Definitive Interconnection System Impact Study for Generation Interconnection Requests

(DISIS-2012-001)

July 2012

Generation Interconnection

SPP Southwest Power Pool

Revision History

Date	Author	Change Description
07/26/2012	SPP	Report Issued (DISIS-2012-001)

Executive Summary

Generation Interconnection customers have requested a Definitive Interconnection System Impact Study (DISIS) under the Generation Interconnection Procedures (GIP) in the Southwest Power Pool Open Access Transmission Tariff (OATT). The Interconnection Customers' requests have been clustered together for the following System Impact Cluster Study window which closed March 31, 2012. The customers will be referred to in this study as the DISIS-2012-001 Interconnection Customers. This System Impact Study analyzes the interconnecting of multiple generation interconnection requests associated with new generation totaling approximately 816.3 MW of new generation which would be located within the transmission systems of Midwest Energy Inc. (MIDW), Mid-Kansas Electric Power LLC (MKEC), Oklahoma Gas and Electric (OKGE), Sunflower Electric Power Corporation (SUNC), and Southwestern Public Service (SPS). 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.

Power flow analysis has indicated that for the power flow cases studied, 816.3 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 Order No. 661-A for wind farm interconnection requests and those requirements are listed for each interconnection request within the contents of this report. Dynamic stability analysis has determined that the transmission system will remain stable with the assigned Network Upgrades and necessary reactive compensation requirements.

The total estimated minimum cost for interconnecting the DISIS-2012-001 interconnection customers is $75,319,677. These costs are shown in Appendix E and F. Interconnection Service to DISIS-2012-001 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 do not include the Interconnection Customer Interconnection Facilities as defined by the SPP Open Access Transmission Tariff (OATT). This cost does not include additional network constraints in the SPP transmission system identified and shown in Appendix H.

Network Constraints listed in Appendix H are in the local area of the new generation when this generation is injected throughout the SPP footprint for the Energy Resource (ERIS) Interconnection Request. Certain Interconnection Requests were also studied for Network Resource

[1] The generation interconnection requests in-service dates will need to be deferred based on the required lead time for the Network Upgrades necessary. The Interconnection Customer's 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.

Interconnection Service (NRIS). Those constraints are also listed in Appendix H. Additional Network constraints will have to be verified with a Transmission Service Request (TSR) and associated studies. With a defined source and sink in a TSR, this 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 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.

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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, 2012. The customers will be referred to in this study as the DISIS-2012-001 Interconnection Customers. This System Impact Study analyzes the interconnecting of multiple generation interconnection requests associated with new generation totaling 816.3 MW of new generation which would be located within the transmission systems of Midwest Energy Inc. (MIDW), Mid-Kansas Electric Power LLC (MKEC), Oklahoma Gas and Electric (OKGE), Sunflower Electric Power Corporation (SUNC), and Southwestern Public Service (SPS). 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.

The primary objective of this Definitive Interconnection System Impact Study is to identify the system constraints associated with connecting the generation to the area transmission system. The Impact and other subsequent Interconnection Studies are designed to identify attachment facilities, Network Upgrades and other Direct Assignment Facilities needed to accept power into the grid at each specific interconnection receipt point.

[2] The generation interconnection requests in-service dates will need to be deferred based on the required lead time for the Network Upgrades necessary. The Interconnection Customer's that proceed to the Facility Study will be provided a new in-service date based on the competition of the Facility Study.

Model Development

Interconnection Requests Included in the Cluster

SPP has included all interconnection requests that submitted a Definitive Interconnection System Impact Study Agreement no later than March 31, 2012 and were subsequently accepted by Southwest Power Pool under the terms of the Generator Interconnection Procedures (GIP). The interconnection requests that are included in this study are listed in Appendix A.

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 with equal distribution across the SPP footprint. Prior queued projects that requested Network Resource Interconnection Service (NRIS) were dispatched in an additional analysis into the balancing authority of the interconnecting transmission owner.

Development of Base Cases

Power Flow

The 2011 series Transmission Service Request (TSR) Models 2012 spring, 2012 summer and winter peak, and the 2017 summer and winter peak scenario 0 cases were used for this study. After the cases were developed, each of the control areas' resources were then re-dispatched to account for the new generation requests using current dispatch orders.

Dynamic Stability

The 2011 series SPP Model Development Working Group (MDWG) Models 2012 winter and 2012 summer were used as starting points for this study.

Base Case Upgrades

The following facilities are part of the SPP Transmission Expansion Plan or the Balanced Portfolio or recently approved Priority Projects. These facilities, have an approved Notice 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-2012-001 Customers have not been assigned acceleration costs for the below listed projects. <u>The DISIS-2012-001 Customers Generation Facilities in service dates may need to be delayed until the completion of the following upgrades.</u> If for some reason, construction on these projects is discontinued, additional restudies will be needed to determine the interconnection needs of the DISIS customers.

- Hitchland 230/115kV area projects[3]:

[3] SPP Regional Reliability Projects identified in 2007 STEP. As of the writing of this report, SPP Project Tracking TAGIT shows some of these project's in-service dates have been delayed from the original 2010/2011 in-service dates.

  - Hitchland – Ochiltree 230kV Project, scheduled for 2/1/2013 in-service
- Balanced Portfolio Projects[4]:
  - Woodward – Border – TUCO 345kV project, scheduled for 5/19/2014 in-service
    - Woodward 345/138kV circuit #2 autotransformer
    - TUCO 345/138kV circuit #2 autotransformer
    - Reactors at Woodward and Border
  - Iatan– Nashua 345kV, scheduled for 6/1/2015 in-service
    - Nashua 345/161kV autotransformer
  - Muskogee– Seminole 345kV, scheduled for 12/31/2013 in-service
  - Post Rock – Axtell 345kV, scheduled for 6/1/2013 in-service
  - Cleveland – Sooner 345kV, scheduled for 12/31/2012 in-service
  - Tap Stillwell – Swissvale 345kV line at West Gardner, scheduled for 12/31/2012 in-service
- Priority Projects[5]:
  - Hitchland – Woodward double circuit 345kV, scheduled for 6/30/2014 in-service
    - Hitchland 345/230kV circuit #2 autotransformer
  - Woodward – Thistle double circuit 345kV, scheduled for 12/31/2014 in-service
  - Spearville – Clark double circuit 345kV, scheduled for 12/31/2014 in-service
  - Clark – Thistle double circuit 345kV, scheduled for 12/31/2014 in-service
  - Thistle – Wichita double circuit 345kV, scheduled for 12/31/2014 in-service
  - Thistle 345/138kV autotransformer, scheduled for 12/31/2014 in-service
  - Thistle – Flat Ridge 138kV, scheduled for 12/31/2014 in-service
- Various MKEC Transmission System Upgrades[6]
  - Harper – Flat Ridge 138kV rebuild, scheduled for 6/15/2013 in-service
  - Flat Ridge – Medicine Lodge 138kV rebuild, scheduled for 12/31/2013 in-service
  - Pratt – Medicine Lodge 115kV rebuild, scheduled for 6/15/2014 in-service
  - Medicine Lodge 138/115kV autotransformer replacement, scheduled for 6/1/2013 in-service
- Northwest 345/138/13.8kV circuit #3 autotransformer, scheduled for 6/1/2017 in-service[7]
- Woodward (OKGE) – Woodward (WFEC) 69kV rebuild, scheduled for 12/1/2013 in-service[8]
- Sheldon – SW7th and Pleasant Hill 115kV circuit #2 rebuild, scheduled for 5/15/2013 in-service[9]
- Moundridge 138/115/13.8kV autotransformer circuit #2, scheduled for 12/1/2014 in-service[10]
- Grassland – Wolfforth 230kV, scheduled for 3/1/2018 in-service[11]

[4] Notice to Construct (NTC) issued June 2009.
[5] Notice to Construct (NTC) issued June 2010.
[6] SPP Transmission Service Projects identified in SPP-2007-AG3-AFS-9.
[7] SPP Transmission Service Project identified in SPP-2009-AG2-AFS6. Per SPP-NTC-20137.
[8] SPP Regional Reliability Project. Per SPP-NTC-20003.
[9] SPP Regional Reliability 2012 ITPNT Project. Per SPP-NTC-200171.
[10] SPP Regional Reliability 2012 ITP10 Project. Per SPP-NTC-200181.
[11] SPP Regional Reliability 2012 ITP10 Project. Per SPP-NTC-200184.

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-2012-001 study and are assumed to be in service. This list may not be all inclusive. <u>The DISIS-2012-001 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 GIA or withdraw from the interconnection queue. The DISIS-2012-001 Customer Generation Facilities in service dates may need to be delayed until the completion of the following upgrades.</u>

- Finney – Holcomb 345kV circuit #2, assigned to GEN-2006-049 interconnection customer[12]
- Upgrades assigned to DISIS-2009-001 Interconnection Customers:
    - Fort Dodge – North Fort Dodge – Spearville 115kV circuit #2
    - Albion – Petersburg – Neligh 115kV rerate
    - Fort Randall – Madison County – Kelly 230kV rerate (320MVA)
    - Spearville 345/115kV autotransformer
- Upgrades assigned to DISIS-2010-001 Interconnection Customers:
    - Post Rock 345/230kV circuit #2 autotransformer
    - South Hays – Hays Plant – Vine Street 115kV rebuild
    - Switch 2749 – Wildorado 69kV rebuild
    - Madison County – Kelly 230kV rerate (478MVA)
    - Washita – Gracemont 138kV circuit #2
- Upgrades assigned to DISIS-2010-002 Interconnection Customers:
    - Beaver County 345kV Expansion (Tap & Tie Hitchland – Woodward CKT 2 into Beaver County 345kV)
    - Twin Church – Dixon County 230kV rerate (320MVA)
    - (NRIS only) Spearville – Mullergren 230kV circuit #1 rebuild
- Upgrades assigned to DISIS-2011-001 interconnection Customers:
    - Beaver County – Gray County 345kV
    - Spearville – Mullergren – Reno double circuit 345kV
    - Tatonga – Matthewson - Cimarron 345kV circuit #2
        - Tatonga terminal equipment upgrade (1792 MVA)
    - Rice County – Circle 230kV conversion
    - Rice County – Lyons 115kV rebuild
    - Rice County 230/115kV autotransformer
    - Lyons – Wheatland 115kV rerate (199 MVA)
    - Hoskins – Dixon County – Twin Church 230kV rerate
    - (NRIS only) Benton – Wichita 345kV rerate (1195MVA)
    - (NRIS only) Chisolm – Maize – Evans Energy Center 138kV rerate
    - (NRIS only) Deaf Smith County – South Randle County 230kV rerate
    - (NRIS only) EL Reno – Roman Nose 138kV rebuild

[12] Impact Study posted February 2012.

    - (NRIS only) FPL Switch – Woodward = Mooreland 138kV rebuild
    - (NRIS only) Hitchland 230/115/13.2kV transformer circuit #2
    - (NRIS only) Knoll – North Hays – Vine 115kV rebuild
- Upgrades assigned to DISIS-2011-002 interconnection Customers:
    - Harbine – Crete 115kV re-build
    - Jones – Lubbock South 230kV CKT 2 - Replace Line Traps
    - Power System Stabilizers - Install Power System Stabilizers @ Tolk(Units: 1,2) and Jones (Units: 1,2,3,4)
    - SUB 967 - SUB 968 69kV CKT 1 - replace terminal equipment
    - (NRIS only) Allen – Lubbock South 115kV rebuild
    - (NRIS only) Cimarron – Draper 345kV replace Cimarron line trap and Draper CT
    - (NRIS only) Glass Mountain – Mooreland 138kV rebuild
    - (NRIS only) Hydro Carbon Tap - Sub974 69kV rewire CT
    - (NRIS only) Jones – TUCO 230kV CKT 1 - Replace line traps
    - (NRIS only) Lubbock South - Lubbock East 115kV CKT 1 - Rebuild
    - (NRIS only) Lubbock South 230/115kV Autotransformer build CKT 2
    - (NRIS only) Nebraska City U Syracuse – SUB 970 CKT 1 - replace terminal equipment

Potential Upgrades Not in the Base Case

Any potential upgrades that do not have a Notification to Construct (NTC) and 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 were grouped together in fifteen different regional groups based on geographical and electrical impacts. These groupings are shown in Appendix C.

To determine interconnection impacts, fifteen different generation dispatch scenarios of the spring base case models were developed to accommodate the regional groupings.

Power Flow

For each group, the various wind generating plants were modeled at 80% nameplate of maximum generation. The wind generating plants in the other areas were modeled at 20% nameplate of maximum generation. This process created fifteen different scenarios with each group being studied at 80% nameplate rating. These projects were dispatched as Energy Resources with equal distribution across the SPP footprint. Certain projects that requested Network Resource Interconnection Service were dispatched in an additional analysis into the balancing authority of the interconnecting transmission owner. This method allowed for the identification of network constraints that were common to the regional groupings that could then in turn have the mitigating upgrade cost allocated throughout the entire cluster. Other sensitivity analyses are also performed with each interconnection request modeled at 100% nameplate.

Peaking units were not dispatched in the 2012 spring model. To study peaking units' impacts, the 2012 summer and winter and 2017 summer and winter seasonal models were chosen and peaking units were modeled at 100% of the nameplate rating and wind generating facilities were modeled at 10% of the nameplate rating. Each interconnection request was also modeled separately at 100% nameplate for certain analyses.

Dynamic Stability

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

Identification of Network Constraints

The initial set of network constraints were found by using PTI MUST First Contingency Incremental Transfer Capability (FCITC) analysis on the entire cluster grouping dispatched at the various levels mentioned above. These constraints were then screened to determine if any of the generation interconnection requests had at least a 20% Distribution Factor (DF) upon the constraint. Constraints that measured at least a 20% DF from at least one interconnection request were considered for mitigation. Interconnection Requests that have requested Network Resource Interconnection Service (NRIS) were also studied in the NRIS analysis to determine if any constraint had at least a 3% DF. If so, these constraints were considered for mitigation.

Determination of Cost Allocated Network Upgrades

Cost Allocated Network Upgrades of wind generation interconnection requests were determined using the 2012 spring model. Cost Allocated Network Upgrades of peaking units was determined using the 2017 summer peak model. A MUST sensitivity analysis was performed to determine the Distribution Factors (DF), a distribution factor with no contingency that each generation interconnection request had on each new upgrade. The impact each generation interconnection request had on each upgrade project was weighted by the size of each request. Finally the costs due by each request for a particular project were then determined by allocating the portion of each request's impact over the impact of all affecting requests.

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

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

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

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

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

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

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

- 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 for Amounts Advanced for Network Upgrades

Interconnection Customer shall be entitled to credits 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 816.3 MW of generation into the existing and proposed transmission systems in the affected areas of the SPP transmission footprint consist of the necessary cost allocated shared facilities listed in Appendix F by upgrade. The interconnection requirements for the cluster total $75,319,677. 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.

A list of constraints that were identified and used for mitigation are listed in Appendix G. Listed within Appendix G are the ERIS constraints with greater than or equal to a 20% DF, as well as, the NRIS constraints that have a DF of 3% or greater. Other Network Constraints which are not requiring mitigation are shown in Appendix H. With a defined source and sink in a TSR, this list of Network Constraints will be refined and expanded to account for all Network Upgrade requirements.

Power Flow Analysis

Power Flow Analysis Methodology

The Southwest Power Pool (SPP) Criteria states that:

> "The transmission system of the SPP region shall be planned and constructed so that the contingencies as set forth in the Criteria will meet the applicable *NERC Reliability Standards* for transmission planning. All MDWG power flow models shall be tested to verify compliance with the System Performance Standards from NERC Table 1 – Category A."

The ACCC function of PSS/E was 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. This satisfies the "more probable" contingency testing criteria mandated by NERC and the SPP criteria.

Power Flow Analysis

A power flow analysis was conducted for each Interconnection Customer's facility using modified versions of the 2012 spring peak, 2012 summer and winter peak, and the 2017 summer and winter peak models. The output of the Interconnection Customer's facility was offset in each model by a reduction in output of existing online SPP generation. This method allows the request to be studied as an Energy Resource (ER) Interconnection Request. Certain requests that requested Network Resource Interconnection Service (NRIS) had an additional analysis conducted for displacing resources in the interconnecting Transmission Owner's balancing authority.

This analysis was conducted assuming that previous queued requests in the immediate area of these interconnect requests were in-service. The analysis of each Customer's project indicates that criteria violations will occur on the MIDW, SPS, SUNC, and WERE transmission systems under system intact and contingency conditions in the peak seasons.

Cluster Group 1 (Woodward Area)

In addition to the 5,151.8 MW of previously queued generation in the area, 0 MW of new interconnection service was studied. No new constraints were found in this area.

Cluster Group 2 (Hitchland Area)

In addition to the 3,529.4 MW of previously queued generation in the area, 0 MW of new interconnection service was studied. No new constraints were found in this area.

Cluster Group 3 (Spearville Area)

In addition to the 5,422.9 MW of previously queued generation in the area, 542.5 MW of new interconnection service was studied. Possible voltage collapse was identified around the Post Rock area for an N-1 contingency of GEN-2011-017T – Post Rock 345kV segment of the Spearville – Post Rock 345kV line. This requires a second circuit from GEN-2011-017T – Post Rock 345kV to be built to mitigate the constraint.

Cluster Group 4 (Mingo/NW Kansas Group)

In addition to the 744.0 MW of previously queued generation in the area, 101.2 MW of new interconnection service was studied. No new constraints were found in this area.

Cluster Group 5 (Amarillo Area)

In addition to the 1,572.6 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 6 (South Texas Panhandle/New Mexico)

In addition to the 2,706.1 MW of previously queued generation in the area, 131.2 MW of new interconnection service was studied. For interconnection customers that requested NRIS, a number of additional upgrades may have been identified and listed in Appendices E and F.

Cluster Group 7 (Southwestern Oklahoma)

In addition to the 1,991.0 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 8 (South Central Kansas/North Oklahoma)

In addition to the 1,986.3 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 9/10 (Nebraska)

In addition to the 1,931.1 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 11 (North Central Kansas)

In addition to the 1,445.1 MW of previously queued generation in the area, 0 MW of new interconnection service was studied. No new constraints were found in this area.

Cluster Group 12 (Northwest Arkansas)

In addition to the 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 13 (Northwest Missouri)

In addition to the 585.6 MW of previously queued generation in the area, 0 MW of new interconnection service was studied. No new constraints were found in this area.

Cluster Group 14 (South Central Oklahoma)

In addition to the 420.8 MW of previously queued generation in the area, 41.4 MW of new interconnection service was studied. No new ERIS constraints were found in this area.

Cluster Group 15 (reserved)

This group has been retired and all prior Group 15 requests have been re-designated as Group 9/10 requests.

Stability Analysis

A stability analysis was conducted for each Interconnection Customer's facility using modified versions of the 2012 summer and 2012 winter peak models. The stability analysis was conducted with all upgrades in service that were identified in the power flow analysis. For each group, the interconnection requests were studied at 100% nameplate output while the other groups were dispatched at 20% output for wind requests and 100% output for fossil requests. The output of the Interconnection Customer's facility was offset in each model by a reduction in output of existing online SPP generation. The following synopsis is included for each group. The entire stability study for each group can be found in the Appendices.

Cluster Group 1 (Woodward Area)

There was no stability analysis conducted in the Woodward area due to no requests in the area.

Cluster Group 2 (Hitchland Area)

There was no stability analysis conducted in the Hitchland area due to no requests in the area.

Cluster Group 3 (Spearville Area)

The Group 3 stability analysis for this study was performed by Mitsubishi Electric Power Products, Inc. Stability analysis has determined that Group 3 projects require the addition of a second 345 kV line between G11-017 POI and Post Rock. With the addition of the second line between G11-017 POI and Post Rock and with the addition of previously assigned network upgrades, the 542.5 MW of new generation interconnection requests can be accommodated. Once the previously assigned upgrades are placed in service the transmission system will remain stable and low voltage ride through requirements are satisfied for the contingencies studied.

With the power factor requirements and all network upgrades in service, all interconnection requests in Group 3 will meet FERC Order #661A low voltage ride through (LVRT) requirements.

Power Factor Requirements:

Request	Size (MW)	Generator Model	Point of Interconnection	Power Factor Requirement at POI	
				Lagging (supplying)	Leading (absorbing)
GEN-2012-003	21.21 Winter 20.74 Summer	GENSAL	Hugoton 115kV (562114)	0.95	0.95
GEN-2012-007	120.0 Winter 96.0 Summer	GENSAL	Rubart 115kV (562116)	0.95	0.95
GEN-2012-011	200.0	GE 1.6MW	Tap Spearville – Post Rock 345kV (576704)	0.95	0.95
GEN-2012-012	200.0	Clipper 2.5MW	Clark County 345kV (539800)	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 4 (Mingo Area)

The Group 4 stability analysis for this study was performed by Excel Engineering, Inc. Stability analysis has determined that the 101.2 MW of new generation interconnection requests can be accommodated with the addition of previously assigned network upgrades. Once the previously assigned upgrades are placed in service the transmission system will remain stable and low voltage ride through requirements are satisfied for the contingencies studied.

With the power factor requirements and all network upgrades in service, all interconnection requests in Group 4 will meet FERC Order #661A low voltage ride through (LVRT) requirements.

Power Factor Requirements:

Request	Size (MW)	Generator Model	Point of Interconnection	Power Factor Requirement at POI	
				Lagging (supplying)	Leading (absorbing)
GEN-2012-002	101.2	Siemens 2.3MW	Tap Pile – Scott City 115kV (562110)	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 5 (Amarillo Area)

There was no stability analysis conducted in the Amarillo area due to no requests in the area.

Cluster Group 6 (South Texas Panhandle/New Mexico)

The Group 6 stability analysis for this study was performed by S&C Electric Company. Stability analysis has determined that GEN-2012-001 requires the addition of 24 MVAR capacitor bank on its 34.5 kV bus. With the previously allocated Power System Stabilizers (PSS) on certain units within the Southwestern Public Service (SPS) Balancing Authority, the additional reactive support at GEN-2012-001, and with the addition of previously assigned network upgrades, the 131.2 MW of new generation interconnection requests can be accommodated. Once the previously assigned upgrades are placed in service (these upgrades include the Tuco-Woodward 345kV line and the Hitchland-Woodward double circuit 345kV line as well as the Grassland-Wolfforth 230kV line) the transmission system will remain stable and low voltage ride through requirements are satisfied for the contingencies studied.

With the power factor requirements and all network upgrades in service, all interconnection requests in Group 6 will meet FERC Order #661A low voltage ride through (LVRT) requirements.

Power Factor Requirements:

Request	Size (MW)	Generator Model	Point of Interconnection	Power Factor Requirement at POI	
				Lagging (supplying)	Leading (absorbing)
GEN-2012-001	61.2	CCWE 3.6MW	Tap Borden – Grassland 230kV (562089)	0.95	0.95
GEN-2012-008	40	GENROU	Mustang 115kV (527146)	0.95	0.95

Request	Size (MW)	Generator Model	Point of Interconnection	Power Factor Requirement at POI	
				Lagging (supplying)	Leading (absorbing)
GEN-2012-009	15	GENROU	Mustang 230kV (527151)	0.95	0.95
GEN-2012-010	15	GENROU	Mustang 230kV (527151)	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 Area)

There was no stability analysis conducted in the Southwest Oklahoma area due to no requests in the area.

Cluster Group 8 (South Central Kansas/North Oklahoma)

There was no stability analysis conducted in the South Central Kansas/North Oklahoma area due to no requests in the area.

Cluster Group 9/10 (Nebraska)

There was no stability analysis conducted in the Nebraska area due to no requests in the area.

Cluster Group 11 (North Central Kansas Area)

There was no stability analysis conducted in the North Central Kansas area due to no requests in the area.

Cluster Group 12 (Northwest Arkansas Area)

There was no stability analysis conducted in the Northwest Arkansas area due to no requests in the area.

Cluster Group 13 (Northwest Missouri Area)

There was no stability analysis conducted in the Northwest Missouri area due to no requests in the area.

Cluster Group 14 (South Central Oklahoma)

The Group 14 stability analysis for this study was performed by POWER-tek Global Inc. Stability analysis has determined that the 41.4 MW of new generation interconnection requests can be accommodated with the addition of previously assigned network upgrades. Once the previously assigned upgrades are placed in service the transmission system will remain stable and low voltage ride through requirements are satisfied for the contingencies studied.

With the power factor requirements and all network upgrades in service, all interconnection requests in Group 14 will meet FERC Order #661A low voltage ride through (LVRT) requirements.

Power Factor Requirements:

Request	Size (MW)	Generator Model	Point of Interconnection	Power Factor Requirement at POI	
				Lagging (supplying)	Leading (absorbing)

Request	Size (MW)	Generator Model	Point of Interconnection	Power Factor Requirement at POI	
				Lagging (supplying)	Leading (absorbing)
GEN-2012-004	41.4	Siemens 2.3MW	Tap Ratliff – Pooleville 138kV (562038)	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 15 (reserved)

This group has been retired and all prior Group 15 requests have been re-designated as Group 9/10 requests.

Conclusion

The minimum cost of interconnecting 816.3 MW of new interconnection requests included in this Definitive Interconnection System Impact Study is estimated at $75,319,677 for the Allocated Network Upgrades and Transmission Owner Interconnection Facilities are listed in Appendix E and F. These costs do not include the cost of upgrades of other transmission facilities listed in Appendix H which are Network Constraints.

These interconnection costs do not include any cost of Network Upgrades determined to be required by short circuit analysis. These studies will be performed if the Interconnection Customer executes the appropriate Interconnection Facilities Study Agreement and provides the required data along with demonstration of Site Control and the appropriate deposit. At the time of the Interconnection Facilities Study, a better determination of the interconnection facilities may be available.

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).

Appendix

A: Generation Interconnection Requests Considered for Impact Study

See next page.

A: Generation Interconnection Requests Considered for Impact 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*
GEN-2012-001	61.2	ER/NR	SPS	Tap Grassland - Borden County 230kV	Tap Grassland - Borden County 230kV	11/30/2012	12/31/2014
GEN-2012-002	101.2	ER	SUNCMKEC	Tap Pile - Scott City 115kV	Tap Pile - Scott City 115kV	1/1/2014	12/31/2014
GEN-2012-003	22.5	ER	SUNCMKEC	Tap Hugoton - Rolla 69kV	Tap Hugoton - Rolla 69kV	12/1/2013	TBD
GEN-2012-004	41.4	ER/NR	OKGE	Pooleville 138kV	Ratliff - Pooleville 138kV	12/31/2013	
GEN-2012-007	120.0	ER/NR	SUNCMKEC	Rubart 115kV	Rubart 115kV	6/1/2014	TBD
GEN-2012-008	40.0	ER	SPS	Mustang 115kV & Mustang 230kV	Mustang 115kV & Mustang 230kV	4/1/2015	12/31/2014
GEN-2012-009	15.0	ER	SPS	Mustang 230kV	Mustang 230kV	4/1/2015	12/31/2014
GEN-2012-010	15.0	ER	SPS	Mustang 230kV	Mustang 230kV	4/1/2015	12/31/2014
GEN-2012-011	200.0	ER	SUNCMKEC	Tap Spearville - Post Rock 345kV (GEN-2011-017 Tap)	Tap Spearville - Post Rock 345kV (GEN-2011-017 Tap)	11/1/2013	TBD
GEN-2012-012	200.0	ER/NR	SUNCMKEC	Clark County 345kV	Clark County 345kV	12/31/2015	TBD
TOTAL	**816.3**						

*request dependent upon Priority Projects or Balanced Portfolio may be delayed until 12/31/2014.
Other projects in service date to be determined after Facility Study.

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	AECI	Tap Fairfax Tap - Fairfax (AECI) 138kV	AECI queue Affected Study
ASGI-2010-010	42	SPS	Lovington 115kV	Lea County Affected Study
ASGI-2010-011	48	SPS	TC-Texas County 69kV	Tri-County Affected Study
ASGI-2010-020	30	SPS	Tap LE-Tatum - LE-Crossroads 69kV	Lea County Affected Study
ASGI-2010-021	15	SPS	Tap LE-Saunders Tap - LE-Anderson 69kV	Lea County Affected Study
ASGI-2011-001	28.8	SPS	LE-Lovington 115kV	Lea County Affected Study
ASGI-2011-002	10	SPS	Herring 115kV	AECI queue Affected Study
ASGI-2011-003	10	SPS	Hendricks 115kV	AECI queue Affected Study
ASGI-2011-004	20	SPS	Pleasant Hill 69kV	Under Study (DISIS-2011-002)
GEN-2001-014	96	WFEC	Ft Supply 138kV	On-Line
GEN-2001-026	74	WFEC	Washita 138kV	On-Line
GEN-2001-033	180	SPS	San Juan Tap 230kV	On-Line
GEN-2001-036	80	SPS	Norton 115kV	On-Line
GEN-2001-037	100	OKGE	FPL Moreland Tap 138kV	On-Line
GEN-2001-039A	105	SUNCMKEC	Tap Greensburg - Ft Dodge 115kV	On Schedule for 2012
GEN-2001-039M	100	SUNCMKEC	Central Plains Tap 115kV	On-Line
GEN-2002-004	200	WERE	Latham 345kV	On-Line at 150MW
GEN-2002-005	120	WFEC	Red Hills Tap 138kV	On-Line
GEN-2002-008	240	SPS	Hitchland 345kV	On-Line at 120MW
GEN-2002-009	80	SPS	Hansford 115kV	On-Line
GEN-2002-022	240	SPS	Bushland 230kV	On-Line
GEN-2002-023N	0.8	NPPD	Harmony 115kV	On-Line
GEN-2002-025A	150	SUNCMKEC	Spearville 230kV	On-Line
GEN-2003-004 GEN-2004-023 GEN-2005-003	151.2	WFEC	Washita 138kV	On-Line
GEN-2003-005	100	WFEC	Anadarko - Paradise (Blue Canyon) 138kV	On-Line
GEN-2003-006A	200	SUNCMKEC	Elm Creek 230kV	On-Line
GEN-2003-019	250	MIDW	Smoky Hills Tap 230kV	On-Line
GEN-2003-020	160	SPS	Martin 115kV	On-Line at 80MW
GEN-2003-021N	75	NPPD	Ainsworth Wind Tap 115kV	On-Line
GEN-2003-022	120	AEPW	Washita 34.5kV	On-Line
GEN-2004-005N	30	NPPD	St Francis 115kV	IA Pending
GEN-2004-014	154.5	SUNCMKEC	Spearville 230kV	On Schedule for 2012
GEN-2004-020	27	AEPW	Washita 34.5kV	On-Line
GEN-2004-023N	75	NPPD	Columbus County 115kV	On Schedule
GEN-2005-005	18	OKGE	FPL Moreland Tap 138kV	IA Pending
GEN-2005-008	120	OKGE	Woodward 138kV	On-Line
GEN-2005-012	250	SUNCMKEC	Spearville 345kV	On Schedule for 2012
GEN-2005-013	201	WERE	Tap Latham - Neosho (Caney River) 345kV	On-Line
GEN-2006-002	101	AEPW	Sweetwater 230kV	On-Line
GEN-2006-006	205.5	SUNCMKEC	Spearville 345kV	IA Pending
GEN-2006-014	300	MIPU	Tap Maryville - Midway 161kV	On Suspension
GEN-2006-018	170	SPS	Antelope 230kV	On-Line
GEN-2006-020N	42	NPPD	Bloomfield 115kV	On-Line
GEN-2006-020S	18.9	SPS	DWS Frisco 115kV	On Schedule for 3/2012

Request	Amount	Area	Requested/Proposed Point of Interconnection	Status or In-Service Date
GEN-2006-021	101	SUNCMKEC	Flat Ridge Tap 138kV	On-Line
GEN-2006-022	150	SUNCMKEC	Pratt 115kV	On Suspension
GEN-2006-024S	19.8	WFEC	Buffalo Bear Tap 69kV	On-Line
GEN-2006-026	502	SPS	Hobbs 230kV	On-Line
GEN-2006-031	75	MIDW	Knoll 115kV	On-Line
GEN-2006-032	200	MIDW	South Hays 230kV	On Suspension
GEN-2006-035	225	AEPW	Sweetwater 230kV	On-Line at 132MW
GEN-2006-037N1	75	NPPD	Broken Bow 115kV	On Suspension
GEN-2006-038N005	80	NPPD	Broken Bow 115kV	On Schedule for 2012
GEN-2006-038N019	80	NPPD	Petersburg 115kV	On-Line
GEN-2006-040	108	SUNCMKEC	Mingo 115kV	On Suspension
GEN-2006-043	99	AEPW	Sweetwater 230kV	On-Line
GEN-2006-044	370	SPS	Hitchland 345kV	On Schedule for 2012
GEN-2006-044N	40.5	NPPD	Petersburg 115kV	On-Line
GEN-2006-044N02	100.5	NPPD	Tap Ft Randle - Columbus (Madison County) 230kV	IA Pending
GEN-2006-045	240	SPS	Tap and Tie both Potter - Plant X 230kV and Bushland - Deaf Smith (South Randle County) 230kV	On Suspension
GEN-2006-046	131	OKGE	Dewey 138kV	On-Line
GEN-2006-047	240	SPS	Tap and Tie both Potter - Plant X 230kV and Bushland - Deaf Smith (South Randle County) 230kV	On Suspension
GEN-2006-049	400	SPS	Tap Finney - Hitchland (Stevens County) 345kV	On Schedule for 2014
GEN-2007-011	135	SUNCMKEC	Syracuse 115kV	On Suspension
GEN-2007-011N08	81	NPPD	Bloomfield 115kV	On-Line
GEN-2007-015	135	WERE	Tap Kelly(WERE) - S1399(OPPD) 161kV	On Suspension
GEN-2007-021	201	OKGE	Tatonga 345kV	On Schedule for 2014
GEN-2007-025	300	WERE	Tap Wichita - Woodring (Sumner County) 345kV	On Schedule for 2012
GEN-2007-032	150	WFEC	Tap Clinton Junction - Clinton 138kV	On Schedule for 2013
GEN-2007-038	200	SUNCMKEC	Spearville 345kV	On Schedule for 2015
GEN-2007-040	200	SUNCMKEC	Tap Holcomb - Spearville (Gray County) 345kV	On Schedule for 2012
GEN-2007-043	200	OKGE	Minco 345kV	On-Line
GEN-2007-044	300	OKGE	Tatonga 345kV	On Schedule for 2014
GEN-2007-046	199.5	SPS	Hitchland 115kV	On Schedule for 2014
GEN-2007-048	400	SPS	Tap Amarillo S - Swisher 230kV	On Schedule for 2014
GEN-2007-050	170	OKGE	Woodward EHV 138kV	On-Line at 150MW
GEN-2007-051	200	WFEC	Mooreland 138kV	On Schedule for 2014
GEN-2007-052	150	WFEC	Anadarko 138kV	On-Line
GEN-2007-057	34.5	SPS	Moore County East 115kV	On Schedule for 2014
GEN-2007-062	765	OKGE	Woodward EHV 345kV	On Schedule for 2014
GEN-2008-003	101	OKGE	Woodward EHV 138kV	On-Line
GEN-2008-008	60	SPS	Graham 69kV	On Schedule for 2014
GEN-2008-009	60	SPS	San Juan Tap 230kV	On Schedule for 2014
GEN-2008-013	300	OKGE	Tap Wichita - Woodring (South of GEN-2007-025) 345kV	On Schedule for 2012
GEN-2008-014	150	SPS	Tap Tuco- Oklaunion 345kV	On Schedule for 2014
GEN-2008-016	248	SPS	Grassland 230kV	IA Pending
GEN-2008-017	300	SUNCMKEC	Setab 345kV	On Schedule for 2014
GEN-2008-018	405	SPS	Finney 345kV	On Schedule for 2012
GEN-2008-019	300	OKGE	Tatonga 345kV	On Schedule for 2015
GEN-2008-021	42.0	WERE	Wolf Creek 345kV	On-Line

