.8

6. Short Circuit Analysis

The short circuit analysis was performed on the 2017 & 2025 Summer Peak power flow cases using the PSS/E ASCC program. Since the power flow model does not contain negative and zero sequence data, only three-phase symmetrical fault current levels were calculated at the point of interconnection up to and including five levels away.

Short Circuit Analysis was conducting using flat conditions with the following PSS/E ASCCC program settings:

- BUS VOLTAGES SET TO 1 PU AT 0 PHASE ANGLE
- GENERATOR P=0, Q=0
- TRANSFORMER TAP RATIOS=1.0 PU and PHASE ANGLES=0.0
- LINE CHARGING=0.0 IN +/-/0 SEQUENCE
- LOAD=0.0 IN +/- SEQUENCE, CONSIDERED IN ZERO SEQUENCE
- LINE/FIXED/SWITCHED SHUNTS=0.0 AND MAGNETIZING ADMITTANCE=0.0 IN +/-/0 SEQUENCE
- DC LINES AND FACTS DEVICES BLOCKED
- TRANSFORMER ZERO SEQUENCE IMPEDANCE CORRECTIONS IGNORED

Results

The results of the short circuit analysis are shown in **Appendix H**.

7. Conclusion

DISIS-2015-001-3 Group 6 Interconnection Customer(s) have requested an Impact Study to determine the impacts of interconnecting generation to the SPP Transmission System.

A stability cluster impact analysis was performed for the generation projects from the DISIS-2015-001-3 Group 6 study. The analysis was performed on five (5) seasonal models including 2016 winter peak (16WP), the 2017 summer peak (17SP), the 2020 summer peak (20SP), the 2020 winter peak (20WP) and the 2025 summer peak (25SP) cases. These cases are modified versions of the 2015 model series of Model Development Working Group (MDWG) dynamic study models. A total of one-hundred-twenty-one (121) contingencies were evaluated for the five (5) seasonal cases.

The stability analysis has determined with all previously assigned network upgrades, all generators in the monitored areas remained stable and within the pre-contingency, voltage recovery, and post fault voltage recovery criterion of 0.7pu to 1.2pu for the entire modeled disturbances. Under certain system conditions the interconnection requests may be required to curtail generation output to maintain system reliability.

In addition to the cluster impact stability analysis, a stand-alone stability analysis was conducted for each request.

Power factor analysis for each generation project was performed on the current study 2016 winter peak, 2017 summer peak, the 2020 summer peak (20SP), the 2020 winter peak (20WP) and 2025 summer peak cases with identified system upgrades. 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.

A reduced generation analysis was conducted for wind farms and solar farms to determine reactor size necessary to compensate the capacitive effects on the transmission system during low or reduced generation conditions. The capacitive effect is caused by the interconnecting project's generator lead transmission line and collector systems. Each request may be required to install the following reactors on their facilities: GEN-2015-014 – 7.0 Mvar and GEN-2015-022 – 1.8 Mvar.

Short Circuit analysis was conducted using the current study 2017 summer peak and 2025 summer peak cases with identified system upgrades.

Nothing in this study should be construed as a guarantee of delivery or transmission service. If the customer wishes to sell power from the facility, a separate request for transmission service must be requested on Southwest Power Pool's OASIS by the Customer.

Appendix A – 2016 Winter Peak Stability Plots

(Available on request)

Appendix B – 2017 Summer Peak Stability Plots

(Available on request)

Appendix C – 2020 Summer Peak Stability Plots

(Available on request)

Appendix D – 2020 Winter Peak Stability Plots

(Available on request)

Appendix E – 2025 Summer Peak Stability Plots

(Available on request)

Appendix F – Power Factor Analysis Results

Table F-1: GEN-2015-014 Power Factor Analysis Results

GEN-2015-014 POI Lehman 115 kV (560030) Power at POI (MW): 150.0		DISIS-2015-001-3 Group 06 Leading power factor is absorbing vars; Lagging power factor is providing vars														
		2016 Winter Peak POI Voltage = 1.007 pu			2017 Summer Peak POI Voltage = 1.0 pu			2020 Summer Peak POI Voltage = 1.0 pu			2020 Winter Peak POI Voltage = 1.006 pu			2025 Summer Peak POI Voltage = 1.0 pu		
	Contingency Name	Mvars at POI	Power Factor		Mvars at POI	Power Factor		Mvars at POI	Power Factor		Mvars at POI	Power Factor		Mvars at POI	Power Factor	
0	FLT_000_NOFAULT	-34.87	0.974	LEAD	-26.63	0.985	LEAD	-30.56	0.98	LEAD	-33.25	0.976	LEAD	-19.14	0.992	LEAD
1	FLT_01_TOLKWEST6_PLANTX6_230kV_3PH	-35.01	0.974	LEAD	-26.67	0.985	LEAD	-30.53	0.98	LEAD	-33.24	0.976	LEAD	-19.3	0.992	LEAD
2	FLT_03_TOLKWEST6_LAMBCNTY6_230kV_3PH	-31.69	0.978	LEAD	-18.87	0.992	LEAD	-21.23	0.99	LEAD	-32.08	0.978	LEAD	-10.08	0.998	LEAD
3	FLT_04_TUCOINT3_TUCOINT6_115_230kV_3PH	-34.88	0.974	LEAD	-26.49	0.985	LEAD	-30.41	0.98	LEAD	-33.21	0.976	LEAD	-19.1	0.992	LEAD
4	FLT_05_TUCOINT7_TUCOINT6_345_230kV_3PH	-35	0.974	LEAD	-26.7	0.985	LEAD	-30.52	0.98	LEAD	-33.08	0.977	LEAD	-19.19	0.992	LEAD
5	FLT_06_TUCOINT6_TOLKEAST6_230kV_3PH	-33.11	0.976	LEAD	-25.84	0.985	LEAD	-29.61	0.981	LEAD	-31.62	0.978	LEAD	-18.46	0.993	LEAD
6	FLT_07_TUCOINT6_JONES6_230kV_3PH	-34.64	0.974	LEAD	-26.66	0.985	LEAD	-30.24	0.98	LEAD	-32.82	0.977	LEAD	-18.89	0.992	LEAD
7	FLT_11_PLSNTHILL3_ECLOVIS3_115kV_3PH	-34.88	0.974	LEAD	-26.63	0.985	LEAD	-30.56	0.98	LEAD	-33.26	0.976	LEAD	-19.14	0.992	LEAD
8	FLT_12_PLSNTHILL3_NCLOVISTP3_115kV_3PH	-34.86	0.974	LEAD	-26.62	0.985	LEAD	-30.56	0.98	LEAD	-33.24	0.976	LEAD	-19.13	0.992	LEAD
9	FLT_13_PLSNTHILL3_FEHOLLAND3_115kV_3PH	-34.88	0.974	LEAD	-26.64	0.985	LEAD	-30.57	0.98	LEAD	-33.26	0.976	LEAD	-19.15	0.992	LEAD
10	FLT_14_PLSNTHILL6_PLSNTHILL3_230_115kV_3PH	-34.87	0.974	LEAD	-26.64	0.985	LEAD	-30.54	0.98	LEAD	-33.26	0.976	LEAD	-19.12	0.992	LEAD
11	FLT_15_PLSNTHILL6_OASIS6_230kV_3PH	-34.86	0.974	LEAD	-26.63	0.985	LEAD	-30.55	0.98	LEAD	-33.23	0.976	LEAD	-19.13	0.992	LEAD
12	FLT_16_PLSNTHILL6_ROSEVELTN6_230kV_3PH	-34.86	0.974	LEAD	-26.62	0.985	LEAD	-30.54	0.98	LEAD	-33.24	0.976	LEAD	-19.11	0.992	LEAD
13	FLT_17_OASIS6_OASIS3_230_115kV_3PH	-34.91	0.974	LEAD	-26.67	0.985	LEAD	-30.55	0.98	LEAD	-33.21	0.976	LEAD	-19.14	0.992	LEAD
14	FLT_18_FECLVSINT3_NCLOVISTP3_115kV_3PH	-34.87	0.974	LEAD	-26.63	0.985	LEAD	-30.56	0.98	LEAD	-33.25	0.976	LEAD	-19.14	0.992	LEAD
15	FLT_19_FECLVSINT3_WCLOVIS3_115kV_3PH	-34.86	0.974	LEAD	-26.62	0.985	LEAD	-30.55	0.98	LEAD	-33.23	0.976	LEAD	-19.13	0.992	LEAD
16	FLT_20_TUCOINT7_YOAKUM345_345kV_3PH **(20/25)**							-26.72	0.985	LEAD	-30.86	0.979	LEAD	-10.01	0.998	LEAD
17	FLT_21_POTTERCO7_POTTERCO6_345_230kV_3PH	-34.24	0.975	LEAD	-26.36	0.985	LEAD	-30.28	0.98	LEAD	-32.53	0.977	LEAD	-19.06	0.992	LEAD
18	FLT_22_BORDER7_TUCOINT7_345kV_3PH	-35.43	0.973	LEAD	-26.92	0.984	LEAD	-31.03	0.979	LEAD	-34.05	0.975	LEAD	-19.37	0.992	LEAD
19	FLT_23_OASIS3_PERIMETER3_115kV_3PH	-34.87	0.974	LEAD	-26.62	0.985	LEAD	-30.55	0.98	LEAD	-33.23	0.976	LEAD	-19.13	0.992	LEAD
20	FLT_24_OASIS3_FECHZPLT3_115kV_3PH	-34.87	0.974	LEAD	-26.63	0.985	LEAD	-30.54	0.98	LEAD	-33.23	0.976	LEAD	-19.12	0.992	LEAD
21	FLT_25_OASIS3_PORTALES3_115kV_3PH	-34.88	0.974	LEAD	-26.64	0.985	LEAD	-30.56	0.98	LEAD	-33.25	0.976	LEAD	-19.14	0.992	LEAD
22	FLT_26_PORTALES3_ROOSEVELT3_115kV_3PH	-34.86	0.974	LEAD	-26.62	0.985	LEAD	-30.55	0.98	LEAD	-33.24	0.976	LEAD	-19.12	0.992	LEAD
23	FLT_27_PORTALES3_PORTALES2_115_69kV_3PH	-34.87	0.974	LEAD	-26.62	0.985	LEAD	-30.56	0.98	LEAD	-33.25	0.976	LEAD	-19.14	0.992	LEAD
24	FLT_28_CURRY3_DS#203_115kV_3PH	-34.88	0.974	LEAD	-26.62	0.985	LEAD	-30.49	0.98	LEAD	-33.17	0.976	LEAD	-19.14	0.992	LEAD
25	FLT_29_CURRY3_NORRISTP3_115kV_3PH	-34.86	0.974	LEAD	-26.62	0.985	LEAD	-30.55	0.98	LEAD	-33.23	0.976	LEAD	-19.12	0.992	LEAD

GEN-2015-014 POI Lehman 115 kV (560030) Power at POI (MW): 150.0		DISIS-2015-001-3 Group 06 Leading power factor is absorbing vars; Lagging power factor is providing vars														
		2016 Winter Peak POI Voltage = 1.007 pu			2017 Summer Peak POI Voltage = 1.0 pu			2020 Summer Peak POI Voltage = 1.0 pu			2020 Winter Peak POI Voltage = 1.006 pu			2025 Summer Peak POI Voltage = 1.0 pu		
	Contingency Name	Mvars at POI	Power Factor		Mvars at POI	Power Factor		Mvars at POI	Power Factor		Mvars at POI	Power Factor		Mvars at POI	Power Factor	
26	FLT_30_CURRY3_ECLOVIS3_115kV_3PH	-34.87	0.974	LEAD	-26.63	0.985	LEAD	-30.58	0.98	LEAD	-33.26	0.976	LEAD	-19.16	0.992	LEAD
27	FLT_31_CURRY3_FECLOVIS23_115kV_3PH	-34.87	0.974	LEAD	-26.63	0.985	LEAD	-30.59	0.98	LEAD	-33.26	0.976	LEAD	-19.17	0.992	LEAD
28	FLT_32_CURRY3_ROOSEVELT3_115kV_3PH	-34.87	0.974	LEAD	-26.64	0.985	LEAD	-30.47	0.98	LEAD	-33.2	0.976	LEAD	-19.06	0.992	LEAD
29	FLT_33_CURRY3_BAILEYCO3_115kV_3PH	-34.89	0.974	LEAD	-26.72	0.985	LEAD	-30.36	0.98	LEAD	-33.22	0.976	LEAD	-18.82	0.992	LEAD
30	FLT_34_CURRY3_CURRY2_115_69kV_3PH	-34.87	0.974	LEAD	-26.63	0.985	LEAD	-30.56	0.98	LEAD	-33.25	0.976	LEAD	-19.14	0.992	LEAD
31	FLT_35_EMU&VLYTP3_BAILEYCO3_115kV_3PH	-34.76	0.974	LEAD	-26.38	0.985	LEAD	-30.01	0.981	LEAD	-33.02	0.977	LEAD	-18.87	0.992	LEAD
32	FLT_36_EMU&VLYTP3_PLANTX3_115kV_3PH	-34.74	0.974	LEAD	-26.33	0.985	LEAD	-29.77	0.981	LEAD	-32.97	0.977	LEAD	-19.06	0.992	LEAD
33	FLT_37_OASIS6_SNJUANTAP6_230kV_3PH	-35.23	0.974	LEAD	-27.03	0.984	LEAD	-30.94	0.979	LEAD	-33.62	0.976	LEAD	-19.41	0.992	LEAD
34	FLT_38_OASIS6_SW4K336_230kV_3PH	-34.83	0.974	LEAD	-26.57	0.985	LEAD	-30.54	0.98	LEAD	-33.22	0.976	LEAD	-19.04	0.992	LEAD
35	FLT_39_ROSEVELTN6_SW4K336_230kV_3PH	-34.88	0.974	LEAD	-26.64	0.985	LEAD	-30.58	0.98	LEAD	-33.26	0.976	LEAD	-19.14	0.992	LEAD
36	FLT_40_ROSEVELTN6_ROOSEVELT3_230_115kV_3PH	-34.88	0.974	LEAD	-26.63	0.985	LEAD	-30.52	0.98	LEAD	-33.21	0.976	LEAD	-19.04	0.992	LEAD
37	FLT_41_ROSEVELTS6_SW4K336_230kV_3PH	-34.79	0.974	LEAD	-26.51	0.985	LEAD	-30.58	0.98	LEAD	-33.18	0.976	LEAD	-18.9	0.992	LEAD
38	FLT_42_TOLKWEST6_TOLKTAP6_230kV_3PH	-34.83	0.974	LEAD	-26.71	0.985	LEAD	-30.67	0.98	LEAD	-33.27	0.976	LEAD	-19.3	0.992	LEAD
39	FLT_43_TOLKEAST6_PLANTX6_230kV_3PH	-35	0.974	LEAD	-26.67	0.985	LEAD	-30.53	0.98	LEAD	-33.24	0.976	LEAD	-19.29	0.992	LEAD
40	FLT_44_TOLKEAST6_TOLKTAP6_230kV_3PH	-34.85	0.974	LEAD	-26.63	0.985	LEAD	-30.54	0.98	LEAD	-33.16	0.976	LEAD	-19.18	0.992	LEAD
41	FLT_45_SWISHER3_KRESSINT3_115kV_3PH	-34.95	0.974	LEAD	-26.68	0.985	LEAD	-30.63	0.98	LEAD	-33.32	0.976	LEAD	-19.18	0.992	LEAD
42	FLT_46_SWISHER3_SWISHER6_115_230kV_3PH	-34.8	0.974	LEAD	-26.62	0.985	LEAD	-30.57	0.98	LEAD	-33.19	0.976	LEAD	-19.07	0.992	LEAD
43	FLT_47_KRESSINT3_TULIATP3_115kV_3PH	-34.82	0.974	LEAD	-26.65	0.985	LEAD	-30.56	0.98	LEAD	-33.18	0.976	LEAD	-19.13	0.992	LEAD
44	FLT_48_KRESSINT3_KRESSRURAL3_115kV_3PH	-34.83	0.974	LEAD	-26.51	0.985	LEAD	-30.44	0.98	LEAD	-33.21	0.976	LEAD	-19.02	0.992	LEAD
45	FLT_49_KRESSINT3_HALECNTY3_115kV_3PH	-34.87	0.974	LEAD	-26.61	0.985	LEAD	-30.55	0.98	LEAD	-33.25	0.976	LEAD	-19.13	0.992	LEAD
46	FLT_50_KRESSINT3_NEWHART3_115kV_3PH	-34.85	0.974	LEAD	-26.57	0.985	LEAD	-30.47	0.98	LEAD	-33.2	0.976	LEAD	-19.09	0.992	LEAD
47	FLT_51_RANDALL3_MANHATTAN3_115kV_3PH	-34.85	0.974	LEAD	-26.61	0.985	LEAD	-30.54	0.98	LEAD	-33.22	0.976	LEAD	-19.15	0.992	LEAD
48	FLT_52_RANDALL3_GEORGIA3_115kV_3PH	-34.87	0.974	LEAD	-26.62	0.985	LEAD	-30.56	0.98	LEAD	-33.24	0.976	LEAD	-19.14	0.992	LEAD
49	FLT_53_RANDALL3_SOUTHEAST3_115kV_3PH	-34.85	0.974	LEAD	-26.6	0.985	LEAD	-30.53	0.98	LEAD	-33.21	0.976	LEAD	-19.12	0.992	LEAD
50	FLT_54_RANDALL3_CANYONETP3_115kV_3PH	-34.83	0.974	LEAD	-26.65	0.985	LEAD	-30.58	0.98	LEAD	-33.17	0.976	LEAD	-19.18	0.992	LEAD
51	FLT_55_RANDALL3_PALODURO3_115kV_3PH	-34.83	0.974	LEAD	-26.59	0.985	LEAD	-30.52	0.98	LEAD	-33.19	0.976	LEAD	-19.13	0.992	LEAD
52	FLT_56_RANDALL3_RANDALL6_115_230kV_3PH	-34.87	0.974	LEAD	-26.63	0.985	LEAD	-30.57	0.98	LEAD	-33.25	0.976	LEAD	-19.14	0.992	LEAD
53	FLT_57_HALECNTY3_COX3_115kV_3PH	-34.81	0.974	LEAD	-26.54	0.985	LEAD	-30.46	0.98	LEAD	-33.18	0.976	LEAD	-19.05	0.992	LEAD
54	FLT_58_HALECNTY3_LAMTON3_115kV_3PH	-34.79	0.974	LEAD	-26.58	0.985	LEAD	-30.51	0.98	LEAD	-33.15	0.976	LEAD	-19.09	0.992	LEAD
55	FLT_59_HALECNTY3_PLANTX3_115kV_3PH	-34.61	0.974	LEAD	-26.39	0.985	LEAD	-30.32	0.98	LEAD	-32.99	0.977	LEAD	-18.92	0.992	LEAD
56	FLT_60_HALECNTY3_HALECNTY2_115_69kV_3PH	-34.87	0.974	LEAD	-26.61	0.985	LEAD	-30.55	0.98	LEAD	-33.24	0.976	LEAD	-19.13	0.992	LEAD
57	FLT_61_COX3_KISER3_115kV_3PH	-34.87	0.974	LEAD	-26.61	0.985	LEAD	-30.55	0.98	LEAD	-33.24	0.976	LEAD	-19.12	0.992	LEAD