Request	Amount	Area	Requested/Proposed Point of Interconnection	Status or In-Service Date
GEN-2008-022	300	SPS	Tap Eddy Co - Tolk (Chaves County) 345kV	On Schedule for 2015
GEN-2008-023	150	AEPW	Hobart Junction 138kV	On Schedule for 2012
GEN-2008-025	101	SUNCMKEC	Ruleton 115kV	On SchedulE for 2015
GEN-2008-029	250	OKGE	Woodward EHV 138kV	On Schedule for 2014
GEN-2008-037	101	WFEC	Tap Washita - Blue Canyon Wind 138kV	On-Line
GEN-2008-044	197.8	OKGE	Tatonga 345kV	On-Line
GEN-2008-046	200	OKGE	Sunnyside 345kV	On Suspension
GEN-2008-047	300	SPS	Tap Hitchland - Woodward Ckt 1 (Beaver County) 345kV	IA Pending
GEN-2008-051	322	SPS	Potter County 345kV	On Schedule for 2012
GEN-2008-071	76.8	OKGE	Newkirk 138kV	On Suspension
GEN-2008-079	100.5	SUNCMKEC	Tap Cudahy - Ft Dodge 115kV	On Schedule for 2012
GEN-2008-086N02	200	NPPD	Tap Ft Randle - Columbus (Madison County) 230kV	On Schedule for 2014
GEN-2008-088	50.6	SPS	Vega 69kV	IA Pending
GEN-2008-092	201	MIDW	Postrock 230kV	IA Pending
GEN-2008-098	100.8	WERE	Tap Lacygne - Wolf Creek (Anderson County) 345kV	IA Pending
GEN-2008-119O	60	OPPD	S1399 161kV	On-Line
GEN-2008-123N	89.7	NPPD	Tap Guide Rock - Pauline 115kV	On Suspension
GEN-2008-124	200	SUNCMKEC	Spearville 345kV	On Schedule for 2014
GEN-2008-129	80	MIPU	Pleasant Hill 161kV	On-Line
GEN-2009-008	199.5	MIDW	South Hays 230kV	On Suspension
GEN-2009-016	100.8	AEPW	Falcon Road 138kV	On Suspension
GEN-2009-020	48.6	MIDW	Tap Nekoma - Bazine 69kV	On Suspension
GEN-2009-025	60	OKGE	Tap Deer Creek - Sinclair Blackwell 69kV	On Schedule for 2012
GEN-2009-040	73.8	WERE	Tap Smittyville - Knob Hill 115kV	On Suspension
GEN-2009-067S	20	SPS	Seven Rivers 69kV	On Suspension
GEN-2010-001	300	SPS	Tap Hitchland - Woodward Ckt 1 (Beaver County) 345kV	ule for 2014 (204 MW) and 2015
GEN-2010-003	100.8	WERE	Tap Lacygne - Wolf Creek (Anderson County) 345kV	IA Pending
GEN-2010-005	300	WERE	Tap Wichita - Woodring (Sumner County) 345kV	On Schedule for 2012
GEN-2010-006	205	SPS	Jones 230kV	On-Line
GEN-2010-009	165.6	SUNCMKEC	Tap Holcomb - Spearville (Gray County) 345kV	On Schedule for 2012
GEN-2010-011	30	OKGE	Tatonga 345kV	On Line
GEN-2010-012	65	WFEC	Brantley 138kV	On Schedule for 2015
GEN-2010-014	360	SPS	Hitchland 345kV	IA Pending
GEN-2010-015	200.1	SUNCMKEC	Spearville 345kV	On Schedule for 2015
GEN-2010-020	20	SPS	Roswell 69kV	IA Pending
GEN-2010-029	450	SUNCMKEC	Spearville 345kV	IA Pending
GEN-2010-036	4.6	WERE	6th Street 115kV	On Schedule for 2012
GEN-2010-040	300	OKGE	Cimarron 345kV	On Schedule for 2012
GEN-2010-041	10.5	OPPD	S 1399 161kV	Facility Study
GEN-2010-044	99	NPPD	Harbine 115kV	Under Study (DISIS-2011-002)
GEN-2010-045	197.8	SUNCMKEC	Tap Holcomb - Spearville (Gray County) 345kV	IA Pending
GEN-2010-046	56	SPS	Tuco 230kV	On Schedule for 2016
GEN-2010-048	70	MIDW	Tap Beach Station - Redline 115kV	IA Pending
GEN-2010-051	200	NPPD	Tap Twin Church - Hoskins 230kV	On Schedule for 2014
GEN-2010-053	199.8	SUNCMKEC	Clark County 345kV	IA Pending
GEN-2010-055	4.5	AEPW	Wekiwa 138kV	IA Pending
GEN-2010-056	151	MIPU	Tap Saint Joseph - Cooper 345kV	IA Pending

Request	Amount	Area	Requested/Proposed Point of Interconnection	Status or In-Service Date
GEN-2010-057	201	WERE	Rice County 230kV	On Schedule for 2012
GEN-2010-058	20	SPS	Chaves County 115kV	IA Pending
GEN-2010-061	180	MIDW	Tap Post Rock - Spearville 345kV	Under Study (DISIS-2011-002)
GEN-2011-007	250	OKGE	Tap Cimarron - Woodring (Matthewson) 345kV	IA Pending
GEN-2011-008	600	SUNCMKEC	Clark County 345kV	Facility Study
GEN-2011-010	100.8	OKGE	Minco 345kV	On Schedule for 2012
GEN-2011-011	50	KACP	Iatan 345kV	IA Pending
GEN-2011-012	104.5	SPS	Tap Moore County - Hitchland 345kV	IA Pending
GEN-2011-014	201	SPS	Tap Hitchland - Woodward Ckt 1 (Beaver County) 345kV	IA Pending
GEN-2011-016	200.1	SUNCMKEC	Spearville 345kV	IA Pending
GEN-2011-017	299	SUNCMKEC	Tap Spearville - PostRock 345kV	Facility Study
GEN-2011-018	73.6	NPPD	Steele City 115kV	Facility Study
GEN-2011-019	299	OKGE	Woodward 345kV	IA Pending
GEN-2011-020	299	OKGE	Woodward 345kV	IA Pending
GEN-2011-021	299	SPS	Tap Hitchland - Beaver 345kV	Facility Study
GEN-2011-022	299	SPS	Hitchland 345kV	IA Pending
GEN-2011-023	299	SUNCMKEC	Clark 345kV	Facility Study
GEN-2011-024	299	OKGE	Tatonga 345kV	IA Pending
GEN-2011-025	82.3	SPS	Tap Floyd County - Crosby County 115kV	IA Pending
GEN-2011-027	120	NPPD	Tap Twin Church - Hoskins 230kV (GEN-2010-51 Tap)	Facility Study
GEN-2011-037	7	WFEC	Blue Canyon 5 138kV	IA Pending
GEN-2011-040	111	OKGE	Tap Ratliff - Pooleville 138kV	Under Study (DISIS-2011-002)
GEN-2011-043	150	SUNCMKEC	Thistle 345kV	Under Study (DISIS-2011-002)
GEN-2011-044	150	SUNCMKEC	Thistle 345kV	Under Study (DISIS-2011-002)
GEN-2011-045	205	SPS	Jones 230kV	Facility Study
GEN-2011-046	27	SPS	Lopez 115kV	Facility Study
GEN-2011-048	165	SPS	Mustang 230kV	Under Study (DISIS-2011-002)
GEN-2011-049	250	OKGE	Border 345kV	Under Study (DISIS-2011-002)
GEN-2011-050	109.8	AEPW	Tap Rush Springs - Marlow 138kV	Under Study (DISIS-2011-002)
GEN-2011-051	104.4	OKGE	Tap Woodward - Tatonga 345kV	Under Study (DISIS-2011-002)
GEN-2011-054	300	OKGE	Cimarron 345kV	Under Study (DISIS-2011-002)
GEN-2011-055	52.8	OPPD	South Sterling 69kV	Under Study (DISIS-2011-002)
GEN-2011-056	3.6	NPPD	Jeffrey 115kV	Under Study (DISIS-2011-002)
GEN-2011-056A	3.6	NPPD	John 1 115kV	Under Study (DISIS-2011-002)
GEN-2011-056B	4.5	NPPD	John 2 115kV	Under Study (DISIS-2011-002)
GEN-2011-057	150.4	WERE	Creswell 138kV	Under Study (DISIS-2011-002)
Gray County Wind (Montezuma)	110	SUNCMKEC	Haggard 115kV	On-Line
Llano Estacado (White Deer)	80	SPS	Llano Wind 115kV	On-Line
NPPD Distributed (Broken Bow)	8.3	NPPD	Broken Bow 115kV	On-Line
NPPD Distributed (Burwell)	3	NPPD	Ord 115kV	On-Line
NPPD Distributed (Columbus Hydro)	45	NPPD	Columbus 115kV	On-Line
NPPD Distributed (Jeffrey)	18.0	NPPD	Jeffrey 115kV	On-Line
NPPD Distributed (John Lake 1)	19.0	NPPD	John Lake 1 115kV	On-Line
NPPD Distributed (John Lake 2)	19.0	NPPD	John Lake 2 115kV	On-Line
NPPD Distributed (Ord)	10.8	NPPD	Ord 115kV	On-Line
NPPD Distributed (Stuart)	2.1	NPPD	Ainsworth 115kV	On-Line
SPS Distributed (Dumas 19th St)	20	SPS	Dumas 19th Street 115kV	On-Line

Request	Amount	Area	Requested/Proposed Point of Interconnection	Status or In-Service Date
SPS Distributed (Etter)	20	SPS	Etter 115kV	On-Line
SPS Distributed (Moore E)	25	SPS	Moore East 115kV	On-Line
SPS Distributed (Sherman)	20	SPS	Sherman 115kV	On-Line
SPS Distributed (Spearman)	10	SPS	Spearman 69kV	On-Line
SPS Distributed (TC-Texas County)	20	SPS	Texas County 115kV	On-Line
TOTAL	27,486.7			

C: Study Groupings

See next page

C. Study Groups

GROUP 1: WOODWARD AREA			
Request	Capacity	Area	Proposed Point of Interconnection
GEN-2001-014	96.0	WFEC	Ft Supply 138kV
GEN-2001-037	100.0	OKGE	FPL Moreland Tap 138kV
GEN-2005-005	18.0	OKGE	FPL Moreland Tap 138kV
GEN-2005-008	120.0	OKGE	Woodward 138kV
GEN-2006-024S	19.8	WFEC	Buffalo Bear Tap 69kV
GEN-2006-046	131.0	OKGE	Dewey 138kV
GEN-2007-021	201.0	OKGE	Tatonga 345kV
GEN-2007-043	200.0	OKGE	Minco 345kV
GEN-2007-044	300.0	OKGE	Tatonga 345kV
GEN-2007-050	170.0	OKGE	Woodward EHV 138kV
GEN-2007-051	200.0	WFEC	Mooreland 138kV
GEN-2007-062	765.0	OKGE	Woodward EHV 345kV
GEN-2008-003	101.0	OKGE	Woodward EHV 138kV
GEN-2008-019	300.0	OKGE	Tatonga 345kV
GEN-2008-029	250.0	OKGE	Woodward EHV 138kV
GEN-2008-044	197.8	OKGE	Tatonga 345kV
GEN-2010-011	30.0	OKGE	Tatonga 345kV
GEN-2010-040	300.0	OKGE	Cimarron 345kV
GEN-2011-007	250.0	OKGE	Tap Cimarron - Woodring (Matthewson) 345kV
GEN-2011-010	100.8	OKGE	Minco 345kV
GEN-2011-019	299.0	OKGE	Woodward 345kV
GEN-2011-020	299.0	OKGE	Woodward 345kV
GEN-2011-024	299.0	OKGE	Tatonga 345kV
GEN-2011-051	104.4	OKGE	Tap Woodward - Tatonga 345kV
GEN-2011-054	300.0	OKGE	Cimarron 345kV
PRIOR QUEUED SUBTOTAL	5,151.8		
AREA TOTAL	5,151.8		

GROUP 2: HITCHLAND AREA Request	Capacity	Area	Proposed Point of Interconnection
ASGI-2010-011	48.0	SPS	TC-Texas County 69kV
GEN-2002-008	240.0	SPS	Hitchland 345kV
GEN-2002-009	80.0	SPS	Hansford 115kV
GEN-2003-020	160.0	SPS	Martin 115kV
GEN-2006-020S	18.9	SPS	DWS Frisco 115kV
GEN-2006-044	370.0	SPS	Hitchland 345kV
GEN-2006-049	400.0	SPS	Tap Finney - Hitchland (Stevens County) 345kV
GEN-2007-046	199.5	SPS	Hitchland 115kV
GEN-2007-057	34.5	SPS	Moore County East 115kV
GEN-2008-047	300.0	SPS	Tap Hitchland - Woodward Ckt 1 (Beaver County) 345kV
GEN-2010-001	300.0	SPS	Tap Hitchland - Woodward Ckt 1 (Beaver County) 345kV
GEN-2010-014	360.0	SPS	Hitchland 345kV
GEN-2011-012	104.5	SPS	Tap Moore County - Hitchland 345kV
GEN-2011-014	201.0	SPS	Tap Hitchland - Woodward Ckt 1 (Beaver County) 345kV
GEN-2011-021	299.0	SPS	Tap Hitchland - Beaver 345kV
GEN-2011-022	299.0	SPS	Hitchland 345kV
SPS Distributed (Dumas 19th St)	20.0	SPS	Dumas 19th Street 115kV
SPS Distributed (Etter)	20.0	SPS	Etter 115kV
SPS Distributed (Moore E)	25.0	SPS	Moore East 115kV
SPS Distributed (Sherman)	20.0	SPS	Sherman 115kV
SPS Distributed (Spearman)	10.0	SPS	Spearman 69kV
SPS Distributed (TC-Texas County)	20.0	SPS	Texas County 115kV
PRIOR QUEUED SUBTOTAL	3,529.4		
AREA TOTAL	3,529.4		

GROUP 3: SPEARVILLE AREA			
Request	Capacity	Area	Proposed Point of Interconnection
GEN-2001-039A	105.0	SUNCMKEC	Tap Greensburg - Ft Dodge 115kV
GEN-2002-025A	150.0	SUNCMKEC	Spearville 230kV
GEN-2004-014	154.5	SUNCMKEC	Spearville 230kV
GEN-2005-012	250.0	SUNCMKEC	Spearville 345kV
GEN-2006-006	205.5	SUNCMKEC	Spearville 345kV
GEN-2006-021	101.0	SUNCMKEC	Flat Ridge Tap 138kV
GEN-2006-022	150.0	SUNCMKEC	Pratt 115kV
GEN-2007-038	200.0	SUNCMKEC	Spearville 345kV
GEN-2007-040	200.0	SUNCMKEC	Tap Holcomb - Spearville (Gray County) 345kV
GEN-2008-018	405.0	SPS	Finney 345kV
GEN-2008-079	100.5	SUNCMKEC	Tap Cudahy - Ft Dodge 115kV
GEN-2008-124	200.0	SUNCMKEC	Spearville 345kV
GEN-2010-009	165.6	SUNCMKEC	Tap Holcomb - Spearville (Gray County) 345kV
GEN-2010-015	200.1	SUNCMKEC	Spearville 345kV
GEN-2010-029	450.0	SUNCMKEC	Spearville 345kV
GEN-2010-045	197.8	SUNCMKEC	Tap Holcomb - Spearville (Gray County) 345kV
GEN-2010-053	199.8	SUNCMKEC	Clark County 345kV
GEN-2010-061	180.0	MIDW	Tap Post Rock - Spearville 345kV
GEN-2011-008	600.0	SUNCMKEC	Clark County 345kV
GEN-2011-016	200.1	SUNCMKEC	Spearville 345kV
GEN-2011-017	299.0	SUNCMKEC	Tap Spearville - PostRock 345kV
GEN-2011-023	299.0	SUNCMKEC	Clark 345kV
GEN-2011-043	150.0	SUNCMKEC	Thistle 345kV
GEN-2011-044	150.0	SUNCMKEC	Thistle 345kV
Gray County Wind (Montezuma)	110.0	SUNCMKEC	Haggard 115kV
PRIOR QUEUED SUBTOTAL	**5,422.9**		
GEN-2012-003	22.5	SUNCMKEC	Tap Hugoton - Rolla 69kV
GEN-2012-007	120.0	SUNCMKEC	Rubart 115kV
GEN-2012-011	200.0	SUNCMKEC	Tap Spearville - Post Rock 345kV (GEN-2011-017T)
GEN-2012-012	200.0	SUNCMKEC	Clark County 345kV
CURRENT CLUSTER SUBTOTAL	**542.5**		
AREA TOTAL	**5,965.4**		

GROUP 4: MINGO/NW KANSAS AREA			
Request	Capacity	Area	Proposed Point of Interconnection
GEN-2001-039M	100.0	SUNCMKEC	Central Plains Tap 115kV
GEN-2006-040	108.0	SUNCMKEC	Mingo 115kV
GEN-2007-011	135.0	SUNCMKEC	Syracuse 115kV
GEN-2008-017	300.0	SUNCMKEC	Setab 345kV
GEN-2008-025	101.0	SUNCMKEC	Ruleton 115kV
PRIOR QUEUED SUBTOTAL	**744.0**		
GEN-2012-002	101.2	SUNCMKEC	Tap Pile - Scott City 115kV
CURRENT CLUSTER SUBTOTAL	**101.2**		
AREA TOTAL	**845.2**		

GROUP 5: AMARILLO AREA

Request	Capacity	Area	Proposed Point of Interconnection
GEN-2002-022	240.0	SPS	Bushland 230kV
GEN-2006-045	240.0	SPS	Tap and Tie both Potter - Plant X 230kV and Bushland - Deaf Smith (South Randle County) 230kV
GEN-2006-047	240.0	SPS	Tap and Tie both Potter - Plant X 230kV and Bushland - Deaf Smith (South Randle County) 230kV
GEN-2007-048	400.0	SPS	Tap Amarillo S - Swisher 230kV
GEN-2008-051	322.0	SPS	Potter County 345kV
GEN-2008-088	50.6	SPS	Vega 69kV
Llano Estacado (White Deer)	80.0	SPS	Llano Wind 115kV
PRIOR QUEUED SUBTOTAL	**1,572.6**		
AREA TOTAL	**1,572.6**		

GROUP 6: S-TX PANHANDLE/NW AREA

Request	Capacity	Area	Proposed Point of Interconnection
ASGI-2010-010	42.0	SPS	Lovington 115kV
ASGI-2010-020	30.0	SPS	Tap LE-Tatum - LE-Crossroads 69kV
ASGI-2010-021	15.0	SPS	Tap LE-Saunders Tap - LE-Anderson 69kV
ASGI-2011-001	28.8	SPS	LE-Lovington 115kV
ASGI-2011-002	10.0	SPS	Herring 115kV
ASGI-2011-003	10.0	SPS	Hendricks 115kV
ASGI-2011-004	20.0	SPS	Pleasant Hill 69kV
GEN-2001-033	180.0	SPS	San Juan Tap 230kV
GEN-2001-036	80.0	SPS	Norton 115kV
GEN-2006-018	170.0	SPS	Antelope 230kV
GEN-2006-026	502.0	SPS	Hobbs 230kV
GEN-2008-008	60.0	SPS	Graham 69kV
GEN-2008-009	60.0	SPS	San Juan Tap 230kV
GEN-2008-014	150.0	SPS	Tap Tuco- Oklaunion 345kV
GEN-2008-016	248.0	SPS	Grassland 230kV
GEN-2008-022	300.0	SPS	Tap Eddy Co - Tolk (Chaves County) 345kV
GEN-2009-067S	20.0	SPS	Seven Rivers 69kV
GEN-2010-006	205.0	SPS	Jones 230kV
GEN-2010-020	20.0	SPS	Roswell 69kV
GEN-2010-046	56.0	SPS	Tuco 230kV
GEN-2010-058	20.0	SPS	Chaves County 115kV
GEN-2011-025	82.3	SPS	Tap Floyd County - Crosby County 115kV
GEN-2011-045	205.0	SPS	Jones 230kV
GEN-2011-046	27.0	SPS	Lopez 115kV
GEN-2011-048	165.0	SPS	Mustang 230kV
PRIOR QUEUED SUBTOTAL	**2,706.1**		
GEN-2012-001	61.2	SPS	Tap Grassland - Borden County 230kV
GEN-2012-008	40.0	SPS	Mustang 115kV & Mustang 230kV
GEN-2012-009	15.0	SPS	Mustang 230kV
GEN-2012-010	15.0	SPS	Mustang 230kV
CURRENT CLUSTER SUBTOTAL	**131.2**		
AREA TOTAL	**2,837.3**		

GROUP 7: SW OKLAHOMA AREA			
Request	**Capacity**	**Area**	**Proposed Point of Interconnection**
GEN-2001-026	74.0	WFEC	Washita 138kV
GEN-2002-005	120.0	WFEC	Red Hills Tap 138kV
GEN-2003-004 GEN-2004-023 GEN-2005-003	151.2	WFEC	Washita 138kV
GEN-2003-005	100.0	WFEC	Anadarko - Paradise (Blue Canyon) 138kV
GEN-2003-022	120.0	AEPW	Washita 34.5kV
GEN-2004-020	27.0	AEPW	Washita 34.5kV
GEN-2006-002	101.0	AEPW	Sweetwater 230kV
GEN-2006-035	225.0	AEPW	Sweetwater 230kV
GEN-2006-043	99.0	AEPW	Sweetwater 230kV
GEN-2007-032	150.0	WFEC	Tap Clinton Junction - Clinton 138kV
GEN-2007-052	150.0	WFEC	Anadarko 138kV
GEN-2008-023	150.0	AEPW	Hobart Junction 138kV
GEN-2008-037	101.0	WFEC	Tap Washita - Blue Canyon Wind 138kV
GEN-2009-016	100.8	AEPW	Falcon Road 138kV
GEN-2010-012	65.0	WFEC	Brantley 138kV
GEN-2011-037	7.0	WFEC	Blue Canyon 5 138kV
GEN-2011-049	250.0	OKGE	Border 345kV
PRIOR QUEUED SUBTOTAL	**1,991.0**		
AREA TOTAL	**1,991.0**		

GROUP 8: N-OK/S-KS AREA			
Request	**Capacity**	**Area**	**Proposed Point of Interconnection**
ASGI-2010-006	150.0	AECI	Tap Fairfax Tap - Fairfax (AECI) 138kV
GEN-2002-004	200.0	WERE	Latham 345kV
GEN-2005-013	201.0	WERE	Tap Latham - Neosho (Caney River) 345kV
GEN-2007-025	300.0	WERE	Tap Wichita - Woodring (Sumner County) 345kV
GEN-2008-013	300.0	OKGE	Tap Wichita - Woodring (South of GEN-2007-025) 345kV
GEN-2008-021	42.0	WERE	Wolf Creek 345kV
GEN-2008-071	76.8	OKGE	Newkirk 138kV
GEN-2008-098	100.8	WERE	Tap Lacygne - Wolf Creek (Anderson County) 345kV
GEN-2009-025	60.0	OKGE	Tap Deer Creek - Sinclair Blackwell 69kV
GEN-2010-003	100.8	WERE	Tap Lacygne - Wolf Creek (Anderson County) 345kV
GEN-2010-005	300.0	WERE	Tap Wichita - Woodring (Sumner County) 345kV
GEN-2010-055	4.5	AEPW	Wekiwa 138kV
GEN-2011-057	150.4	WERE	Creswell 138kV
PRIOR QUEUED SUBTOTAL	**1,986.3**		
AREA TOTAL	**1,986.3**		

GROUP 9/10: NEBRASKA AREA			
Request	Capacity	Area	Proposed Point of Interconnection
GEN-2002-023N	0.8	NPPD	Harmony 115kV
GEN-2003-021N	75.0	NPPD	Ainsworth Wind Tap 115kV
GEN-2004-005N	30.0	NPPD	St Francis 115kV
GEN-2004-023N	75.0	NPPD	Columbus County 115kV
GEN-2006-020N	42.0	NPPD	Bloomfield 115kV
GEN-2006-037N1	75.0	NPPD	Broken Bow 115kV
GEN-2006-038N005	80.0	NPPD	Broken Bow 115kV
GEN-2006-038N019	80.0	NPPD	Petersburg 115kV
GEN-2006-044N	40.5	NPPD	Petersburg 115kV
GEN-2006-044N02	100.5	NPPD	Tap Ft Randle - Columbus (Madison County) 230kV
GEN-2007-011N08	81.0	NPPD	Bloomfield 115kV
GEN-2007-015	135.0	WERE	Tap Kelly(WERE) - S1399(OPPD) 161kV
GEN-2008-086N02	200.0	NPPD	Tap Ft Randle - Columbus (Madison County) 230kV
GEN-2008-119O	60.0	OPPD	S1399 161kV
GEN-2008-123N	89.7	NPPD	Tap Guide Rock - Pauline 115kV
GEN-2009-040	73.8	WERE	Tap Smittyville - Knob Hill 115kV
GEN-2010-041	10.5	OPPD	S 1399 161kV
GEN-2010-044	99.0	NPPD	Harbine 115kV
GEN-2010-051	200.0	NPPD	Tap Twin Church - Hoskins 230kV
GEN-2011-018	73.6	NPPD	Steele City 115kV
GEN-2011-027	120.0	NPPD	Tap Twin Church - Hoskins 230kV (GEN-2010-51 Tap)
GEN-2011-055	52.8	OPPD	South Sterling 69kV
GEN-2011-056	3.6	NPPD	Jeffrey 115kV
GEN-2011-056A	3.6	NPPD	John 1 115kV
GEN-2011-056B	4.5	NPPD	John 2 115kV
NPPD Distributed (Broken Bow)	8.3	NPPD	Broken Bow 115kV
NPPD Distributed (Burwell)	3.0	NPPD	Ord 115kV
NPPD Distributed (Columbus Hydro)	45.0	NPPD	Columbus 115kV
NPPD Distributed (Jeffrey)	18.0	NPPD	Jeffrey 115kV
NPPD Distributed (John Lake 1)	19.0	NPPD	John Lake 1 115kV
NPPD Distributed (John Lake 2)	19.0	NPPD	John Lake 2 115kV
NPPD Distributed (Ord)	10.8	NPPD	Ord 115kV
NPPD Distributed (Stuart)	2.1	NPPD	Ainsworth 115kV
PRIOR QUEUED SUBTOTAL	**1,931.1**		
AREA TOTAL	**1,931.1**		

GROUP 11: N KANSAS AREA			
Request	Capacity	Area	Proposed Point of Interconnection
GEN-2003-006A	200.0	SUNCMKEC	Elm Creek 230kV
GEN-2003-019	250.0	MIDW	Smoky Hills Tap 230kV
GEN-2006-031	75.0	MIDW	Knoll 115kV
GEN-2006-032	200.0	MIDW	South Hays 230kV
GEN-2008-092	201.0	MIDW	Postrock 230kV
GEN-2009-008	199.5	MIDW	South Hays 230kV
GEN-2009-020	48.6	MIDW	Tap Nekoma - Bazine 69kV
GEN-2010-048	70.0	MIDW	Tap Beach Station - Redline 115kV
GEN-2010-057	201.0	WERE	Rice County 230kV
PRIOR QUEUED SUBTOTAL	1,445.1		
AREA TOTAL	1,445.1		

GROUP 12: NW AR AREA			
Request	Capacity	Area	Proposed Point of Interconnection
AREA TOTAL	0.0		

GROUP 13: NW MISSOURI AREA			
Request	Capacity	Area	Proposed Point of Interconnection
GEN-2006-014	300.0	MIPU	Tap Maryville - Midway 161kV
GEN-2008-129	80.0	MIPU	Pleasant Hill 161kV
GEN-2010-036	4.6	WERE	6th Street 115kV
GEN-2010-056	151.0	MIPU	Tap Saint Joseph - Cooper 345kV
GEN-2011-011	50.0	KACP	Iatan 345kV
PRIOR QUEUED SUBTOTAL	585.6		
AREA TOTAL	585.6		

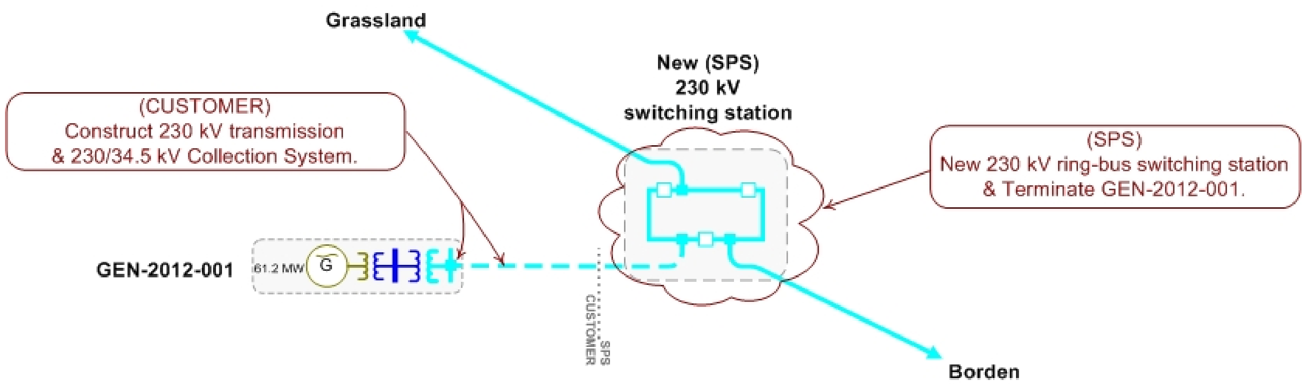
GROUP 14: S OKLAHOMA AREA			
Request	Capacity	Area	Proposed Point of Interconnection
GEN-2008-046	200.0	OKGE	Sunnyside 345kV
GEN-2011-040	111.0	OKGE	Tap Ratliff - Pooleville 138kV
GEN-2011-050	109.8	AEPW	Tap Rush Springs - Marlow 138kV
PRIOR QUEUED SUBTOTAL	420.8		
GEN-2012-004	41.4	OKGE	Ratliff - Pooleville 138kV
CURRENT CLUSTER SUBTOTAL	41.4		
AREA TOTAL	462.2		

GROUP 15: RESERVED			
Request	Capacity	Area	Proposed Point of Interconnection
AREA TOTAL	0.0		

CLUSTER TOTAL (CURRENT STUDY)	816.3	MW
PQ TOTAL (PRIOR QUEUED)	27,486.7	MW
CLUSTER TOTAL (INCLUDING PRIOR QUEUED)	28,303.0	MW

D: Proposed Point of Interconnection One line Diagrams

GEN-2012-001



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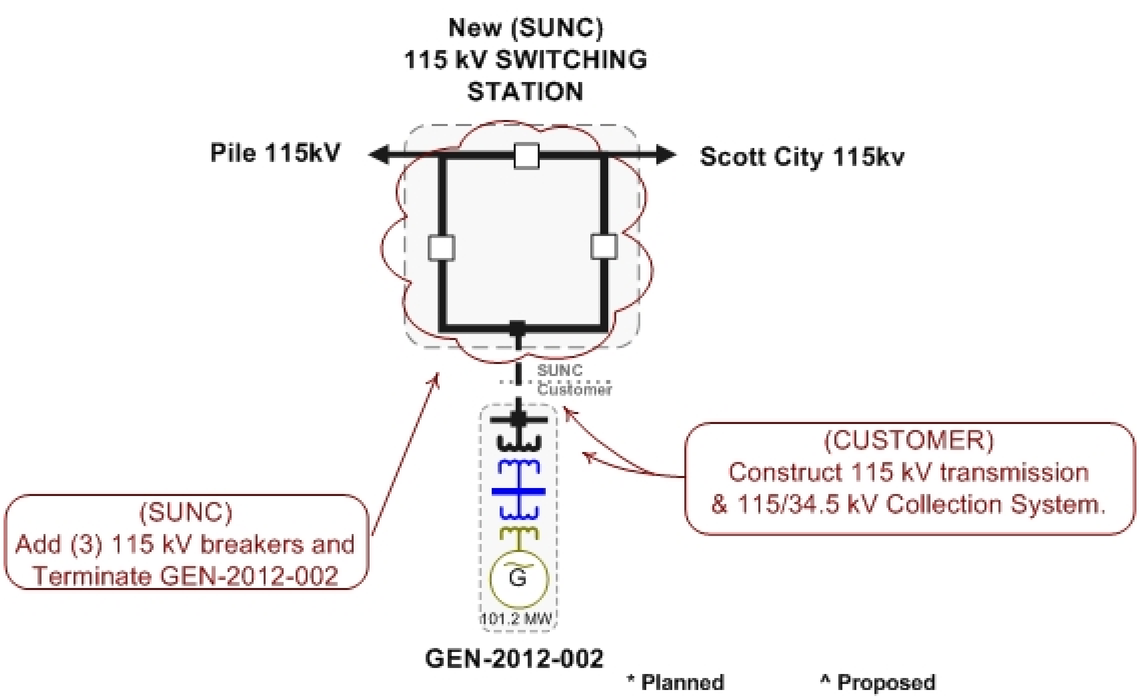

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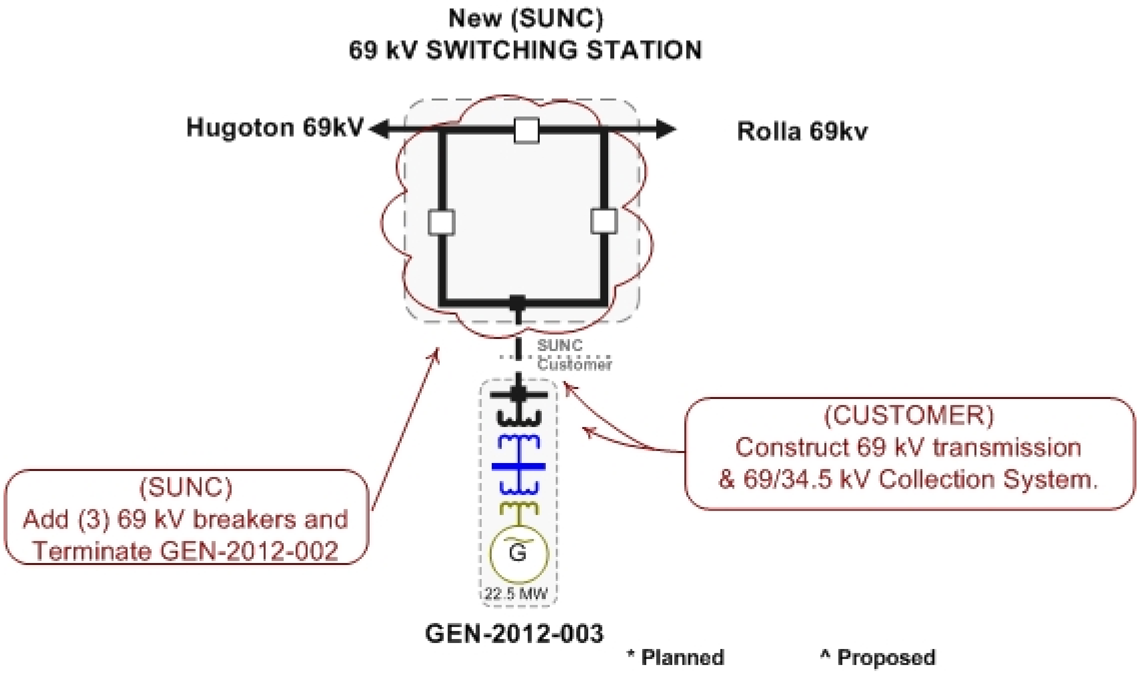

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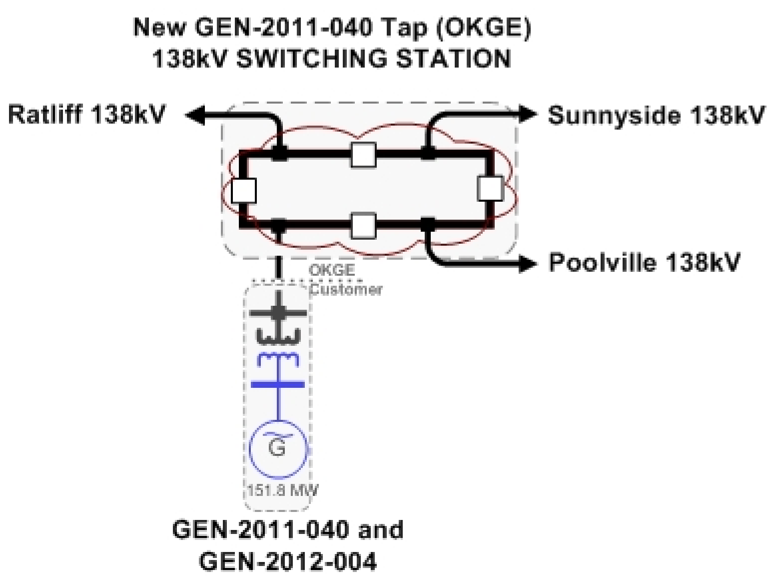

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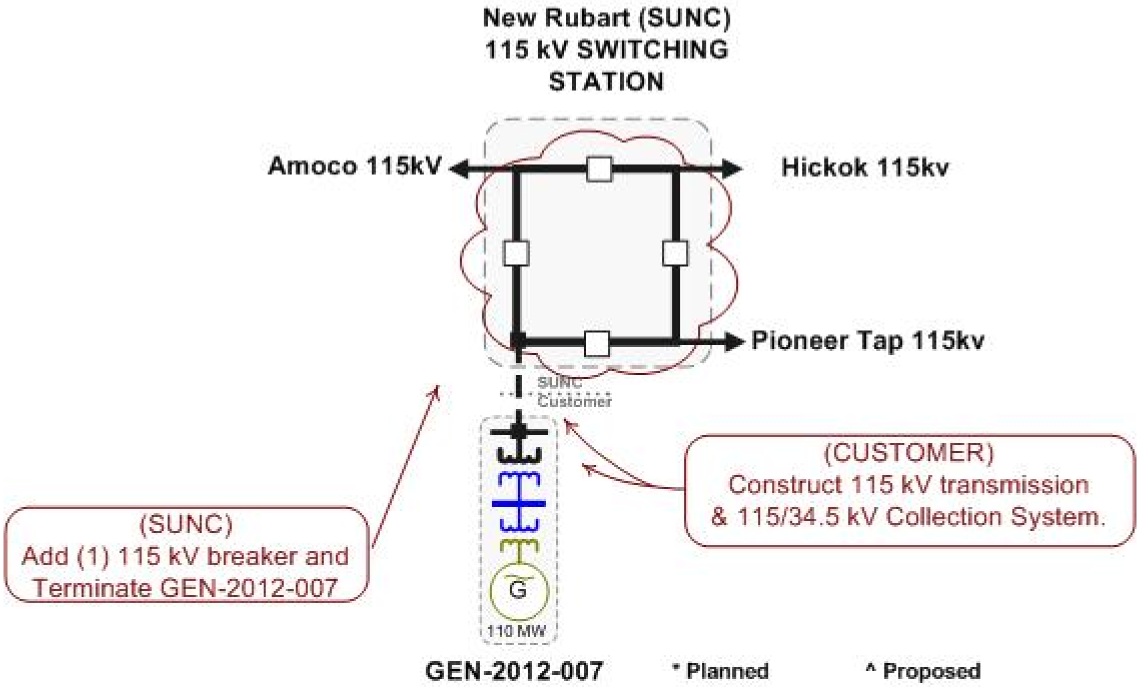

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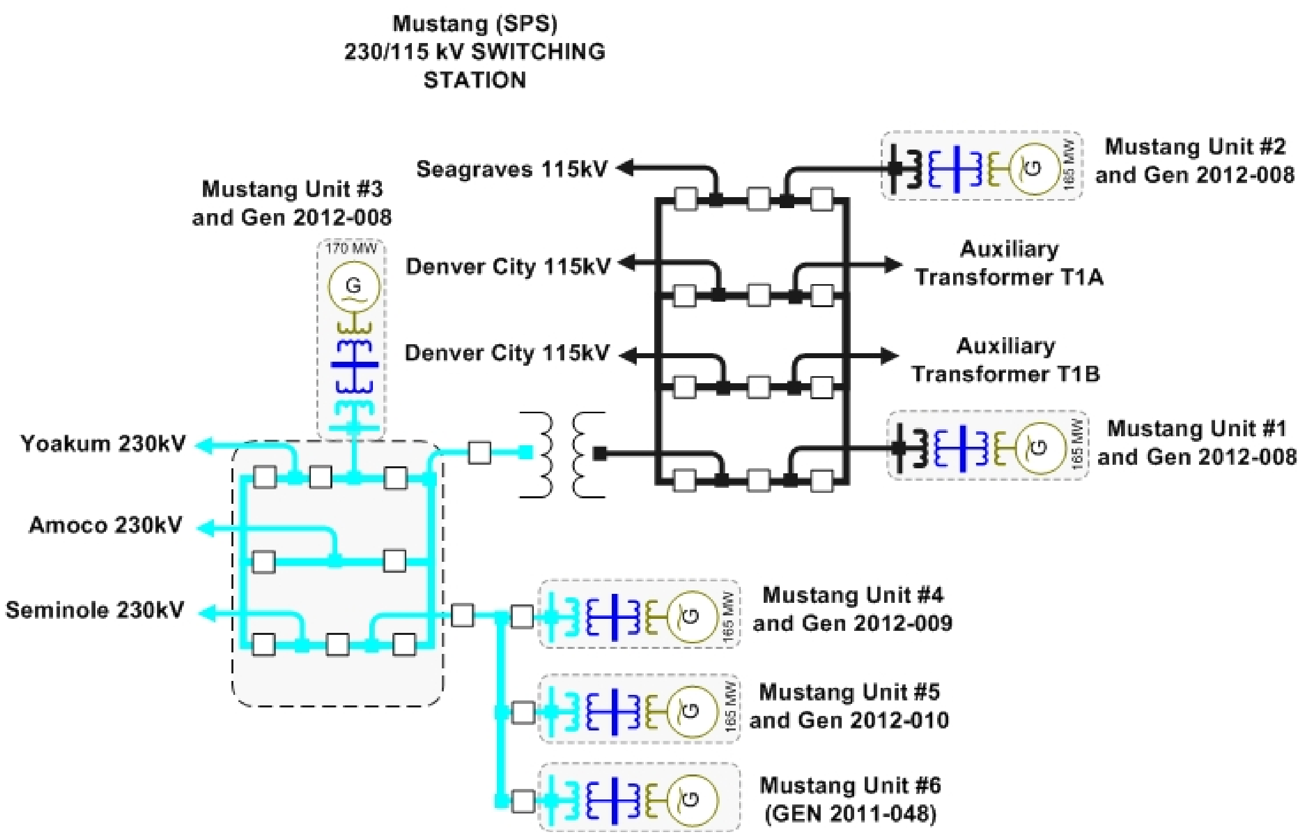

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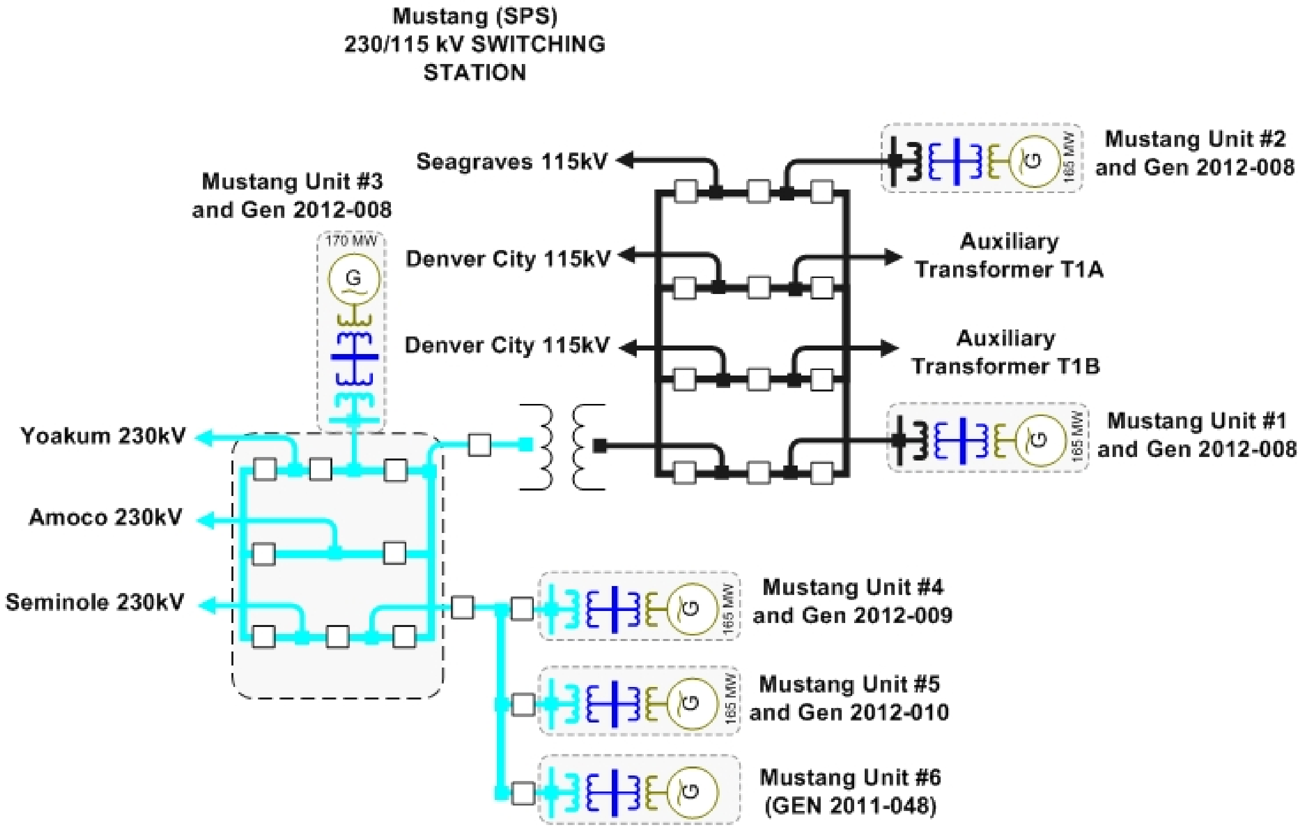

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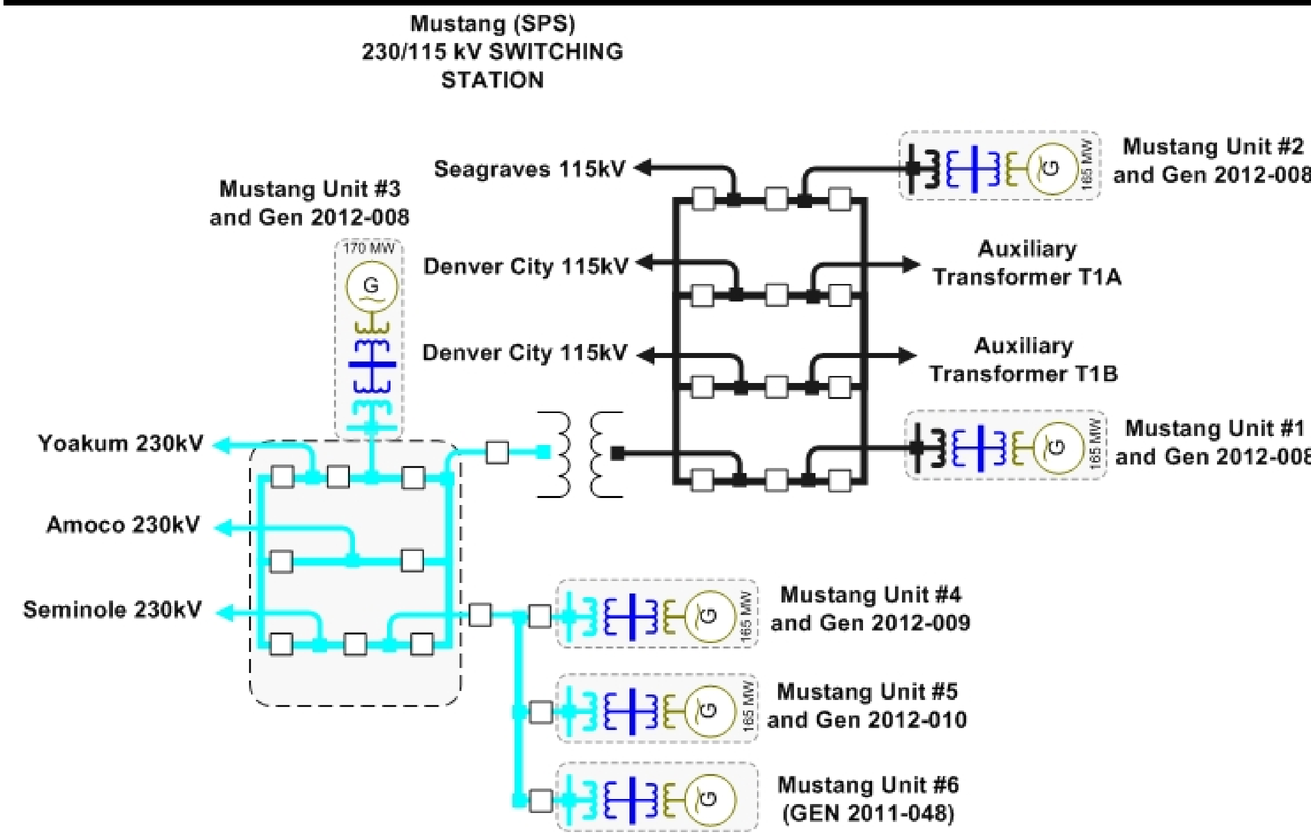

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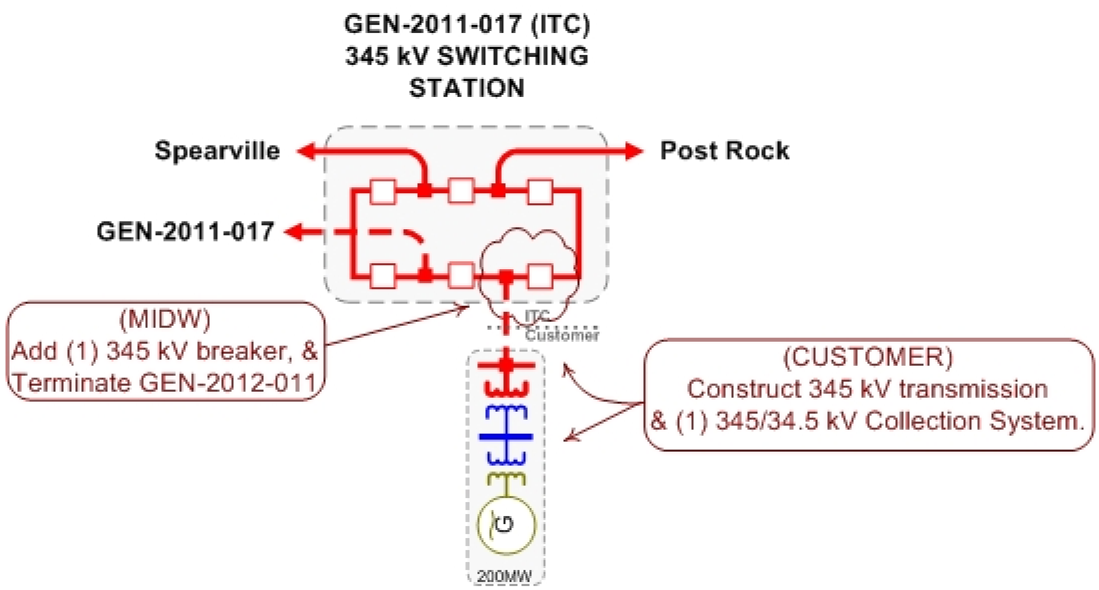
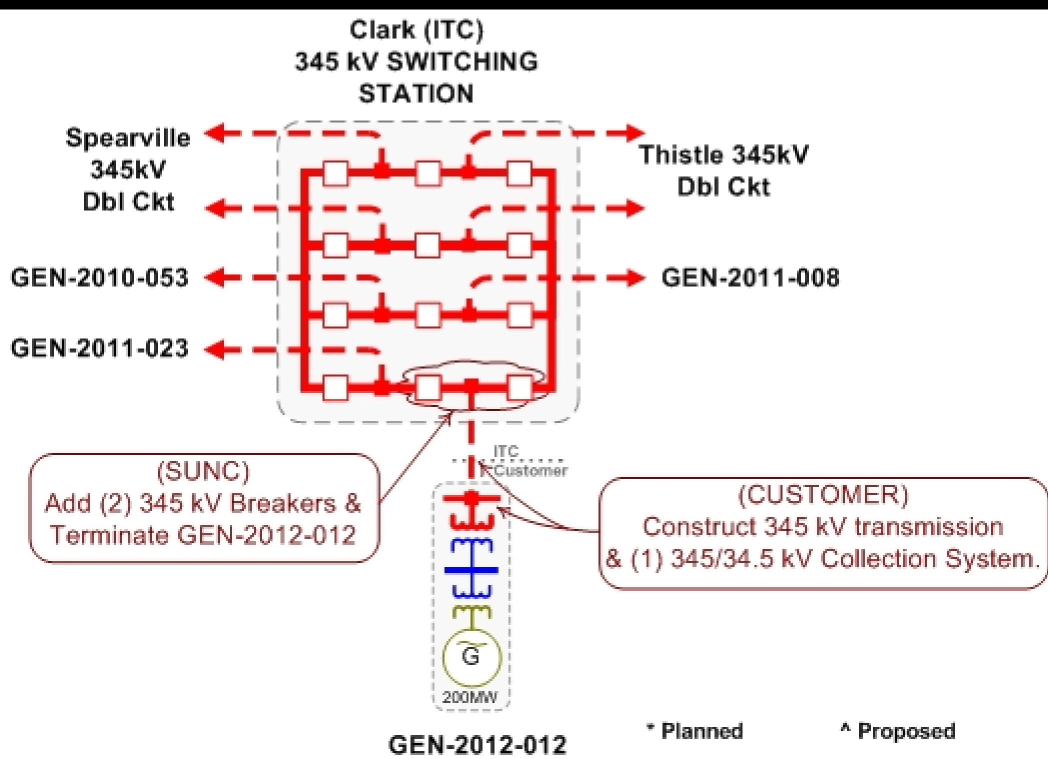


GEN-2012-012



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 a Interconnection Request choose to go into service prior to the operation date of any necessary Network Upgrades, the costs associated with those upgrades may be reallocated to the impacted Interconnection Request. The actual costs allocated to each Generation Interconnection Request Customer will be determined at the time of a restudy.

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

Appendix E. Cost Allocation Per Request

(Including Previously Allocated Network Upgrades*)

Interconnection Request and Upgrades	Upgrade Type	Allocated Cost	Upgrade Cost
GEN-2012-001			
GEN-2012-001 Interconnection Costs See Oneline Diagram.	Current Study	$7,316,677.00	$7,316,677.00
Allen - Lubbock South 115kV CKT 1 NRIS only required upgrade: Rebuild approximately 6 miles of 115kV from Allen - Lubbock South	Previously Allocated		$3,000,000.00
Beaver County - Woodward 345kV Dbl CKT Priority Project: Hitchland - Woodward Dbl 345kV CKT (Total Project E&C Cost Shown)	Previously Allocated		$226,790,727.00
Beaver County 345kV Expansion Beaver County Expansion: Tap & Tie in Hitchland - Woodward 345kV CKT 2	Previously Allocated		$3,500,000.00
Border - Tuco Interchange 345KV CKT 1 Balanced Portfolio: Tuco - Woodward 345kV CKT 1 (Total Project E&C Cost Shown)	Previously Allocated		$249,932,114.00
Border - Woodward 345KV CKT 1 Balanced Portfolio: Tuco - Woodward 345kV CKT 1 (Total Project E&C Cost Shown)	Previously Allocated		$249,932,114.00
Grassland - Wolfforth 230kV CKT 1 Per SPP 2012 ITP 20 CNTC	Previously Allocated		$50,068,309.00
Hitchland 345/230kV Autotransformer CKT 2 Priority Project: Hitchland 345/230kV Autotransformer CKT 2 (Total Project E&C Cost Shown).	Previously Allocated		$8,883,760.00
Jones - Lubbock South 230kV CKT 2 Replace Line Traps	Previously Allocated		$200,000.00
Jones - TUCO 230kV CKT 1 NRIS only required upgrade: Replace line traps	Previously Allocated		$200,000.00
Lubbock South - Lubbock East 115kV CKT 1 NRIS only required upgrade: Rebuild approximately 7 miles of 115kV from Lubbock South - Lubbock East	Previously Allocated		$3,500,000.00
Lubbock South 230/115kV Autotransformer CKT 2 NRIS only required upgrade: Install 2nd 230/115/13.2kV Autotransformer	Previously Allocated		$4,000,000.00
Thistle - Wichita 345KV Dbl CKT Priority Project: Thistle - Wichita Dbl 345kV CKT (Total Project E&C Cost Shown.)	Previously Allocated		$168,750,000.00
Thistle - Woodward 345KV Dbl CKT Priority Project: Thistle - Woodward Dbl 345kV CKT (Total Project E&C Cost Shown)	Previously Allocated		$212,090,000.00

* 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
Woodward XFMR 345/138/13.8kV CKT 2 Balanced Portfolio: Woodward 345/138kV Transformer CKT 2 & 50 MVAR Reactor (Total Project E&C Cost Shown).	Previously Allocated		$15,000,000.00
	Current Study Total	$7,316,677.00	

GEN-2012-002

Interconnection Request and Upgrades	Upgrade Type	Allocated Cost	Upgrade Cost
GEN-2012-002 Interconnection Costs See Oneline Diagram.	Current Study	$5,000,000.00	$5,000,000.00
Beaver County - Gray County (Buckner) 345kV Build approximately 90 miles of 345kV from Beaver County - Gray County @ 3000 amps	Previously Allocated		$170,209,050.00
Beaver County - Woodward 345kV Dbl CKT Priority Project: Hitchland - Woodward Dbl 345kV CKT (Total Project E&C Cost Shown)	Previously Allocated		$226,790,727.00
Beaver County 345kV Expansion Beaver County Expansion: Tap & Tie in Hitchland - Woodward 345kV CKT 2	Previously Allocated		$3,500,000.00
Clark - Thistle 345KV Dbl CKT Priority Project: Spearville - Clark - Thistle Dbl 345kV CKT (Total Project E&C Cost Shown.)	Previously Allocated		$291,088,131.00
Finney Switching Station - Holcomb 345KV CKT 2 Per GEN-2006-049 Facility Study	Previously Allocated		$10,507,445.00
Hitchland 345/230kV Autotransformer CKT 2 Priority Project: Hitchland 345/230kV Autotransformer CKT 2 (Total Project E&C Cost Shown).	Previously Allocated		$8,883,760.00
Mullergren - Reno 345kV Dbl CKT Build approximately 92 miles of new Dbl 345kV circuit from Mullergren - Reno @ 3000 amps	Previously Allocated		$210,887,465.33
Spearville - Mullergren 345kV Dbl CKT Build approximately 85 miles of new Dbl 345kV circuit from Spearville - Mullergren @ 3000 amps	Previously Allocated		$196,323,921.67
	Current Study Total	$5,000,000.00	

GEN-2012-003

Interconnection Request and Upgrades	Upgrade Type	Allocated Cost	Upgrade Cost
GEN-2012-003 Interconnection Costs See Oneline Diagram.	Current Study	$5,000,000.00	$5,000,000.00
Post Rock - GEN-2011-017 Tap 345kV CKT 2 Build second 345kV circuit from Post Rock - GEN-2011-017 Tap	Current Study	$593,141.05	$42,003,000.00
Axtell - PostRock 345KV CKT 1 Balanced Portfolio: PostRock - Axtell 345kV CKT 1 (Total Project E&C Cost Shown)	Previously Allocated		$148,000,000.00
Beaver County - Gray County (Buckner) 345kV Build approximately 90 miles of 345kV from Beaver County - Gray County @ 3000 amps	Previously Allocated		$170,209,050.00

* 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
Beaver County - Woodward 345kV Dbl CKT Priority Project: Hitchland - Woodward Dbl 345kV CKT (Total Project E&C Cost Shown)	Previously Allocated		$226,790,727.00
Beaver County 345kV Expansion Beaver County Expansion: Tap & Tie in Hitchland - Woodward 345kV CKT 2	Previously Allocated		$3,500,000.00
Clark - Thistle 345KV Dbl CKT Priority Project: Spearville - Clark - Thistle Dbl 345kV CKT (Total Project E&C Cost Shown.)	Previously Allocated		$291,088,131.00
Matthewson - Cimarron 345kV CKT 2 Build second 345kV circuit from Matthewson - Cimarron @ 3000 amps	Previously Allocated		$42,903,753.00
Mullergren - Reno 345kV Dbl CKT Build approximately 92 miles of new Dbl 345kV circuit from Mullergren - Reno @ 3000 amps	Previously Allocated		$210,887,465.33
Spearville 345/115/13.8kV Transfomer CKT 1 New 345/115kV Spearville Transformer (Partial Cost allocation)	Previously Allocated		$3,745,000.00
Spearville -Clark 345KV Dbl CKT Priority Project: Spearville - Clark - Thistle Dbl 345kV CKT (Total Project E&C Cost Shown.)	Previously Allocated		$291,088,131.00
Tatonga - Matthewson 345kV CKT 2 Build second 345kV circuit from Tatonga - Matthewson @ 3000 amps	Previously Allocated		$104,260,473.00
Thistle - Wichita 345KV Dbl CKT Priority Project: Thistle - Wichita Dbl 345kV CKT (Total Project E&C Cost Shown.)	Previously Allocated		$168,750,000.00
TUCO Interchange 345/230/13.2KV Autotransformer CKT 2 Balanced Portfolio: TUCO 345/230 kV Transformer CKT 2 (Total Project E&C Cost Shown)	Previously Allocated		$14,900,907.00
Woodward XFMR 345/138/13.8kV CKT 2 Balanced Portfolio: Woodward 345/138kV Transformer CKT 2 & 50 MVAR Reactor (Total Project E&C Cost Shown).	Previously Allocated		$15,000,000.00
	Current Study Total	$5,593,141.05	
GEN-2012-004			
GEN-2012-004 Interconnection Costs See Oneline Diagram.	Current Study	$0.00	$0.00
Sunnyside - Hugo 345kV CKT 1 NTC 20017 & 20018 for In Service 4/1/2012.	Previously Allocated		$202,000,000.00
	Current Study Total	$0.00	
GEN-2012-007			
GEN-2012-007 Interconnection Costs See Oneline Diagram.	Current Study	$6,000,000.00	$6,000,000.00

* 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
Post Rock - GEN-2011-017 Tap 345kV CKT 2 Build second 345kV circuit from Post Rock - GEN-2011-017 Tap	Current Study	$2,958,957.69	$42,003,000.00
Axtell - PostRock 345KV CKT 1 Balanced Portfolio: PostRock - Axtell 345kV CKT 1 (Total Project E&C Cost Shown)	Previously Allocated		$148,000,000.00
Beaver County - Gray County (Buckner) 345kV Build approximately 90 miles of 345kV from Beaver County - Gray County @ 3000 amps	Previously Allocated		$170,209,050.00
Beaver County - Woodward 345kV Dbl CKT Priority Project: Hitchland - Woodward Dbl 345kV CKT (Total Project E&C Cost Shown)	Previously Allocated		$226,790,727.00
Beaver County 345kV Expansion Beaver County Expansion: Tap & Tie in Hitchland - Woodward 345kV CKT 2	Previously Allocated		$3,500,000.00
Benton - Wichita 345kV CKT 1 NRIS only required upgrade: Replace terminal equipment at Benton and Wichita	Previously Allocated		$1,183,000.00
Clark - Thistle 345KV Dbl CKT Priority Project: Spearville - Clark - Thistle Dbl 345kV CKT (Total Project E&C Cost Shown.)	Previously Allocated		$291,088,131.00
Matthewson - Cimarron 345kV CKT 2 Build second 345kV circuit from Matthewson - Cimarron @ 3000 amps	Previously Allocated		$42,903,753.00
Mullergren - Reno 345kV Dbl CKT Build approximately 92 miles of new Dbl 345kV circuit from Mullergren - Reno @ 3000 amps	Previously Allocated		$210,887,465.33
Mullergren - Spearville 230kV CKT 1 NRIS only upgrade: Rebuild approximately 62 miles of 230kV line	Previously Allocated		$36,107,610.00
Spearville 345/115/13.8kV Transfomer CKT 1 New 345/115kV Spearville Transformer (Partial Cost allocation)	Previously Allocated		$3,745,000.00
Spearville -Clark 345KV Dbl CKT Priority Project: Spearville - Clark - Thistle Dbl 345kV CKT (Total Project E&C Cost Shown.)	Previously Allocated		$291,088,131.00
Tatonga - Matthewson 345kV CKT 2 Build second 345kV circuit from Tatonga - Matthewson @ 3000 amps	Previously Allocated		$104,260,473.00
Thistle - Wichita 345KV Dbl CKT Priority Project: Thistle - Wichita Dbl 345kV CKT (Total Project E&C Cost Shown.)	Previously Allocated		$168,750,000.00
TUCO Interchange 345/230/13.2KV Autotransformer CKT 2 Balanced Portfolio: TUCO 345/230 kV Transformer CKT 2 (Total Project E&C Cost Shown)	Previously Allocated		$14,900,907.00
Woodward XFMR 345/138/13.8kV CKT 2 Balanced Portfolio: Woodward 345/138kV Transformer CKT 2 & 50 MVAR Reactor (Total Project E&C Cost Shown).	Previously Allocated		$15,000,000.00
	Current Study Total	$8,958,957.69	