		DISIS-2015-001-3 Group 06 Leading power factor is absorbing vars; Lagging power factor is providing vars														
GEN-2015-014 POI Lehman 115 kV (560030) Power at POI (MW): 150.0		2016 Winter Peak POI Voltage = 1.007 pu			2017 Summer Peak POI Voltage = 1.0 pu			2020 Summer Peak POI Voltage = 1.0 pu			2020 Winter Peak POI Voltage = 1.006 pu			2025 Summer Peak POI Voltage = 1.0 pu		
	Contingency Name	Mvars at POI	Power Factor		Mvars at POI	Power Factor		Mvars at POI	Power Factor		Mvars at POI	Power Factor		Mvars at POI	Power Factor	
58	FLT_62_COX3_FLOYDCNTY3_115kV_3PH	-34.91	0.974	LEAD	-26.73	0.984	LEAD	-30.68	0.98	LEAD	-33.31	0.976	LEAD	-19.24	0.992	LEAD
59	FLT_63_NEWHART3_CASTROCNTY3_115kV_3PH	-34.6	0.974	LEAD	-26.54	0.985	LEAD	-30.48	0.98	LEAD	-33	0.977	LEAD	-19.04	0.992	LEAD
60	FLT_64_NEWHART3_HARTINDUST3_115kV_3PH	-34.88	0.974	LEAD	-26.67	0.985	LEAD	-30.61	0.98	LEAD	-33.25	0.976	LEAD	-19.19	0.992	LEAD
61	FLT_65_NEWHART3_NEWHART6_115_230kV_3PH	-34.83	0.974	LEAD	-26.62	0.985	LEAD	-30.56	0.98	LEAD	-33.21	0.976	LEAD	-19.14	0.992	LEAD
62	FLT_66_SWISHER6_NEWHART6_230kV_3PH	-34.58	0.974	LEAD	-26.57	0.985	LEAD	-30.55	0.98	LEAD	-33.07	0.977	LEAD	-19.05	0.992	LEAD
63	FLT_67_SWISHER6_TUCOINT6_230kV_3PH	-34.6	0.974	LEAD	-26.79	0.984	LEAD	-30.86	0.979	LEAD	-33.02	0.977	LEAD	-19.23	0.992	LEAD
64	FLT_68_LEHMAN3_LEHMAN3_115kV_3PH	-31.88	0.978	LEAD	-23.82	0.988	LEAD	-24.05	0.987	LEAD	-23.42	0.988	LEAD	-12.8	0.996	LEAD
65	FLT_69_LEHMAN3_COCHRAN3_115kV_3PH	-13.8	0.996	LEAD	-16.32	0.994	LEAD	-19.85	0.991	LEAD	-20.93	0.99	LEAD	-20.11	0.991	LEAD
66	FLT_70_LEHMAN3_LGPLAINS3_115kV_3PH	-31.33	0.979	LEAD	-22.56	0.989	LEAD	-22.57	0.989	LEAD	-22.7	0.989	LEAD	-11.04	0.997	LEAD
67	FLT_71_PLAINSINT3_YOAKUM3_115kV_3PH	-27.63	0.983	LEAD	0.27	1	LAG	-14.14	0.996	LEAD	-29.78	0.981	LEAD	3.18	1	LAG
68	FLT_72_PLAINSINT3_LGPLAINS3_115kV_3PH	-32.63	0.977	LEAD	-23.06	0.988	LEAD	-23.01	0.988	LEAD	-24	0.987	LEAD	-11.43	0.997	LEAD
69	FLT_73_PLAINSINT3_LEPLNSINT2_115_69kV_3PH	-34.87	0.974	LEAD	-26.63	0.985	LEAD	-30.56	0.98	LEAD	-33.25	0.976	LEAD	-19.14	0.992	LEAD
70	FLT_74_COCHRAN3_PACIFIC3_115kV_3PH	-7.99	0.999	LEAD	-7.94	0.999	LEAD	-5.15	0.999	LEAD	-13.62	0.996	LEAD	2.72	1	LAG
71	FLT_75_COCHRAN3_COCHRAN2_115_69kV_3PH	-34.33	0.975	LEAD	-24.21	0.987	LEAD	-27.34	0.984	LEAD	-32.56	0.977	LEAD	-14.94	0.995	LEAD
72	FLT_76_SUNDOWN3_LCOPDYKE3_115kV_3PH	-43.07	0.961	LEAD	-37.29	0.97	LEAD	-42.48	0.962	LEAD	-40.26	0.966	LEAD	-35.61	0.973	LEAD
73	FLT_77_SUNDOWN3_AMOCOTP3_115kV_3PH	-40.17	0.966	LEAD	-35.4	0.973	LEAD	-40.89	0.965	LEAD	-38.67	0.968	LEAD	-28.36	0.983	LEAD
74	FLT_78_SUNDOWN3_SUNDOWN6_115_230kV_3PH	-12.44	0.997	LEAD	2.49	1	LAG	5.55	0.999	LAG	-15.98	0.994	LEAD	19.13	0.992	LAG
75	FLT_79_SUNDOWN6_PLANTX6_230kV_3PH	-21.95	0.989	LEAD	-17.34	0.993	LEAD	-20.97	0.99	LEAD	-24.23	0.987	LEAD	-8.12	0.999	LEAD
76	FLT_80_SUNDOWN6_AMOCOSS6_230kV_3PH	-29.86	0.981	LEAD	-26.94	0.984	LEAD	-31.23	0.979	LEAD	-34.2	0.975	LEAD	-17.37	0.993	LEAD
77	FLT_81_YOAKUM3_PRENTICE3_115kV_3PH	-34.55	0.974	LEAD	-26.14	0.985	LEAD	-29.8	0.981	LEAD	-32.78	0.977	LEAD	-18.51	0.992	LEAD
78	FLT_82_YOAKUM3_ARCOTP3_115kV_3PH	-38	0.969	LEAD	-31.34	0.979	LEAD	-35.23	0.974	LEAD	-37.17	0.971	LEAD	-25.48	0.986	LEAD
79	FLT_83_YOAKUM3_LGPLSHILL3_115kV_3PH	-34.12	0.975	LEAD	-27.03	0.984	LEAD	-30.95	0.979	LEAD	-33.23	0.976	LEAD	-19.95	0.991	LEAD
80	FLT_84_TUCOINT3_LUBBCKEST3_115kV_3PH	-34.79	0.974	LEAD	-26.56	0.985	LEAD	-30.52	0.98	LEAD	-33.12	0.976	LEAD	-19.09	0.992	LEAD
81	FLT_85_CARLISLE3_LPDOUDTP3_115kV_3PH	-33.71	0.976	LEAD	-24.88	0.987	LEAD	-29.1	0.982	LEAD	-31.85	0.978	LEAD	-16.83	0.994	LEAD
82	FLT_86_CARLISLE3_MURPHY3_115kV_3PH	-35.79	0.973	LEAD	-27.98	0.983	LEAD	-31.55	0.979	LEAD	-32.95	0.977	LEAD	-20.84	0.99	LEAD
83	FLT_87_CARLISLE6_LPMILWAKEE6_230kV_3PH	-34.96	0.974	LEAD	-27.51	0.984	LEAD	-30.96	0.979	LEAD	-33.4	0.976	LEAD	-19.2	0.992	LEAD
84	FLT_88_CARLISLE6_TUCOINT6_230kV_3PH							-29.2	0.982	LEAD	-32	0.978	LEAD	-17.13	0.994	LEAD
85	FLT_89_CARLISLE6_WOLFFORTH6_230kV_3PH **(20/25)**	-33.49	0.976	LEAD	-23.28	0.988	LEAD	-29.14	0.982	LEAD	-32.88	0.977	LEAD	-17.35	0.993	LEAD
86	FLT_90_CARLISLE3_CARLISLE6_115_230kV_3PH	-32.22	0.978	LEAD	-25.92	0.985	LEAD	-29.74	0.981	LEAD	-32.78	0.977	LEAD	-17.58	0.993	LEAD
87	FLT_91_JONES6_LPHOLLY6_230kV_3PH	-34.79	0.974	LEAD	-26.38	0.985	LEAD	-30.32	0.98	LEAD	-33.15	0.976	LEAD	-19	0.992	LEAD
88	FLT_92_JONES6_LUBBCKSTH6_230kV_3PH	-34.76	0.974	LEAD	-26.4	0.985	LEAD	-30.25	0.98	LEAD	-32.8	0.977	LEAD	-18.89	0.992	LEAD
89	FLT_93_JONES6_LUBBCKEST6_230kV_3PH	-34.66	0.974	LEAD	-25.8	0.986	LEAD	-29.83	0.981	LEAD	-32.96	0.977	LEAD	-17.96	0.993	LEAD

GEN-2015-014 POI Lehman 115 kV (560030) Power at POI (MW): 150.0		DISIS-2015-001-3 Group 06 Leading power factor is absorbing vars; Lagging power factor is providing vars														
		2016 Winter Peak POI Voltage = 1.007 pu			2017 Summer Peak POI Voltage = 1.0 pu			2020 Summer Peak POI Voltage = 1.0 pu			2020 Winter Peak POI Voltage = 1.006 pu			2025 Summer Peak POI Voltage = 1.0 pu		
	Contingency Name	Mvars at POI	Power Factor		Mvars at POI	Power Factor		Mvars at POI	Power Factor		Mvars at POI	Power Factor		Mvars at POI	Power Factor	
90	FLT_94_YUMAINT3_SPWOLFTP3_115kV_3PH	-34.55	0.974	LEAD	-26.12	0.985	LEAD	-29.88	0.981	LEAD	-32.41	0.977	LEAD	-18.53	0.992	LEAD
91	FLT_95_YUMAINT3_WOLFFORTH3_115kV_3PH	-36.4	0.972	LEAD	-28.58	0.982	LEAD	-32.39	0.977	LEAD	-34.04	0.975	LEAD	-22.15	0.989	LEAD
92	FLT_96_SPWOLFTP3_LPDOUDTP3_115kV_3PH	-34.01	0.975	LEAD	-25.48	0.986	LEAD	-29.25	0.982	LEAD	-32.05	0.978	LEAD	-17.66	0.993	LEAD
93	FLT_97_CARLISLE3_CARLISLE2_115_69kV_3PH	-34.9	0.974	LEAD	-26.19	0.985	LEAD	-30.19	0.98	LEAD	-33.28	0.976	LEAD	-18.79	0.992	LEAD
94	FLT_98_LUBBCKSTH3_SPWOODROW3_115kV_3PH	-34.81	0.974	LEAD	-26.59	0.985	LEAD	-30.64	0.98	LEAD	-33.42	0.976	LEAD	-19.36	0.992	LEAD
95	FLT_99_LUBBCKSTH3_LUBBCKSTH2_115_69kV_3PH	-34.97	0.974	LEAD	-26.74	0.984	LEAD	-30.66	0.98	LEAD	-33.31	0.976	LEAD	-19.26	0.992	LEAD
96	FLT_100_LUBBCKSTH3_LUBBCKSTH6_115_230kV_3PH	-35.01	0.974	LEAD	-26.75	0.984	LEAD	-30.58	0.98	LEAD	-33.23	0.976	LEAD	-19.2	0.992	LEAD
97	FLT_101_WOLFFORTH3_TERRYCNTY3_115kV_3PH	-30.89	0.979	LEAD	-22.94	0.989	LEAD	-28.17	0.983	LEAD	-32.29	0.978	LEAD	-14.17	0.996	LEAD
98	FLT_102_WOLFFORTH3_WOLFFORTH6_115_230kV_3PH	-33.41	0.976	LEAD	-24.16	0.987	LEAD	-28.55	0.982	LEAD	-32.2	0.978	LEAD	-15.87	0.994	LEAD
99	FLT_103_WOLFFORTH6_LUBBCKSTH6_230kV_3PH	-25.97	0.985	LEAD	-20.64	0.991	LEAD	-26.47	0.985	LEAD	-31.53	0.979	LEAD	-13.91	0.996	LEAD
100	FLT_104_WOLFFORTH6_SUNDOWN6_230kV_3PH	-30.85	0.979	LEAD	-20.03	0.991	LEAD	-22.36	0.989	LEAD	-30.87	0.979	LEAD	-10.31	0.998	LEAD
101	FLT_105_TERRYCNTY3_LGCLAUENE3_115kV_3PH	-34.72	0.974	LEAD	-26.73	0.984	LEAD	-30.84	0.98	LEAD	-33.07	0.977	LEAD	-19.2	0.992	LEAD
102	FLT_106_TERRYCNTY3_PRENTICE3_115kV_3PH	-34.63	0.974	LEAD	-26.42	0.985	LEAD	-30.35	0.98	LEAD	-33.09	0.977	LEAD	-18.96	0.992	LEAD
103	FLT_107_TERRYCNTY3_DENVERN3_115kV_3PH	-35.32	0.973	LEAD	-26.51	0.985	LEAD	-30.66	0.98	LEAD	-33.5	0.976	LEAD	-19.21	0.992	LEAD
104	FLT_108_TERRYCNTY3_SULPHUR3_115kV_3PH	-34.63	0.974	LEAD	-26.73	0.984	LEAD	-31.04	0.979	LEAD	-33.15	0.976	LEAD	-19.72	0.991	LEAD
105	FLT_109_TERRYCNTY3_TERRYCNTY2_115_69kV_3PH	-34.78	0.974	LEAD	-26.11	0.985	LEAD	-30.18	0.98	LEAD	-33.2	0.976	LEAD	-18.61	0.992	LEAD
106	FLT_110_TOLKTAP6_TOLK7_230_345kV_3PH	-35.27	0.973	LEAD	-27.03	0.984	LEAD	-31.06	0.979	LEAD	-33.9	0.975	LEAD	-19.29	0.992	LEAD
107	FLT_111_TOLKWEST6_G13027TAP_230kV_3PH	-30.91	0.979	LEAD	-22.39	0.989	LEAD	-29.22	0.982	LEAD	-31.74	0.978	LEAD	-17.25	0.993	LEAD
108	FLT_112_G13027TAP_YOAKUM6_230kV_3PH	-25.78	0.986	LEAD	-20.51	0.991	LEAD	-28.08	0.983	LEAD	-30.42	0.98	LEAD	-14.75	0.995	LEAD
109	FLT_114_YOAKUM6_AMOCOSS6_230kV_3PH	-33.08	0.977	LEAD	-25.51	0.986	LEAD	-27.91	0.983	LEAD	-31.51	0.979	LEAD	-16.72	0.994	LEAD
110	FLT_115_YOAKUM6_OXYBRUTP6_230kV_3PH	-34.71	0.974	LEAD	-26.47	0.985	LEAD	-30.73	0.98	LEAD	-33.45	0.976	LEAD	-19.13	0.992	LEAD
111	FLT_116_YOAKUM6_MUSTANG6_230kV_3PH	-34.48	0.975	LEAD	-26.22	0.985	LEAD	-30.52	0.98	LEAD	-33.22	0.976	LEAD	-18.98	0.992	LEAD
112	FLT_117_YOAKUM6_HOBBSINT6_230kV_3PH	-30.35	0.98	LEAD	-20.95	0.99	LEAD	-28.05	0.983	LEAD	-31.63	0.978	LEAD	-14.73	0.995	LEAD
113	FLT_118_YOAKUM6_YOAKUM3_230_115kV_3PH	-32.45	0.977	LEAD	-24.33	0.987	LEAD	-26.59	0.985	LEAD	-30.12	0.98	LEAD	-13.77	0.996	LEAD
114	FLT_121_TOLKWEST6_ROSEVELTN6_230kV_3PH	-34.8	0.974	LEAD	-26.52	0.985	LEAD	-30.51	0.98	LEAD	-33.18	0.976	LEAD	-18.97	0.992	LEAD
115	FLT_123_BORDER7_WWRDEHV7_345kV_3PH	-35.58	0.973	LEAD	-27.01	0.984	LEAD	-31.13	0.979	LEAD	-34.21	0.975	LEAD	-19.52	0.992	LEAD
116	FLT_124_OKU7_TUCOINT7_345kV_3PH	-35.92	0.973	LEAD	-27.01	0.984	LEAD	-30.99	0.979	LEAD	-34.22	0.975	LEAD	-19.31	0.992	LEAD