* 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-2012-008			
GEN-2012-008 Interconnection Costs See Oneline Diagram.	Current Study	$0.00	$0.00
Beaver County - Woodward 345kV Dbl CKT Priority Project: Hitchland - Woodward Dbl 345kV CKT (Total Project E&C Cost Shown)	Previously Allocated		$226,790,727.00
Beaver County 345kV Expansion Beaver County Expansion: Tap & Tie in Hitchland - Woodward 345kV CKT 2	Previously Allocated		$3,500,000.00
Border - Tuco Interchange 345KV CKT 1 Balanced Portfolio: Tuco - Woodward 345kV CKT 1 (Total Project E&C Cost Shown)	Previously Allocated		$249,932,114.00
Border - Woodward 345KV CKT 1 Balanced Portfolio: Tuco - Woodward 345kV CKT 1 (Total Project E&C Cost Shown)	Previously Allocated		$249,932,114.00
Power System Stabilizers (PSS) Install Power System Stabilizers @ Tolk(Units: 1,2) and Jones (Units: 1,2,3,4)	Previously Allocated		$300,000.00
Thistle - Wichita 345KV Dbl CKT Priority Project: Thistle - Wichita Dbl 345kV CKT (Total Project E&C Cost Shown.)	Previously Allocated		$168,750,000.00
Thistle - Woodward 345KV Dbl CKT Priority Project: Thistle - Woodward Dbl 345kV CKT (Total Project E&C Cost Shown)	Previously Allocated		$212,090,000.00
Thistle 345/138KV Transformer CKT 1 Priority Project: Thistle 345/138kV Transformer CKT 1 & Thistle - Flat Ridge 138kV CKT 1 (Total Project E&C Cost Shown.)	Previously Allocated		$9,106,306.00
Woodward XFMR 345/138/13.8kV CKT 2 Balanced Portfolio: Woodward 345/138kV Transformer CKT 2 & 50 MVAR Reactor (Total Project E&C Cost Shown).	Previously Allocated		$15,000,000.00
	Current Study Total	$0.00	
GEN-2012-009			
GEN-2012-009 Interconnection Costs See Oneline Diagram.	Current Study	$0.00	$0.00
Beaver County - Woodward 345kV Dbl CKT Priority Project: Hitchland - Woodward Dbl 345kV CKT (Total Project E&C Cost Shown)	Previously Allocated		$226,790,727.00
Beaver County 345kV Expansion Beaver County Expansion: Tap & Tie in Hitchland - Woodward 345kV CKT 2	Previously Allocated		$3,500,000.00
Border - Tuco Interchange 345KV CKT 1 Balanced Portfolio: Tuco - Woodward 345kV CKT 1 (Total Project E&C Cost Shown)	Previously Allocated		$249,932,114.00
Border - Woodward 345KV CKT 1 Balanced Portfolio: Tuco - Woodward 345kV CKT 1 (Total Project E&C Cost Shown)	Previously Allocated		$249,932,114.00

* 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
Power System Stabilizers (PSS) Install Power System Stabilizers @ Tolk(Units: 1,2) and Jones (Units: 1,2,3,4)	Previously Allocated		$300,000.00
Thistle - Wichita 345KV Dbl CKT Priority Project: Thistle - Wichita Dbl 345kV CKT (Total Project E&C Cost Shown.)	Previously Allocated		$168,750,000.00
Thistle - Woodward 345KV Dbl CKT Priority Project: Thistle - Woodward Dbl 345kV CKT (Total Project E&C Cost Shown)	Previously Allocated		$212,090,000.00
Thistle 345/138KV Transformer CKT 1 Priority Project: Thistle 345/138kV Transformer CKT 1 & Thistle - Flat Ridge 138kV CKT 1 (Total Project E&C Cost Shown.)	Previously Allocated		$9,106,306.00
Woodward XFMR 345/138/13.8kV CKT 2 Balanced Portfolio: Woodward 345/138kV Transformer CKT 2 & 50 MVAR Reactor (Total Project E&C Cost Shown).	Previously Allocated		$15,000,000.00
	Current Study Total	$0.00	

GEN-2012-010

Interconnection Request and Upgrades	Upgrade Type	Allocated Cost	Upgrade Cost
GEN-2012-010 Interconnection Costs See Oneline Diagram.	Current Study	$0.00	$0.00
Beaver County - Woodward 345kV Dbl CKT Priority Project: Hitchland - Woodward Dbl 345kV CKT (Total Project E&C Cost Shown)	Previously Allocated		$226,790,727.00
Beaver County 345kV Expansion Beaver County Expansion: Tap & Tie in Hitchland - Woodward 345kV CKT 2	Previously Allocated		$3,500,000.00
Border - Tuco Interchange 345KV CKT 1 Balanced Portfolio: Tuco - Woodward 345kV CKT 1 (Total Project E&C Cost Shown)	Previously Allocated		$249,932,114.00
Border - Woodward 345KV CKT 1 Balanced Portfolio: Tuco - Woodward 345kV CKT 1 (Total Project E&C Cost Shown)	Previously Allocated		$249,932,114.00
Power System Stabilizers (PSS) Install Power System Stabilizers @ Tolk(Units: 1,2) and Jones (Units: 1,2,3,4)	Previously Allocated		$300,000.00
Thistle - Wichita 345KV Dbl CKT Priority Project: Thistle - Wichita Dbl 345kV CKT (Total Project E&C Cost Shown.)	Previously Allocated		$168,750,000.00
Thistle - Woodward 345KV Dbl CKT Priority Project: Thistle - Woodward Dbl 345kV CKT (Total Project E&C Cost Shown)	Previously Allocated		$212,090,000.00
Thistle 345/138KV Transformer CKT 1 Priority Project: Thistle 345/138kV Transformer CKT 1 & Thistle - Flat Ridge 138kV CKT 1 (Total Project E&C Cost Shown.)	Previously Allocated		$9,106,306.00
Woodward XFMR 345/138/13.8kV CKT 2 Balanced Portfolio: Woodward 345/138kV Transformer CKT 2 & 50 MVAR Reactor (Total Project E&C Cost Shown).	Previously Allocated		$15,000,000.00

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

Interconnection Request and Upgrades	Upgrade Type	Allocated Cost	Upgrade Cost
	Current Study Total	$0.00	

GEN-2012-011

Interconnection Request and Upgrades	Upgrade Type	Allocated Cost	Upgrade Cost
GEN-2012-011 Interconnection Costs See Oneline Diagram.	Current Study	$5,000,000.00	$5,000,000.00
Post Rock - GEN-2011-017 Tap 345kV CKT 2 Build second 345kV circuit from Post Rock - GEN-2011-017 Tap	Current Study	$29,137,782.87	$42,003,000.00
Axtell - PostRock 345KV CKT 1 Balanced Portfolio: PostRock - Axtell 345kV CKT 1 (Total Project E&C Cost Shown)	Previously Allocated		$148,000,000.00
Beaver County - Gray County (Buckner) 345kV Build approximately 90 miles of 345kV from Beaver County - Gray County @ 3000 amps	Previously Allocated		$170,209,050.00
Beaver County - Woodward 345kV Dbl CKT Priority Project: Hitchland - Woodward Dbl 345kV CKT (Total Project E&C Cost Shown)	Previously Allocated		$226,790,727.00
Beaver County 345kV Expansion Beaver County Expansion: Tap & Tie in Hitchland - Woodward 345kV CKT 2	Previously Allocated		$3,500,000.00
Border - Tuco Interchange 345KV CKT 1 Balanced Portfolio: Tuco - Woodward 345kV CKT 1 (Total Project E&C Cost Shown)	Previously Allocated		$249,932,114.00
Border - Woodward 345KV CKT 1 Balanced Portfolio: Tuco - Woodward 345kV CKT 1 (Total Project E&C Cost Shown)	Previously Allocated		$249,932,114.00
Clark - Thistle 345KV Dbl CKT Priority Project: Spearville - Clark - Thistle Dbl 345kV CKT (Total Project E&C Cost Shown.)	Previously Allocated		$291,088,131.00
Hitchland 345/230kV Autotransformer CKT 2 Priority Project: Hitchland 345/230kV Autotransformer CKT 2 (Total Project E&C Cost Shown).	Previously Allocated		$8,883,760.00
Matthewson - Cimarron 345kV CKT 2 Build second 345kV circuit from Matthewson - Cimarron @ 3000 amps	Previously Allocated		$42,903,753.00
Mullergren - Reno 345kV Dbl CKT Build approximately 92 miles of new Dbl 345kV circuit from Mullergren - Reno @ 3000 amps	Previously Allocated		$210,887,465.33
Post Rock 345/230/13.8kV Autotransformer CKT 2 DISIS-2010-001 Restudy	Previously Allocated		$13,749,527.00
Spearville - Mullergren 345kV Dbl CKT Build approximately 85 miles of new Dbl 345kV circuit from Spearville - Mullergren @ 3000 amps	Previously Allocated		$196,323,921.67
Spearville -Clark 345KV Dbl CKT Priority Project: Spearville - Clark - Thistle Dbl 345kV CKT (Total Project E&C Cost Shown.)	Previously Allocated		$291,088,131.00

* 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
Tatonga - Matthewson 345kV CKT 2 Build second 345kV circuit from Tatonga - Matthewson @ 3000 amps	Previously Allocated		$104,260,473.00
Thistle - Wichita 345KV Dbl CKT Priority Project: Thistle - Wichita Dbl 345kV CKT (Total Project E&C Cost Shown.)	Previously Allocated		$168,750,000.00
Thistle - Woodward 345KV Dbl CKT Priority Project: Thistle - Woodward Dbl 345kV CKT (Total Project E&C Cost Shown)	Previously Allocated		$212,090,000.00
TUCO Interchange 345/230/13.2KV Autotransformer CKT 2 Balanced Portfolio: TUCO 345/230 kV Transformer CKT 2 (Total Project E&C Cost Shown)	Previously Allocated		$14,900,907.00
Woodward XFMR 345/138/13.8kV CKT 2 Balanced Portfolio: Woodward 345/138kV Transformer CKT 2 & 50 MVAR Reactor (Total Project E&C Cost Shown).	Previously Allocated		$15,000,000.00
	Current Study Total	$34,137,782.87	

GEN-2012-012

Interconnection Request and Upgrades	Upgrade Type	Allocated Cost	Upgrade Cost
GEN-2012-012 Interconnection Costs See Oneline Diagram.	Current Study	$5,000,000.00	$5,000,000.00
Post Rock - GEN-2011-017 Tap 345kV CKT 2 Build second 345kV circuit from Post Rock - GEN-2011-017 Tap	Current Study	$9,313,118.38	$42,003,000.00
Axtell - PostRock 345KV CKT 1 Balanced Portfolio: PostRock - Axtell 345kV CKT 1 (Total Project E&C Cost Shown)	Previously Allocated		$148,000,000.00
Beaver County - Gray County (Buckner) 345kV Build approximately 90 miles of 345kV from Beaver County - Gray County @ 3000 amps	Previously Allocated		$170,209,050.00
Beaver County - Woodward 345kV Dbl CKT Priority Project: Hitchland - Woodward Dbl 345kV CKT (Total Project E&C Cost Shown)	Previously Allocated		$226,790,727.00
Beaver County 345kV Expansion Beaver County Expansion: Tap & Tie in Hitchland - Woodward 345kV CKT 2	Previously Allocated		$3,500,000.00
Benton - Wichita 345kV CKT 1 NRIS only required upgrade: Replace terminal equipment at Benton and Wichita	Previously Allocated		$1,183,000.00
Border - Tuco Interchange 345KV CKT 1 Balanced Portfolio: Tuco - Woodward 345kV CKT 1 (Total Project E&C Cost Shown)	Previously Allocated		$249,932,114.00
Border - Woodward 345KV CKT 1 Balanced Portfolio: Tuco - Woodward 345kV CKT 1 (Total Project E&C Cost Shown)	Previously Allocated		$249,932,114.00
Clark - Thistle 345KV Dbl CKT Priority Project: Spearville - Clark - Thistle Dbl 345kV CKT (Total Project E&C Cost Shown.)	Previously Allocated		$291,088,131.00

* 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
Hitchland 345/230kV Autotransformer CKT 2 Priority Project: Hitchland 345/230kV Autotransformer CKT 2 (Total Project E&C Cost Shown).	Previously Allocated		$8,883,760.00
Matthewson - Cimarron 345kV CKT 2 Build second 345kV circuit from Matthewson - Cimarron @ 3000 amps	Previously Allocated		$42,903,753.00
Mullergren - Reno 345kV Dbl CKT Build approximately 92 miles of new Dbl 345kV circuit from Mullergren - Reno @ 3000 amps	Previously Allocated		$210,887,465.33
Mullergren - Spearville 230kV CKT 1 NRIS only upgrade: Rebuild approximately 62 miles of 230kV line	Previously Allocated		$36,107,610.00
Post Rock 345/230/13.8kV Autotransformer CKT 2 DISIS-2010-001 Restudy	Previously Allocated		$13,749,527.00
Spearville - Mullergren 345kV Dbl CKT Build approximately 85 miles of new Dbl 345kV circuit from Spearville - Mullergren @ 3000 amps	Previously Allocated		$196,323,921.67
Tatonga - Matthewson 345kV CKT 2 Build second 345kV circuit from Tatonga - Matthewson @ 3000 amps	Previously Allocated		$104,260,473.00
Thistle - Wichita 345KV Dbl CKT Priority Project: Thistle - Wichita Dbl 345kV CKT (Total Project E&C Cost Shown.)	Previously Allocated		$168,750,000.00
Thistle - Woodward 345KV Dbl CKT Priority Project: Thistle - Woodward Dbl 345kV CKT (Total Project E&C Cost Shown)	Previously Allocated		$212,090,000.00
TUCO Interchange 345/230/13.2KV Autotransformer CKT 2 Balanced Portfolio: TUCO 345/230 kV Transformer CKT 2 (Total Project E&C Cost Shown)	Previously Allocated		$14,900,907.00
Woodward XFMR 345/138/13.8kV CKT 2 Balanced Portfolio: Woodward 345/138kV Transformer CKT 2 & 50 MVAR Reactor (Total Project E&C Cost Shown).	Previously Allocated		$15,000,000.00
	Current Study Total	$14,313,118.38	

TOTAL CURRENT STUDY COSTS: $75,319,676.99

* 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

GEN-2012-001 Interconnection Costs **$7,316,677.00**

See Oneline Diagram.

GEN-2012-001	$7,316,677.00
Total Allocated Costs	**$7,316,677.00**

GEN-2012-002 Interconnection Costs **$5,000,000.00**

See Oneline Diagram.

GEN-2012-002	$5,000,000.00
Total Allocated Costs	**$5,000,000.00**

GEN-2012-003 Interconnection Costs **$5,000,000.00**

See Oneline Diagram.

GEN-2012-003	$5,000,000.00
Total Allocated Costs	**$5,000,000.00**

GEN-2012-004 Interconnection Costs **$0.00**

See Oneline Diagram.

GEN-2012-004	$0.00
Total Allocated Costs	**$0.00**

GEN-2012-007 Interconnection Costs **$6,000,000.00**

See Oneline Diagram.

GEN-2012-007	$6,000,000.00
Total Allocated Costs	**$6,000,000.00**

GEN-2012-008 Interconnection Costs **$0.00**

See Oneline Diagram.

GEN-2012-008	$0.00
Total Allocated Costs	**$0.00**

GEN-2012-009 Interconnection Costs **$0.00**

See Oneline Diagram.

GEN-2012-009	$0.00
Total Allocated Costs	**$0.00**

GEN-2012-010 Interconnection Costs **$0.00**

See Oneline Diagram.

GEN-2012-010	$0.00

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

	Total Allocated Costs	**$0.00**

GEN-2012-011 Interconnection Costs		**$5,000,000.00**
See Oneline Diagram.		
	GEN-2012-011	$5,000,000.00
	Total Allocated Costs	**$5,000,000.00**

GEN-2012-012 Interconnection Costs		**$5,000,000.00**
See Oneline Diagram.		
	GEN-2012-012	$5,000,000.00
	Total Allocated Costs	**$5,000,000.00**

Post Rock - GEN-2011-017 Tap 345kV CKT 2		**$42,003,000.00**
Build second 345kV circuit from Post Rock - GEN-2011-017 Tap		
	GEN-2012-003	$593,141.05
	GEN-2012-007	$2,958,957.69
	GEN-2012-011	$29,137,782.87
	GEN-2012-012	$9,313,118.38
	Total Allocated Costs	**$42,003,000.00**

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

G: Power Flow Analysis (Constraints For Mitigation)

See next page.

SOLUTION	GROUP	SCENARIO	SEASON	SOURCE	DIRECTION	MONITORED ELEMENT	RATEB (MVA)	TDF	TC%LOADING (% MVA)	CONTINGENCY
FDNS	06NR	0	12G	G12_001	FROM->TO	JONES STATION - TUCO INTERCHANGE 230KV CKT 1	351	0.21909	106.4431	TOLK STATION EAST - TUCO INTERCHANGE 230KV CKT 1
FDNS	06NR	2	12G	G12_001	FROM->TO	JONES STATION - TUCO INTERCHANGE 230KV CKT 1	351	0.21909	106.4306	TOLK STATION EAST - TUCO INTERCHANGE 230KV CKT 1
FDNS	00NR	2	17SP	G12_001	FROM->TO	Jones Station Bus#2 - LUBBOCK SOUTH INTERCHANGE 230KV CKT 2	351	0.11189	106.9816	JONES STATION - LUBBOCK SOUTH INTERCHANGE 230KV CKT 1
FDNS	00NR	2	17SP	G12_001	TO->FROM	LUBBOCK EAST INTERCHANGE - LUBBOCK SOUTH INTERCHANGE 115KV CKT 1	160	0.07547	110.0559	Jones Station Bus#2 - LUBBOCK EAST INTERCHANGE 230KV CKT 1
FDNS	00NR	2	17SP	G12_001	TO->FROM	ALLEN SUB - LUBBOCK SOUTH INTERCHANGE 115KV CKT 1	160	0.05364	105.7393	WOLFFORTH INTERCHANGE - YUMA INTERCHANGE 115KV CKT 1
FDNS	00NR	2	17SP	G12_001	TO->FROM	ALLEN SUB - LUBBOCK SOUTH INTERCHANGE 115KV CKT 1	160	0.05364	100.2297	LP-DOUD_TP 3115.00 - YUMA INTERCHANGE 115KV CKT 1
FDNS	00NR	0	17SP	G12_001	FROM->TO	LUBBOCK SOUTH INTERCHANGE (ABB LLM60043) 230/115/13.2KV TRANSFORMER CKT 1	290	0.05119	115.9137	Jones Station Bus#2 - LUBBOCK EAST INTERCHANGE 230KV CKT 1
FDNS	00NR	0	17SP	G12_001	FROM->TO	LUBBOCK SOUTH INTERCHANGE (ABB LLM60043) 230/115/13.2KV TRANSFORMER CKT 1	290	0.05119	107.031	Jones Station Bus#2 - LUBBOCK EAST INTERCHANGE 230KV CKT 1
FDNS	00NR	2	17SP	G12_001	FROM->TO	LUBBOCK SOUTH INTERCHANGE (ABB LLM60043) 230/115/13.2KV TRANSFORMER CKT 1	290	0.05119	115.9061	Jones Station Bus#2 - LUBBOCK EAST INTERCHANGE 230KV CKT 1
FDNS	00NR	2	17SP	G12_001	FROM->TO	LUBBOCK SOUTH INTERCHANGE (ABB LLM60043) 230/115/13.2KV TRANSFORMER CKT 1	290	0.05119	107.0253	Jones Station Bus#2 - LUBBOCK EAST INTERCHANGE 230KV CKT 1
FDNS	00NR	2	17SP	G12_001	TO->FROM	ALLEN SUB - LUBBOCK SOUTH INTERCHANGE 115KV CKT 1	160	0.04283	102.3749	CARLISLE INTERCHANGE - TUCO INTERCHANGE 230KV CKT 1
FNSL-Blown up	03ALL	0	12G	G12_011		Non-Converged Contingency	1792	0.35408	-	G11-17T 345.00 - POST ROCK 345KV CKT 1
FNSL-Blown up	03ALL	0	12G	G12_012		Non-Converged Contingency	1792	0.11332	-	G11-17T 345.00 - POST ROCK 345KV CKT 1
FDNS	03NR	0	12G	G12_012	TO->FROM	MULLERGREN - SPEARVILLE 230KV CKT 1	355.3	0.05658	113.8654	G11-17T 345.00 - POST ROCK 345KV CKT 1
FDNS	00NR	0	12SP	G12_012	TO->FROM	BENTON - WICHITA 345KV CKT 1	956	0.04033	101.1683	GEN532751 1-WOLF CREEK GENERATING STATION UNIT 1
FDNS	00NR	2	12SP	G12_012	TO->FROM	BENTON - WICHITA 345KV CKT 1	956	0.03981	100.7057	GEN532751 1-WOLF CREEK GENERATING STATION UNIT 1
FDNS	03NR	0	12G	G12_012	TO->FROM	BENTON - WICHITA 345KV CKT 1	956	0.0357	110.8642	GEN532751 1-WOLF CREEK GENERATING STATION UNIT 1
FDNS	03NR	2	12G	G12_012	TO->FROM	BENTON - WICHITA 345KV CKT 1	956	0.03542	110.1288	GEN532751 1-WOLF CREEK GENERATING STATION UNIT 1

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

See next page.

SOLUTION	GROUP	SCENARIO	SEASON	SOURCE	DIRECTION	MONITORED ELEMENT	RATEB (MVA)	TDF	TC%LOADING (% MVA)	CONTINGENCY
FDNS	03ALL	0	12G	G12_001	FROM->TO	MATTHEWSON 345.00 - NORTHWEST 345KV CKT 1	1195	0.11264	100	CIMARRON - MATTHEWSON 345.00 345KV CKT 1
FDNS	03ALL	0	12G	G12_001	FROM->TO	MATTHEWSON 345.00 - NORTHWEST 345KV CKT 1	1195	0.11264	100	CIMARRON - MATTHEWSON 345.00 345KV CKT 2
FDNS	0	0	17SP	G12_001	FROM->TO	HOBBS INTERCHANGE (ME C0482951) 230/115/13.2KV TRANSFORMER CKT 1	150	0.09344	106.2375	HOBBS INTERCHANGE - LEA COUNTY INTERCHANGE 230KV CKT 1
FDNS	0	0	17SP	G12_001	FROM->TO	HOBBS INTERCHANGE (ME C0482951) 230/115/13.2KV TRANSFORMER CKT 1	150	0.09344	105.2032	HOBBS INTERCHANGE - LEA COUNTY INTERCHANGE 230KV CKT 1
FDNS	0	0	17WP	G12_001	FROM->TO	HOBBS INTERCHANGE (ME C0482951) 230/115/13.2KV TRANSFORMER CKT 1	150	0.09029	136.2727	HOBBS INTERCHANGE - LEA COUNTY INTERCHANGE 230KV CKT 1
FDNS	0	0	17WP	G12_001	FROM->TO	HOBBS INTERCHANGE (ME C0482951) 230/115/13.2KV TRANSFORMER CKT 1	150	0.09029	134.5971	HOBBS INTERCHANGE - LEA COUNTY INTERCHANGE 230KV CKT 1
FDNS	14	0	12G	G12_001	FROM->TO	HOBBS INTERCHANGE (ME C0482951) 230/115/13.2KV TRANSFORMER CKT 1	150	0.08995	125.5144	HOBBS INTERCHANGE - LEA COUNTY INTERCHANGE 230KV CKT 1
FDNS	14	0	12G	G12_001	FROM->TO	HOBBS INTERCHANGE (ME C0482951) 230/115/13.2KV TRANSFORMER CKT 1	150	0.08995	124.698	HOBBS INTERCHANGE - LEA COUNTY INTERCHANGE 230KV CKT 1
FDNS	6	0	12G	G12_001	FROM->TO	HOBBS INTERCHANGE (ME C0482951) 230/115/13.2KV TRANSFORMER CKT 1	150	0.08989	120.8895	HOBBS INTERCHANGE - LEA COUNTY INTERCHANGE 230KV CKT 1
FDNS	6	0	12G	G12_001	FROM->TO	HOBBS INTERCHANGE (ME C0482951) 230/115/13.2KV TRANSFORMER CKT 1	150	0.08989	120.1043	HOBBS INTERCHANGE - LEA COUNTY INTERCHANGE 230KV CKT 1
FDNS	4	0	12G	G12_001	FROM->TO	HOBBS INTERCHANGE (ME C0482951) 230/115/13.2KV TRANSFORMER CKT 1	150	0.08987	125.3953	HOBBS INTERCHANGE - LEA COUNTY INTERCHANGE 230KV CKT 1
FDNS	4	0	12G	G12_001	FROM->TO	HOBBS INTERCHANGE (ME C0482951) 230/115/13.2KV TRANSFORMER CKT 1	150	0.08987	124.5797	HOBBS INTERCHANGE - LEA COUNTY INTERCHANGE 230KV CKT 1
FDNS	0	0	12WP	G12_001	FROM->TO	HOBBS INTERCHANGE (ME C0482951) 230/115/13.2KV TRANSFORMER CKT 1	150	0.08942	127.1187	HOBBS INTERCHANGE - LEA COUNTY INTERCHANGE 230KV CKT 1
FDNS	0	0	12WP	G12_001	FROM->TO	HOBBS INTERCHANGE (ME C0482951) 230/115/13.2KV TRANSFORMER CKT 1	150	0.08942	126.1655	HOBBS INTERCHANGE - LEA COUNTY INTERCHANGE 230KV CKT 1
FDNS	3	0	12G	G12_001	FROM->TO	HOBBS INTERCHANGE (ME C0482951) 230/115/13.2KV TRANSFORMER CKT 1	150	0.08905	126.9348	HOBBS INTERCHANGE - LEA COUNTY INTERCHANGE 230KV CKT 1
FDNS	3	0	12G	G12_001	FROM->TO	HOBBS INTERCHANGE (ME C0482951) 230/115/13.2KV TRANSFORMER CKT 1	150	0.08905	126.1088	HOBBS INTERCHANGE - LEA COUNTY INTERCHANGE 230KV CKT 1
FDNS	03ALL	0	12G	G12_001	TO->FROM	BENTON - WICHITA 345KV CKT 1	956	0.07226	100.2974	TATONGA7 345.00 - WOODWARD DISTRICT EHV 345KV CKT 1
FDNS	0	0	17SP	G12_001	FROM->TO	LUBBOCK SOUTH INTERCHANGE (ABB LLM60043) 230/115/13.2KV TRANSFORMER CKT 1	290	0.06903	112.2405	Jones Station Bus#2 - LUBBOCK EAST INTERCHANGE 230KV CKT 1
FDNS	0	0	17SP	G12_001	FROM->TO	LUBBOCK SOUTH INTERCHANGE (ABB LLM60043) 230/115/13.2KV TRANSFORMER CKT 1	290	0.06903	104.5477	Jones Station Bus#2 - LUBBOCK EAST INTERCHANGE 230KV CKT 1
FDNS	03ALL	0	12G	G12_001	TO->FROM	BENTON - WICHITA 345KV CKT 1	956	0.06222	100.5599	WICHITA (WICHT12X) 345/138/13.8KV TRANSFORMER CKT 1
FDNS	03ALL	0	12G	G12_001	TO->FROM	BENTON - WICHITA 345KV CKT 1	956	0.06017	122.1853	GEN532751 1-WOLF CREEK GENERATING STATION UNIT 1
FDNS	03ALL	0	12G	G12_001	TO->FROM	CIMARRON - MATTHEWSON 345.00 345KV CKT 1	956	0.06001	105.6416	MATTHEWSON 345.00 - NORTHWEST 345KV CKT 1
FDNS	03ALL	0	12G	G12_001	TO->FROM	CIMARRON - MATTHEWSON 345.00 345KV CKT 2	956	0.06001	105.6416	MATTHEWSON 345.00 - NORTHWEST 345KV CKT 1
FDNS	3	0	12G	G12_001	TO->FROM	BENTON - WICHITA 345KV CKT 1	956	0.05988	105.2673	GEN532751 1-WOLF CREEK GENERATING STATION UNIT 1
FDNS	03ALL	0	12G	G12_001	TO->FROM	BENTON - WICHITA 345KV CKT 1	956	0.05401	106.4045	G08-13T 345.00 - WOODRING 345KV CKT 1
FDNS	03ALL	0	12G	G12_001	TO->FROM	BENTON - WICHITA 345KV CKT 1	956	0.05401	104.3005	G08-13T 345.00 - SUMNERCO 345.00 345KV CKT 1
FDNS	03ALL	0	12G	G12_001	TO->FROM	BENTON - WICHITA 345KV CKT 1	956	0.05401	100.5711	SUMNERCO 345.00 - WICHITA 345KV CKT 1
FDNS	03ALL	0	12G	G12_001	FROM->TO	SWISSVALE - WEST GARDNER 345KV CKT 1	752	0.03686	101.5313	HOYT - STRANGER CREEK 345KV CKT 1
FDNS	03ALL	0	12G	G12_001	FROM->TO	SWISSVALE - WEST GARDNER 345KV CKT 1	752	0.03368	102.3304	WRTOD400
FDNS	03ALL	0	12G	G12_001	FROM->TO	SWISSVALE - WEST GARDNER 345KV CKT 1	752	0.03326	100.894	HOYT - JEFFREY ENERGY CENTER 345KV CKT 1
FDNS	03ALL	0	12G	G12_002	FROM->TO	MATTHEWSON 345.00 - NORTHWEST 345KV CKT 1	1195	0.12076	100	CIMARRON - MATTHEWSON 345.00 345KV CKT 1
FDNS	03ALL	0	12G	G12_002	FROM->TO	MATTHEWSON 345.00 - NORTHWEST 345KV CKT 1	1195	0.12076	100	CIMARRON - MATTHEWSON 345.00 345KV CKT 2
FDNS	03ALL	0	12G	G12_002	TO->FROM	BENTON - WICHITA 345KV CKT 1	956	0.11871	106.4045	G08-13T 345.00 - WOODRING 345KV CKT 1
FDNS	03ALL	0	12G	G12_002	TO->FROM	BENTON - WICHITA 345KV CKT 1	956	0.11871	104.3005	G08-13T 345.00 - SUMNERCO 345.00 345KV CKT 1
FDNS	03ALL	0	12G	G12_002	TO->FROM	BENTON - WICHITA 345KV CKT 1	956	0.11871	100.5711	SUMNERCO 345.00 - WICHITA 345KV CKT 1
FDNS	03ALL	0	12G	G12_002	TO->FROM	BENTON - WICHITA 345KV CKT 1	956	0.11453	100.2974	TATONGA7 345.00 - WOODWARD DISTRICT EHV 345KV CKT 1
FDNS	03ALL	0	12G	G12_002	TO->FROM	BENTON - WICHITA 345KV CKT 1	956	0.10508	100.5599	WICHITA (WICHT12X) 345/138/13.8KV TRANSFORMER CKT 1
FDNS	03ALL	0	12G	G12_002	TO->FROM	BENTON - WICHITA 345KV CKT 1	956	0.10229	122.1853	GEN532751 1-WOLF CREEK GENERATING STATION UNIT 1
FDNS	3	0	12G	G12_002	TO->FROM	BENTON - WICHITA 345KV CKT 1	956	0.102	105.2673	GEN532751 1-WOLF CREEK GENERATING STATION UNIT 1
FDNS	03ALL	0	12G	G12_002	TO->FROM	CIMARRON - MATTHEWSON 345.00 345KV CKT 1	956	0.09566	105.6416	MATTHEWSON 345.00 - NORTHWEST 345KV CKT 1
FDNS	03ALL	0	12G	G12_002	TO->FROM	CIMARRON - MATTHEWSON 345.00 345KV CKT 2	956	0.09566	105.6416	MATTHEWSON 345.00 - NORTHWEST 345KV CKT 1
FDNS	03ALL	0	12G	G12_002	TO->FROM	CIMARRON - MATTHEWSON 345.00 345KV CKT 2	956	0.08602	101.0338	CIMARRON - MATTHEWSON 345.00 345KV CKT 1
FDNS	03ALL	0	12G	G12_002	TO->FROM	CIMARRON - MATTHEWSON 345.00 345KV CKT 1	956	0.08602	101.0338	CIMARRON - MATTHEWSON 345.00 345KV CKT 2
FDNS	03ALL	0	12G	G12_002	FROM->TO	SWISSVALE - WEST GARDNER 345KV CKT 1	752	0.05505	101.5313	HOYT - STRANGER CREEK 345KV CKT 1
FDNS	03ALL	0	12G	G12_002	FROM->TO	SWISSVALE - WEST GARDNER 345KV CKT 1	752	0.05083	102.3304	WRTOD400
FDNS	03ALL	0	12G	G12_002	FROM->TO	SWISSVALE - WEST GARDNER 345KV CKT 1	752	0.05024	100.894	HOYT - JEFFREY ENERGY CENTER 345KV CKT 1
FDNS	03ALL	0	12G	G12_002	TO->FROM	DEAF SMITH COUNTY INTERCHANGE - S-RANDLCO 230.00 230KV CKT 1	350	0.04022	117.0803	PLANT X STATION - S-RANDLCO 230.00 230KV CKT 1
FDNS	03ALL	0	12G	G12_002	FROM->TO	EVANS ENERGY CENTER NORTH - MAIZE 138KV CKT 1	382	0.03816	110.032	BENTON - WICHITA 345KV CKT 1
FDNS	03ALL	0	12G	G12_002	TO->FROM	CHISHOLM - MAIZE 138KV CKT 1	382	0.03816	107.4772	BENTON - WICHITA 345KV CKT 1
FDNS	3	0	12G	G12_002	FROM->TO	EVANS ENERGY CENTER NORTH - MAIZE 138KV CKT 1	382	0.03669	100.1747	BENTON - WICHITA 345KV CKT 1
FDNS	03ALL	0	12G	G12_002	FROM->TO	SMOKYHL6 230.00 - SUMMIT 230KV CKT 1	319	0.03416	116.9482	AXTELL - POST ROCK 345KV CKT 1
FDNS	03ALL	0	12G	G12_002	TO->FROM	DEAF SMITH COUNTY INTERCHANGE - S-RANDLCO 230.00 230KV CKT 1	350	0.03323	102.5183	BORDER 7345.00 - TUCO INTERCHANGE 345KV CKT 1
FDNS	03ALL	0	12G	G12_002	TO->FROM	DEAF SMITH COUNTY INTERCHANGE - S-RANDLCO 230.00 230KV CKT 1	350	0.03323	100.2878	BORDER 7345.00 - WOODWARD DISTRICT EHV 345KV CKT 1
FDNS	03ALL	0	12G	G12_002	FROM->TO	WICHITA (WICHT12X) 345/138/13.8KV TRANSFORMER CKT 1	440	0.03223	122.9888	BENTON - WICHITA 345KV CKT 1
FDNS	03ALL	0	12G	G12_002	FROM->TO	WICHITA (WICHT12X) 345/138/13.8KV TRANSFORMER CKT 1	440	0.03223	122.1063	BENTON - WICHITA 345KV CKT 1
FDNS	03ALL	0	12G	G12_002	TO->FROM	DEAF SMITH COUNTY INTERCHANGE - S-RANDLCO 230.00 230KV CKT 1	350	0.03048	105.5738	G07-48T 230.00 - SWISHER COUNTY INTERCHANGE 230KV CKT 1
FDNS	03ALL	0	12G	G12_002	TO->FROM	DEAF SMITH COUNTY INTERCHANGE - S-RANDLCO 230.00 230KV CKT 1	350	0.03048	100.3251	AMARILLO SOUTH INTERCHANGE - G07-48T 230.00 230KV CKT 1
FDNS	03ALL	0	12G	G12_002	TO->FROM	DEAF SMITH COUNTY INTERCHANGE - S-RANDLCO 230.00 230KV CKT 1	350	0.03046	100.1469	CANYON EAST SUB - OSAGE SWITCHING STATION 115KV CKT 1
FDNS	0	0	17SP	G12_009	FROM->TO	LUBBOCK SOUTH INTERCHANGE (ABB LLM60043) 230/115/13.2KV TRANSFORMER CKT 1	290	0.03079	112.2405	Jones Station Bus#2 - LUBBOCK EAST INTERCHANGE 230KV CKT 1
FDNS	0	0	17SP	G12_009	FROM->TO	LUBBOCK SOUTH INTERCHANGE (ABB LLM60043) 230/115/13.2KV TRANSFORMER CKT 1	290	0.03079	104.5477	Jones Station Bus#2 - LUBBOCK EAST INTERCHANGE 230KV CKT 1
FDNS	0	0	17SP	G12_010	FROM->TO	LUBBOCK SOUTH INTERCHANGE (ABB LLM60043) 230/115/13.2KV TRANSFORMER CKT 1	290	0.03079	112.2405	Jones Station Bus#2 - LUBBOCK EAST INTERCHANGE 230KV CKT 1
FDNS	0	0	17SP	G12_010	FROM->TO	LUBBOCK SOUTH INTERCHANGE (ABB LLM60043) 230/115/13.2KV TRANSFORMER CKT 1	290	0.03079	104.5477	Jones Station Bus#2 - LUBBOCK EAST INTERCHANGE 230KV CKT 1
FDNS	03ALL	0	12G	G12_011	TO->FROM	BENTON - WICHITA 345KV CKT 1	956	0.15025	106.4045	G08-13T 345.00 - WOODRING 345KV CKT 1
FDNS	03ALL	0	12G	G12_011	TO->FROM	BENTON - WICHITA 345KV CKT 1	956	0.15025	104.3005	G08-13T 345.00 - SUMNERCO 345.00 345KV CKT 1
FDNS	03ALL	0	12G	G12_011	TO->FROM	BENTON - WICHITA 345KV CKT 1	956	0.15025	100.5711	SUMNERCO 345.00 - WICHITA 345KV CKT 1
FDNS	03ALL	0	12G	G12_011	TO->FROM	KNOLL 230 - POSTROCK6 230.00 230KV CKT 1	398	0.14476	109.8562	AXTELL - POST ROCK 345KV CKT 1
FDNS	03ALL	0	12G	G12_011	TO->FROM	BENTON - WICHITA 345KV CKT 1	956	0.13436	100.2974	TATONGA7 345.00 - WOODWARD DISTRICT EHV 345KV CKT 1
FDNS	03ALL	0	12G	G12_011	TO->FROM	BENTON - WICHITA 345KV CKT 1	956	0.12835	100.5599	WICHITA (WICHT12X) 345/138/13.8KV TRANSFORMER CKT 1
FDNS	03ALL	0	12G	G12_011	TO->FROM	BENTON - WICHITA 345KV CKT 1	956	0.12512	122.1853	GEN532751 1-WOLF CREEK GENERATING STATION UNIT 1