Table F-2: GEN-2015-022 Power Factor Analysis Results

GEN-2015-022 POI Swisher 115 kV (525212) Power at POI (MW): 112.0		DISIS-2015-001-3 Group 06 Leading power factor is absorbing vars; Lagging power factor is providing vars														
		2016 Winter Peak POI Voltage = 1.011 pu			2017 Summer Peak POI Voltage = 1.015 pu			2020 Summer Peak POI Voltage = 1.005 pu			2020 Winter Peak POI Voltage = 1.011 pu			2025 Summer Peak POI Voltage = 1.015 pu		
	Contingency Name	**Mvars at POI**	**Power Factor**		**Mvars at POI**	**Power Factor**		**Mvars at POI**	**Power Factor**		**Mvars at POI**	**Power Factor**		**Mvars at POI**	**Power Factor**	
0	FLT_000_NOFAULT	-12.33	0.994	LEAD	-18.13	0.987	LEAD	-18.03	0.987	LEAD	-13.41	0.993	LEAD	-20.31	0.984	LEAD
1	FLT_01_TOLKWEST6_PLANTX6_230kV_3PH	-12.45	0.994	LEAD	-18.19	0.987	LEAD	-18.17	0.987	LEAD	-13.58	0.993	LEAD	-20.6	0.983	LEAD
2	FLT_03_TOLKWEST6_LAMBCNTY6_230kV_3PH	-13.33	0.993	LEAD	-18.63	0.986	LEAD	-18.62	0.986	LEAD	-14.33	0.992	LEAD	-20.73	0.983	LEAD
3	FLT_04_TUCOINT3_TUCOINT6_115_230kV_3PH	-12.65	0.994	LEAD	-17.09	0.989	LEAD	-16.02	0.99	LEAD	-12.8	0.994	LEAD	-18.92	0.986	LEAD
4	FLT_05_TUCOINT7_TUCOINT6_345_230kV_3PH	-11.08	0.995	LEAD	-17.98	0.987	LEAD	-17.25	0.988	LEAD	-13.05	0.993	LEAD	-19.91	0.985	LEAD
5	FLT_06_TUCOINT6_TOLKEAST6_230kV_3PH	-5.06	0.999	LEAD	-16.41	0.989	LEAD	-16.87	0.989	LEAD	-10.07	0.996	LEAD	-18.99	0.986	LEAD
6	FLT_07_TUCOINT6_JONES6_230kV_3PH	-12.24	0.994	LEAD	-20.28	0.984	LEAD	-18.44	0.987	LEAD	-14.36	0.992	LEAD	-20.7	0.983	LEAD
7	FLT_11_PLSNTHILL3_ECLOVIS3_115kV_3PH	-12.36	0.994	LEAD	-18.16	0.987	LEAD	-18.05	0.987	LEAD	-13.44	0.993	LEAD	-20.33	0.984	LEAD
8	FLT_12_PLSNTHILL3_NCLOVISTP3_115kV_3PH	-12.31	0.994	LEAD	-18.11	0.987	LEAD	-17.99	0.987	LEAD	-13.39	0.993	LEAD	-20.29	0.984	LEAD
9	FLT_13_PLSNTHILL3_FEHOLLAND3_115kV_3PH	-12.37	0.994	LEAD	-18.17	0.987	LEAD	-18.07	0.987	LEAD	-13.45	0.993	LEAD	-20.34	0.984	LEAD
10	FLT_14_PLSNTHILL6_PLSNTHILL3_230_115kV_3PH	-12.35	0.994	LEAD	-18.06	0.987	LEAD	-18	0.987	LEAD	-13.45	0.993	LEAD	-20.28	0.984	LEAD
11	FLT_15_PLSNTHILL6_OASIS6_230kV_3PH	-12.27	0.994	LEAD	-18.09	0.987	LEAD	-17.98	0.987	LEAD	-13.37	0.993	LEAD	-20.28	0.984	LEAD
12	FLT_16_PLSNTHILL6_ROSEVELTN6_230kV_3PH	-12.3	0.994	LEAD	-18.09	0.987	LEAD	-17.99	0.987	LEAD	-13.38	0.993	LEAD	-20.29	0.984	LEAD
13	FLT_17_OASIS6_OASIS3_230_115kV_3PH	-12.18	0.994	LEAD	-18.12	0.987	LEAD	-18.04	0.987	LEAD	-13.31	0.993	LEAD	-20.27	0.984	LEAD
14	FLT_18_FECLVSINT3_NCLOVISTP3_115kV_3PH	-12.33	0.994	LEAD	-18.13	0.987	LEAD	-18.02	0.987	LEAD	-13.41	0.993	LEAD	-20.31	0.984	LEAD
15	FLT_19_FECLVSINT3_WCLOVIS3_115kV_3PH	-12.31	0.994	LEAD	-18.12	0.987	LEAD	-18.02	0.987	LEAD	-13.39	0.993	LEAD	-20.3	0.984	LEAD
16	FLT_20_TUCOINT7_YOAKUM345_345kV_3PH **(20/25)**							-18.01	0.987	LEAD	-12.03	0.994	LEAD	-22.03	0.981	LEAD
17	FLT_21_POTTERCO7_POTTERCO6_345_230kV_3PH	-10.06	0.996	LEAD	-17.59	0.988	LEAD	-17.87	0.988	LEAD	-13.95	0.992	LEAD	-19.24	0.986	LEAD
18	FLT_22_BORDER7_TUCOINT7_345kV_3PH	-2.72	1	LEAD	-13.35	0.993	LEAD	-12.21	0.994	LEAD	-2.58	1	LEAD	-19.05	0.986	LEAD
19	FLT_23_OASIS3_PERIMETER3_115kV_3PH	-12.27	0.994	LEAD	-18.08	0.987	LEAD	-17.98	0.987	LEAD	-13.36	0.993	LEAD	-20.28	0.984	LEAD
20	FLT_24_OASIS3_FECHZPLT3_115kV_3PH	-12.29	0.994	LEAD	-18.1	0.987	LEAD	-17.99	0.987	LEAD	-13.38	0.993	LEAD	-20.27	0.984	LEAD
21	FLT_25_OASIS3_PORTALES3_115kV_3PH	-12.3	0.994	LEAD	-18.11	0.987	LEAD	-18.02	0.987	LEAD	-13.4	0.993	LEAD	-20.3	0.984	LEAD
22	FLT_26_PORTALES3_ROOSEVELT3_115kV_3PH	-12.29	0.994	LEAD	-18.11	0.987	LEAD	-18	0.987	LEAD	-13.39	0.993	LEAD	-20.29	0.984	LEAD
23	FLT_27_PORTALES3_PORTALES2_115_69kV_3PH	-12.3	0.994	LEAD	-18.12	0.987	LEAD	-18.02	0.987	LEAD	-13.41	0.993	LEAD	-20.31	0.984	LEAD
24	FLT_28_CURRY3_DS#203_115kV_3PH	-11.79	0.995	LEAD	-17.58	0.988	LEAD	-17.58	0.988	LEAD	-13.31	0.993	LEAD	-20.06	0.984	LEAD
25	FLT_29_CURRY3_NORRISTP3_115kV_3PH	-12.3	0.994	LEAD	-18.11	0.987	LEAD	-18.01	0.987	LEAD	-13.39	0.993	LEAD	-20.29	0.984	LEAD
26	FLT_30_CURRY3_ECLOVIS3_115kV_3PH	-12.34	0.994	LEAD	-18.16	0.987	LEAD	-18.06	0.987	LEAD	-13.43	0.993	LEAD	-20.34	0.984	LEAD
27	FLT_31_CURRY3_FECLOVIS23_115kV_3PH	-12.35	0.994	LEAD	-18.16	0.987	LEAD	-18.07	0.987	LEAD	-13.43	0.993	LEAD	-20.35	0.984	LEAD
28	FLT_32_CURRY3_ROOSEVELT3_115kV_3PH	-12.14	0.994	LEAD	-17.99	0.987	LEAD	-17.9	0.987	LEAD	-13.33	0.993	LEAD	-20.21	0.984	LEAD
29	FLT_33_CURRY3_BAILEYCO3_115kV_3PH	-12.43	0.994	LEAD	-18.52	0.987	LEAD	-18.34	0.987	LEAD	-13.54	0.993	LEAD	-20.51	0.984	LEAD