SOLUTION	GROUP	SCENARIO	SEASON	SOURCE	DIRECTION	MONITORED ELEMENT	RATEB (MVA)	TDF	TC%LOADING (% MVA)	CONTINGENCY
FDNS	3	0	12G	G12_011	TO->FROM	BENTON - WICHITA 345KV CKT 1	956	0.12484	105.2673	GEN532751 1-WOLF CREEK GENERATING STATION UNIT 1
FDNS	03ALL	0	12G	G12_011	FROM->TO	SMOKYHL6 230.00 - SUMMIT 230KV CKT 1	319	0.10451	116.9482	AXTELL - POST ROCK 345KV CKT 1
FDNS	03ALL	0	12G	G12_011	FROM->TO	MATTHEWSON 345.00 - NORTHWEST 345KV CKT 1	1195	0.10111	100	CIMARRON - MATTHEWSON 345.00 345KV CKT 1
FDNS	03ALL	0	12G	G12_011	FROM->TO	MATTHEWSON 345.00 - NORTHWEST 345KV CKT 1	1195	0.10111	100	CIMARRON - MATTHEWSON 345.00 345KV CKT 2
FDNS	03ALL	0	12G	G12_011	TO->FROM	CIMARRON - MATTHEWSON 345.00 345KV CKT 1	956	0.08375	105.6416	MATTHEWSON 345.00 - NORTHWEST 345KV CKT 1
FDNS	03ALL	0	12G	G12_011	TO->FROM	CIMARRON - MATTHEWSON 345.00 345KV CKT 2	956	0.08375	105.6416	MATTHEWSON 345.00 - NORTHWEST 345KV CKT 1
FDNS	03ALL	0	12G	G12_011	TO->FROM	CIMARRON - MATTHEWSON 345.00 345KV CKT 2	956	0.07857	101.0338	CIMARRON - MATTHEWSON 345.00 345KV CKT 1
FDNS	03ALL	0	12G	G12_011	TO->FROM	CIMARRON - MATTHEWSON 345.00 345KV CKT 1	956	0.07857	101.0338	CIMARRON - MATTHEWSON 345.00 345KV CKT 2
FDNS	03ALL	0	12G	G12_011	FROM->TO	SWISSVALE - WEST GARDNER 345KV CKT 1	752	0.07487	101.5313	HOYT - STRANGER CREEK 345KV CKT 1
FDNS	03ALL	0	12G	G12_011	FROM->TO	SWISSVALE - WEST GARDNER 345KV CKT 1	752	0.06955	102.3304	WRTOD400
FDNS	03ALL	0	12G	G12_011	FROM->TO	SWISSVALE - WEST GARDNER 345KV CKT 1	752	0.06867	100.894	HOYT - JEFFREY ENERGY CENTER 345KV CKT 1
FDNS	03ALL	0	12G	G12_011	FROM->TO	EVANS ENERGY CENTER NORTH - MAIZE 138KV CKT 1	382	0.04704	110.032	BENTON - WICHITA 345KV CKT 1
FDNS	03ALL	0	12G	G12_011	TO->FROM	CHISHOLM - MAIZE 138KV CKT 1	382	0.04704	107.4772	BENTON - WICHITA 345KV CKT 1
FDNS	03ALL	0	12G	G12_011	TO->FROM	N HAYS3 115.00 - VINE STREET 115KV CKT 1	99	0.04674	133.4966	KNOLL 230 - POSTROCK6 230.00 230KV CKT 1
FDNS	03ALL	0	12G	G12_011	TO->FROM	KNOLL - N HAYS3 115.00 115KV CKT 1	99	0.04674	128.9221	KNOLL 230 - POSTROCK6 230.00 230KV CKT 1
FDNS	03ALL	0	12G	G12_011	FROM->TO	SOUTH HAYS (S HAYS T1) 230/115/12.47KV TRANSFORMER CKT 1	166.7	0.04674	100.9626	KNOLL 230 - POSTROCK6 230.00 230KV CKT 1
FDNS	03ALL	0	12G	G12_011	FROM->TO	SOUTH HAYS (S HAYS T1) 230/115/12.47KV TRANSFORMER CKT 1	166.7	0.04674	100	KNOLL 230 - POSTROCK6 230.00 230KV CKT 1
FDNS	3	0	12G	G12_011	TO->FROM	N HAYS3 115.00 - VINE STREET 115KV CKT 1	99	0.04647	126.5538	KNOLL 230 - POSTROCK6 230.00 230KV CKT 1
FDNS	3	0	12G	G12_011	TO->FROM	KNOLL - N HAYS3 115.00 115KV CKT 1	99	0.04647	121.8527	KNOLL 230 - POSTROCK6 230.00 230KV CKT 1
FDNS	3	0	12G	G12_011	FROM->TO	EVANS ENERGY CENTER NORTH - MAIZE 138KV CKT 1	382	0.04556	100.1747	BENTON - WICHITA 345KV CKT 1
FDNS	03ALL	0	12G	G12_011	FROM->TO	WICHITA (WICHT12X) 345/138/13.8KV TRANSFORMER CKT 1	440	0.03874	122.9888	BENTON - WICHITA 345KV CKT 1
FDNS	03ALL	0	12G	G12_011	FROM->TO	WICHITA (WICHT12X) 345/138/13.8KV TRANSFORMER CKT 1	440	0.03874	122.1063	BENTON - WICHITA 345KV CKT 1
FDNS	03ALL	0	12G	G12_011	TO->FROM	MOUNDRIDGE - RENO COUNTY 115KV CKT 1	245	0.03857	105.0089	RENO COUNTY - WICHITA 345KV CKT 1
FDNS	03ALL	0	12G	G12_011	TO->FROM	DEAF SMITH COUNTY INTERCHANGE - S-RANDLCO 230.00 230KV CKT 1	350	0.03416	117.0803	PLANT X STATION - S-RANDLCO 230.00 230KV CKT 1
FDNS	03ALL	0	12G	G12_011	FROM->TO	WICHITA (WICHT11X) 345/138/13.8KV TRANSFORMER CKT 1	440	0.03365	106.856	BENTON - WICHITA 345KV CKT 1
FDNS	03ALL	0	12G	G12_011	FROM->TO	WICHITA (WICHT11X) 345/138/13.8KV TRANSFORMER CKT 1	440	0.03365	106.0773	BENTON - WICHITA 345KV CKT 1
FDNS	3	0	12G	G12_011	FROM->TO	MOUNDRIDGE (MOUND10X) 138/115/13.8KV TRANSFORMER CKT 1	110	0.03274	147.1241	RENO COUNTY - WICHITA 345KV CKT 1
FDNS	3	0	12G	G12_011	FROM->TO	MOUNDRIDGE (MOUND10X) 138/115/13.8KV TRANSFORMER CKT 1	110	0.03274	146.5172	RENO COUNTY - WICHITA 345KV CKT 1
FDNS	03ALL	0	12G	G12_011	FROM->TO	MOUNDRIDGE (MOUND10X) 138/115/13.8KV TRANSFORMER CKT 1	110	0.03163	187.8763	RENO COUNTY - WICHITA 345KV CKT 1
FDNS	03ALL	0	12G	G12_011	FROM->TO	MOUNDRIDGE (MOUND10X) 138/115/13.8KV TRANSFORMER CKT 1	110	0.03163	187.3334	RENO COUNTY - WICHITA 345KV CKT 1
FDNS	03ALL	0	12G	G12_012	TO->FROM	BENTON - WICHITA 345KV CKT 1	956	0.17558	106.4045	G08-13T 345.00 - WOODRING 345KV CKT 1
FDNS	03ALL	0	12G	G12_012	TO->FROM	BENTON - WICHITA 345KV CKT 1	956	0.17558	104.3005	G08-13T 345.00 - SUMNERCO 345.00 345KV CKT 1
FDNS	03ALL	0	12G	G12_012	TO->FROM	BENTON - WICHITA 345KV CKT 1	956	0.17558	100.5711	SUMNERCO 345.00 - WICHITA 345KV CKT 1
FDNS	03ALL	0	12G	G12_012	TO->FROM	BENTON - WICHITA 345KV CKT 1	956	0.15999	100.2974	TATONGA7 345.00 - WOODWARD DISTRICT EHV 345KV CKT 1
FDNS	03ALL	0	12G	G12_012	TO->FROM	BENTON - WICHITA 345KV CKT 1	956	0.15373	100.5599	WICHITA (WICHT12X) 345/138/13.8KV TRANSFORMER CKT 1
FDNS	03ALL	0	12G	G12_012	TO->FROM	BENTON - WICHITA 345KV CKT 1	956	0.14923	122.1853	GEN532751 1-WOLF CREEK GENERATING STATION UNIT 1
FDNS	3	0	12G	G12_012	TO->FROM	BENTON - WICHITA 345KV CKT 1	956	0.14894	105.2673	GEN532751 1-WOLF CREEK GENERATING STATION UNIT 1
FDNS	03ALL	0	12G	G12_012	FROM->TO	MATTHEWSON 345.00 - NORTHWEST 345KV CKT 1	1195	0.11536	100	CIMARRON - MATTHEWSON 345.00 345KV CKT 1
FDNS	03ALL	0	12G	G12_012	FROM->TO	MATTHEWSON 345.00 - NORTHWEST 345KV CKT 1	1195	0.11536	100	CIMARRON - MATTHEWSON 345.00 345KV CKT 2
FDNS	03ALL	0	12G	G12_012	TO->FROM	CIMARRON - MATTHEWSON 345.00 345KV CKT 1	956	0.09461	105.6416	MATTHEWSON 345.00 - NORTHWEST 345KV CKT 1
FDNS	03ALL	0	12G	G12_012	TO->FROM	CIMARRON - MATTHEWSON 345.00 345KV CKT 2	956	0.09461	105.6416	MATTHEWSON 345.00 - NORTHWEST 345KV CKT 1
FDNS	03ALL	0	12G	G12_012	TO->FROM	CIMARRON - MATTHEWSON 345.00 345KV CKT 2	956	0.08795	101.0338	CIMARRON - MATTHEWSON 345.00 345KV CKT 1
FDNS	03ALL	0	12G	G12_012	TO->FROM	CIMARRON - MATTHEWSON 345.00 345KV CKT 1	956	0.08795	101.0338	CIMARRON - MATTHEWSON 345.00 345KV CKT 2
FDNS	03ALL	0	12G	G12_012	FROM->TO	SWISSVALE - WEST GARDNER 345KV CKT 1	752	0.07708	101.5313	HOYT - STRANGER CREEK 345KV CKT 1
FDNS	03ALL	0	12G	G12_012	FROM->TO	SWISSVALE - WEST GARDNER 345KV CKT 1	752	0.07166	102.3304	WRTOD400
FDNS	03ALL	0	12G	G12_012	FROM->TO	SWISSVALE - WEST GARDNER 345KV CKT 1	752	0.0708	100.894	HOYT - JEFFREY ENERGY CENTER 345KV CKT 1
FDNS	03ALL	0	12G	G12_012	FROM->TO	EVANS ENERGY CENTER NORTH - MAIZE 138KV CKT 1	382	0.05501	110.032	BENTON - WICHITA 345KV CKT 1
FDNS	03ALL	0	12G	G12_012	TO->FROM	CHISHOLM - MAIZE 138KV CKT 1	382	0.05501	107.4772	BENTON - WICHITA 345KV CKT 1
FDNS	3	0	12G	G12_012	FROM->TO	EVANS ENERGY CENTER NORTH - MAIZE 138KV CKT 1	382	0.05353	100.1747	BENTON - WICHITA 345KV CKT 1
FDNS	03ALL	0	12G	G12_012	TO->FROM	KNOLL 230 - POSTROCK6 230.00 230KV CKT 1	398	0.04968	109.8562	AXTELL - POST ROCK 345KV CKT 1
FDNS	03ALL	0	12G	G12_012	FROM->TO	WICHITA (WICHT12X) 345/138/13.8KV TRANSFORMER CKT 1	440	0.04859	122.9888	BENTON - WICHITA 345KV CKT 1
FDNS	03ALL	0	12G	G12_012	FROM->TO	WICHITA (WICHT12X) 345/138/13.8KV TRANSFORMER CKT 1	440	0.04859	122.1063	BENTON - WICHITA 345KV CKT 1
FDNS	03ALL	0	12G	G12_012	FROM->TO	WICHITA (WICHT11X) 345/138/13.8KV TRANSFORMER CKT 1	440	0.04222	106.856	BENTON - WICHITA 345KV CKT 1
FDNS	03ALL	0	12G	G12_012	FROM->TO	WICHITA (WICHT11X) 345/138/13.8KV TRANSFORMER CKT 1	440	0.04222	106.0773	BENTON - WICHITA 345KV CKT 1
FDNS	03ALL	0	12G	G12_012	FROM->TO	SMOKYHL6 230.00 - SUMMIT 230KV CKT 1	319	0.03724	116.9482	AXTELL - POST ROCK 345KV CKT 1
FDNS	03ALL	0	12G	G12_012	TO->FROM	DEAF SMITH COUNTY INTERCHANGE - S-RANDLCO 230.00 230KV CKT 1	350	0.03376	117.0803	PLANT X STATION - S-RANDLCO 230.00 230KV CKT 1
FDNS	03NR	0	12G	G12_012	TO->FROM	BENTON - WICHITA 345KV CKT 1	956	0.03266	111.828	DBL-TGA-MATT
FDNS	03NR	2	12G	G12_012	TO->FROM	BENTON - WICHITA 345KV CKT 1	956	0.03208	110.6399	DBL-TGA-MATT
FDNS	03NR	2	12G	G12_012	TO->FROM	MULLERGREN - SPEARVILLE 230KV CKT 1	398	0.05168	101.0289	DBL-G1117T-P

I: Group 3 Dynamic Stability Analysis Report

See next page.

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ELECTRIC

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Southwest Power Pool, Inc. (SPP)

DISIS-2012-001 (Group 3) Definitive Impact Study

Final Report

PXE-0601
Revision #02

July 2012

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

Title: **DISIS-2012-001 (Group 3) Definitive Impact Study: Final Report PXE-0601**
Date: July 2012

Author: Nicholas W. Tenza; Engineer I, Power Systems Engineering Dept. *Nicholas W. Tenza*
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Robert T. Hellested, Deputy Mngr., Power Systems Engineering Dept. *Robert T. Hellested*

EXECUTIVE SUMMARY

SPP requested a Definitive Interconnection System Impact Study (DISIS). The DISIS required a Power Factor Analysis and a Stability Analysis detailing the impacts of the interconnecting projects as shown in Table ES-1.

Table ES-1
Interconnection Projects Evaluated

Request	Size (MW)	Turbine Model	Point of Interconnection (POI)
GEN-2012-003	20.74/21.21	GENSAL	Tap on Rolla - Hugoton 69 kV (562114)
GEN-2012-007	96/120	GENSAL	Tap on Kickok - Satanta 115 kV (562116)
GEN-2012-011	200	GE 1.6 MW	Tap on Spearville - Post Rock 345 kV Line (G11-017 POI, 576704)
GEN-2012-012	200	Clipper 2.5 MW	Clark County 345 kV (539800)

SUMMARY OF POWER FACTOR ANALYSIS

The Power Factor Analysis shows that GEN-2012-011 has reactive requirements for a power factor range of 0.8731 to 0.9912 lagging (supplying) and GEN-2012-012 has reactive requirements for a power factor range of 0.9076 to 0.9576 lagging (supplying).

Note that Case 1 (3 phase fault on the G11-017-POI to Post Rock 345 kV line) does not initially converge. After discussion with SPP, it was determined that a second 345 kV circuit should be added from G11-017 POI 345 kV (576704) to Post Rock 345 kV (530583). For the Power Factor Analysis, Case 1, both Summer and Winter Peak seasons, was the only case to be simulated with this additional line.

SUMMARY OF STABILITY ANALYSIS

For Summer Peak conditions, the Stability Analysis determined that there was no wind turbine tripping or system instability that occurs from interconnecting GEN-2012-003, GEN-2012-007, GEN-2012-011, and GEN-2012-012 at 100% output.

For Winter Peak conditions, with the addition of the G11-017 POI to Post Rock 345 kV line circuit #2, the Stability Analysis determined that there was no wind turbine tripping or system instability that occurs from interconnecting GEN-2012-003, GEN-2012-007, GEN-2012-011, and GEN-2012-012 at 100% output.

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SECTION 1: OBJECTIVES

The objective of this report is to provide Southwest Power Pool, Inc. (SPP) with the deliverables for the "GEN-2012-001 (Group 3) Definitive Impact Study." SPP requested an Interconnection System Impact Study for GEN-2012-003, GEN-2012-007, GEN-2012-011, and GEN-2012-012, which requires a Power Factor Analysis for the wind interconnection requests, a Stability Analysis, and an Impact Study Report.

SECTION 2: BACKGROUND

The Siemens Power Technologies, Inc. PSS/E power system simulation program Version 30.3.3 was used for this study. SPP provided the stability database cases for summer peak and winter peak seasons and a list of contingencies to be examined. The model includes the study project and the previously queued projects as listed in Table 2-1 and Table 2-2, respectively. Refer to Appendix A for the steady-state and dynamic model data for the study projects. A power flow one-line diagram of GEN-2012-003, GEN-2012-007, GEN-2012-011, and GEN-2012-012 interconnection projects are shown in Figures 2-1 through 2-4, respectively.

The Power Factor analysis will determine the power factor at the point of interconnection for the wind interconnection project for pre-contingency and post-contingency conditions. Table 2-4 lists the contingencies developed from the three-phase fault definitions provided in the Group's interconnection impact study request.

The Stability Analysis will determine the impacts of the new interconnecting project on the stability and voltage recovery of the nearby system 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 will be investigated. Three-phase and single-phase faults will be examined as listed in Table 2-3.

Note that contingencies 23 through 27, double line outages, were not simulated for the Power Factor Analysis. These contingencies were simulated in the Stability Analysis.

Table 2-1
Interconnection Projects Evaluated

Request	Size (MW)	Turbine Model	Point of Interconnection (POI)
GEN-2012-003	20.74/21.21	GENSAL	Tap on Rolla - Hugoton 69 kV (562114)
GEN-2012-007	96/120	GENSAL	Tap on Kickok - Satanta 115 kV (562116)
GEN-2012-011	200	GE 1.6 MW	Tap on Spearville - Post Rock 345 kV Line (G11-017 POI, 576704)
GEN-2012-012	200	Clipper 2.5 MW	Clark County 345 kV (539800)

Table 2-2
Previously Queued Nearby Interconnection Projects Included

Request	Size (MW)	Turbine Model	Point of Interconnection (POI)
GEN-2001-039A	104	GE 1.6 MW	Tap on Fort Dodge - Geensburg 115 kV Line (579025)
GEN-2002-025A	150	GE 1.5 MW	Spearville 230 kV (539695)
GEN-2004-014	154.5	GE 1.5 MW	Spearville 230 kV (539695)
GEN-2005-012	250.7	Siemens 2.3 MW	Spearville 345 kV (531469)
GEN-2006-006	205.5	GE 1.5 MW	Spearville 345 kV (531469)
GEN-2006-021	100	Clipper 2.5 MW	Flat Ridge 138 kV (539639)
GEN-2006-022	150	Clipper 2.5 MW	Pratt 115 kV (539687)
GEN-2007-038	200	Clipper 2.5 MW	Spearville 345 kV (531469)
GEN-2007-040	200.1	Siemens 2.3 MW	Gray County 345 kV (579284)
GEN-2008-018	405	GE 1.5 MW	Finney 345 kV (523853)
GEN-2008-079	99.2	GE 1.5 MW & 1.6 MW	Tap on Cudahy - Fort Dodge 115 kV Line (573029)
GEN-2008-124	200.1	Siemens 2.3 MW	Spearville 345 kV (531469)

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

Request	Size (MW)	Turbine Model	Point of Interconnection (POI)
GEN-2010-009	165.6	Siemens SWT 2.3 MW	Gray County 345 kV (579284)
GEN-2010-015	200.1	Siemens SWT 2.3 MW	Spearville 345 kV (531469)
GEN-2010-029	450	Vestas V90 1.8 MW	Spearville 345 kV (531469)
GEN-2010-045	197.8	Siemens 2.3 MW	Gray County 345 kV (579284)
GEN-2010-053	199.8	Vestas V90 1.8 MW	Clark County 345 kV (539800)
GEN-2010-061	179.4	Siemens 2.3 MW	Tap on Spearville - Post Rock 345 kV Line (G11-017 POI, 576704)
GEN-2011-008	600	GE 1.6 MW	Clark County 345 kV (539800)
GEN-2011-016	200.1	Siemens 2.3 MW	Spearville 345 kV (531469)
GEN-2011-017	299	Siemens 2.3 MW	Tap on Spearville - Post Rock 345 kV Line (G11-017 POI, 576704)
GEN-2011-023	299	Siemens 2.3 MW	Clark County 345 kV (539800)
GEN-2011-043	149.5	Siemens 2.3 MW	Thistle 345 kV (539801)
GEN-2011-044	149.5	Siemens 2.3 MW	Thistle 345 kV (539801)

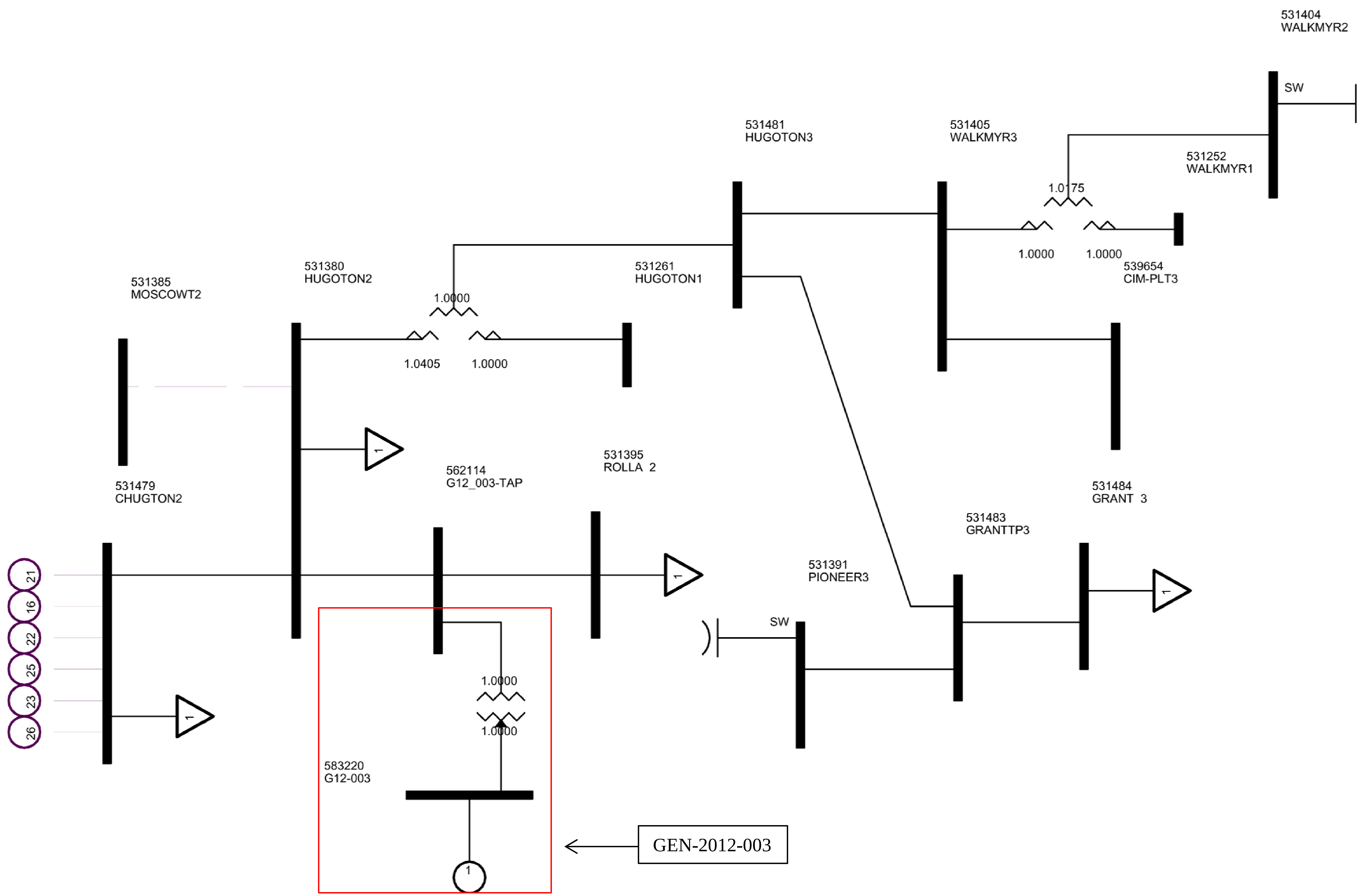

Figure 2-1. Power flow one-line diagram for interconnection project GEN-2012-003.

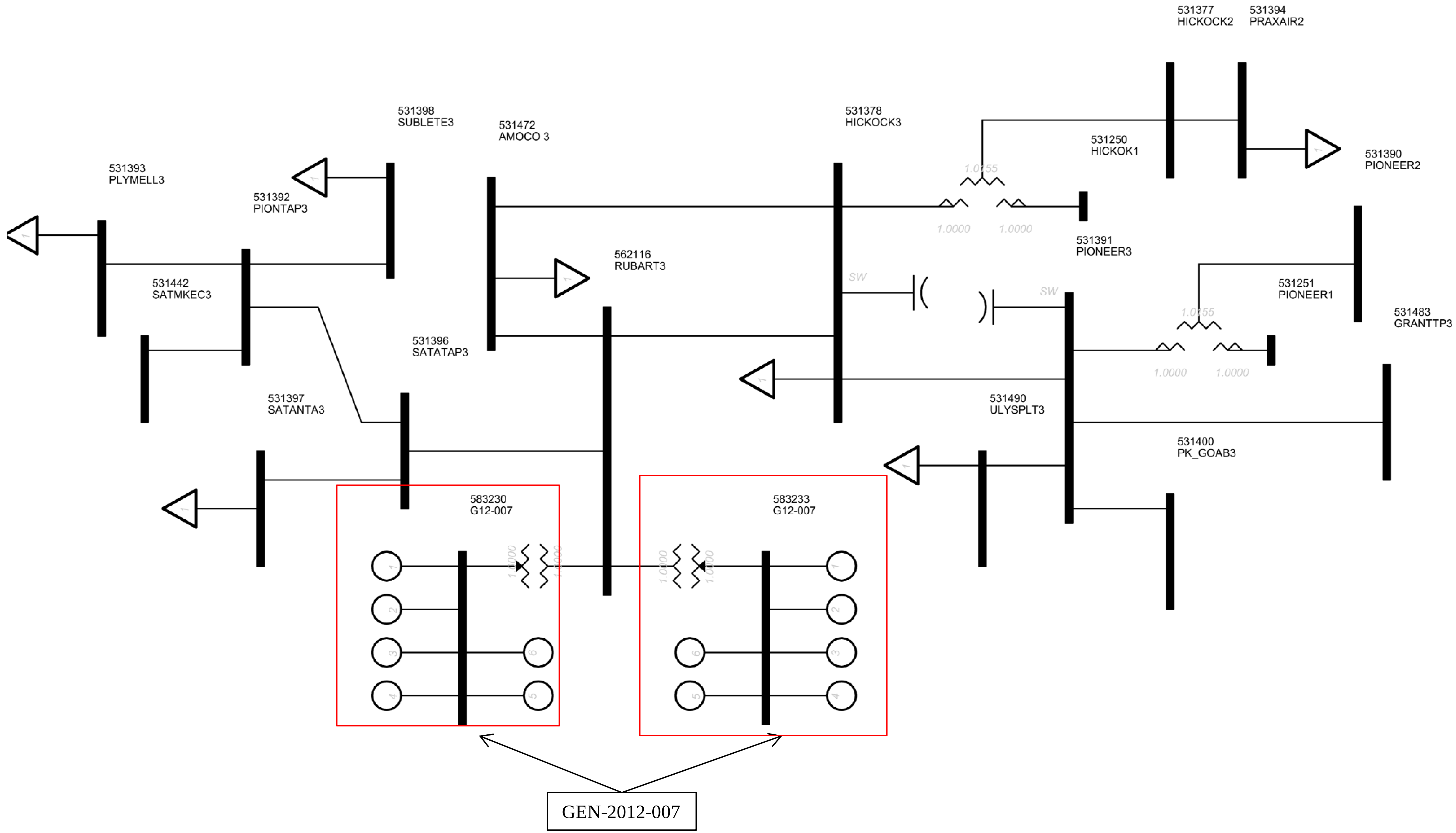

Figure 2-2. Power flow one-line diagram for interconnection project GEN-2012-007.

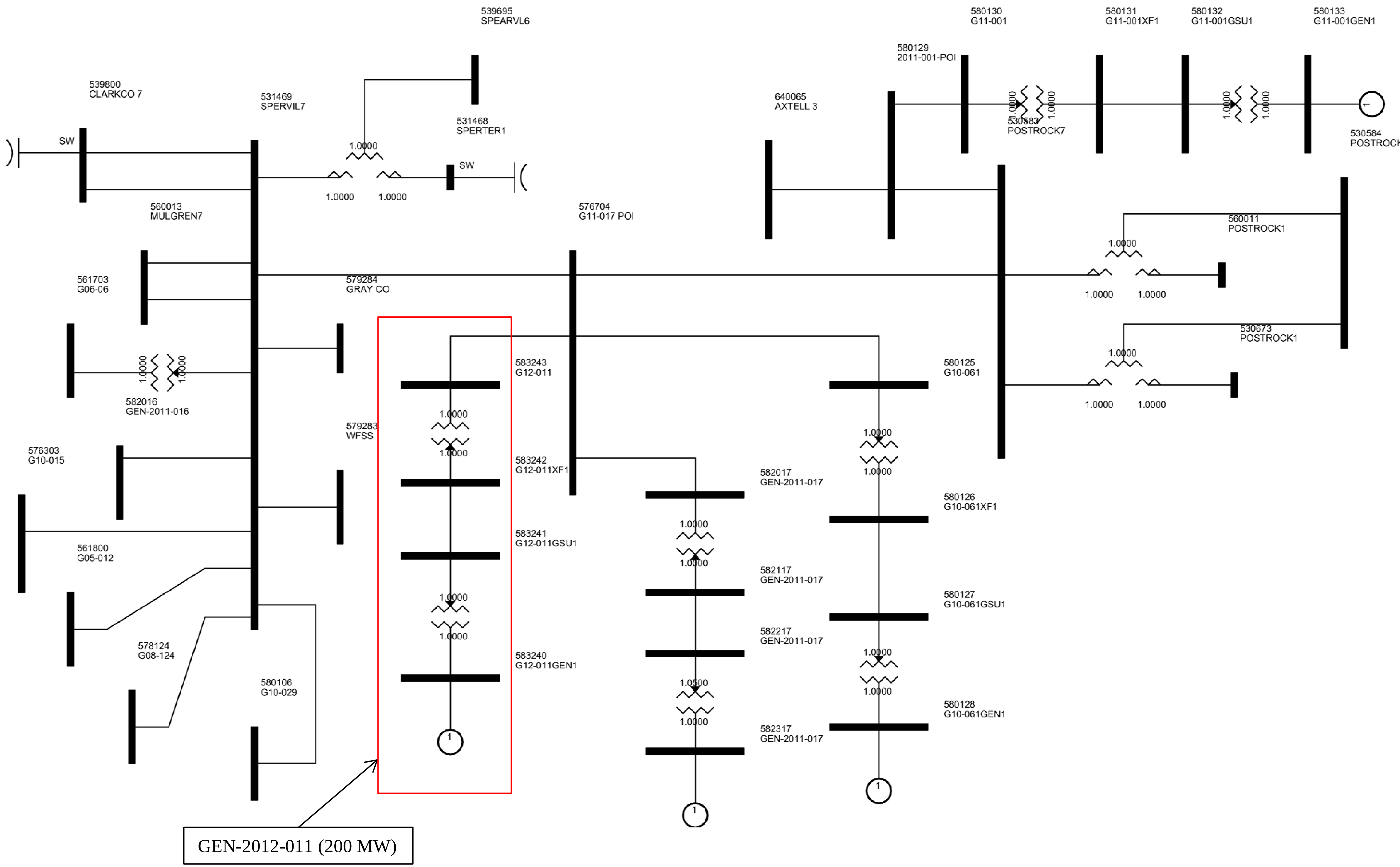

Figure 2-3. Power flow one-line diagram for interconnection project GEN-2012-011 (200 MW).

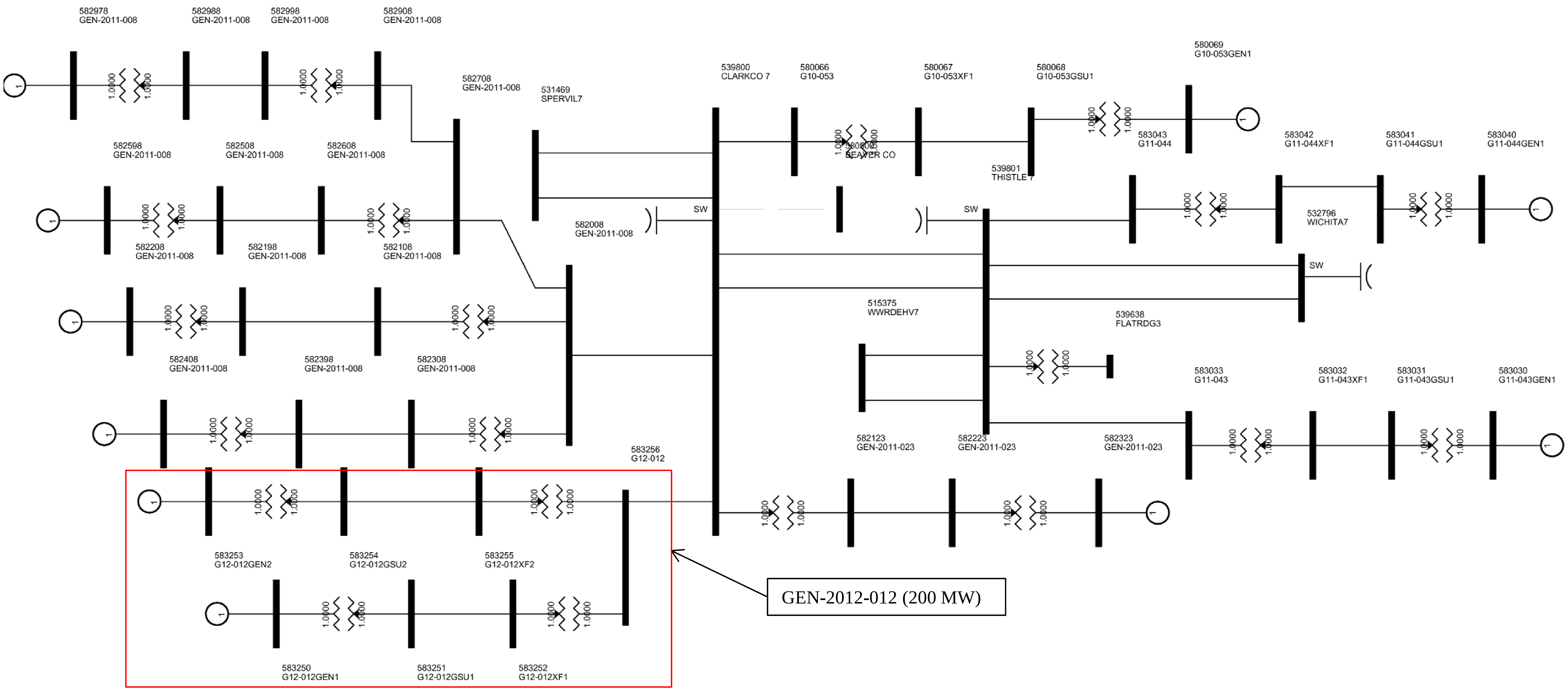

Figure 2-4. Power flow one-line diagram for interconnection project GEN-2012-012 (200 MW).

Table 2-3
Case List with Contingency Description

Ref. No.	Case Name	Description
1	FLT01-3PH	3 phase fault on the G11-017 POI (576704) to Post Rock (530583) 345 kV line, near G11-017 POI. a. Apply fault at the G11-017 POI 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.
2	FLT02-1PH	*Single phase fault and sequence like previous*
3	FLT03-3PH	3 phase fault on the G11-017 POI (576704) to Spearville (531469) 345 kV line, near G11-017 POI. a. Apply fault at the G11-017 POI 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.
4	FLT04-1PH	*Single phase fault and sequence like previous*
5	FLT05-3PH	3 phase fault on the Post Rock (530583) to Axtell (640065) 345 kV line, near Post Rock. a. Apply fault at the Post Rock 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.
6	FLT06-1PH	*Single phase fault and sequence like previous*
7	FLT07-3PH	3 phase fault on the Spearville (531469) to Gray County (579284) 345 kV line, near Spearville. a. Apply fault at the Spearville 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.
8	FLT08-1PH	*Single phase fault and sequence like previous*
9	FLT09-3PH	3 phase fault on the Spearville (531469) to Mullgren (560013) 345 kV line Ckt #1, near Spearville. a. Apply fault at the Spearville 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.
10	FLT10-1PH	*Single phase fault and sequence like previous*
11	FLT11-3H	3 phase fault on the Spearville (531469) to Clark County (539800) 345 kV line Ckt #1, near Spearville. a. Apply fault at the Spearville 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.
12	FLT12-1PH	*Single phase fault and sequence like previous*
13	FLT13-3PH	3 phase fault on the Gray County (579284) to Holcomb (531449) 345 kV line, near Gray County. a. Apply fault at the Gray County 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.
14	FLT14-1PH	*Single phase fault and sequence like previous*

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

Ref. No.	Case Name	Description
15	FLT15-3PH	3 phase fault on the Gray County (579284) to Beaver County (580500) 345 kV line, near Gray County. a. Apply fault at the Gray County 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.
16	FLT16-1PH	*Single phase fault and sequence like previous*
17	FLT17-3PH	3 phase fault on the Thistle (539801) to Woodward (515375) 345 kV line Ckt #1, near Thistle. a. Apply fault at the Thistle 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.
18	FLT18-1PH	*Single phase fault and sequence like previous*
19	FLT19-3PH	3 phase fault on the Thistle (539801) to Wichita (532796) 345 kV line Ckt #1, near Thistle. a. Apply fault at the Thistle 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.
20	FLT20-1PH	*Single phase fault and sequence like previous*
21	FLT21-3PH	3 phase fault on the Thistle (539801) to Clark County (539800) 345 kV line Ckt #1, near Thistle. a. Apply fault at the Thistle 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.
22	FLT22-1PH	*Single phase fault and sequence like previous*
23	FLT23-3PH	3 phase fault on the Thistle (539801) to Woodward (515375) 345 kV line Ckt #1 and #2, near Thistle. a. Apply fault at the Thistle 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.
24	FLT24-3PH	3 phase fault on the Thistle (539801) to Wichita (532796) 345 kV line Ckt #1 and #2, near Thistle. a. Apply fault at the Thistle 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.
25	FLT25-3PH	3 phase fault on the Thistle (539801) to Clark County (539800) 345 kV Line Ckt #1 and #2, near Thistle. a. Apply fault at the Thistle 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.
26	FLT26-3PH	3 phase fault on the Spearville (531469) to Mullgren (560013) 345 kV line Ckt #1 and #2, near Spearville. a. Apply fault at the Spearville 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.

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

Ref. No.	Case Name	Description
27	FLT27-3PH	3 phase fault on the Spearville (531469) to Clark County (539800) 345 kV line Ckt #1 and #2, near Spearville. a. Apply fault at the Spearville 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.
28	FLT28-3PH	3 phase fault on the Thistle (539801) 345 kV to Flatridge (539368) 138 kV xfmr, near the 138 kV bus. a. Apply fault at the Flatridge 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
29	FLT29-3PH	3 phase fault on the Post Rock (530583) 345 kV to Post Rock (530584) 138/13.8 kV xfmr, near the 138 kV bus. a. Apply fault at the Post Rock 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
30	FLT30-3PH	3 phase fault on the Spearville (531469) 345 kV to Spearville (539695) 230/13.8 kV xfmr, near the 230 kV bus. a. Apply fault at the Spearville 230 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
31	FLT31-3PH	3 phase fault on the Hugoton (531481) to Walkemeyer (531405) 115 kV line Ckt #1, near Hugoton. a. Apply fault at the Hugoton 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	FLT32-1PH	*Single phase fault and sequence like previous*
33	FLT33-3PH	3 phase fault on the Hugoton (531481) to Grant Tap (531483) 115 kV line Ckt #1, near Hugoton. a. Apply fault at the Hugoton 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	FLT34-1PH	*Single phase fault and sequence like previous*
35	FLT35-3PH	3 phase fault on the Walkemeyer (531405) to Cimarron (539654) 115 kV line Ckt #1, near Walkemeyer. a. Apply fault at the Walkemeyer 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.
36	FLT36-1PH	*Single phase fault and sequence like previous*
37	FLT37-3PH	3 phase fault on the Walkemeyer (531405) 115 kV to Walkemeyer (531404) 69/13.8 kV xfmr, near the 115 kV bus. a. Apply fault at the Walkemeyer 115 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
38	FLT38-3PH	3 phase fault on the Cimarron (539654) to Seward (531467) 115 kV line Ckt. 1, near Cimarron. a. Apply fault at the Cimarron River Station 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.
39	FLT39-1PH	*Single phase fault and sequence like previous*

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

Ref. No.	Case Name	Description
40	FLT40-3PH	3 phase fault on the Cimarron (539654) to Hayne Tap (539640) 115 kV line Ckt. 1, near Cimarron. a. Apply fault at the Cimarron 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.
41	FLT41-1PH	*Single phase fault and sequence like previous*
42	FLT42-3PH	3 phase fault on the Cimarron (539654) to Cimarron River Tap (539652) 115 kV line Ckt. 1, near Cimarron. a. Apply fault at the Cimarron River Station 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.
43	FLT43-1PH	*Single phase fault and sequence like previous*
44	FLT44-3PH	3 phase fault on the Kismet (539646) to Cudahy (539659) 115 kV line Ckt #1, near Kismet. a. Apply fault at the Kismet 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.
45	FLT45-1PH	*Single phase fault and sequence like previous*
46	FLT46-3PH	3 phase fault on the East Liberal (539672) to Txphsf (523106) 115 kV line, near East Liberal. a. Apply fault at the East Liberal 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	FLT47-1PH	*Single phase fault and sequence like previous*
48	FLT48-3PH	3 phase fault on the GEN-2012-007 (562116) to Satanta (531396) 115 kV line, near GEN-2012-007. a. Apply fault at the GEN-2012-007 115 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	FLT49-1PH	*Single phase fault and sequence like previous*
50	FLT50-3PH	3 phase fault on the GEN-2012-007 (562116) to Hickok (531378) 115 kV line, near GEN-2012-007. a. Apply fault at the GEN-2012-007 115 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	FLT51-1PH	*Single phase fault and sequence like previous*
52	FLT52-3PH	3 phase fault on the GEN-2012-007 (562116) to Amoco (531472) 115 kV line, near GEN-2012-007. a. Apply fault at the GEN-2012-007 115 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	FLT53-1PH	*Single phase fault and sequence like previous*

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

Ref. No.	Case Name	Description
54	FLT54-3PH	3 phase fault on the Hickok (531378) to Amoco (531472) 115 kV line Ckt #1, near Hickok. a. Apply fault at the Hickok 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	FLT55-1PH	*Single phase fault and sequence like previous*
56	FLT56-3PH	3 phase fault on the Hickok (531378) to Pioneer (531391) 115 kV line Ckt #1, near Hickok. a. Apply fault at the Hickok 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	FLT57-1PH	*Single phase fault and sequence like previous*
58	FLT58-3PH	3 phase fault on the Pioneer Tap (531392) to Sat MKEC (531442) 115 kV line Ckt #1, near Pioneer Tap. a. Apply fault at the Pioneer 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.
59	FLT59-1PH	*Single phase fault and sequence like previous*
60	FLT60-3PH	3 phase fault on the Pioneer Tap (531392) to Plymell (531393) 115 kV line Ckt #1, near Pioneer Tap. a. Apply fault at the Pioneer 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.
61	FLT61-1PH	*Single phase fault and sequence like previous*
62	FLT62-3PH	3 phase fault on the Plymell (531393) to Holcomb (531448) 115 kV line Ckt #1, near Pioneer Tap. a. Apply fault at the Plymell 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.
63	FLT63-1PH	*Single phase fault and sequence like previous*
64	FLT64-3PH	3 phase fault on the Pioneer (531391) to PK GOAB (531400) 115 kV line Ckt #1, near Pioneer. a. Apply fault at the Pioneer 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	FLT65-1PH	*Single phase fault and sequence like previous*
66	FLT66-3PH	3 phase fault on the Pioneer (531391) to Grant Tap (531483) 115 kV line Ckt #1, near Pioneer. a. Apply fault at the Pioneer 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	FLT67-1PH	*Single phase fault and sequence like previous*

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

Ref. No.	Case Name	Description
68	FLT68-3PH	3 phase fault on the Pioneer (531391) 115 kV to Pioneer (531390) 69 kV/13.8 kV xfmr, near the 115 kV bus.
		a. Apply fault at the Pioneer 115 kV bus.
		b. Clear fault after 5 cycles by tripping the faulted transformer.
69	FLT69-3PH	3 phase fault on the ULYSPLT (531490) to Big Bow (531491) 115 kV line Ckt #1, near ULYSPLT.
		a. Apply fault at the ULSYSPLT 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	FLT70-1PH	*Single phase fault and sequence like previous*
71	FLT71-3PH	3 phase fault on the Fletcher (531420) to Holcomb (531448) 115 kV line Ckt #1, near Fletcher.
		a. Apply fault at the Fletcher 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	FLT72-1PH	*Single phase fault and sequence like previous*

SECTION 3: POWER FACTOR ANALYSIS

The objective of this task is to quantify the power factor at the point of interconnection for the wind farms during base case and system contingencies. SPP transmission planning practice determines the requirements for wind farm generation interconnection projects by studying them to maintain a voltage schedule at the Point of Interconnection (POI) for system intact and post contingency conditions. This is analyzed by having the wind farm maintain a prescribed voltage schedule at the point of interconnection of 1.0 p.u. voltage, or if the pre-project voltage is higher than 1.0 p.u., to maintain the pre-project voltage schedule.

Both winter peak and summer peak power flows provided by SPP were examined prior to the Power Factor Analysis to ensure they contained the proposed study project modeled at 100% of the nameplate rating and any previously queued projects listed in Table 2-2. There was no suspect power flow data in the study area. The proposed study project and any previously queued projects at the same point of interconnection were turned off during the power factor analysis. The wind farm(s) were then replaced by a generator modeled at the high side bus with the same real power (MW) capability as the wind farm(s) and open limits for the reactive power set points (Mvar). The generator was set to hold the POI scheduled bus voltage. Contingencies from the three-phase fault definitions provided in Table 2-3 were then applied and the reactive power required to maintain the bus voltage was recorded.

Note that Case 1 does not initially converge. After discussion with SPP, it was determined that a second 345 kV circuit should be added from G11-017 POI 345 kV (576704) to Post Rock 345 kV (530583). Case 1, both summer and winter peak seasons, was the only case to be simulated with this additional line; all other cases were simulated without the additional circuit.

3.1 Study Project – GEN-2012-011

Approach

The study project (GEN-2012-011) and two previous queued projects (GEN-2010-061 and GEN-2011-017) share the same POI (Tap on the Spearville to Post Rock 345 kV line – Bus 576704). These projects were disabled and two generators were placed at the study project's high side bus, one was modeled with PGEN = 200 MW (GEN-2012-011), QMin = -9999 Mvar, and QMax = 9999 Mvar and the other generator was modeled with PGEN = 478.4 MW (GEN-2010-061 and GEN-2011-017), QMin = -9999 Mvar, and QMax = 9999 Mvar. All buses and transformers connected from the study project's high side bus to the corresponding generators were disabled. The pre-project voltage at the POI (G11-017 345 kV bus – 576704) for the summer peak conditions is 0.9653 p.u. and for the winter peak conditions is 0.9802 p.u.. Therefore, the scheduled voltage for the POI was set to 1.00 p.u. for summer and winter peak conditions.

Results

The power factor was calculated for summer and winter peak conditions. Table 3-1 shows the power factor results for GEN-2012-011 (200 MW). Note that a positive Q (Mvar) output illustrates that the generator is absorbing reactive power from the system, implying a leading power factor; a negative Q (Mvar) illustrates that the generator is supplying reactive power to the system, implying a lagging power factor.

Table 3-1
Power Factor Analysis: GEN-2012-011 (P_{GEN}=200 MW)*

Case	Summer Peak			Winter Peak		
	Power Factor		Q** (MVAR)	Power Factor		Q** (MVAR)
Base	0.9367	Lagging	-74.756	0.9398	Lagging	-72.714
C1[1]	0.9405	Lagging	-72.273	0.9398	Lagging	-72.714
C3	0.9912	Lagging	-26.704	0.9887	Lagging	-30.343
C5	0.9367	Lagging	-74.756	0.9398	Lagging	-72.714
C7	0.9043	Lagging	-94.438	0.9045	Lagging	-94.319
C9	0.9014	Lagging	-96.058	0.9045	Lagging	-94.309
C11	0.9337	Lagging	-76.681	0.9378	Lagging	-74.015
C13	0.9278	Lagging	-80.439	0.9322	Lagging	-77.656
C15	0.8862	Lagging	-104.536	0.8884	Lagging	-103.358
C17	0.9274	Lagging	-80.658	0.9274	Lagging	-80.661
C19	0.9007	Lagging	-96.448	0.8988	Lagging	-97.521
C21	0.8731	Lagging	-111.682	0.8759	Lagging	-110.184
C28	0.9367	Lagging	-74.768	0.9400	Lagging	-72.593
C29	0.9349	Lagging	-75.901	0.9365	Lagging	-74.891
C30	0.9374	Lagging	-74.284	0.9398	Lagging	-72.754
C31	0.9367	Lagging	-74.736	0.9399	Lagging	-72.674
C33	0.9367	Lagging	-74.774	0.9397	Lagging	-72.766
C35	0.9367	Lagging	-74.768	0.9398	Lagging	-72.726
C37	0.9367	Lagging	-74.756	0.9398	Lagging	-72.714
C38	0.9368	Lagging	-74.714	0.9399	Lagging	-72.668
C40	0.9364	Lagging	-74.972	0.9396	Lagging	-72.828
C42	0.9366	Lagging	-74.836	0.9397	Lagging	-72.787
C44	0.9336	Lagging	-76.736	0.9368	Lagging	-74.714
C46	0.9366	Lagging	-74.813	0.9398	Lagging	-72.720
C48	0.9366	Lagging	-74.843	0.9397	Lagging	-72.806
C50	0.9367	Lagging	-74.759	0.9398	Lagging	-72.718
C52	0.9367	Lagging	-74.748	0.9398	Lagging	-72.727
C54	0.9367	Lagging	-74.743	0.9398	Lagging	-72.708
C56	0.9366	Lagging	-74.829	0.9397	Lagging	-72.811
C58	0.9367	Lagging	-74.766	0.9398	Lagging	-72.739
C60	0.9368	Lagging	-74.675	0.9400	Lagging	-72.568
C62	0.9368	Lagging	-74.670	0.9401	Lagging	-72.552
C64	0.9368	Lagging	-74.696	0.9399	Lagging	-72.657
C66	0.9367	Lagging	-74.782	0.9397	Lagging	-72.770
C68	0.9367	Lagging	-74.756	0.9398	Lagging	-72.714
C69	0.9366	Lagging	-74.832	0.9398	Lagging	-72.753
C71	0.9366	Lagging	-74.825	0.9399	Lagging	-72.644

Note 1: Case 1 was simulated with a second circuit added from G11-017 POI to Post Rock 345 kV.
*The scheduled voltage for the POI (Tap on Spearville - Post Rock 345 kV) was 1.00 p.u. for summer peak and winter peak conditions.
**A positive Q (Mvar) output illustrates the generator is absorbing Mvars from the system, which implies a leading power factor; negative Q (Mvar) output shows the generator is supplying Mvars to the system implying a lagging power factor.

Summary

The Power Factor Analysis shows that GEN-2012-011 has a power factor requirement of 0.8731 to 0.9912 lagging (supplying).

3.2 Study Project – GEN-2012-012

Approach

The study project (GEN-2012-012) and three previous queued project (GEN-2010-053, GEN-2011-008, and GEN-2011-023) share the same POI (Clark County 345 kV bus – 539800). These projects were disabled and two generators were placed at the study project's high side bus, one was modeled with PGEN = 200 MW (GEN-2012-012), QMin = -9999 Mvar, and QMax = 9999 Mvar and the other generator was modeled with PGEN = 1098.8 MW (GEN-2010-053, GEN-2011-008, GEN-2011-023), QMin = -9999 Mvar, and QMax = 9999 Mvar. All buses and transformers connected from the study project's and queued project's high side bus to the corresponding generators were disabled. The pre-project voltage at the POI (Clark County 345 kV bus – 539800) for the summer peak conditions is 0.967 p.u. and for the winter peak conditions is 0.968 p.u.. Therefore, the scheduled voltage for the POI was set to 1.00 p.u. for summer and winter peak conditions.

Results

The power factor was calculated for summer and winter peak conditions. Table 3-2 shows the power factor results for GEN-2012-012 (200 MW). Note that a positive Q (Mvar) output illustrates that the generator is absorbing reactive power from the system, implying a leading power factor; a negative Q (Mvar) illustrates that the generator is supplying reactive power to the system, implying a lagging power factor.

Table 3-2
Power Factor Analysis: GEN-2012-012 (P_{GEN}=200 MW)*

Case	Summer Peak			Winter Peak		
	Power Factor		Q** (MVAR)	Power Factor		Q** (MVAR)
Base	0.9524	Lagging	-64.028	0.9514	Lagging	-64.743
C1[1]	0.9520	Lagging	-64.316	0.9534	Lagging	-63.304
C3	0.9423	Lagging	-71.086	0.9354	Lagging	-75.620
C5	0.9524	Lagging	-64.028	0.9514	Lagging	-64.743
C7	0.9307	Lagging	-78.629	0.9310	Lagging	-78.435
C9	0.9256	Lagging	-81.762	0.9256	Lagging	-81.806
C11	0.9576	Lagging	-60.191	0.9534	Lagging	-63.309
C13	0.9464	Lagging	-68.230	0.9469	Lagging	-67.899
C15	0.9084	Lagging	-92.073	0.9076	Lagging	-92.498
C17	0.9407	Lagging	-72.120	0.9368	Lagging	-74.710
C19	0.9450	Lagging	-69.207	0.9447	Lagging	-69.431
C21	0.9142	Lagging	-88.640	0.9180	Lagging	-86.386
C28	0.9512	Lagging	-64.909	0.9505	Lagging	-65.365
C29	0.9516	Lagging	-64.613	0.9508	Lagging	-65.150
C30	0.9547	Lagging	-62.320	0.9532	Lagging	-63.411
C31	0.9524	Lagging	-64.028	0.9514	Lagging	-64.742
C33	0.9523	Lagging	-64.089	0.9513	Lagging	-64.833
C35	0.9524	Lagging	-64.039	0.9513	Lagging	-64.807
C37	0.9524	Lagging	-64.028	0.9514	Lagging	-64.743
C38	0.9524	Lagging	-64.045	0.9513	Lagging	-64.775
C40	0.9521	Lagging	-64.258	0.9512	Lagging	-64.868
C42	0.9523	Lagging	-64.090	0.9513	Lagging	-64.798
C44	0.9500	Lagging	-65.702	0.9491	Lagging	-66.363
C46	0.9523	Lagging	-64.078	0.9513	Lagging	-64.800
C48	0.9523	Lagging	-64.105	0.9513	Lagging	-64.837
C50	0.9524	Lagging	-64.030	0.9514	Lagging	-64.746
C52	0.9524	Lagging	-64.019	0.9514	Lagging	-64.751
C54	0.9524	Lagging	-64.017	0.9514	Lagging	-64.736
C56	0.9523	Lagging	-64.073	0.9513	Lagging	-64.813
C58	0.9523	Lagging	-64.124	0.9512	Lagging	-64.864
C60	0.9524	Lagging	-64.013	0.9515	Lagging	-64.639
C62	0.9524	Lagging	-64.019	0.9515	Lagging	-64.631
C64	0.9524	Lagging	-63.993	0.9515	Lagging	-64.696
C66	0.9523	Lagging	-64.103	0.9513	Lagging	-64.841
C68	0.9524	Lagging	-64.028	0.9514	Lagging	-64.743
C69	0.9523	Lagging	-64.072	0.9514	Lagging	-64.762
C71	0.9523	Lagging	-64.081	0.9515	Lagging	-64.683

Note 1: Case 1 was simulated with a second circuit added from G11-017 POI to Post Rock 345 kV.

*The scheduled voltage for the POI (Clark County 345 kV) was 1.00 p.u. for summer peak and winter peak conditions.

**A positive Q (Mvar) output illustrates the generator is absorbing Mvars from the system, which implies a leading power factor; negative Q (Mvar) output shows the generator is supplying Mvars to the system implying a lagging power factor.

Summary

The Power Factor Analysis shows that GEN-2012-012 has a power factor requirement of 0.9076 to 0.9576 lagging (supplying).

3.3 Overall Summary

The Power Factor Analysis shows that GEN-2012-011 has a power factor requirement of 0.8731 to 0.9912 lagging (supplying) and GEN-2012-012 has a power factor requirement of 0.9076 to 0.9576 lagging (supplying).

SECTION 4: STABILITY ANALYSIS

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

Approach

Both winter peak and summer peak power flows provided by SPP were examined prior to the Stability Analysis to ensure they contained the proposed study projects (GEN-2012-003, GEN-2012-007, GEN-2012-011, and GEN-2012-012) modeled at 100% of the nameplate rating and any previously queued projects listed in Table 2-2. There was no suspect power flow data in the study area. The dynamic datasets were also verified and stable initial system conditions (i.e., “flat lines”) were achieved. Three-phase and single line-to-ground faults listed in Table 2-3 were examined. Single-phase fault impedances were calculated to result in a voltage of approximately 60% of the pre-fault voltage. Refer to Table 4-1 for a list of the calculated single-phase fault impedances used for this analysis.

Table 4-1
Calculated Single-Phase Fault Impedances

Ref. No.	Casename	Single-Phase Fault Impedance (MVA)	
		Summer Peak	Winter Peak
1	FLT02-1PH	-3625.0	-3625.0
2	FLT04-1PH	-3625.0	-3625.0
3	FLT06-1PH	-3218.8	-3015.6
4	FLT08-1PH	-6875.0	-6875.0
5	FLT10-1PH	-6875.0	-6875.0
6	FLT12-1PH	-6875.0	-6875.0
7	FLT14-1PH	-5250.0	-5250.0
8	FLT16-1PH	-5250.0	-5250.0
9	FLT18-1PH	-5250.0	-4843.8
10	FLT20-1PH	-5250.0	-4843.8
11	FLT22-1PH	-5250.0	-4843.8
12	FLT32-1PH	-468.8	-468.8
13	FLT34-1PH	-468.8	-468.8
14	FLT36-1PH	-468.8	-437.5
15	FLT39-1PH	-750.0	-625.0
16	FLT41-1PH	-750.0	-625.0
17	FLT43-1PH	-750.0	-625.0
18	FLT45-1PH	-625.0	-531.3
19	FLT47-1PH	-625.0	-531.3
20	FLT49-1PH	-937.5	-875.0
21	FLT51-1PH	-937.5	-875.0
22	FLT53-1PH	-937.5	-875.0
23	FLT55-1PH	-875.0	-812.5
24	FLT57-1PH	-875.0	-812.5
25	FLT59-1PH	-875.0	-875.0
26	FLT61-1PH	-875.0	-875.0
27	FLT63-1PH	-1062.5	-1000.0
28	FLT65-1PH	-812.5	-781.3
29	FLT67-1PH	-812.5	-781.3
30	FLT70-1PH	-562.5	-562.5
31	FLT72-1PH	-1000.0	-937.5

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

- 520 AEPW
- 524 OKGE
- 525 WFEC
- 526 SPS
- 531 MIDW
- 534 SUNC
- 536 WERE
- 640 NPPD
- 645 OPPD
- 650 LES
- 652 WAPA

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

Results

Refer to Table 4-2 for a summary of the Stability Analysis results for the cases listed in Table 2-3. The initial simulations were run for summer and winter peak conditions. There were several contingencies that initially had a prior queued project (GEN-2011-016) tripping offline because of the under voltage trip relay. These contingencies included:

- Contingency #1: 3 phase fault on the G11-017 POI to Post Rock 345 kV line
- Contingency #2: 1 phase fault on the G11-017 POI to Post Rock 345 kV line
- Contingency #5: 3 phase fault on the Post Rock to Axtell 345 kV line
- Contingency #6: 1 phase fault on the Post Rock to Axtell 345 kV line
- Contingency #7: 3 phase fault on the Spearville to Gray County 345 kV line
- Contingency #8: 1 phase fault on the Spearville to Gray County 345 kV line
- Contingency #15: 3 phase fault on the Gray County to Beaver County 345 kV line
- Contingency #16: 1 phase fault on the Gray County to Beaver County 345 kV line

- Contingency #21: 3 phase fault on the Thistle to Clark 345 kV line, Ckt #1
- Contingency #22: 1 phase fault on the Thistle to Clark 345 kV line, Ckt #1
- Contingency #23: 3 phase fault on the Thistle to Woodward 345 kV line, Ckt #1 and #2
- Contingency #24: 3 phase fault on the Thistle to Wichita 345 kV line, Ckt #1
- Contingency #25: 3 phase fault on the Thistle to Clark 345 kV line, Ckt #1 and #2
- Contingency #26: 3 phase fault on the Spearville to Mullergren 345 kV line, Ckt #1, #2

For all of these contingencies, the voltage and frequency relays for GEN-2011-016 were disabled. It was determined that there were no wind turbine tripping or instability for all of these contingencies except for Contingencies # 25 and #26 for the Summer Peak and Winter Peak case and Contingency #1 and #2 for the Winter Peak season only. For this set of contingencies, GEN-2012-012 tripped offline due to the under voltage trip relay. Contingencies #25 and #26 are double line outages and are listed here for SPP's reference. Refer to plots of the generator's response and system voltages in Appendix B and Appendix C for the Summer Peak and Winter Peak cases, respectively.

Based on the Power Factor Analysis, Contingency #1 and #2 were simulated with the additional 345 kV line from G11-017 POI (576704) to Post Rock 345 kV (530583). After implementing this solution, the system remained stable for these two cases with acceptable voltages and no wind turbine tripping. Note that without the addition of the G11-017 POI to Post Rock 345 kV line, 2 x 10 Mvar capacitor banks are required at the GEN-2012-012 high side voltage bus (Bus 583252 and Bus 583255). The addition of the G11-017 POI to Post Rock 345 kV line mitigates the need for the 2 x 10 Mvar capacitor banks and GEN-2011-016 no longer trips offline for Contingency #1 and Contingency #2 during the Summer and Winter Peak seasons.

Figure 4-1 shows the response of GEN-2012-012 (Gen 1) wind farm during a three-phase fault on the G11-017 POI to Post Rock 345 kV line without any mitigation for Winter Peak conditions (Contingency #1: FLT01-3PH). Figures 4-2 through 4-5 show the response of the GEN-2012-012 (Gen 1) wind farm, GEN-2012-003 generation, GEN-2012-007 (Gen 1) generation, and GEN-2012-011 wind farm, respectively, for the same fault (Contingency #1) with the additional G11-017 POI to Post Rock 345 kV line. Figure 4-6 and Figure 4-7 shows selected bus voltages in the study area during Contingency #1 (FLT01-3PH) which is a representative case for the "most severe" voltage dip for Winter Peak conditions.

Figures 4-8 through 4-11 show the response of the GEN-2012-003 generation, GEN-2012-007 (Gen 1) generation, GEN-2012-011 wind farm, and GEN-2012-012 (Gen 1) wind farm for Contingency #1 (FLT01-3PH) during Summer Peak conditions with the additional 345 kV line. Figure 4-12 and Figure 4-13 shows selected bus voltages in the study area during Contingency #1 (FLT01-3PH) which is a representative case for the "most severe" voltage dip for Summer Peak conditions.