GEN-2015-022 POI Swisher 115 kV (525212) Power at POI (MW): 112.0		DISIS-2015-001-3 Group 06 Leading power factor is absorbing vars; Lagging power factor is providing vars														
		2016 Winter Peak POI Voltage = 1.011 pu			2017 Summer Peak POI Voltage = 1.015 pu			2020 Summer Peak POI Voltage = 1.005 pu			2020 Winter Peak POI Voltage = 1.011 pu			2025 Summer Peak POI Voltage = 1.015 pu		
	Contingency Name	Mvars at POI	Power Factor		Mvars at POI	Power Factor		Mvars at POI	Power Factor		Mvars at POI	Power Factor		Mvars at POI	Power Factor	
30	FLT_34_CURRY3_CURRY2_115_69kV_3PH	-12.33	0.994	LEAD	-18.14	0.987	LEAD	-18.03	0.987	LEAD	-13.41	0.993	LEAD	-20.31	0.984	LEAD
31	FLT_35_EMU&VLYTP3_BAILEYCO3_115kV_3PH	-11.94	0.994	LEAD	-17.29	0.988	LEAD	-17.35	0.988	LEAD	-12.95	0.993	LEAD	-19.75	0.985	LEAD
32	FLT_36_EMU&VLYTP3_PLANTX3_115kV_3PH	-11.83	0.994	LEAD	-17.11	0.989	LEAD	-17.16	0.988	LEAD	-12.86	0.993	LEAD	-19.66	0.985	LEAD
33	FLT_37_OASIS6_SNJUANTAP6_230kV_3PH	-12.33	0.994	LEAD	-18.14	0.987	LEAD	-18.46	0.987	LEAD	-13.86	0.992	LEAD	-20.31	0.984	LEAD
34	FLT_38_OASIS6_SW4K336_230kV_3PH	-12.27	0.994	LEAD	-18.14	0.987	LEAD	-18.01	0.987	LEAD	-13.35	0.993	LEAD	-20.3	0.984	LEAD
35	FLT_39_ROSEVELTN6_SW4K336_230kV_3PH	-12.29	0.994	LEAD	-18.1	0.987	LEAD	-18.07	0.987	LEAD	-13.42	0.993	LEAD	-20.29	0.984	LEAD
36	FLT_40_ROSEVELTN6_ROOSEVELT3_230_115kV_3PH	-12.13	0.994	LEAD	-18.07	0.987	LEAD	-18.04	0.987	LEAD	-13.36	0.993	LEAD	-20.22	0.984	LEAD
37	FLT_41_ROSEVELTS6_SW4K336_230kV_3PH	-12.18	0.994	LEAD	-18.16	0.987	LEAD	-18.32	0.987	LEAD	-13.32	0.993	LEAD	-20.27	0.984	LEAD
38	FLT_42_TOLKWEST6_TOLKTAP6_230kV_3PH	-12.31	0.994	LEAD	-18.17	0.987	LEAD	-18.06	0.987	LEAD	-13.42	0.993	LEAD	-20.39	0.984	LEAD
39	FLT_43_TOLKEAST6_PLANTX6_230kV_3PH	-12.44	0.994	LEAD	-18.19	0.987	LEAD	-18.16	0.987	LEAD	-13.57	0.993	LEAD	-20.59	0.984	LEAD
40	FLT_44_TOLKEAST6_TOLKTAP6_230kV_3PH	-12.29	0.994	LEAD	-18.14	0.987	LEAD	-18.03	0.987	LEAD	-13.39	0.993	LEAD	-20.36	0.984	LEAD
41	FLT_45_SWISHER3_KRESSINT3_115kV_3PH	-6.28	0.998	LEAD	-60.1	0.881	LEAD	-41.03	0.939	LEAD	3.38	1	LAG	-72.88	0.838	LEAD
42	FLT_46_SWISHER3_SWISHER6_115_230kV_3PH	-11.73	0.995	LEAD	44.98	0.928	LAG	26.44	0.973	LAG	-22.62	0.98	LEAD	60.38	0.88	LAG
43	FLT_47_KRESSINT3_TULIATP3_115kV_3PH	-19.73	0.985	LEAD	-32.35	0.961	LEAD	-28.55	0.969	LEAD	-21.06	0.983	LEAD	-29.96	0.966	LEAD
44	FLT_48_KRESSINT3_KRESSRURAL3_115kV_3PH	-12.57	0.994	LEAD	-25.83	0.974	LEAD	-25.63	0.975	LEAD	-14.57	0.992	LEAD	-34.82	0.955	LEAD
45	FLT_49_KRESSINT3_HALECNTY3_115kV_3PH	-13.33	0.993	LEAD	-25.67	0.975	LEAD	-24.88	0.976	LEAD	-12.23	0.994	LEAD	-33.48	0.958	LEAD
46	FLT_50_KRESSINT3_NEWHART3_115kV_3PH	-17.84	0.988	LEAD	-13.27	0.993	LEAD	-2.17	1	LEAD	-11.25	0.995	LEAD	-14.07	0.992	LEAD
47	FLT_51_RANDALL3_MANHATTAN3_115kV_3PH	-10.44	0.996	LEAD	-15.95	0.99	LEAD	-15.76	0.99	LEAD	-10.37	0.996	LEAD	-21.23	0.983	LEAD
48	FLT_52_RANDALL3_GEORGIA3_115kV_3PH	-12.95	0.993	LEAD	-18.5	0.987	LEAD	-18.59	0.987	LEAD	-13.65	0.993	LEAD	-22.1	0.981	LEAD
49	FLT_53_RANDALL3_SOUTHEAST3_115kV_3PH	-12.47	0.994	LEAD	-18.46	0.987	LEAD	-18.45	0.987	LEAD	-13.7	0.993	LEAD	-20.77	0.983	LEAD
50	FLT_54_RANDALL3_CANYONETP3_115kV_3PH	-12.07	0.994	LEAD	-19.07	0.986	LEAD	-18.24	0.987	LEAD	-12.2	0.994	LEAD	-21.08	0.983	LEAD
51	FLT_55_RANDALL3_PALODURO3_115kV_3PH	-12.74	0.994	LEAD	-10.35	0.996	LEAD	-8.88	0.997	LEAD	-13.7	0.993	LEAD	-4.11	0.999	LEAD
52	FLT_56_RANDALL3_RANDALL6_115_230kV_3PH	-12.29	0.994	LEAD	-18.06	0.987	LEAD	-18.04	0.987	LEAD	-14	0.992	LEAD	-18.57	0.987	LEAD
53	FLT_57_HALECNTY3_COX3_115kV_3PH	-11.89	0.994	LEAD	-16.26	0.99	LEAD	-15.99	0.99	LEAD	-12.48	0.994	LEAD	-17.25	0.988	LEAD
54	FLT_58_HALECNTY3_LAMTON3_115kV_3PH	-12.66	0.994	LEAD	-18.08	0.987	LEAD	-17.52	0.988	LEAD	-12.73	0.994	LEAD	-20.15	0.984	LEAD
55	FLT_59_HALECNTY3_PLANTX3_115kV_3PH	-11.36	0.995	LEAD	-14.15	0.992	LEAD	-14.78	0.991	LEAD	-12.08	0.994	LEAD	-15.96	0.99	LEAD
56	FLT_60_HALECNTY3_HALECNTY2_115_69kV_3PH	-12.15	0.994	LEAD	-17.47	0.988	LEAD	-17.22	0.988	LEAD	-13.18	0.993	LEAD	-19.29	0.985	LEAD
57	FLT_61_COX3_KISER3_115kV_3PH	-12.37	0.994	LEAD	-19.97	0.984	LEAD	-20.23	0.984	LEAD	-13.72	0.993	LEAD	-26.34	0.973	LEAD
58	FLT_62_COX3_FLOYDCNTY3_115kV_3PH	-7.38	0.998	LEAD	-8.86	0.997	LEAD	-6.47	0.998	LEAD	-8.99	0.997	LEAD	-7.06	0.998	LEAD
59	FLT_63_NEWHART3_CASTROCNTY3_115kV_3PH	-20.06	0.984	LEAD	-27.51	0.971	LEAD	-29.33	0.967	LEAD	-23.02	0.98	LEAD	-28.93	0.968	LEAD
60	FLT_64_NEWHART3_HARTINDUST3_115kV_3PH	-12.3	0.994	LEAD	-19.38	0.985	LEAD	-20.35	0.984	LEAD	-13.7	0.993	LEAD	-21.83	0.982	LEAD
61	FLT_65_NEWHART3_NEWHART6_115_230kV_3PH	-10.31	0.996	LEAD	-15.35	0.991	LEAD	-13.74	0.993	LEAD	-10.56	0.996	LEAD	-18.29	0.987	LEAD

GEN-2015-022 POI Swisher 115 kV (525212) Power at POI (MW): 112.0		DISIS-2015-001-3 Group 06 Leading power factor is absorbing vars; Lagging power factor is providing vars														
		2016 Winter Peak POI Voltage = 1.011 pu			2017 Summer Peak POI Voltage = 1.015 pu			2020 Summer Peak POI Voltage = 1.005 pu			2020 Winter Peak POI Voltage = 1.011 pu			2025 Summer Peak POI Voltage = 1.015 pu		
	Contingency Name	Mvars at POI	Power Factor		Mvars at POI	Power Factor		Mvars at POI	Power Factor		Mvars at POI	Power Factor		Mvars at POI	Power Factor	
62	FLT_66_SWISHER6_NEWHART6_230kV_3PH	-5.99	0.999	LEAD	-19.27	0.986	LEAD	-23.92	0.978	LEAD	-16.45	0.989	LEAD	-19.49	0.985	LEAD
63	FLT_67_SWISHER6_TUCOINT6_230kV_3PH	-17.69	0.988	LEAD	-8.24	0.997	LEAD	-6.25	0.998	LEAD	-21.26	0.982	LEAD	-7.15	0.998	LEAD
64	FLT_68_LEHMAN3_LEHMAN3_115kV_3PH	-12.35	0.994	LEAD	-18.12	0.987	LEAD	-17.88	0.987	LEAD	-13.14	0.993	LEAD	-20.23	0.984	LEAD
65	FLT_69_LEHMAN3_COCHRAN3_115kV_3PH	-12.47	0.994	LEAD	-18.07	0.987	LEAD	-18.1	0.987	LEAD	-13.69	0.993	LEAD	-20.37	0.984	LEAD
66	FLT_70_LEHMAN3_LGPLAINS3_115kV_3PH	-12.33	0.994	LEAD	-18.11	0.987	LEAD	-17.89	0.987	LEAD	-13.15	0.993	LEAD	-20.23	0.984	LEAD
67	FLT_71_PLAINSINT3_YOAKUM3_115kV_3PH	-12.33	0.994	LEAD	-17.91	0.987	LEAD	-17.92	0.987	LEAD	-13.35	0.993	LEAD	-20.22	0.984	LEAD
68	FLT_72_PLAINSINT3_LGPLAINS3_115kV_3PH	-12.36	0.994	LEAD	-18.13	0.987	LEAD	-17.92	0.987	LEAD	-13.18	0.993	LEAD	-20.24	0.984	LEAD
69	FLT_73_PLAINSINT3_LEPLNSINT2_115_69kV_3PH	-12.33	0.994	LEAD	-18.13	0.987	LEAD	-18.03	0.987	LEAD	-13.41	0.993	LEAD	-20.31	0.984	LEAD
70	FLT_74_COCHRAN3_PACIFIC3_115kV_3PH	-12.37	0.994	LEAD	-18.16	0.987	LEAD	-17.99	0.987	LEAD	-13.54	0.993	LEAD	-20.27	0.984	LEAD
71	FLT_75_COCHRAN3_COCHRAN2_115_69kV_3PH	-12.3	0.994	LEAD	-18.07	0.987	LEAD	-17.94	0.987	LEAD	-13.38	0.993	LEAD	-20.27	0.984	LEAD
72	FLT_76_SUNDOWN3_LCOPDYKE3_115kV_3PH	-12.06	0.994	LEAD	-18.53	0.987	LEAD	-18.49	0.987	LEAD	-13.46	0.993	LEAD	-20.43	0.984	LEAD
73	FLT_77_SUNDOWN3_AMOCOTP3_115kV_3PH	-11.63	0.995	LEAD	-17.67	0.988	LEAD	-17.6	0.988	LEAD	-12.99	0.993	LEAD	-20.02	0.984	LEAD
74	FLT_78_SUNDOWN3_SUNDOWN6_115_230kV_3PH	-12.06	0.994	LEAD	-18.22	0.987	LEAD	-17.97	0.987	LEAD	-13.36	0.993	LEAD	-20.27	0.984	LEAD
75	FLT_79_SUNDOWN6_PLANTX6_230kV_3PH	-9.33	0.997	LEAD	-15.36	0.991	LEAD	-15.46	0.991	LEAD	-10.58	0.996	LEAD	-17.31	0.988	LEAD
76	FLT_80_SUNDOWN6_AMOCOSS6_230kV_3PH	-13.06	0.993	LEAD	-18.74	0.986	LEAD	-17.32	0.988	LEAD	-12.68	0.994	LEAD	-19.92	0.985	LEAD
77	FLT_81_YOAKUM3_PRENTICE3_115kV_3PH	-12.29	0.994	LEAD	-17.99	0.987	LEAD	-17.95	0.987	LEAD	-13.36	0.993	LEAD	-20.25	0.984	LEAD
78	FLT_82_YOAKUM3_ARCOTP3_115kV_3PH	-12.27	0.994	LEAD	-18.19	0.987	LEAD	-18.09	0.987	LEAD	-13.43	0.993	LEAD	-20.31	0.984	LEAD
79	FLT_83_YOAKUM3_LGPLSHILL3_115kV_3PH	-12.3	0.994	LEAD	-18.08	0.987	LEAD	-18	0.987	LEAD	-13.4	0.993	LEAD	-20.29	0.984	LEAD
80	FLT_84_TUCOINT3_LUBBCKEST3_115kV_3PH	-11.51	0.995	LEAD	-17.5	0.988	LEAD	-18.15	0.987	LEAD	-12.31	0.994	LEAD	-19.79	0.985	LEAD
81	FLT_85_CARLISLE3_LPDOUDTP3_115kV_3PH	-13.08	0.993	LEAD	-18.66	0.986	LEAD	-18.44	0.987	LEAD	-13.78	0.993	LEAD	-20.61	0.983	LEAD
82	FLT_86_CARLISLE3_MURPHY3_115kV_3PH	-14.05	0.992	LEAD	-19.03	0.986	LEAD	-18.63	0.986	LEAD	-13.23	0.993	LEAD	-20.7	0.983	LEAD
83	FLT_87_CARLISLE6_LPMILWAKEE6_230kV_3PH	-13.19	0.993	LEAD	-18.99	0.986	LEAD	-18.44	0.987	LEAD	-13.66	0.993	LEAD	-20.32	0.984	LEAD
84	FLT_88_CARLISLE6_TUCOINT6_230kV_3PH	-13.68	0.993	LEAD	-20.85	0.983	LEAD	-19.43	0.985	LEAD	-15.43	0.991	LEAD	-20.76	0.983	LEAD
85	FLT_89_CARLISLE6_WOLFFORTH6_230kV_3PH **(20/25)**							-18.6	0.986	LEAD	-13.48	0.993	LEAD	-20.45	0.984	LEAD
86	FLT_90_CARLISLE3_CARLISLE6_115_230kV_3PH	-14.34	0.992	LEAD	-17.93	0.987	LEAD	-17.58	0.988	LEAD	-13.19	0.993	LEAD	-19.31	0.985	LEAD
87	FLT_91_JONES6_LPHOLLY6_230kV_3PH	-12.18	0.994	LEAD	-17.9	0.987	LEAD	-17.87	0.988	LEAD	-13.36	0.993	LEAD	-20.31	0.984	LEAD
88	FLT_92_JONES6_LUBBCKSTH6_230kV_3PH	-12.45	0.994	LEAD	-18.14	0.987	LEAD	-17.89	0.987	LEAD	-13.13	0.993	LEAD	-20.31	0.984	LEAD
89	FLT_93_JONES6_LUBBCKEST6_230kV_3PH	-11.13	0.995	LEAD	-14.65	0.992	LEAD	-15.19	0.991	LEAD	-12.03	0.994	LEAD	-15.69	0.99	LEAD
90	FLT_94_YUMAINT3_SPWOLFTP3_115kV_3PH	-12.56	0.994	LEAD	-18.34	0.987	LEAD	-18.22	0.987	LEAD	-13.68	0.993	LEAD	-20.42	0.984	LEAD
91	FLT_95_YUMAINT3_WOLFFORTH3_115kV_3PH	-11.15	0.995	LEAD	-17.41	0.988	LEAD	-17.58	0.988	LEAD	-13.08	0.993	LEAD	-19.89	0.985	LEAD
92	FLT_96_SPWOLFTP3_LPDOUDTP3_115kV_3PH	-12.89	0.993	LEAD	-18.55	0.987	LEAD	-18.38	0.987	LEAD	-13.77	0.993	LEAD	-20.56	0.984	LEAD
93	FLT_97_CARLISLE3_CARLISLE2_115_69kV_3PH	-12.17	0.994	LEAD	-17.46	0.988	LEAD	-17.41	0.988	LEAD	-13.26	0.993	LEAD	-20	0.984	LEAD