Table 4-2
Stability Analysis Summary of Results

Ref. No.	Casename	Summer		Winter	
		Stable?	Acceptable Voltages?	Stable?	Acceptable Voltages?
1	FLT01-3PH	Yes[3]	Yes	Yes[3]	Yes
2	FLT02-1PH	Yes[3]	Yes	Yes[3]	Yes
3	FLT03-3PH	Yes	Yes	Yes	Yes
4	FLT04-1PH	Yes	Yes	Yes	Yes
5	FLT05-3PH	Yes[1]	Yes	Yes	Yes
6	FLT06-1PH	Yes[1]	Yes	Yes	Yes
7	FLT07-3PH	Yes[1]	Yes	Yes[1]	Yes
8	FLT08-1PH	Yes[1]	Yes	Yes[1]	Yes
9	FLT09-3PH	Yes	Yes	Yes	Yes
10	FLT10-1PH	Yes	Yes	Yes	Yes
11	FLT11-3PH	Yes	Yes	Yes	Yes
12	FLT12-1PH	Yes	Yes	Yes	Yes
13	FLT13-3PH	Yes	Yes	Yes	Yes
14	FLT14-1PH	Yes	Yes	Yes	Yes
15	FLT15-3PH	Yes[1]	Yes	Yes[1]	Yes
16	FLT16-1PH	Yes[1]	Yes	Yes[1]	Yes
17	FLT17-3PH	Yes	Yes	Yes	Yes
18	FLT18-1PH	Yes	Yes	Yes	Yes
19	FLT19-3PH	Yes	Yes	Yes	Yes
20	FLT20-1PH	Yes	Yes	Yes	Yes
21	FLT21-3PH	Yes[1]	Yes	Yes[1]	Yes
22	FLT22-1PH	Yes[1]	Yes	Yes[1]	Yes
23	FLT23-3PH	Yes[1]	Yes	Yes[1]	Yes
24	FLT24-3PH	Yes[1]	Yes	Yes[1]	Yes
25	FLT25-3PH	Yes[2]	Yes	Yes[2]	Yes
26	FLT26-3PH	Yes[2]	Yes	Yes[2]	Yes

[1]No wind turbine tripping or system instability after disabling voltage tripping relay for GEN-2011-016

[2]After disabling voltage tripping relay for GEN-2011-016, GEN-2012-012 trips due to under voltage relay without any mitigation

[3]No wind turbine tripping or system instability with the addition of the G11-017 POI to Post Rock 345 kV line, circuit #2

Table 4-2 (Continued)
Stability Analysis Summary of Results

Ref. No.	Casename	Summer		Winter	
		Stable?	Acceptable Voltages?	Stable?	Acceptable Voltages?
27	FLT27-3PH	Yes	Yes	Yes	Yes
28	FLT28-3PH	Yes	Yes	Yes	Yes
29	FLT29-3PH	Yes	Yes	Yes	Yes
30	FLT30-3PH	Yes	Yes	Yes	Yes
31	FLT31-3PH	Yes	Yes	Yes	Yes
32	FLT32-1PH	Yes	Yes	Yes	Yes
33	FLT33-3PH	Yes	Yes	Yes	Yes
34	FLT34-1PH	Yes	Yes	Yes	Yes
35	FLT35-3PH	Yes	Yes	Yes	Yes
36	FLT36-1PH	Yes	Yes	Yes	Yes
37	FLT37-3PH	Yes	Yes	Yes	Yes
38	FLT38-3PH	Yes	Yes	Yes	Yes
39	FLT39-1PH	Yes	Yes	Yes	Yes
40	FLT40-3PH	Yes	Yes	Yes	Yes
41	FLT41-1PH	Yes	Yes	Yes	Yes
42	FLT42-3PH	Yes	Yes	Yes	Yes
43	FLT43-1PH	Yes	Yes	Yes	Yes
44	FLT44-3PH	Yes	Yes	Yes	Yes
45	FLT45-1PH	Yes	Yes	Yes	Yes
46	FLT46-3PH	Yes	Yes	Yes	Yes
47	FLT47-1PH	Yes	Yes	Yes	Yes
48	FLT48-3PH	Yes	Yes	Yes	Yes
49	FLT49-1PH	Yes	Yes	Yes	Yes
50	FLT50-3PH	Yes	Yes	Yes	Yes
51	FLT51-1PH	Yes	Yes	Yes	Yes
52	FLT52-3PH	Yes	Yes	Yes	Yes
53	FLT53-1PH	Yes	Yes	Yes	Yes

Table 4-2 (Continued)
Stability Analysis Summary of Results

Ref. No.	Casename	Summer		Winter	
		Stable?	Acceptable Voltages?	Stable?	Acceptable Voltages?
54	FLT54-3PH	Yes	Yes	Yes	Yes
55	FLT55-1PH	Yes	Yes	Yes	Yes
56	FLT56-3PH	Yes	Yes	Yes	Yes
57	FLT57-1PH	Yes	Yes	Yes	Yes
58	FLT58-3PH	Yes	Yes	Yes	Yes
59	FLT59-3PH	Yes	Yes	Yes	Yes
60	FLT60-3PH	Yes	Yes	Yes	Yes
61	FLT61-1PH	Yes	Yes	Yes	Yes
62	FLT62-3PH	Yes	Yes	Yes	Yes
63	FLT63-1PH	Yes	Yes	Yes	Yes
64	FLT64-3PH	Yes	Yes	Yes	Yes
65	FLT65-1PH	Yes	Yes	Yes	Yes
66	FLT66-3PH	Yes	Yes	Yes	Yes
67	FLT67-1PH	Yes	Yes	Yes	Yes
68	FLT68-3PH	Yes	Yes	Yes	Yes
69	FLT69-3PH	Yes	Yes	Yes	Yes
70	FLT70-1PH	Yes	Yes	Yes	Yes
71	FLT71-3PH	Yes	Yes	Yes	Yes
72	FLT72-1PH	Yes	Yes	Yes	Yes

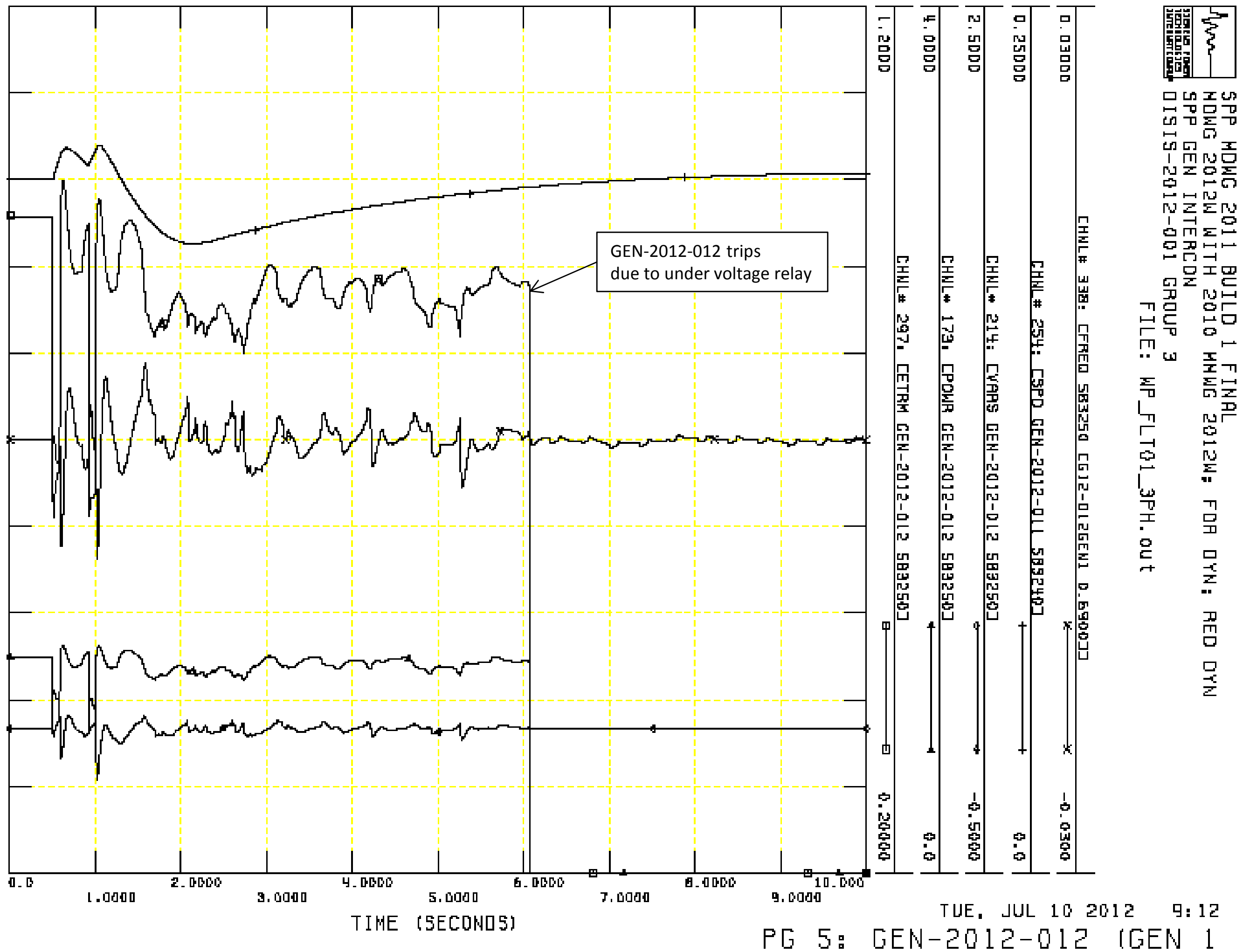

Figure 4-1. Response of GEN-2012-012 (Gen1) project during Contingency #1 (FLT01-3PH) for winter peak conditions without mitigation.

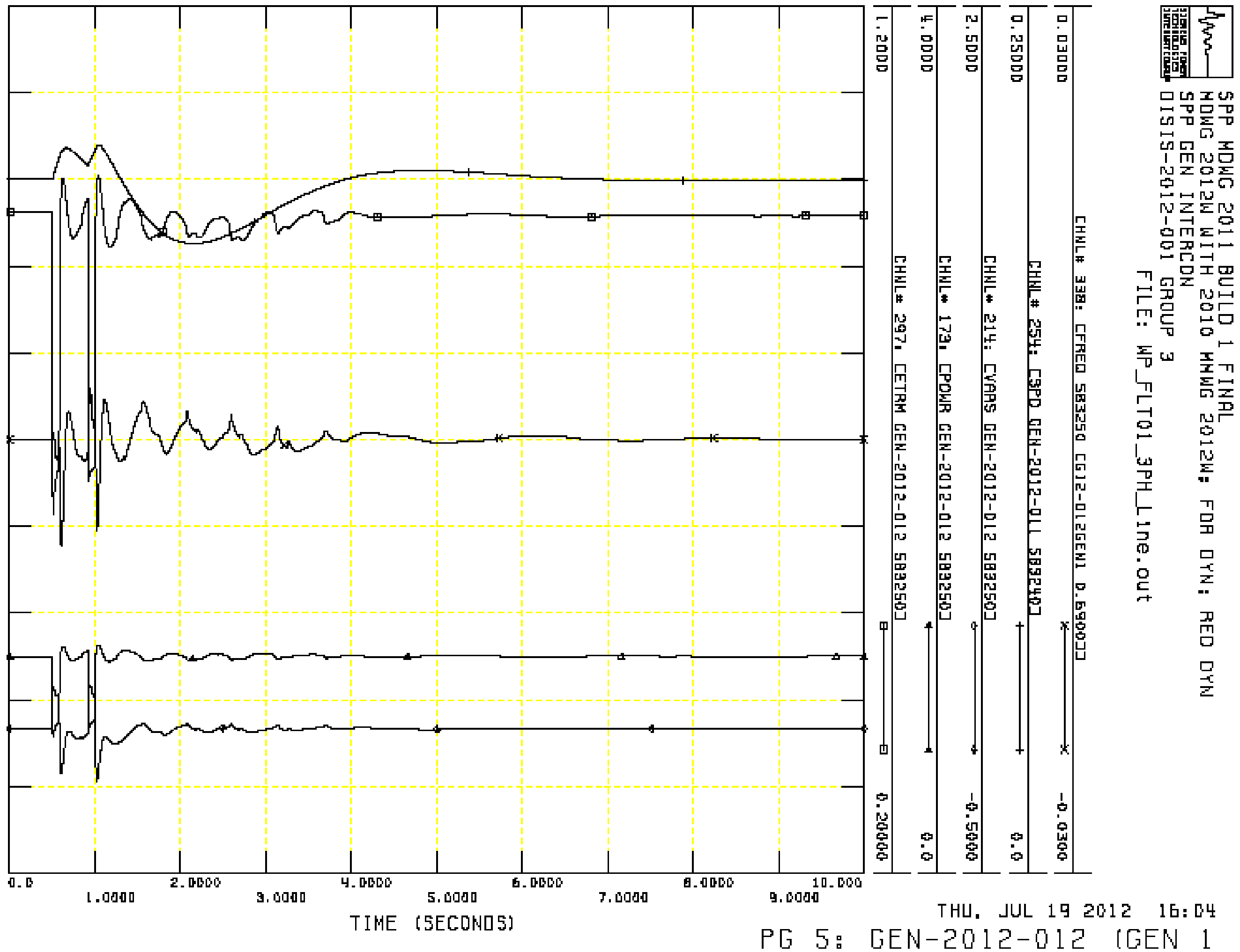

Figure 4-2. Response of GEN-2012-012 project during Contingency #1 for winter peak conditions with the additional 345 kV line.

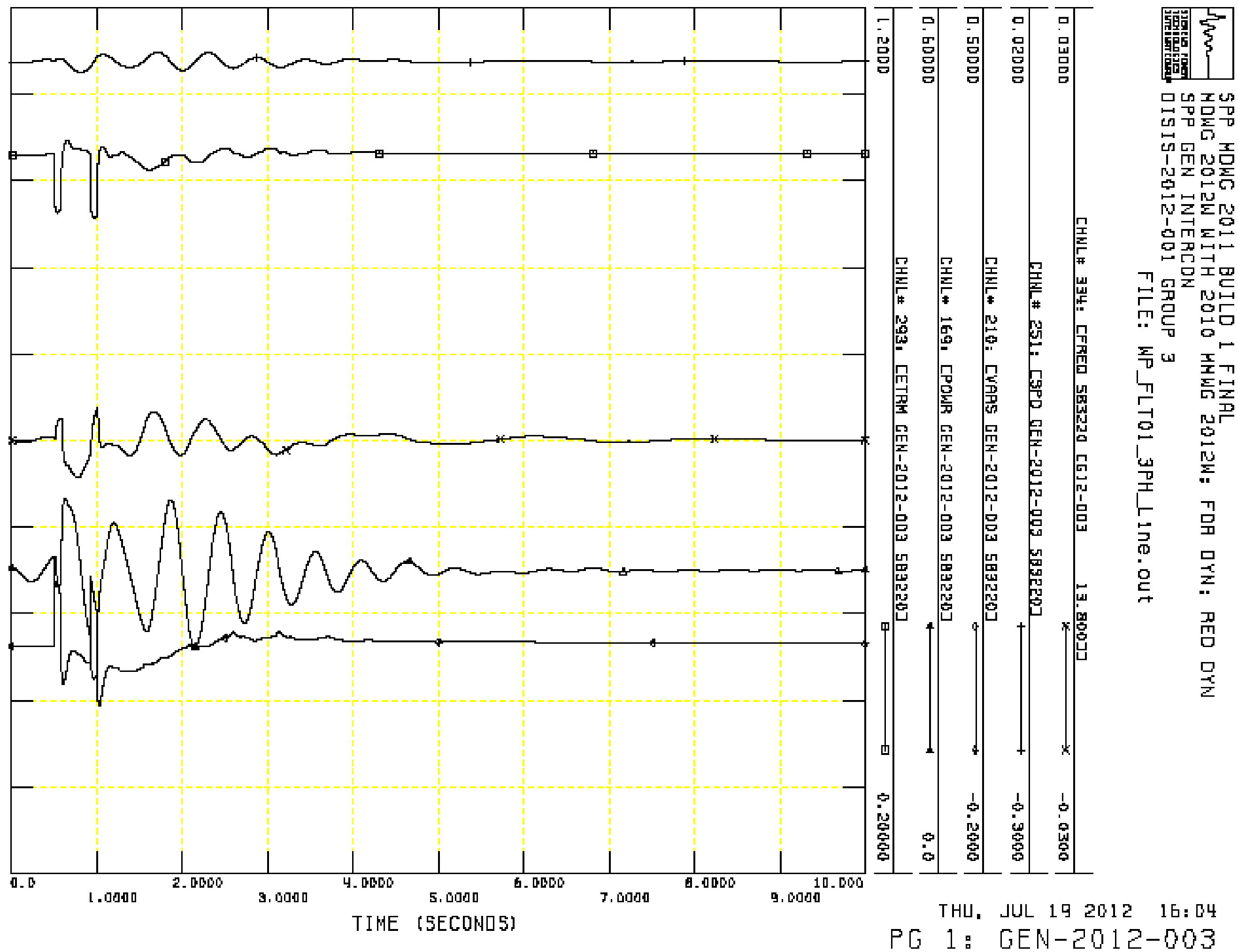

Figure 4-3. Response of GEN-2012-003 project during Contingency #1 for winter peak conditions with the additional 345 kV line.

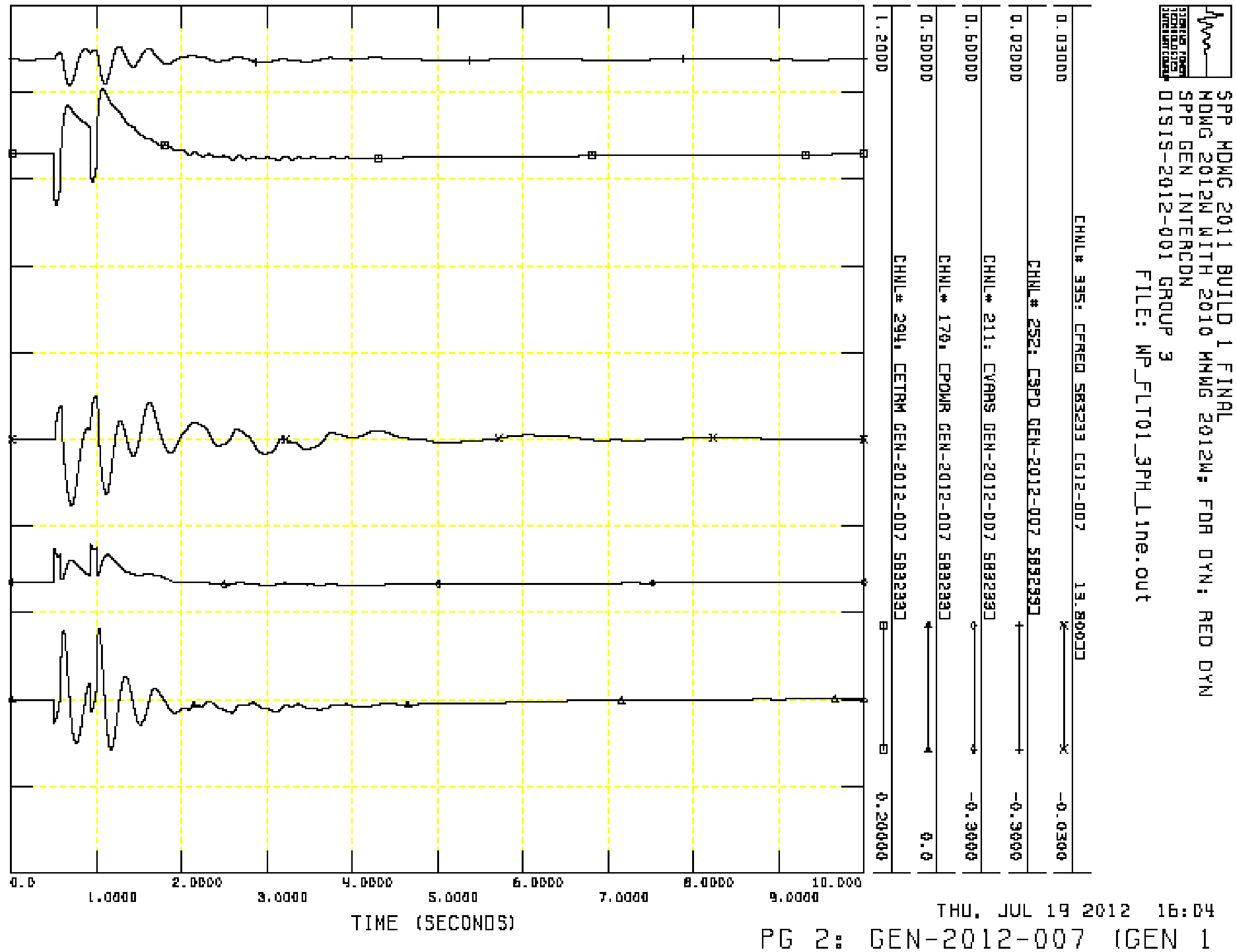

Figure 4-4. Response of GEN-2012-007 project during Contingency #1 for winter peak conditions with the additional 345 kV line.

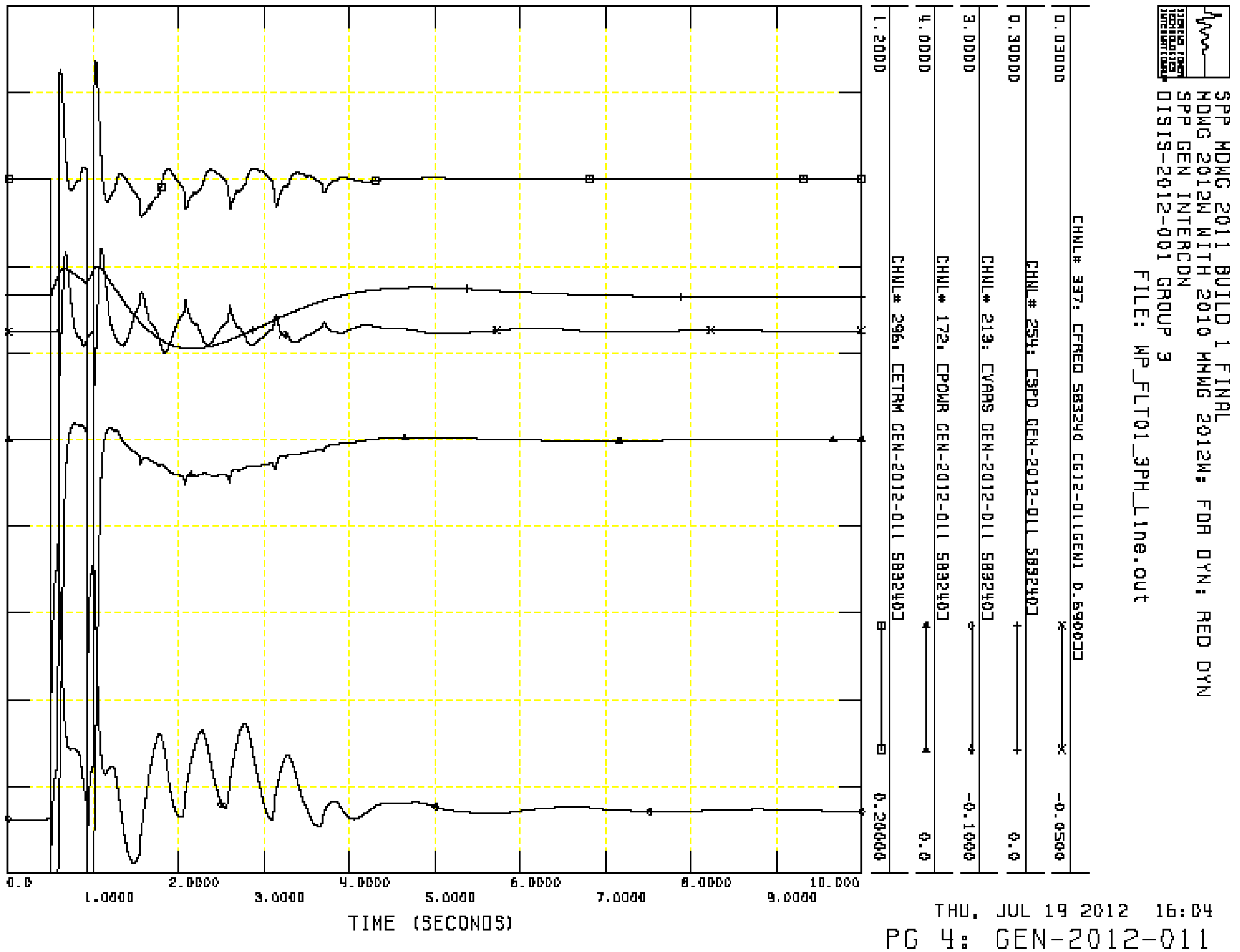

Figure 4-5. Response of GEN-2012-011 project during Contingency #1 for winter peak conditions with the additional 345 kV line.

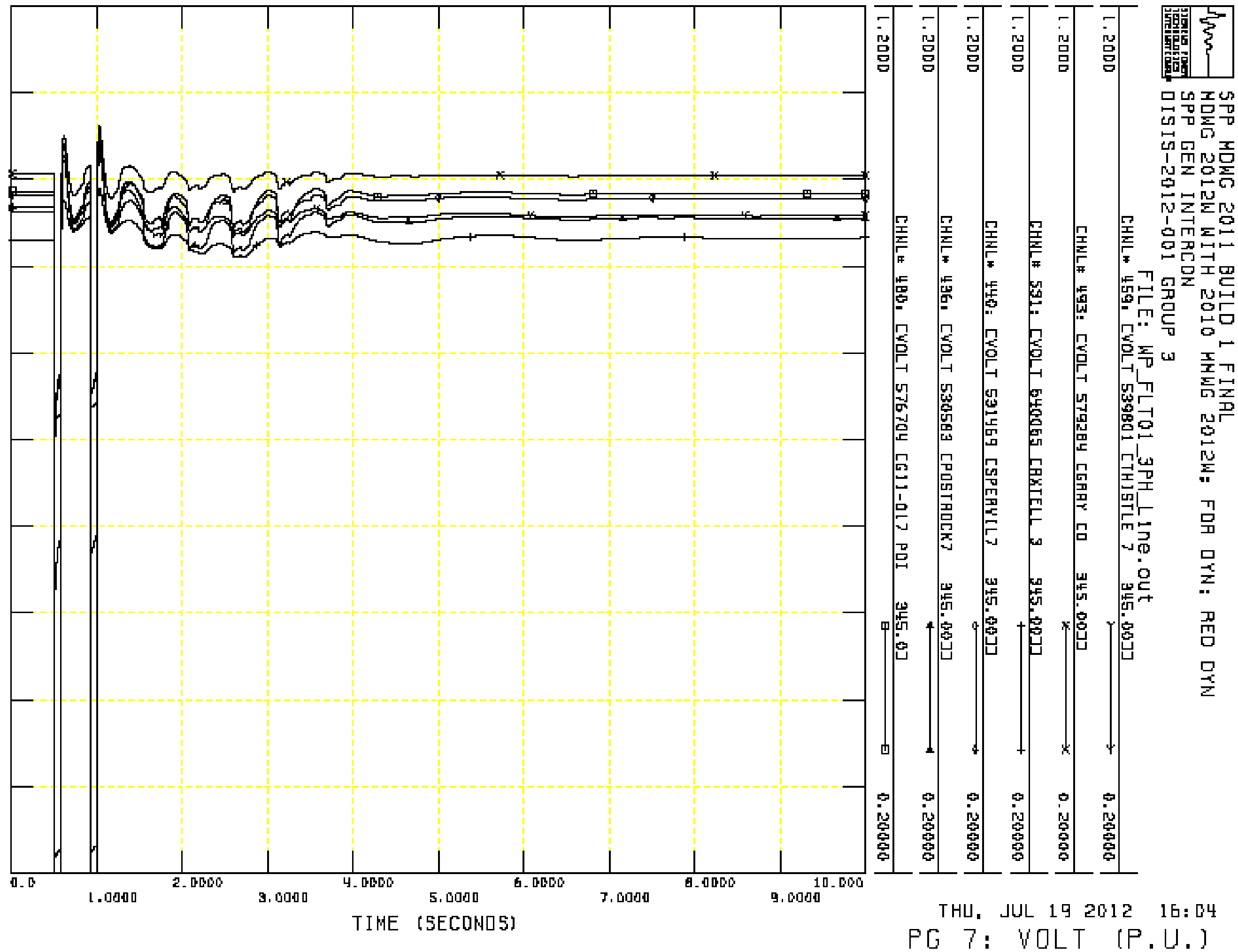

Figure 4-6. Response of selected area 345 kV bus voltages for Contingency #1 for winter peak conditions with the additional 345 kV line.

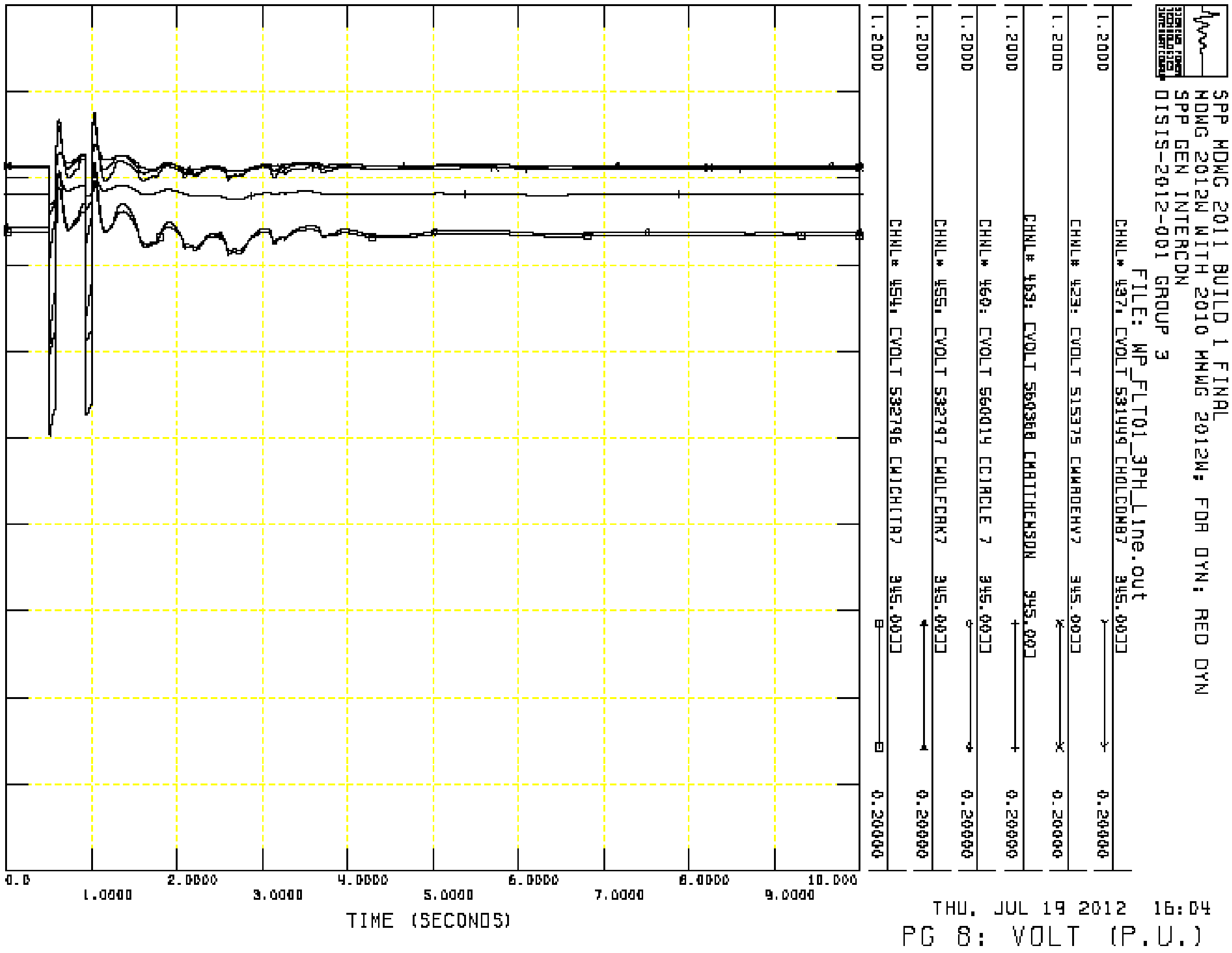

Figure 4-7. Response of selected area 345 kV bus voltages for Contingency #1 for winter peak conditions with the additional 345 kV line.