GEN-2015-022 POI Swisher 115 kV (525212) Power at POI (MW): 112.0		DISIS-2015-001-3 Group 06 Leading power factor is absorbing vars; Lagging power factor is providing vars														
		2016 Winter Peak POI Voltage = 1.011 pu			2017 Summer Peak POI Voltage = 1.015 pu			2020 Summer Peak POI Voltage = 1.005 pu			2020 Winter Peak POI Voltage = 1.011 pu			2025 Summer Peak POI Voltage = 1.015 pu		
	Contingency Name	Mvars at POI	Power Factor		Mvars at POI	Power Factor		Mvars at POI	Power Factor		Mvars at POI	Power Factor		Mvars at POI	Power Factor	
94	FLT_98_LUBBCKSTH3_SPWOODROW3_115kV_3PH	-12.17	0.994	LEAD	-18.01	0.987	LEAD	-18.07	0.987	LEAD	-13.6	0.993	LEAD	-20.44	0.984	LEAD
95	FLT_99_LUBBCKSTH3_LUBBCKSTH2_115_69kV_3PH	-11.33	0.995	LEAD	-17.43	0.988	LEAD	-17.29	0.988	LEAD	-12.58	0.994	LEAD	-20	0.984	LEAD
96	FLT_100_LUBBCKSTH3_LUBBCKSTH6_115_230kV_3PH	-13.04	0.993	LEAD	-18.64	0.986	LEAD	-18.09	0.987	LEAD	-13.32	0.993	LEAD	-20.56	0.984	LEAD
97	FLT_101_WOLFFORTH3_TERRYCNTY3_115kV_3PH	-12.98	0.993	LEAD	-18.6	0.986	LEAD	-18.11	0.987	LEAD	-13.42	0.993	LEAD	-20.55	0.984	LEAD
98	FLT_102_WOLFFORTH3_WOLFFORTH6_115_230kV_3PH	-10.78	0.995	LEAD	-17.47	0.988	LEAD	-17.5	0.988	LEAD	-13.12	0.993	LEAD	-19.97	0.984	LEAD
99	FLT_103_WOLFFORTH6_LUBBCKSTH6_230kV_3PH	-11.88	0.994	LEAD	-16.16	0.99	LEAD	-16.98	0.989	LEAD	-12.91	0.993	LEAD	-19.63	0.985	LEAD
100	FLT_104_WOLFFORTH6_SUNDOWN6_230kV_3PH	-12.47	0.994	LEAD	-19.35	0.985	LEAD	-18.45	0.987	LEAD	-13.32	0.993	LEAD	-20.81	0.983	LEAD
101	FLT_105_TERRYCNTY3_LGCLAUENE3_115kV_3PH	-12.27	0.994	LEAD	-18.1	0.987	LEAD	-18	0.987	LEAD	-13.37	0.993	LEAD	-20.29	0.984	LEAD
102	FLT_106_TERRYCNTY3_PRENTICE3_115kV_3PH	-12.42	0.994	LEAD	-18.15	0.987	LEAD	-18.03	0.987	LEAD	-13.41	0.993	LEAD	-20.31	0.984	LEAD
103	FLT_107_TERRYCNTY3_DENVERN3_115kV_3PH	-12.42	0.994	LEAD	-18.13	0.987	LEAD	-18.04	0.987	LEAD	-13.41	0.993	LEAD	-20.31	0.984	LEAD
104	FLT_108_TERRYCNTY3_SULPHUR3_115kV_3PH	-12.41	0.994	LEAD	-18.23	0.987	LEAD	-18.06	0.987	LEAD	-13.38	0.993	LEAD	-20.34	0.984	LEAD
105	FLT_109_TERRYCNTY3_TERRYCNTY2_115_69kV_3PH	-12.32	0.994	LEAD	-18.1	0.987	LEAD	-18	0.987	LEAD	-13.4	0.993	LEAD	-20.3	0.984	LEAD
106	FLT_110_TOLKTAP6_TOLK7_230_345kV_3PH	-12.42	0.994	LEAD	-18.22	0.987	LEAD	-18.44	0.987	LEAD	-14.03	0.992	LEAD	-20.34	0.984	LEAD
107	FLT_111_TOLKWEST6_G13027TAP_230kV_3PH	-11.81	0.994	LEAD	-17.64	0.988	LEAD	-17.62	0.988	LEAD	-12.94	0.993	LEAD	-19.89	0.985	LEAD
108	FLT_112_G13027TAP_YOAKUM6_230kV_3PH	-11.45	0.995	LEAD	-17.12	0.989	LEAD	-16.58	0.989	LEAD	-11.66	0.995	LEAD	-18.68	0.986	LEAD
109	FLT_114_YOAKUM6_AMOCOSS6_230kV_3PH	-12.44	0.994	LEAD	-18.02	0.987	LEAD	-17.84	0.988	LEAD	-13.22	0.993	LEAD	-20.15	0.984	LEAD
110	FLT_115_YOAKUM6_OXYBRUTP6_230kV_3PH	-12.34	0.994	LEAD	-18.13	0.987	LEAD	-18.04	0.987	LEAD	-13.43	0.993	LEAD	-20.31	0.984	LEAD
111	FLT_116_YOAKUM6_MUSTANG6_230kV_3PH	-12.32	0.994	LEAD	-18.11	0.987	LEAD	-18.02	0.987	LEAD	-13.4	0.993	LEAD	-20.31	0.984	LEAD
112	FLT_117_YOAKUM6_HOBBSINT6_230kV_3PH	-11.97	0.994	LEAD	-17.53	0.988	LEAD	-17.75	0.988	LEAD	-13.2	0.993	LEAD	-20.18	0.984	LEAD
113	FLT_118_YOAKUM6_YOAKUM3_230_115kV_3PH	-12.23	0.994	LEAD	-18.03	0.987	LEAD	-17.96	0.987	LEAD	-13.38	0.993	LEAD	-20.26	0.984	LEAD
114	FLT_121_TOLKWEST6_ROSEVELTN6_230kV_3PH	-12.43	0.994	LEAD	-18.26	0.987	LEAD	-18.1	0.987	LEAD	-13.32	0.993	LEAD	-20.38	0.984	LEAD
115	FLT_123_BORDER7_WWRDEHV7_345kV_3PH	-0.72	1	LEAD	-11.97	0.994	LEAD	-10.15	0.996	LEAD	0.13	1	LAG	-18.07	0.987	LEAD
116	FLT_124_OKU7_TUCOINT7_345kV_3PH	2.46	1	LAG	-8.98	0.997	LEAD	-8.33	0.997	LEAD	3.35	1	LAG	-17.73	0.988	LEAD

Appendix G – Reduced Wind Generation Analysis Results

Below figures are from the 2016WP model with identified upgrades in-service. The other 4 cases (2017SP, 220SP, 2020WP and 2025SP) were almost identical since the Interconnection Request facilities design is the same in all cases.

Figure G-1*:* GEN-2015-014 with generators turned off

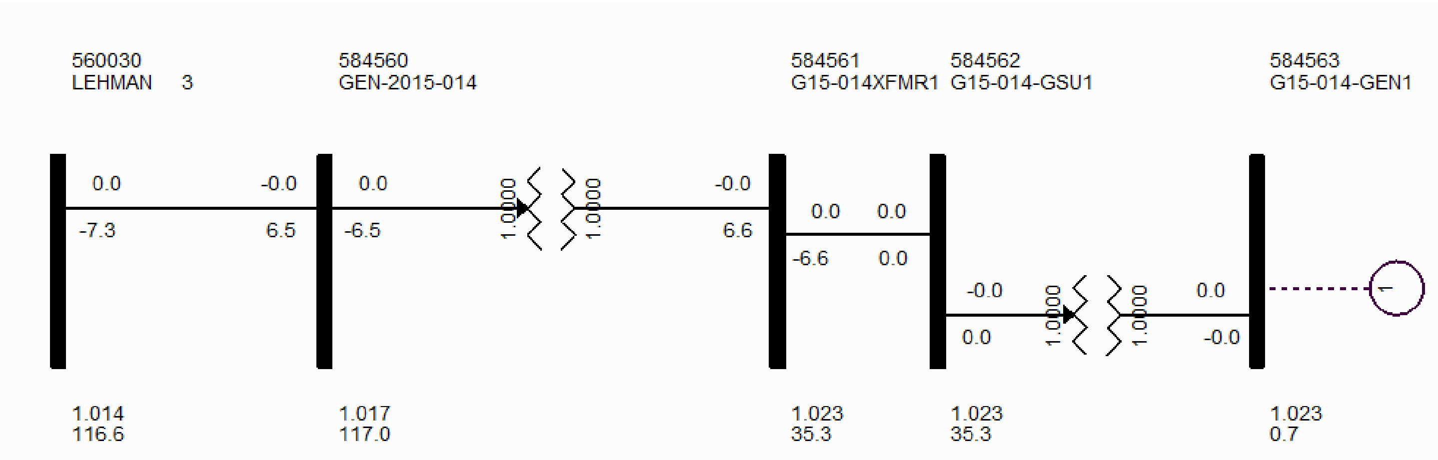


Figure G-2*:* GEN-2015-014 with generators turned off and shunt reactors added to the customer 34.5kV substation

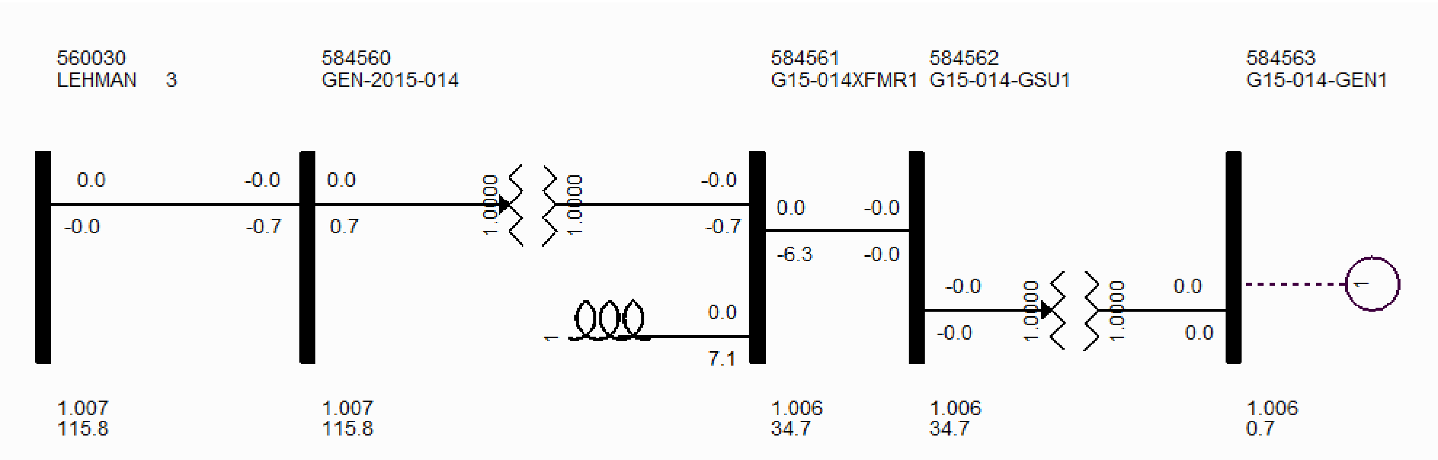


Figure G-3: GEN-2015-022 with generators turned off

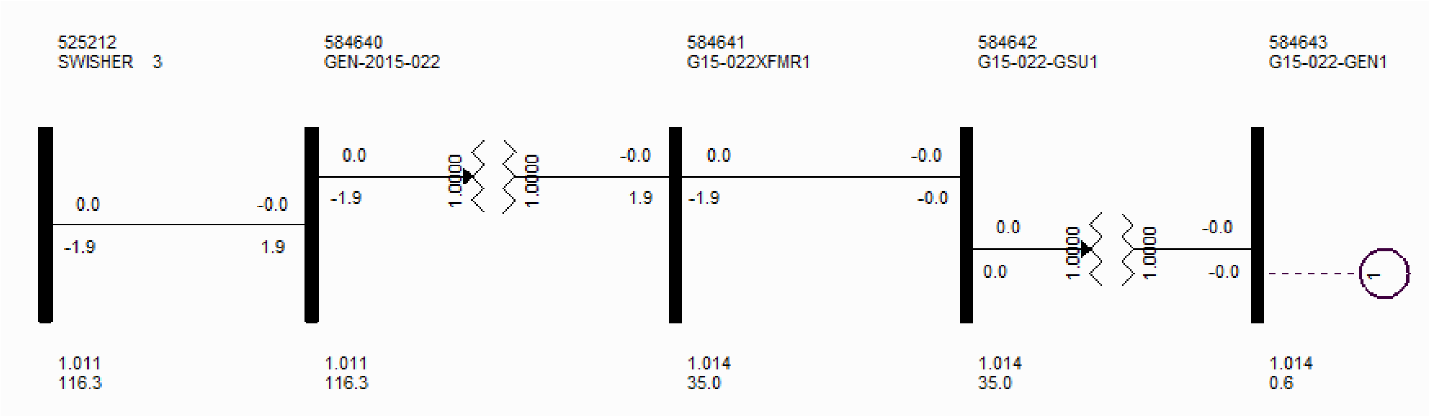
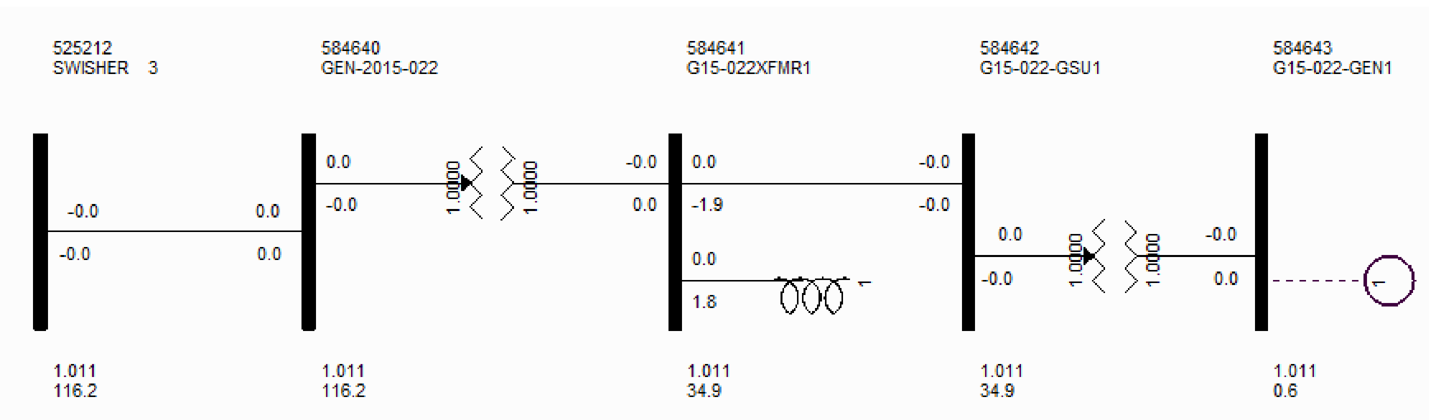


Figure G-4: GEN-2015-022 with generators turned off and shunt reactors added to the customer 34.5kV substation



Appendix H – Short Circuit Analysis Results

GEN-2015-014 Short Circuit Analysis Results

17SP:

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                             PSS®E-32.2.0 ASCC SHORT CIRCUIT CURRENTS          TUE, AUG 15 2017   9:45
2015 MDWG FINAL WITH 2013 MMWG, UPDATED WITH 2014 SERC & MRO
MDWG 17S WITH MMWG 15S, MRO 16W TOPO/16S PROF, SERC 16S

OPTIONS USED:
    - FLAT CONDITIONS
         - BUS VOLTAGES SET TO 1 PU AT 0 PHASE ANGLE
         - GENERATOR P=0, Q=0
         - TRANSFOMRER TAP RATIOS=1.0 PU and PHASE ANGLES=0.0
         - LINE CHARGING=0.0 IN +/-/0 SEQUENCE
         - LOAD=0.0 IN +/- SEQUENCE, CONSIDERED IN ZERO SEQUENCE
         - LINE/FIXED/SWITCHED SHUNTS=0.0 AND MAGNETIZING ADMITTANCE=0.0 IN +/-/0 SEQUENCE
         - DC LINES AND FACTS DEVICES BLOCKED
         - TRANSFORMER ZERO SEQUENCE IMPEDANCE CORRECTIONS IGNORED

                                  THREE PHASE FAULT
X---------- BUS ----------X          /I+/    AN(I+)
560030 [LEHMAN     3115.00] AMP     5407.1   -77.11
526352 [LEHMAN     3115.00] AMP     5212.3   -76.73
526361 [COCHRAN    3115.00] AMP     6308.8   -77.37
526360 [COCHRAN    269.000] AMP     5554.7   -82.77
526424 [PACIFIC    3115.00] AMP     9091.2   -79.54
526944 [LG-PLAINS  3115.00] AMP     7291.5   -77.16
525972 [WHITEFACE  269.000] AMP     3318.1   -66.15
526372 [LG-SUNDOWN 269.000] AMP     2328.1   -62.25
526379 [MIDDLETON  269.000] AMP     3440.1   -79.07
526434 [SUNDOWN    3115.00] AMP    10804.6   -80.98
526928 [PLAINS_INT 3115.00] AMP     8973.4   -78.09
525965 [LC-WHTEFACE269.000] AMP     2321.9   -64.98
526036 [LC-OPDYKE  3115.00] AMP     5704.6   -76.49
526386 [MALLET     269.000] AMP     2909.3   -78.15
526435 [SUNDOWN    6230.00] AMP    10341.7   -82.61
526445 [AMOCO_TP   3115.00] AMP    10228.1   -80.18
526934 [YOAKUM     3115.00] AMP    14424.5   -82.12
528626 [LE-PLNSINT 269.000] AMP     4275.7   -82.83
525481 [PLANT_X    6230.00] AMP    21843.7   -85.24
525963 [BC-S_BAILEY269.000] AMP     1691.4   -64.23
526020 [HOCKLEY    3115.00] AMP     5419.2   -76.27
526395 [TEXACO     269.000] AMP     2546.0   -77.53
526452 [AMOCO_CRYO 3115.00] AMP     6378.1   -77.53
526460 [AMOCO_SS   6230.00] AMP     9022.4   -82.53
526484 [LG-LEVELAND3115.00] AMP     9399.0   -78.96
526525 [WOLFFORTH  6230.00] AMP    12684.3   -83.32
526792 [PRENTICE   3115.00] AMP     5731.4   -75.74
526935 [YOAKUM     6230.00] AMP    11562.6   -83.69
527041 [ARCO_TP    3115.00] AMP    11911.8   -79.01
527194 [LG-PLSHILL 3115.00] AMP     7161.6   -76.41
528740 [LE-PLANS_TP269.000] AMP     3558.4   -79.98
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25SP:

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                             PSS®E-32.2.0 ASCC SHORT CIRCUIT CURRENTS          TUE, AUG 15 2017   9:48
2015 MDWG FINAL WITH 2013 MMWG, UPDATED WITH 2014 SERC & MRO
MDWG 2025S WITH MMWG 2024S, MRO & SERC 2025 SUMMER

OPTIONS USED:
    - FLAT CONDITIONS
         - BUS VOLTAGES SET TO 1 PU AT 0 PHASE ANGLE
         - GENERATOR P=0, Q=0
         - TRANSFOMRER TAP RATIOS=1.0 PU and PHASE ANGLES=0.0
         - LINE CHARGING=0.0 IN +/-/0 SEQUENCE
         - LOAD=0.0 IN +/- SEQUENCE, CONSIDERED IN ZERO SEQUENCE
         - LINE/FIXED/SWITCHED SHUNTS=0.0 AND MAGNETIZING ADMITTANCE=0.0 IN +/-/0 SEQUENCE
         - DC LINES AND FACTS DEVICES BLOCKED
         - TRANSFORMER ZERO SEQUENCE IMPEDANCE CORRECTIONS IGNORED

                                  THREE PHASE FAULT
X---------- BUS ----------X          /I+/    AN(I+)
560030 [LEHMAN     3115.00] AMP     6461.6   -78.16
526352 [LEHMAN     3115.00] AMP     6038.6   -77.45
526361 [COCHRAN    3115.00] AMP     6950.8   -77.60
584560 [GEN-2015-014115.00] AMP     5066.4   -81.27
526360 [COCHRAN    269.000] AMP     5837.1   -83.16
526424 [PACIFIC    3115.00] AMP     9684.6   -79.47
526944 [LG-PLAINS  3115.00] AMP     7801.4   -77.19
525972 [WHITEFACE  269.000] AMP     3416.5   -65.88
526372 [LG-SUNDOWN 269.000] AMP     2375.5   -61.99
526379 [MIDDLETON  269.000] AMP     3547.1   -79.19
526434 [SUNDOWN    3115.00] AMP    11455.2   -80.87
526928 [PLAINS_INT 3115.00] AMP     9634.0   -78.15
525965 [LC-WHTEFACE269.000] AMP     2369.5   -64.77
526036 [LC-OPDYKE  3115.00] AMP     5895.8   -76.27
526386 [MALLET     269.000] AMP     2985.5   -78.23
526435 [SUNDOWN    6230.00] AMP    10885.1   -82.68
526445 [AMOCO_TP   3115.00] AMP    10788.6   -80.04
526934 [YOAKUM     3115.00] AMP    15965.4   -82.65
528626 [LE-PLNSINT 269.000] AMP     4349.8   -82.82
525481 [PLANT_X    6230.00] AMP    23134.2   -85.29
525963 [BC-S_BAILEY269.000] AMP     1716.4   -64.07
526020 [HOCKLEY    3115.00] AMP     5611.0   -76.05
526395 [TEXACO     269.000] AMP     2604.2   -77.58
526452 [AMOCO_CRYO 3115.00] AMP     6590.9   -77.35
526460 [AMOCO_SS   6230.00] AMP     9521.9   -82.61
526484 [LG-LEVELAND3115.00] AMP     9836.5   -78.78
526525 [WOLFFORTH  6230.00] AMP    13450.1   -83.45
526792 [PRENTICE   3115.00] AMP     5881.1   -75.63
526935 [YOAKUM     6230.00] AMP    15294.2   -84.79
527041 [ARCO_TP    3115.00] AMP    12556.4   -78.95
527194 [LG-PLSHILL 3115.00] AMP     7392.3   -76.30
528740 [LE-PLANS_TP269.000] AMP     3610.0   -79.84
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GEN-2015-022 Short Circuit Analysis Results

17SP:

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                             PSS®E-32.2.0 ASCC SHORT CIRCUIT CURRENTS         TUE, AUG 15 2017   9:46
2015 MDWG FINAL WITH 2013 MMWG, UPDATED WITH 2014 SERC & MRO
MDWG 17S WITH MMWG 15S, MRO 16W TOPO/16S PROF, SERC 16S

OPTIONS USED:
    - FLAT CONDITIONS
         - BUS VOLTAGES SET TO 1 PU AT 0 PHASE ANGLE
         - GENERATOR P=0, Q=0
         - TRANSFOMRER TAP RATIOS=1.0 PU and PHASE ANGLES=0.0
         - LINE CHARGING=0.0 IN +/-/0 SEQUENCE
         - LOAD=0.0 IN +/- SEQUENCE, CONSIDERED IN ZERO SEQUENCE
         - LINE/FIXED/SWITCHED SHUNTS=0.0 AND MAGNETIZING ADMITTANCE=0.0 IN +/-/0 SEQUENCE
         - DC LINES AND FACTS DEVICES BLOCKED
         - TRANSFORMER ZERO SEQUENCE IMPEDANCE CORRECTIONS IGNORED

                                  THREE PHASE FAULT
X---------- BUS ----------X          /I+/    AN(I+)
525212 [SWISHER    3115.00] AMP    10171.0   -81.31
525192 [KRESS_INT  3115.00] AMP    11020.3   -79.49
525213 [SWISHER    6230.00] AMP     9971.8   -82.27
584640 [GEN-2015-022115.00] AMP    10171.0   -81.31
524415 [AMA_SOUTH  6230.00] AMP    13255.9   -83.53
525179 [TULIA_TP   3115.00] AMP     6253.2   -80.39
525191 [KRESS_INT  269.000] AMP     4418.2   -86.55
525225 [KRESS_RURAL3115.00] AMP     6198.6   -75.93
525454 [HALE_CNTY  3115.00] AMP    10059.1   -73.67
525460 [NEWHART    3115.00] AMP    14944.3   -81.56
525461 [NEWHART    6230.00] AMP    10650.7   -81.87
525830 [TUCO_INT   6230.00] AMP    19153.7   -84.58
522800 [MU-TULIA   3115.00] AMP     5065.8   -77.27
523959 [POTTER_CO  6230.00] AMP    19999.7   -84.73
524044 [NICHOLS    6230.00] AMP    24864.0   -86.28
524365 [RANDALL    6230.00] AMP    14072.8   -83.68
524414 [AMA_SOUTH  3115.00] AMP    16471.0   -81.94
524746 [CASTRO_CNTY3115.00] AMP    11599.1   -78.94
525124 [HART_INDUST3115.00] AMP     7539.1   -76.43
525154 [HAPPY_INT  3115.00] AMP     5326.7   -80.64
525203 [SW-KRESS   269.000] AMP     4418.2   -86.55
525224 [KRESS_RURL 269.000] AMP     2501.9   -75.96
525257 [N_PLAINVEW 3115.00] AMP     5054.0   -74.01
525326 [COX        3115.00] AMP     5849.9   -71.99
525414 [LAMTON     3115.00] AMP     7754.3   -75.23
525453 [HALE_CNTY  269.000] AMP     6888.2   -82.63
525480 [PLANT_X    3115.00] AMP    20789.9   -84.02
525481 [PLANT_X    6230.00] AMP    21878.9   -85.22
525524 [TOLK_EAST  6230.00] AMP    25292.6   -86.15
525828 [TUCO_INT   3115.00] AMP    18991.1   -82.75
525832 [TUCO_INT   7345.00] AMP    10067.9   -85.98
525840 [ANTELOPE_1 6230.00] AMP    19013.1   -84.59
526161 [CARLISLE   6230.00] AMP    10293.7   -83.06
526337 [JONES      6230.00] AMP    19157.4   -86.25
583340 [GEN-2012-020230.00] AMP     8641.8   -84.17
511456 [O.K.U.-7    345.00] AMP     4944.5   -84.33
515458 [BORDER     7345.00] AMP     4922.0   -86.21
522823 [LP-MILWAKEE6230.00] AMP     9690.1   -82.99
522870 [LP-HOLLY   6230.00] AMP    14458.5   -85.09
523309 [MOORE_CNTY 6230.00] AMP     6662.4   -82.75
523551 [HUTCHISON  6230.00] AMP     7168.3   -83.54
523771 [GRAPEVINE  6230.00] AMP     5090.5   -81.91
523869 [CHAN/TASCOS6230.00] AMP     3835.2   -82.08
523961 [POTTER_CO  7345.00] AMP     7365.5   -86.54
523977 [HARRNG_WST 6230.00] AMP    25597.2   -86.37
523978 [HARRNG_MID 6230.00] AMP    25597.2   -86.37
523979 [HARRNG_EST 6230.00] AMP    25597.2   -86.37
524010 [ROLLHILLS  6230.00] AMP    19051.4   -84.83
524043 [NICHOLS    3115.00] AMP    30260.6   -84.69
524267 [BUSHLAND   6230.00] AMP     9588.5   -82.95
524364 [RANDALL    3115.00] AMP    20681.6   -82.59
524377 [FARMERS    3115.00] AMP    14979.9   -80.76
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524397 [ARROWHEAD  3115.00] AMP    13494.5   -79.20
524404 [OWENSCORN  3115.00] AMP    14694.9   -81.57
524530 [PALO_DURO  3115.00] AMP     6522.9   -81.19
524544 [SPRING_DRW 3115.00] AMP     6343.5   -74.93
524623 [DEAFSMITH  6230.00] AMP     7676.7   -80.80
524694 [DS-#22     3115.00] AMP     4952.7   -75.62
524734 [DS-#21     3115.00] AMP    10763.9   -78.37
524745 [CASTRO_CNTY269.000] AMP     9577.6   -83.34
524911 [ROSEVELT_S 6230.00] AMP     8578.6   -82.08
525019 [EMU&VLY_TP 3115.00] AMP     5083.8   -76.00
525050 [BC-KELLEY  3115.00] AMP     8328.4   -76.40
525056 [BC-EARTH   3115.00] AMP     8735.7   -76.58
525153 [HAPPY_INT  269.000] AMP     3518.2   -84.72
525249 [LH-PLW&FNY 269.000] AMP     1592.4   -70.51
525272 [KISER      3115.00] AMP     5058.5   -73.78
525291 [PLAINVW_TP 269.000] AMP     6465.9   -82.06
525298 [S_PLAINVEW 269.000] AMP     2580.6   -70.20
525325 [COX        269.000] AMP     3353.4   -83.00
525413 [LAMTON     269.000] AMP     5209.0   -82.63
525432 [SP-HALFWAY 269.000] AMP     5848.3   -79.55
525440 [LC-S_OLTON 3115.00] AMP     7392.5   -75.43
525446 [SPGLAKE_TP3 115.00] AMP    10504.7   -77.67
525531 [TOLK_WEST  6230.00] AMP    25292.6   -86.15
525543 [TOLK_TAP   6230.00] AMP    25292.6   -86.15
525636 [LAMB_CNTY  3115.00] AMP     8474.1   -80.19
525780 [FLOYD_CNTY 3115.00] AMP     5974.2   -74.25
525816 [TUCO_INT2  269.000] AMP     4639.9   -87.38
525826 [TUCO_INT   269.000] AMP     7818.2   -87.23
526076 [STANTON_W  3115.00] AMP     9253.0   -76.46
526160 [CARLISLE   3115.00] AMP    12996.1   -80.63
526269 [LUBBCK_STH 6230.00] AMP    16979.2   -85.25
526298 [LUBBCK_EST 3115.00] AMP    14961.7   -82.31
526299 [LUBBCK_EST 6230.00] AMP    12645.4   -84.74
526435 [SUNDOWN    6230.00] AMP    10448.7   -82.64
526525 [WOLFFORTH  6230.00] AMP    12728.7   -83.31
526677 [GRASSLAND  6230.00] AMP     6348.3   -84.59
584220 [GEN-2014-040115.00] AMP    10322.2   -80.84
511468 [L.E.S.-7    345.00] AMP    11293.8   -84.64
515375 [WWRDEHV7    345.00] AMP    15850.9   -85.98
522828 [LP-MILWAKEE269.000] AMP     7470.0   -82.31
522861 [LP-SOUTHEST6230.00] AMP    13474.3   -84.54
522866 [LP-COOK    269.000] AMP    30381.1   -88.40
522888 [LP-WADSWRTH6230.00] AMP    11838.8   -84.55
523095 [HITCHLAND  6230.00] AMP    14414.9   -86.28
523097 [HITCHLAND  7345.00] AMP    14648.0   -85.95
523221 [XIT_INTG   6230.00] AMP     2594.9   -81.66
523267 [PRINGLE    6230.00] AMP     4253.1   -82.78
523308 [MOORE_E    3115.00] AMP    10965.1   -81.54
523339 [FAIN       3115.00] AMP     5266.9   -74.82
523410 [CRMWA_#4   3115.00] AMP     9681.4   -76.57
523544 [HUTCH_N    3115.00] AMP    15533.8   -82.40
523546 [HUTCH_S    3115.00] AMP    15533.8   -82.40
523770 [GRAPEVINE  3115.00] AMP     7380.8   -81.87
523777 [WHEELER    6230.00] AMP     4280.4   -81.75
523817 [MIDSTRM_TP 3115.00] AMP     6698.8   -78.62
524007 [ROLLHILLS  3115.00] AMP    19193.6   -81.56
524016 [ASARCO     3115.00] AMP    26218.3   -79.36
524018 [ASARCO_TP  3115.00] AMP    28323.4   -83.93
524058 [WHITAKER   3115.00] AMP    21728.4   -82.63
524079 [CONWAY     3115.00] AMP     4954.9   -77.33
524163 [EAST_PLANT 6230.00] AMP    13540.8   -84.30
524224 [MANHATTAN  3115.00] AMP    18264.6   -80.29
524266 [BUSHLAND   3115.00] AMP     9304.6   -83.81
524290 [WILDOR2_JUS6230.00] AMP     6581.9   -83.46
524296 [SPNSPUR_WND7345.00] AMP     4430.9   -85.62
524322 [GEORGIA    3115.00] AMP    16244.1   -81.44
524338 [SOUTHEAST  3115.00] AMP    10938.2   -78.34
524345 [OSAGE      3115.00] AMP    13664.4   -78.71
524388 [CROUSE_HIND3115.00] AMP    14985.6   -80.76
524425 [ESTACADO_TP3115.00] AMP    13119.6   -79.77
524522 [CANYON E_TP3115.00] AMP     5143.9   -68.32
524622 [DEAFSMITH  3115.00] AMP    11917.8   -79.72
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524714 [CASTRO_TP  269.000] AMP     3655.0   -70.53
524721 [DS-#15&#19 269.000] AMP     3676.4   -70.41
524728 [DS-CASTRO  269.000] AMP     4453.6   -72.04
524909 [ROSEVELT_N 6230.00] AMP     8578.6   -82.08
524915 [SW_4K33    6230.00] AMP     8578.6   -82.08
525018 [EMULESH&VLY3115.00] AMP     4718.3   -75.80
525028 [BAILEYCO   3115.00] AMP     4864.4   -75.99
525132 [LC-N_OLTON 269.000] AMP     3090.6   -75.02
525143 [HAPPY_CTYTP269.000] AMP     3245.4   -82.93
525271 [KISER      269.000] AMP     3448.5   -82.69
525284 [WESTRIDGE  269.000] AMP     4256.0   -79.00
525307 [E_PLAINVEW 269.000] AMP     2438.8   -77.01
525316 [LH-PROVDNCE269.000] AMP     3353.4   -83.00
525339 [AIKEN_RURL 269.000] AMP     2438.9   -77.02
525393 [SPRINGLAKE 3115.00] AMP     9343.2   -77.52
525404 [LC-OLTON   269.000] AMP     4512.6   -81.31
525425 [CORNER     269.000] AMP     3624.4   -73.11
525549 [TOLK       7345.00] AMP     6849.5   -87.53
525635 [LAMB_CNTY  269.000] AMP     5909.9   -85.13
525637 [LAMB_CNTY  6230.00] AMP     5315.0   -81.86
525731 [SP-ABERNTHY269.000] AMP     3003.8   -82.31
525738 [HALECENTER 269.000] AMP     2452.5   -68.21
525779 [FLOYD_CNTY 269.000] AMP     5281.7   -81.09
525853 [LH-WIL&ELLN269.000] AMP     2571.7   -58.54
525885 [SP-NEWDEAL 269.000] AMP     3368.5   -72.93
525926 [CROSBY     3115.00] AMP     4472.8   -75.19
526020 [HOCKLEY    3115.00] AMP     5463.9   -76.21
526109 [SP-ERSKINE 3115.00] AMP    11218.7   -78.75
526146 [INDIANA    3115.00] AMP     9598.6   -76.85
526159 [CARLISLE   269.000] AMP     2562.5   -87.07
526162 [LP-DOUD_TP 3115.00] AMP    11487.6   -80.16
526192 [MURPHY     3115.00] AMP    10516.5   -78.30
526268 [LUBBCK_STH 3115.00] AMP    18571.3   -84.43
526297 [LUBBCK_EST 269.000] AMP     7990.9   -86.68
526434 [SUNDOWN    3115.00] AMP    11198.1   -80.92
526460 [AMOCO_SS   6230.00] AMP     9101.8   -82.55
526524 [WOLFFORTH  3115.00] AMP    11330.9   -81.75
526676 [GRASSLAND  3115.00] AMP     6088.0   -83.28
526679 [CIRRUS_WND 6230.00] AMP     4963.1   -84.62
562004 [G11-025-TAP 115.00] AMP     4578.4   -73.81
562480 [G13-027-TAP 230.00] AMP     8842.6   -83.13
583090 [G1149&G1504 345.00] AMP     4514.4   -86.07
599955 [PNM-DC6     230.00] AMP     8578.6   -82.08
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25SP:

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                             PSS®E-32.2.0 ASCC SHORT CIRCUIT CURRENTS          TUE, AUG 15 2017   9:48
2015 MDWG FINAL WITH 2013 MMWG, UPDATED WITH 2014 SERC & MRO
MDWG 2025S WITH MMWG 2024S, MRO & SERC 2025 SUMMER

OPTIONS USED:
    - FLAT CONDITIONS
         - BUS VOLTAGES SET TO 1 PU AT 0 PHASE ANGLE
         - GENERATOR P=0, Q=0
         - TRANSFOMRER TAP RATIOS=1.0 PU and PHASE ANGLES=0.0
         - LINE CHARGING=0.0 IN +/-/0 SEQUENCE
         - LOAD=0.0 IN +/- SEQUENCE, CONSIDERED IN ZERO SEQUENCE
         - LINE/FIXED/SWITCHED SHUNTS=0.0 AND MAGNETIZING ADMITTANCE=0.0 IN +/-/0 SEQUENCE
         - DC LINES AND FACTS DEVICES BLOCKED
         - TRANSFORMER ZERO SEQUENCE IMPEDANCE CORRECTIONS IGNORED

                                  THREE PHASE FAULT
X--------- BUS ----------X          /I+/    AN(I+)
525212 [SWISHER    3115.00] AMP    10252.8   -81.26
525192 [KRESS_INT  3115.00] AMP    11118.6   -79.42
525213 [SWISHER    6230.00] AMP    10134.5   -82.25
584640 [GEN-2015-022115.00] AMP    10252.8   -81.26
524415 [AMA_SOUTH  6230.00] AMP    13342.3   -83.57
525179 [TULIA_TP   3115.00] AMP     6278.0   -80.37
525191 [KRESS_INT  269.000] AMP     4427.7   -86.54
525225 [KRESS_RURAL3115.00] AMP     6233.3   -75.87
525454 [HALE_CNTY  3115.00] AMP    10241.3   -73.51
525460 [NEWHART    3115.00] AMP    15073.8   -81.48
525461 [NEWHART    6230.00] AMP    10760.7   -81.83
525830 [TUCO_INT   6230.00] AMP    22210.6   -85.13
522800 [MU-TULIA   3115.00] AMP     5082.0   -77.25
523959 [POTTER_CO  6230.00] AMP    20120.7   -84.70
524044 [NICHOLS    6230.00] AMP    25113.8   -86.28
524365 [RANDALL    6230.00] AMP    14173.9   -83.76
524414 [AMA_SOUTH  3115.00] AMP    16550.5   -81.99
524746 [CASTRO_CNTY3115.00] AMP    11733.5   -78.85
525124 [HART_INDUST3115.00] AMP     7599.9   -76.33
525154 [HAPPY_INT  3115.00] AMP     5342.2   -80.63
525203 [SW-KRESS   269.000] AMP     4427.7   -86.54
525224 [KRESS_RURL 269.000] AMP     2504.9   -75.95
525257 [N_PLAINVEW 3115.00] AMP     5080.9   -73.94
525326 [COX        3115.00] AMP     5891.3   -71.89
525414 [LAMTON     3115.00] AMP     7935.8   -75.05
525453 [HALE_CNTY  269.000] AMP     6939.6   -82.63
525480 [PLANT_X    3115.00] AMP    26549.4   -85.02
525481 [PLANT_X    6230.00] AMP    23134.2   -85.29
525524 [TOLK_EAST  6230.00] AMP    26091.0   -86.11
525828 [TUCO_INT   3115.00] AMP    19865.6   -83.04
525832 [TUCO_INT   7345.00] AMP    12266.3   -86.20
525840 [ANTELOPE_1 6230.00] AMP    22040.4   -85.14
526161 [CARLISLE   6230.00] AMP    13247.5   -83.80
526337 [JONES      6230.00] AMP    20790.1   -86.16
583340 [GEN-2012-020230.00] AMP     9102.0   -84.27
511456 [O.K.U.-7    345.00] AMP     5058.4   -84.32
515458 [BORDER     7345.00] AMP     5048.2   -86.22
522823 [LP-MILWAKEE6230.00] AMP    12863.6   -83.82
522870 [LP-HOLLY   6230.00] AMP    16752.9   -85.26
523309 [MOORE_CNTY 6230.00] AMP     6672.9   -82.74
523551 [HUTCHISON  6230.00] AMP     7189.3   -83.57
523771 [GRAPEVINE  6230.00] AMP     5520.1   -82.00
523869 [CHAN/TASCOS6230.00] AMP     3839.1   -82.07
523961 [POTTER_CO  7345.00] AMP     7387.5   -86.53
523977 [HARRNG_WST 6230.00] AMP    25844.4   -86.37
523978 [HARRNG_MID 6230.00] AMP    25844.4   -86.37
523979 [HARRNG_EST 6230.00] AMP    25844.4   -86.37
524010 [ROLLHILLS  6230.00] AMP    19175.8   -84.81
524043 [NICHOLS    3115.00] AMP    30513.8   -84.82
524267 [BUSHLAND   6230.00] AMP     9620.6   -82.96
524364 [RANDALL    3115.00] AMP    20914.2   -82.90
524377 [FARMERS    3115.00] AMP    15050.1   -80.82
524397 [ARROWHEAD  3115.00] AMP    13548.0   -79.22
524404 [OWENSCORN  3115.00] AMP    14757.8   -81.61
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524530 [PALO_DURO  3115.00] AMP     6542.4   -81.24
524544 [SPRING_DRW 3115.00] AMP     6355.4   -74.93
524623 [DEAFSMITH  6230.00] AMP     7763.4   -81.18
524694 [DS-#22     3115.00] AMP     4976.8   -75.56
524734 [DS-#21     3115.00] AMP    10876.3   -78.29
524745 [CASTRO_CNTY269.000] AMP     9632.7   -83.32
524911 [ROSEVELT_S 6230.00] AMP     8710.5   -82.03
525019 [EMU&VLY_TP 3115.00] AMP     6422.2   -77.12
525050 [BC-KELLEY  3115.00] AMP     8582.5   -76.19
525056 [BC-EARTH   3115.00] AMP     9135.2   -76.32
525153 [HAPPY_INT  269.000] AMP     3522.3   -84.73
525249 [LH-PLW&FNY 269.000] AMP     1593.6   -70.50
525272 [KISER      3115.00] AMP     5086.0   -73.71
525291 [PLAINVW_TP 269.000] AMP     6511.1   -82.06
525298 [S_PLAINVEW 269.000] AMP     2587.6   -70.17
525325 [COX        269.000] AMP     3361.8   -82.99
525413 [LAMTON     269.000] AMP     5257.9   -82.63
525432 [SP-HALFWAY 269.000] AMP     5885.2   -79.53
525440 [LC-S_OLTON 3115.00] AMP     7644.1   -75.21
525446 [SPGLAKE_TP3 115.00] AMP    11476.9   -77.38
525531 [TOLK_WEST  6230.00] AMP    26091.0   -86.11
525543 [TOLK_TAP   6230.00] AMP    26091.0   -86.11
525614 [W_LITLFLDTP3115.00] AMP     8225.4   -77.65
525780 [FLOYD_CNTY 3115.00] AMP     6022.3   -74.19
525816 [TUCO_INT2  269.000] AMP     4669.7   -87.45
525826 [TUCO_INT   269.000] AMP     7903.2   -87.35
526076 [STANTON_W  3115.00] AMP     9462.4   -76.51
526160 [CARLISLE   3115.00] AMP    13464.7   -80.94
526269 [LUBBCK_STH 6230.00] AMP    18795.4   -85.28
526298 [LUBBCK_EST 3115.00] AMP    15341.3   -82.29
526299 [LUBBCK_EST 6230.00] AMP    13382.9   -84.66
526435 [SUNDOWN    6230.00] AMP    10885.1   -82.68
526525 [WOLFFORTH  6230.00] AMP    13450.1   -83.45
526677 [GRASSLAND  6230.00] AMP     6507.2   -84.53
526936 [YOAKUM_345  345.00] AMP     8476.9   -86.28
584220 [GEN-2014-040115.00] AMP    10407.9   -80.79
511468 [L.E.S.-7    345.00] AMP    11819.7   -84.63
515375 [WWRDEHV7    345.00] AMP    18060.1   -86.06
522828 [LP-MILWAKEE269.000] AMP     8294.5   -82.13
522861 [LP-SOUTHEST6230.00] AMP    16918.0   -85.05
522866 [LP-COOK    269.000] AMP    34915.0   -87.69
522888 [LP-WADSWRTH6230.00] AMP    12499.9   -84.47
523095 [HITCHLAND  6230.00] AMP    14508.2   -86.30
523097 [HITCHLAND  7345.00] AMP    14835.9   -85.96
523221 [XIT_INTG   6230.00] AMP     2596.6   -81.66
523267 [PRINGLE    6230.00] AMP     4257.9   -82.77
523308 [MOORE_E    3115.00] AMP    10976.6   -81.53
523339 [FAIN       3115.00] AMP     5271.7   -74.81
523410 [CRMWA_#4   3115.00] AMP     9700.3   -76.56
523544 [HUTCH_N    3115.00] AMP    15625.8   -82.57
523546 [HUTCH_S    3115.00] AMP    15625.8   -82.57
523770 [GRAPEVINE  3115.00] AMP     7727.3   -82.01
523777 [WHEELER    6230.00] AMP     5264.5   -82.10
523817 [MIDSTRM_TP 3115.00] AMP     6705.5   -78.61
524007 [ROLLHILLS  3115.00] AMP    19282.1   -81.57
524016 [ASARCO     3115.00] AMP    26412.0   -79.43
524018 [ASARCO_TP  3115.00] AMP    28557.9   -84.07
524058 [WHITAKER   3115.00] AMP    21858.8   -82.70
524079 [CONWAY     3115.00] AMP     4988.6   -77.31
524163 [EAST_PLANT 6230.00] AMP    13613.0   -84.30
524224 [MANHATTAN  3115.00] AMP    18386.8   -80.39
524266 [BUSHLAND   3115.00] AMP     9319.9   -83.80
524290 [WILDOR2_JUS6230.00] AMP     6596.2   -83.47
524296 [SPNSPUR_WND7345.00] AMP     4438.3   -85.61
524322 [GEORGIA    3115.00] AMP    16331.2   -81.52
524338 [SOUTHEAST  3115.00] AMP    11005.1   -78.48
524345 [OSAGE      3115.00] AMP    13719.3   -78.74
524388 [CROUSE_HIND3115.00] AMP    15056.1   -80.81
524425 [ESTACADO_TP3115.00] AMP    13168.4   -79.80
524522 [CANYON E_TP3115.00] AMP     5472.4   -73.69
524622 [DEAFSMITH  3115.00] AMP    12153.2   -80.48
524714 [CASTRO_TP  269.000] AMP     3662.7   -70.49
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524721 [DS-#15&#19 269.000] AMP     3684.2   -70.38
524728 [DS-CASTRO  269.000] AMP     4465.1   -72.00
524909 [ROSEVELT_N 6230.00] AMP     8710.5   -82.03
524915 [SW_4K33    6230.00] AMP     8710.5   -82.03
525018 [EMULESH&VLY3115.00] AMP     5850.2   -76.77
525028 [BAILEYCO   3115.00] AMP     6363.0   -77.42
525132 [LC-N_OLTON 269.000] AMP     3107.6   -74.97
525143 [HAPPY_CTYTP269.000] AMP     3248.8   -82.93
525271 [KISER      269.000] AMP     3456.4   -82.68
525284 [WESTRIDGE  269.000] AMP     4275.5   -78.98
525307 [E_PLAINVEW 269.000] AMP     2443.2   -76.99
525316 [LH-PROVDNCE269.000] AMP     3361.8   -82.99
525339 [AIKEN_RURL 269.000] AMP     2443.3   -77.00
525393 [SPRINGLAKE 3115.00] AMP    10104.5   -77.25
525404 [LC-OLTON   269.000] AMP     4549.2   -81.30
525425 [CORNER     269.000] AMP     3638.4   -73.07
525549 [TOLK       7345.00] AMP     6932.8   -87.53
525615 [W_LITTLFLD 3115.00] AMP     7690.4   -76.65
525636 [LAMB_CNTY  3115.00] AMP     9649.0   -80.29
525637 [LAMB_CNTY  6230.00] AMP     5529.7   -82.22
525731 [SP-ABERNTHY269.000] AMP     3016.4   -82.33
525738 [HALECENTER 269.000] AMP     2460.9   -68.18
525779 [FLOYD_CNTY 269.000] AMP     5304.4   -81.08
525853 [LH-WIL&ELLN269.000] AMP     2580.6   -58.48
525885 [SP-NEWDEAL 269.000] AMP     3384.4   -72.91
525926 [CROSBY     3115.00] AMP     4496.4   -75.13
526109 [SP-ERSKINE 3115.00] AMP    11553.4   -78.93
526146 [INDIANA    3115.00] AMP     9828.8   -76.93
526159 [CARLISLE   269.000] AMP     2572.8   -87.13
526162 [LP-DOUD_TP 3115.00] AMP    11825.2   -80.37
526192 [MURPHY     3115.00] AMP    10753.4   -78.38
526268 [LUBBCK_STH 3115.00] AMP    19251.7   -84.52
526297 [LUBBCK_EST 269.000] AMP     8054.6   -86.71
526434 [SUNDOWN    3115.00] AMP    11455.2   -80.87
526460 [AMOCO_SS   6230.00] AMP     9521.9   -82.61
526524 [WOLFFORTH  3115.00] AMP    11595.3   -81.87
526676 [GRASSLAND  3115.00] AMP     6156.7   -83.25
526679 [CIRRUS_WND 6230.00] AMP     5058.4   -84.58
526935 [YOAKUM     6230.00] AMP    15294.2   -84.79
527896 [HOBBS_INT  7345.00] AMP     8200.9   -86.77
562004 [G11-025-TAP 115.00] AMP     4601.9   -73.74
562480 [G13-027-TAP 230.00] AMP     9007.2   -83.10
583090 [G1149&G1504 345.00] AMP     4617.3   -86.07
599955 [PNM-DC6     230.00] AMP     8710.5   -82.03
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ASGI-2015-002 Short Circuit Analysis Results

17SP:

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                             PSS®E-32.2.0 ASCC SHORT CIRCUIT CURRENTS         TUE, AUG 15 2017   9:50
2015 MDWG FINAL WITH 2013 MMWG, UPDATED WITH 2014 SERC & MRO
MDWG 17S WITH MMWG 15S, MRO 16W TOPO/16S PROF, SERC 16S

OPTIONS USED:
    - FLAT CONDITIONS
         - BUS VOLTAGES SET TO 1 PU AT 0 PHASE ANGLE
         - GENERATOR P=0, Q=0
         - TRANSFOMRER TAP RATIOS=1.0 PU and PHASE ANGLES=0.0
         - LINE CHARGING=0.0 IN +/-/0 SEQUENCE
         - LOAD=0.0 IN +/- SEQUENCE, CONSIDERED IN ZERO SEQUENCE
         - LINE/FIXED/SWITCHED SHUNTS=0.0 AND MAGNETIZING ADMITTANCE=0.0 IN +/-/0 SEQUENCE
         - DC LINES AND FACTS DEVICES BLOCKED
         - TRANSFORMER ZERO SEQUENCE IMPEDANCE CORRECTIONS IGNORED

                                  THREE PHASE FAULT
X---------- BUS ----------X          /I+/    AN(I+)
526469 [SP-YUMA    269.000] AMP     3058.0   -88.34
526475 [YUMA_INT   3115.00] AMP    10835.7   -80.19
584720 [ASGI2015-00269.000] AMP     2143.0   -82.55
526481 [SP-WOLF_TP 3115.00] AMP    11008.6   -80.14
526524 [WOLFFORTH  3115.00] AMP    11330.9   -81.75
526162 [LP-DOUD_TP 3115.00] AMP    11487.6   -80.16
526483 [SP-WOLFORTH3115.00] AMP     8573.3   -80.21
526525 [WOLFFORTH  6230.00] AMP    12728.7   -83.31
526736 [TERRY_CNTY 3115.00] AMP    10509.1   -77.12
526160 [CARLISLE   3115.00] AMP    12996.1   -80.63
526161 [CARLISLE   6230.00] AMP    10293.7   -83.06
526176 [LP-DOUD    3115.00] AMP     8952.3   -76.59
526269 [LUBBCK_STH 6230.00] AMP    16979.2   -85.25
526435 [SUNDOWN    6230.00] AMP    10448.7   -82.64
526491 [LG-CLAUENE 3115.00] AMP     8904.7   -77.06
526735 [TERRY_CNTY 269.000] AMP     6991.4   -84.14
526792 [PRENTICE   3115.00] AMP     5769.2   -75.67
527130 [DENVER_N   3115.00] AMP    18662.6   -82.33
527262 [SULPHUR    3115.00] AMP     5546.5   -75.37
560058 [G15-077-TAP 115.00] AMP     8040.9   -76.46
583810 [ASGI2013-006115.00] AMP     8573.3   -80.21
522823 [LP-MILWAKEE6230.00] AMP     9690.1   -82.99
522861 [LP-SOUTHEST6230.00] AMP    13474.3   -84.54
525481 [PLANT_X    6230.00] AMP    21878.9   -85.22
525830 [TUCO_INT   6230.00] AMP    19153.7   -84.58
526109 [SP-ERSKINE 3115.00] AMP    11218.7   -78.75
526159 [CARLISLE   269.000] AMP     2562.5   -87.07
526192 [MURPHY     3115.00] AMP    10516.5   -78.30
526268 [LUBBCK_STH 3115.00] AMP    18571.3   -84.43
526337 [JONES      6230.00] AMP    19157.4   -86.25
526434 [SUNDOWN    3115.00] AMP    11198.1   -80.92
526460 [AMOCO_SS   6230.00] AMP     9101.8   -82.55
526484 [LG-LEVELAND3115.00] AMP     9646.8   -78.85
526506 [LG-DOCWEBR 269.000] AMP     4955.4   -77.82
526747 [LG-BROWNFLD269.000] AMP     3570.3   -73.22
526934 [YOAKUM     3115.00] AMP    14679.3   -82.04
527080 [EL_PASO    3115.00] AMP    14277.2   -80.02
527125 [DENVER_CTY 269.000] AMP     8386.1   -87.00
527136 [DENVER_S   3115.00] AMP    18662.6   -82.33
527146 [MUSTANG    3115.00] AMP    19876.9   -83.79
527202 [SEAGRAVES  3115.00] AMP     8140.8   -76.70
527212 [DIAMONDBACK3115.00] AMP     3066.0   -74.62
527261 [SULPHUR    269.000] AMP     3333.3   -83.41
527286 [XTO_RUSSEL 3115.00] AMP     9605.2   -75.02
522828 [LP-MILWAKEE269.000] AMP     7470.0   -82.31
522857 [LP-SOUTHEST269.000] AMP    21372.3   -83.88
522870 [LP-HOLLY   6230.00] AMP    14458.5   -85.09
524623 [DEAFSMITH  6230.00] AMP     7676.7   -80.80
525213 [SWISHER    6230.00] AMP     9971.8   -82.27
525461 [NEWHART    6230.00] AMP    10650.7   -81.87
525480 [PLANT_X    3115.00] AMP    20789.9   -84.02
525524 [TOLK_EAST  6230.00] AMP    25292.6   -86.15
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525531 [TOLK_WEST  6230.00] AMP    25292.6   -86.15
525828 [TUCO_INT   3115.00] AMP    18991.1   -82.75
525832 [TUCO_INT   7345.00] AMP    10067.9   -85.98
525840 [ANTELOPE_1 6230.00] AMP    19013.1   -84.59
526036 [LC-OPDYKE  3115.00] AMP     5764.7   -76.42
526130 [SP-CARLISLE269.000] AMP     2106.2   -82.24
526146 [INDIANA    3115.00] AMP     9598.6   -76.85
526184 [SW_6878    269.000] AMP     2157.3   -83.35
526199 [SP-FRANKFRD3115.00] AMP     9565.4   -77.67
526213 [ALLEN      3115.00] AMP    10595.2   -78.49
526267 [LUBBCK_STH 269.000] AMP     4341.9   -88.11
526298 [LUBBCK_EST 3115.00] AMP    14961.7   -82.31
526299 [LUBBCK_EST 6230.00] AMP    12645.4   -84.74
526424 [PACIFIC    3115.00] AMP     9502.4   -79.54
526445 [AMOCO_TP   3115.00] AMP    10560.6   -80.10
526499 [LG-MEADOW  269.000] AMP     3715.9   -74.09
526602 [SP-WOODROW 3115.00] AMP     9283.2   -78.88
526677 [GRASSLAND  6230.00] AMP     6348.3   -84.59
526754 [BROWNFIELD 269.000] AMP     3055.2   -71.62
526928 [PLAINS_INT 3115.00] AMP     9218.3   -78.07
526935 [YOAKUM     6230.00] AMP    11670.8   -83.68
527036 [SHELL_C2   3115.00] AMP    12005.4   -80.17
527041 [ARCO_TP    3115.00] AMP    11998.4   -78.94
527062 [SHELL_CO2  3115.00] AMP    14455.6   -80.20
527099 [DC_EAST    269.000] AMP     5966.5   -75.60
527105 [SAN_ANDS_TP3115.00] AMP    15021.0   -80.13
527111 [WASSON     269.000] AMP     5841.2   -78.99
527149 [MUSTANG    6230.00] AMP    10291.9   -84.21
527183 [JAYBEE     269.000] AMP     4297.2   -80.41
527194 [LG-PLSHILL 3115.00] AMP     7200.0   -76.35
527201 [SEAGRAVES  269.000] AMP     5303.3   -83.35
527211 [DIAMONDBACK269.000] AMP     3230.9   -79.43
527253 [ADAIR      269.000] AMP     2599.8   -79.09
527271 [LG-FOSTER  269.000] AMP     2690.3   -79.32
527313 [MIDAMERI_TP269.000] AMP     2140.1   -62.84
527363 [HIGG       3115.00] AMP     9768.8   -74.83
583340 [GEN-2012-020230.00] AMP     8641.8   -84.17
583819 [ASGI2014-001115.00] AMP    11218.7   -78.75
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25SP:

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                                 PSS®E-32.2.0 ASCC SHORT CIRCUIT CURRENTS          TUE, AUG 15 2017   9:49
2015 MDWG FINAL WITH 2013 MMWG, UPDATED WITH 2014 SERC & MRO
MDWG 2025S WITH MMWG 2024S, MRO & SERC 2025 SUMMER

OPTIONS USED:
    - FLAT CONDITIONS
         - BUS VOLTAGES SET TO 1 PU AT 0 PHASE ANGLE
         - GENERATOR P=0, Q=0
         - TRANSFOMRER TAP RATIOS=1.0 PU and PHASE ANGLES=0.0
         - LINE CHARGING=0.0 IN +/-/0 SEQUENCE
         - LOAD=0.0 IN +/- SEQUENCE, CONSIDERED IN ZERO SEQUENCE
         - LINE/FIXED/SWITCHED SHUNTS=0.0 AND MAGNETIZING ADMITTANCE=0.0 IN +/-/0 SEQUENCE
         - DC LINES AND FACTS DEVICES BLOCKED
         - TRANSFORMER ZERO SEQUENCE IMPEDANCE CORRECTIONS IGNORED

                                  THREE PHASE FAULT
X--------- BUS ----------X          /I+/    AN(I+)
526469 [SP-YUMA    269.000] AMP     3070.3   -88.40
526475 [YUMA_INT   3115.00] AMP    11114.8   -80.35
584720 [ASGI2015-00269.000] AMP     2149.0   -82.57
526481 [SP-WOLF_TP 3115.00] AMP    11304.4   -80.31
526524 [WOLFFORTH  3115.00] AMP    11595.3   -81.87
526162 [LP-DOUD_TP 3115.00] AMP    11825.2   -80.37
526483 [SP-WOLFORTH3115.00] AMP     8751.3   -80.35
526525 [WOLFFORTH  6230.00] AMP    13450.1   -83.45
526736 [TERRY_CNTY 3115.00] AMP    10746.8   -77.04
526160 [CARLISLE   3115.00] AMP    13464.7   -80.94
526161 [CARLISLE   6230.00] AMP    13247.5   -83.80
526176 [LP-DOUD    3115.00] AMP     9157.3   -76.67
526269 [LUBBCK_STH 6230.00] AMP    18795.4   -85.28
526435 [SUNDOWN    6230.00] AMP    10885.1   -82.68
526491 [LG-CLAUENE 3115.00] AMP     9068.7   -76.98
526735 [TERRY_CNTY 269.000] AMP     7053.7   -84.17
526792 [PRENTICE   3115.00] AMP     5881.1   -75.63
527130 [DENVER_N   3115.00] AMP    19687.2   -82.34
527262 [SULPHUR    3115.00] AMP     5632.7   -75.30
560058 [G15-077-TAP 115.00] AMP     8175.9   -76.38
583810 [ASGI2013-006115.00] AMP     8751.3   -80.35
522823 [LP-MILWAKEE6230.00] AMP    12863.6   -83.82
522861 [LP-SOUTHEST6230.00] AMP    16918.0   -85.05
525481 [PLANT_X    6230.00] AMP    23134.2   -85.29
525830 [TUCO_INT   6230.00] AMP    22210.6   -85.13
526109 [SP-ERSKINE 3115.00] AMP    11553.4   -78.93
526159 [CARLISLE   269.000] AMP     2572.8   -87.13
526192 [MURPHY     3115.00] AMP    10753.4   -78.38
526268 [LUBBCK_STH 3115.00] AMP    19251.7   -84.52
526337 [JONES      6230.00] AMP    20790.1   -86.16
526434 [SUNDOWN    3115.00] AMP    11455.2   -80.87
526460 [AMOCO_SS   6230.00] AMP     9521.9   -82.61
526484 [LG-LEVELAND3115.00] AMP     9836.5   -78.78
526506 [LG-DOCWEBR 269.000] AMP     4986.6   -77.80
526747 [LG-BROWNFLD269.000] AMP     3586.4   -73.19
526934 [YOAKUM     3115.00] AMP    15965.4   -82.65
527080 [EL_PASO    3115.00] AMP    14946.0   -79.99
527125 [DENVER_CTY 269.000] AMP     8505.0   -87.07
527136 [DENVER_S   3115.00] AMP    19687.2   -82.34
527146 [MUSTANG    3115.00] AMP    21047.7   -83.90
527202 [SEAGRAVES  3115.00] AMP     8362.7   -76.63
527212 [DIAMONDBACK3115.00] AMP     3092.1   -74.57
527261 [SULPHUR    269.000] AMP     3351.8   -83.44
527286 [XTO_RUSSEL 3115.00] AMP     9850.8   -74.72
522828 [LP-MILWAKEE269.000] AMP     8294.5   -82.13
522857 [LP-SOUTHEST269.000] AMP    24516.0   -82.79
522870 [LP-HOLLY   6230.00] AMP    16752.9   -85.26
524623 [DEAFSMITH  6230.00] AMP     7763.4   -81.18
525213 [SWISHER    6230.00] AMP    10134.5   -82.25
525461 [NEWHART    6230.00] AMP    10760.7   -81.83
525480 [PLANT_X    3115.00] AMP    26549.4   -85.02
525524 [TOLK_EAST  6230.00] AMP    26091.0   -86.11
525531 [TOLK_WEST  6230.00] AMP    26091.0   -86.11
525828 [TUCO_INT   3115.00] AMP    19865.6   -83.04
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525832 [TUCO_INT   7345.00] AMP    12266.3   -86.20
525840 [ANTELOPE_1 6230.00] AMP    22040.4   -85.14
526036 [LC-OPDYKE  3115.00] AMP     5895.8   -76.27
526130 [SP-CARLISLE269.000] AMP     2113.3   -82.27
526146 [INDIANA    3115.00] AMP     9828.8   -76.93
526184 [SW_6878    269.000] AMP     2164.7   -83.39
526199 [SP-FRANKFRD3115.00] AMP     9716.5   -77.65
526213 [ALLEN      3115.00] AMP    10761.8   -78.41
526267 [LUBBCK_STH 269.000] AMP     4363.5   -88.14
526298 [LUBBCK_EST 3115.00] AMP    15341.3   -82.29
526299 [LUBBCK_EST 6230.00] AMP    13382.9   -84.66
526424 [PACIFIC    3115.00] AMP     9684.6   -79.47
526445 [AMOCO_TP   3115.00] AMP    10788.6   -80.04
526499 [LG-MEADOW  269.000] AMP     3733.3   -74.06
526602 [SP-WOODROW 3115.00] AMP     9445.7   -78.81
526677 [GRASSLAND  6230.00] AMP     6507.2   -84.53
526754 [BROWNFIELD 269.000] AMP     3066.9   -71.59
526928 [PLAINS_INT 3115.00] AMP     9634.0   -78.15
526935 [YOAKUM     6230.00] AMP    15294.2   -84.79
527036 [SHELL_C2   3115.00] AMP    12399.0   -80.06
527041 [ARCO_TP    3115.00] AMP    12556.4   -78.95
527062 [SHELL_CO2  3115.00] AMP    15155.8   -80.19
527099 [DC_EAST    269.000] AMP     6026.3   -75.53
527105 [SAN_ANDS_TP3115.00] AMP    15701.4   -80.05
527111 [WASSON     269.000] AMP     5898.8   -78.96
527149 [MUSTANG    6230.00] AMP    12047.7   -84.63
527183 [JAYBEE     269.000] AMP     4328.3   -80.40
527194 [LG-PLSHILL 3115.00] AMP     7392.3   -76.30
527201 [SEAGRAVES  269.000] AMP     5358.8   -83.39
527211 [DIAMONDBACK269.000] AMP     3248.3   -79.42
527253 [ADAIR      269.000] AMP     2611.1   -79.09
527271 [LG-FOSTER  269.000] AMP     2702.3   -79.32
527313 [MIDAMERI_TP269.000] AMP     2147.4   -62.77
527363 [HIGG       3115.00] AMP    10026.6   -74.50
583340 [GEN-2012-020230.00] AMP     9102.0   -84.27
583819 [ASGI2014-001115.00] AMP    11553.4   -78.93
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