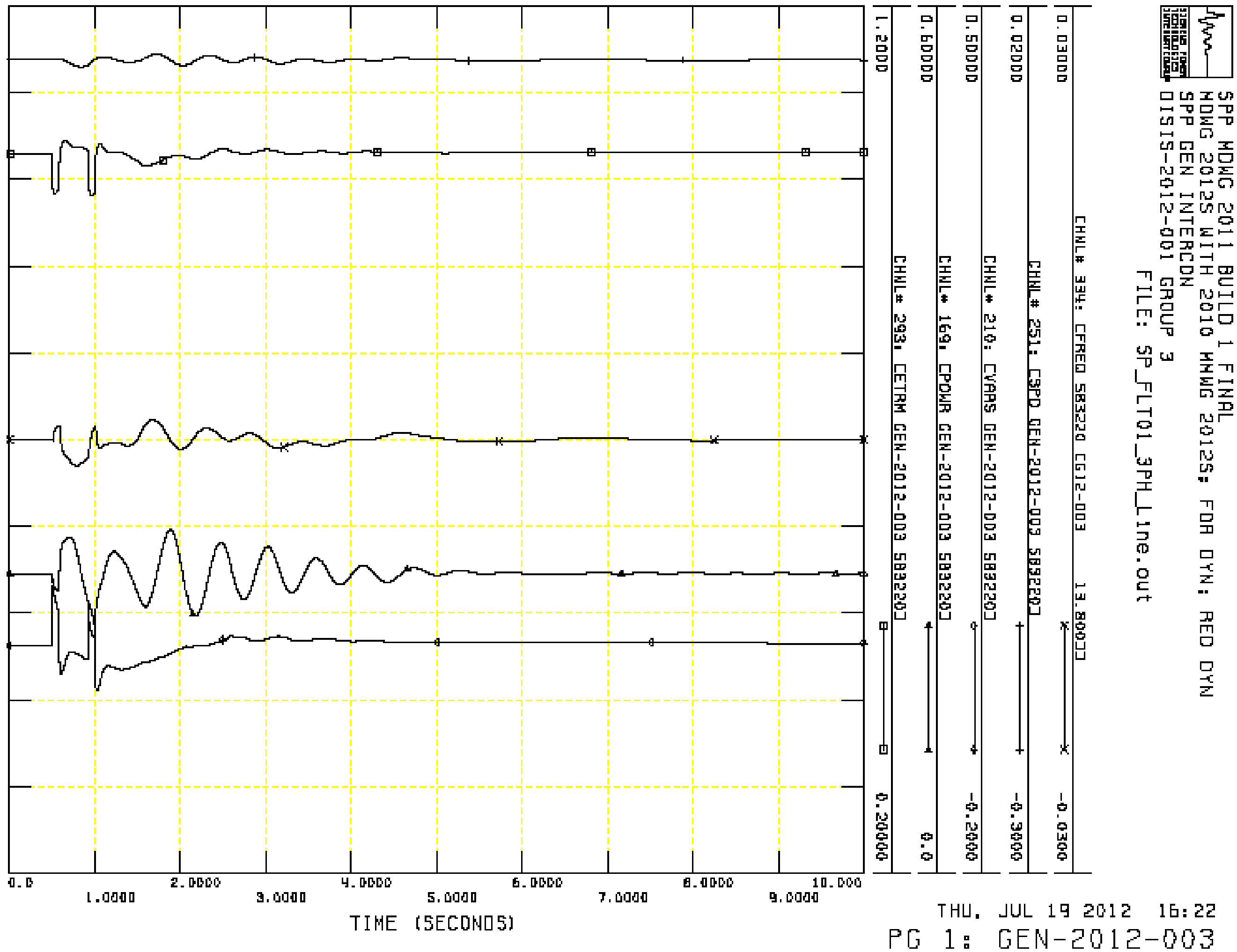

Figure 4-8. Response of GEN-2012-003 project during Contingency #1 (FLT01-3PH) for summer peak conditions with the additional 345 kV line.

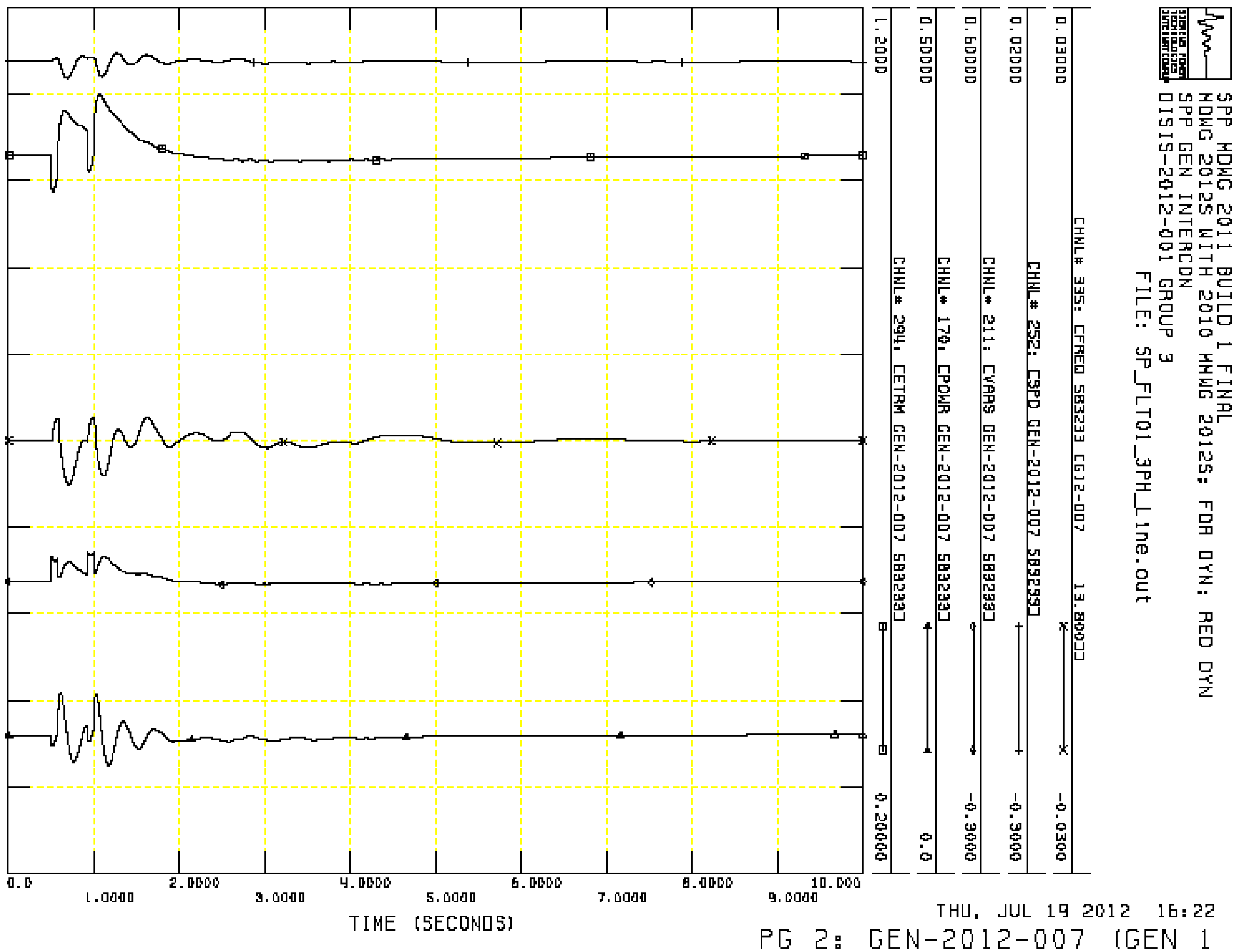

Figure 4-9. Response of GEN-2012-007 (Gen 1) project during Contingency #1 for summer peak conditions with the additional 345 kV line.

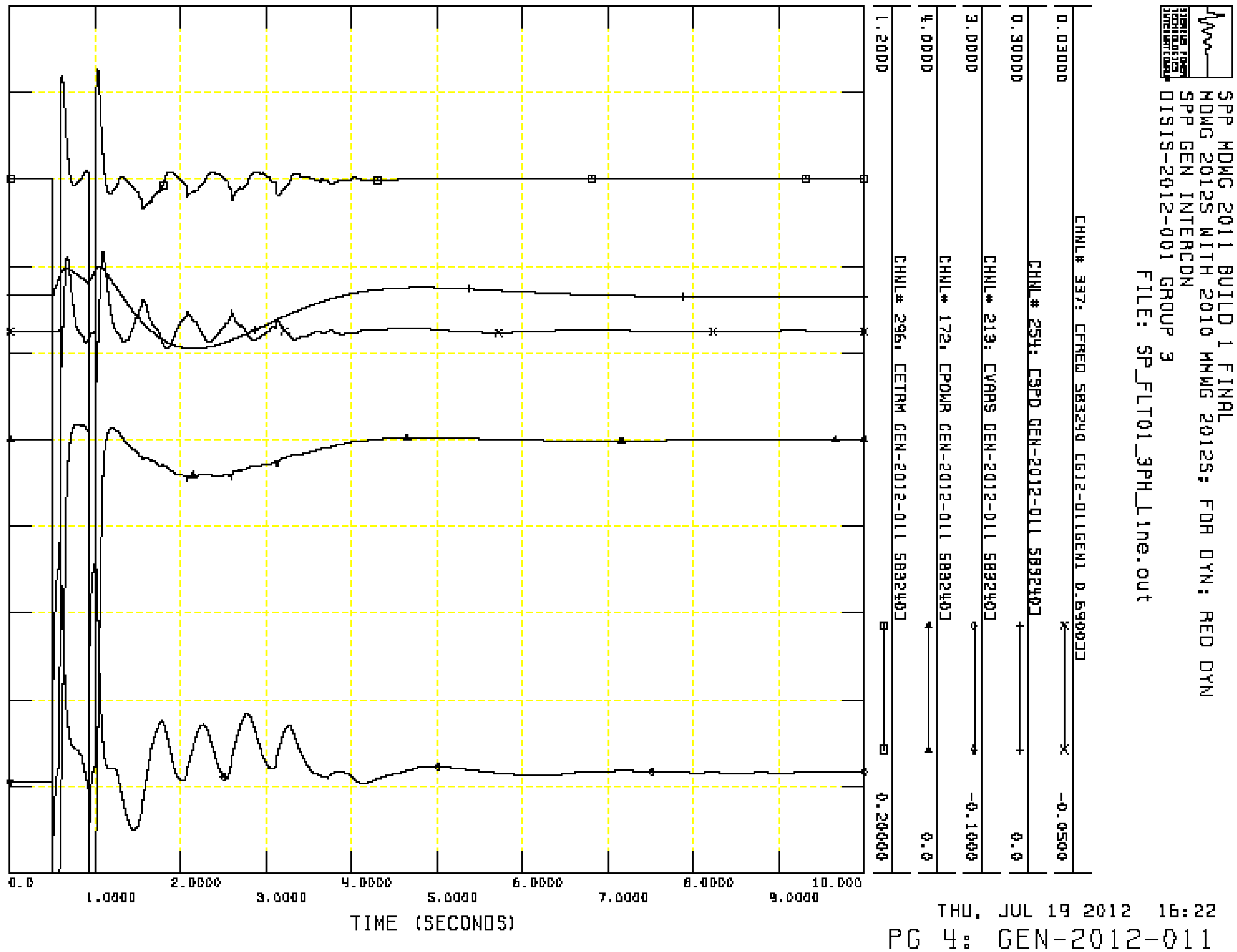

Figure 4-10. Response of GEN-2012-011 project during Contingency #1 for summer peak conditions with the additional 345 kV line.

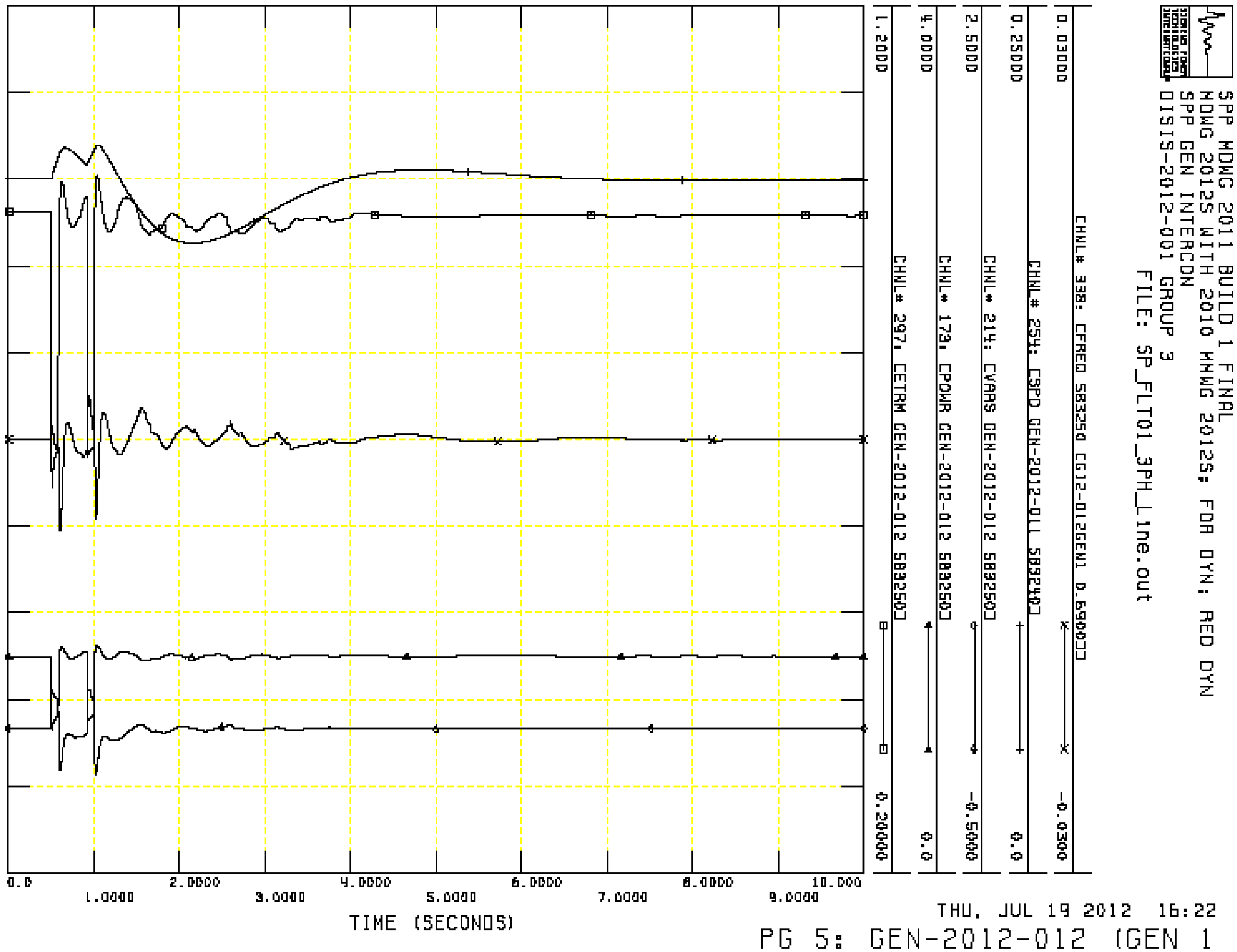

Figure 4-11. Response of GEN-2012-012 (Gen 1) project during Contingency #1 for summer peak conditions with the additional 345 kV line.

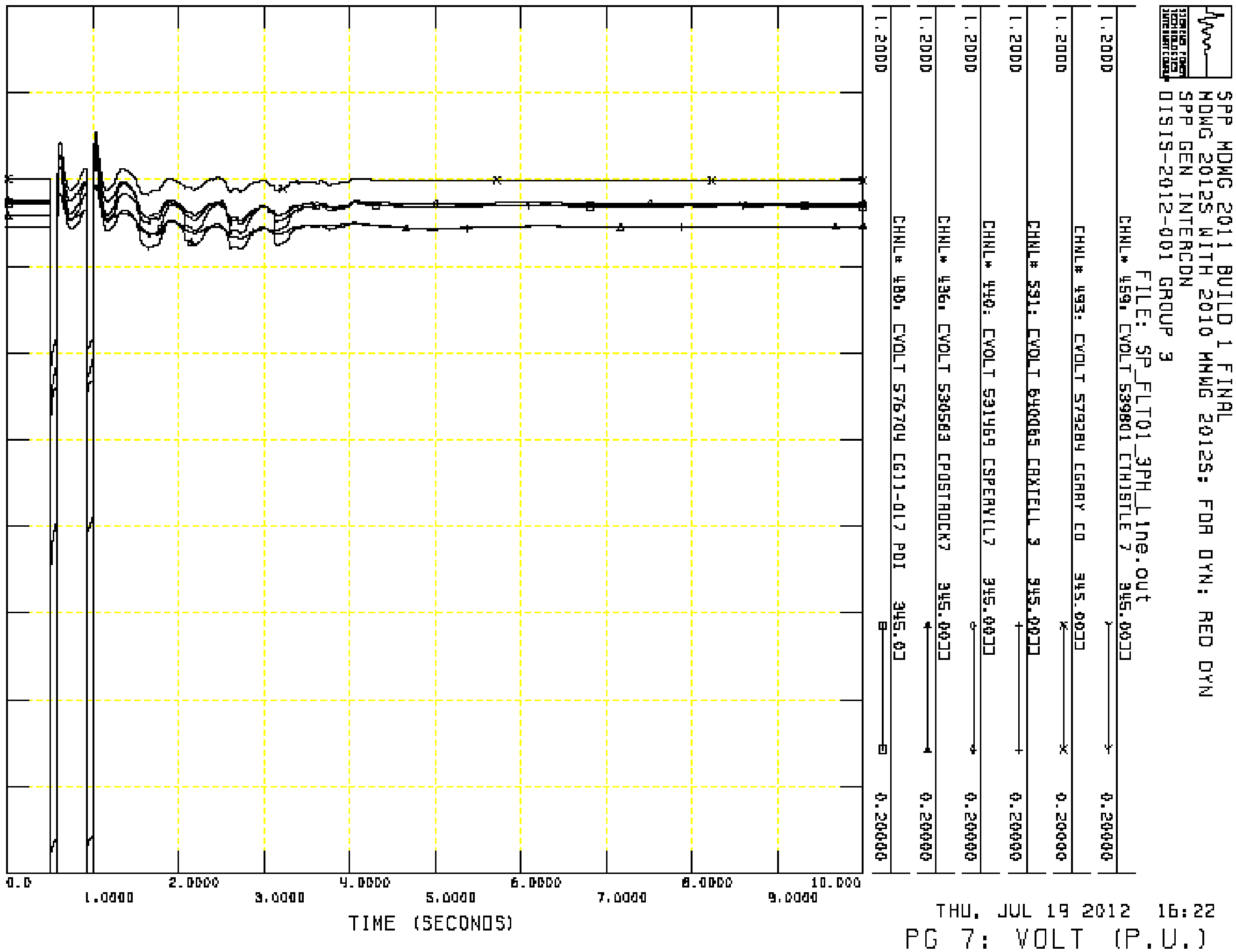

Figure 4-12. Response of selected area 345 kV bus voltages for Contingency #1 for summer peak conditions with the additional 345 kV line.

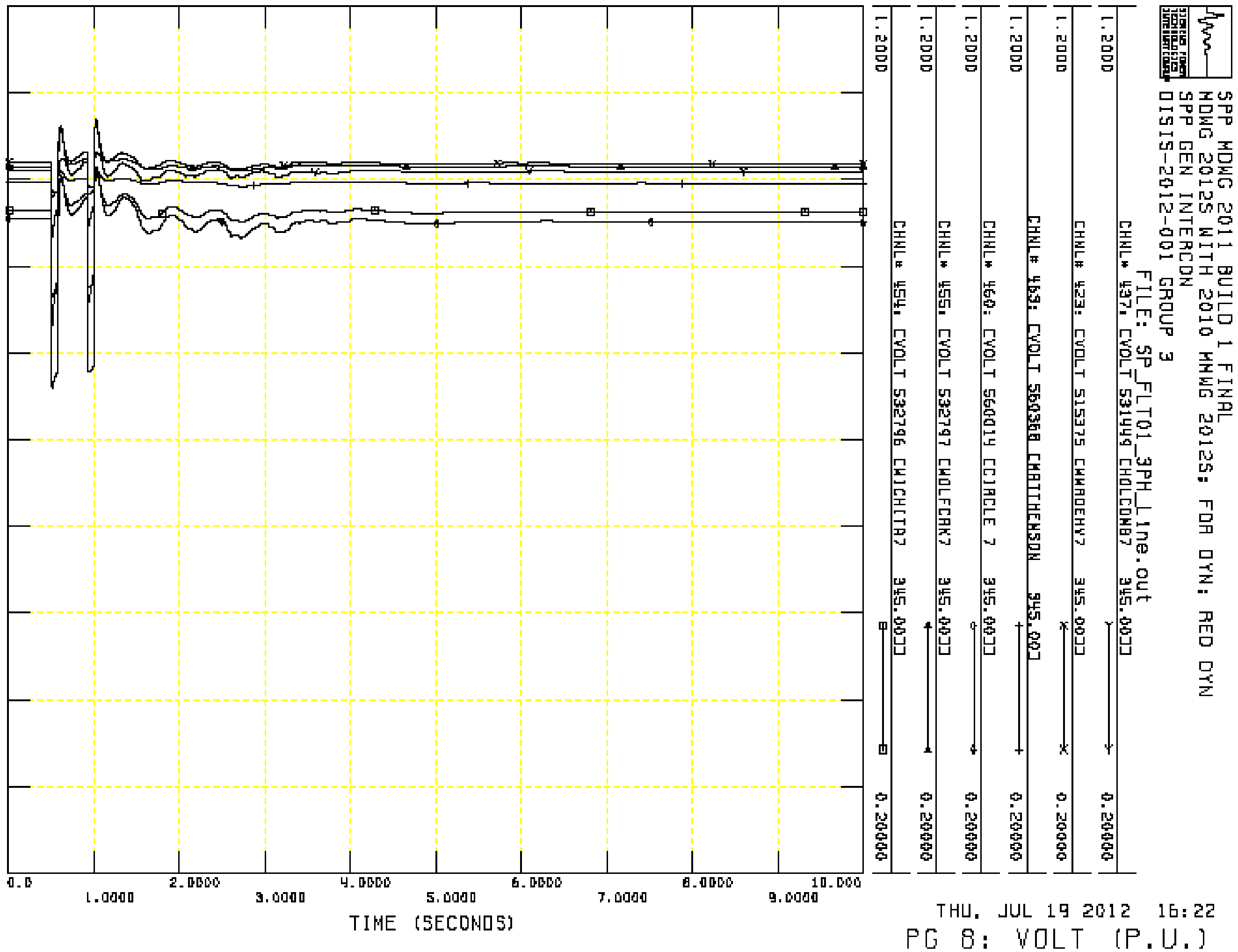

Figure 4-13. Response of selected area bus voltages for Contingency #1 for summer peak conditions with the additional 345 kV line.

Summary

For Summer Peak conditions,, the Stability Analysis determined that there was no wind turbine tripping or system instability that occurs from interconnecting GEN-2012-003, GEN-2012-007, GEN-2012-011, and GEN-2012-012 at 100% output.

For Winter Peak conditions, with the addition of the G11-017 POI to Post Rock 345 kV line circuit #2, the Stability Analysis determined that there was no wind turbine tripping or system instability that occurs from interconnecting GEN-2012-003, GEN-2012-007, GEN-2012-011, and GEN-2012-012 at 100% output.

SECTION 5: CONCLUSIONS

Power Factor Analysis

The Power Factor Analysis shows that GEN-2012-011 has a power factor requirement of 0.8731 to 0.9912 lagging (supplying) and GEN-2012-012 has a power factor requirement of 0.9076 to 0.9576 lagging (supplying).

Stability Analysis

For Summer Peak conditions, the Stability Analysis determined that there was no wind turbine tripping or system instability that occurs from interconnecting GEN-2012-003, GEN-2012-007, GEN-2012-011, and GEN-2012-012 at 100% output.

For Winter Peak conditions, with the addition of the G11-017 POI to Post Rock 345 kV line circuit #2, the Stability Analysis determined that there was no wind turbine tripping or system instability that occurs from interconnecting GEN-2012-003, GEN-2012-007, GEN-2012-011, and GEN-2012-012 at 100% output.

J: Group 4 Dynamic Stability Analysis Report

See next page.

SPP DISIS-2012-001 Group 4
Definitive Impact Study

Final Report for

Southwest Power Pool

Prepared by:
Excel Engineering, Inc.

June 20, 2012

Principal Contributor:

William Quaintance, P.E.

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0. Certification

I hereby certify that this plan, specification, or report was prepared by me or under my direct supervision and that I am a duly Licensed Professional Engineer under the Laws of the State of **Kansas**.

William Quaintance
Kansas License Number 20756

Excel Engineering, Inc.
Kansas Firm License Number E-1611

1. Background and Scope

The DISIS-2012-001 Group 4 Definitive Impact Study is a generation interconnection study performed by Excel Engineering, Inc. for its non-affiliated client, Southwest Power Pool (SPP). Its purpose is to study the impacts of interconnecting the projects shown in Table 1-1. The in-service date assumed for the generation addition was 2012.

Table 1-1. Interconnection Requests Evaluated in this Study

Request	Size (MW)	Generator Type	Point of Interconnection	Gen Buses
GEN-2012-002	101.2	Siemens 2.3MW	Tap on Pile – Scott City 115kV (562110)	583210

The prior-queued requests shown in Table 1-2 were included in this study and dispatched at 100% of rated capacity.

Table 1-2. Nearby Interconnection Requests Already in the Queue

Request	Size (MW)	Generator Type	Point of Interconnection	Gen Buses
GEN-2001-039M	99	Vestas V90VCRS 3.0MW	Central Plains 115kV (531485)	560894
GEN-2006-040	108	Acciona AW1500 1.5MW	Mingo 115kV (531429)	579161
GEN-2007-011	135	Acciona AW1500 1.5MW	Syracuse 115kV (531437)	579223
GEN-2007-013	99	GE 1.5MW	Selkirk 115kV (531434)	560915
GEN-2008-017	300	GE 1.5MW	Setab 345kV (531465)	579420
GEN-2008-025	101.2	Siemens SMK203 2.3MW	Ruleton 115kV (531357)	579448

The study included stability analysis of each proposed interconnection request. Contingencies that resulted in a prior-queued project tripping off-line, if any, were re-run with the prior-queued project's voltage and frequency tripping relays disabled. A power factor analysis was performed for the wind and solar farms in Table 1-1.

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

Study assumptions in general have been based on Excel's knowledge of the electric power system and on the specific information and data provided by SPP. The accuracy of the conclusions contained within this study is sensitive to the assumptions made with respect to generation additions and transmission improvements being contemplated. Changes in the assumptions of the timing of other generation additions or transmission improvements will affect this study's conclusions.

2. Executive Summary

The DISIS-2012-001 Group 4 Definitive Impact Study evaluated the impacts of interconnecting the Table 1-1 study projects to the SPP transmission system.

No stability problems were found for any of the simulated faults. All study projects and prior-queued projects remained stable and on-line following all faults.

Final power factor and capacitor requirements for the Group 4 projects are listed in Table 4-2.

With the assumptions and upgrades described in this report, DISIS-2012-001 Group 4 should be able to connect without causing any stability problems on the SPP transmission grid.

Any change in system or wind farm models or assumptions could change these results.

3. Study Development and Assumptions

3.1 Simulation Tools

The Siemens Power Technologies, Inc. PSS/E power system simulation program Version 30.3.3 was used in this study.

3.2 Models Used

SPP provided its latest stability database cases for both summer and winter peak seasons. These cases included the study and prior-queued projects. A power flow one-line diagram of the study project is shown in Figure 3-1.

The study plant transmission lines and substation transformers are modeled explicitly in the power flow cases. The wind and solar collector systems and generators are modeled as a single equivalent for each substation transformer. Steady-state and dynamic model data for the study plants are given in Appendix D.

One-line diagrams of the SPP 345 and 230 kV systems in the Group 4 area are shown in Appendix E.

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

3.3 Monitored Facilities

All generators and transmission buses in Areas 525, 526, 531, 534, 536, and 640 were monitored.

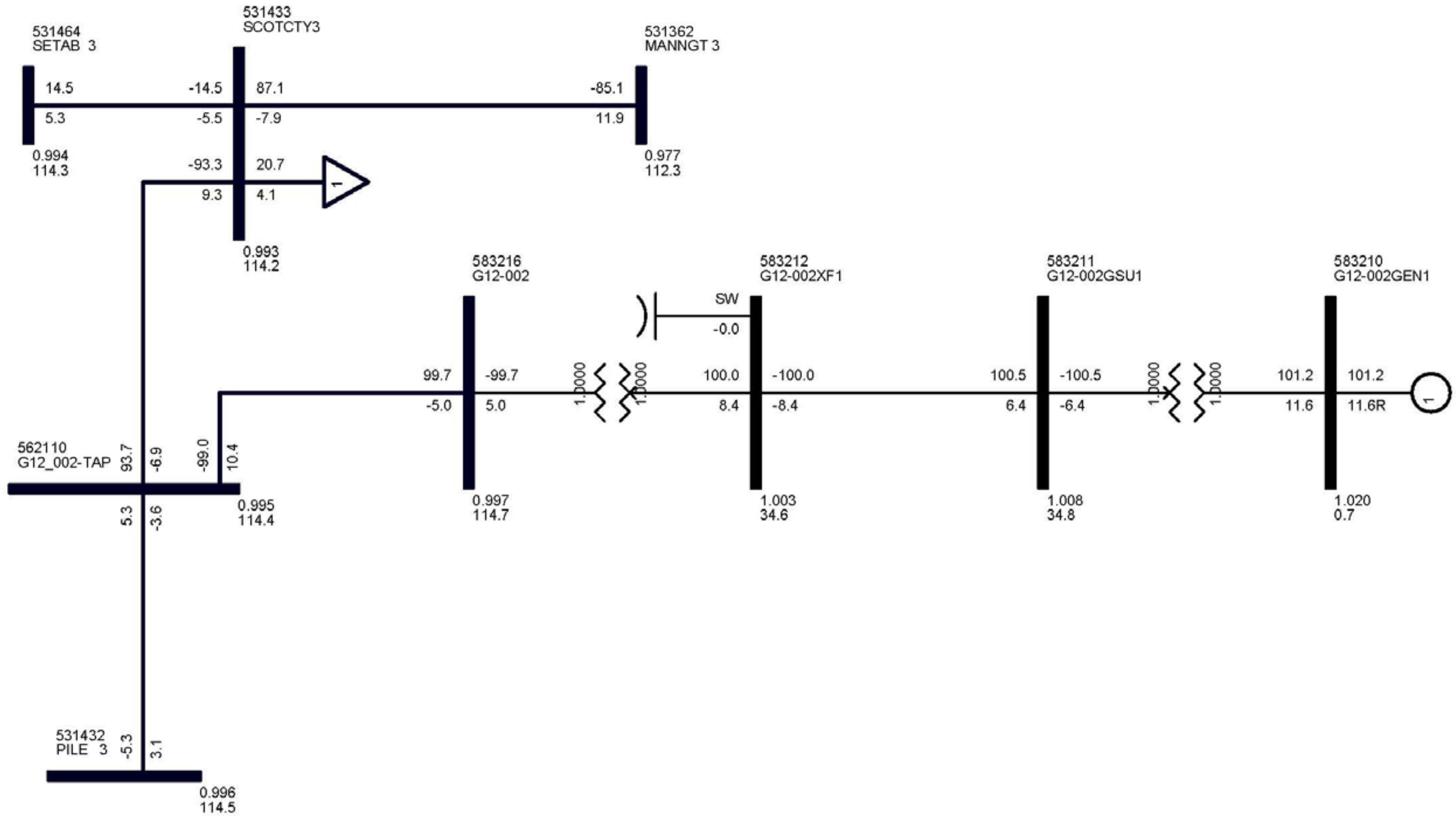

Figure 3-1. Power Flow One-line for GEN-2012-002

3.4 Performance Criteria

Wind generators must comply with FERC Order 661A on low voltage ride through for wind farms. Therefore, the wind generators should not trip off line for faults for under voltage relay actuation. If a wind generator trips off line, an appropriately sized SVC or STATCOM device may need to be specified to keep the wind generator on-line for the fault. SPP was consulted to determine if the addition of an SVC or STATCOM is warranted for the specific condition.

Contingencies that resulted in a prior-queued project tripping off-line, if any, were re-run with the prior-queued project's voltage and frequency tripping disabled to check for stability issues.

3.5 Performance Evaluation Methods

A power factor analysis was performed for all study projects that are wind farms. The power factor analysis consisted of modeling a var generator in each wind farm holding a voltage schedule at the POI. The voltage schedule was set to the higher of the voltage with the wind farm off-line or 1.0 per unit.

If the required power factor at the POI is beyond the capability of the studied wind turbines, then capacitor banks would be considered. Factors used in sizing capacitor banks would include two requirements of FERC Order 661A: the ability of the wind farm to ride through low voltage with and without capacitor banks and the ability of the wind farm to recover to pre-fault voltage. If a wind generator trips on high voltage, a leading power factor may be required.

ATC studies were not performed as part of this study. These studies will be required at the time transmission service is actually requested. Additional transmission facilities may be required based on subsequent ATC analysis.

Stability analysis was performed for each proposed interconnection request. Faults were simulated on transmission lines at the POIs and on other nearby transmission equipment. The faults in Table 3-1 were run for each case (three phase and single phase as noted).

Table 3-1. Fault Definitions for DISIS-2012-001 Group 4

Cont. No.	Contingency Name	Contingency Description
1	FLT01-3PH	3 phase fault on the Setab (531465) to Holcomb (531449) 345kV line, near Setab. a. Apply fault at the Setab 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
2	FLT02-1PH	Single phase fault and sequence like previous
3	FLT03-3PH	3 phase fault on the Setab (531465) to Mingo (531451) 345kV line, near Setab. a. Apply fault at the Setab 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
4	FLT04-1PH	Single phase fault and sequence like previous
5	FLT05-3PH	3 phase fault on the Mingo (531451) to Red Willow (640325) 345kV line, near Mingo. a. Apply fault at the Mingo 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
6	FLT06-1PH	Single phase fault and sequence like previous
7	FLT07-3PH	3 phase fault on the Holcomb (531449) to Gray County (579284) 345kV line, near Holcomb. a. Apply fault at the Holcomb 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
8	FLT08-1PH	Single phase fault and sequence like previous
9	FLT09-3PH	3 phase fault on the Holcomb (531449) to Finney (523853) 345kV line, ckt 1, near Finney. a. Apply fault at the Finney 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
10	FLT10-1PH	Single phase fault and sequence like previous
11	FLT11-3PH	3 phase fault on the Finney (523853) to Lamar (599950) 345kV line, near Finney. a. Apply fault at the Finney 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
12	FLT12-1PH	Single phase fault and sequence like previous
13	FLT13-3PH	3 phase fault on the Finney (523853) to Stevens (560029) 345kV line, near Finney. a. Apply fault at the Finney 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
14	FLT14-1PH	Single phase fault and sequence like previous

Cont. No.	Contingency Name	Contingency Description
15	FLT15-3PH	3 phase fault on the Gray County (579284) to Spearville (531469) 345kV line, near Gray County. a. Apply fault at the Gray County 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
16	FLT16-1PH	Single phase fault and sequence like previous
17	FLT19-3PH	3 phase fault on the Spearville (531469) to Clark County (539800) 345kV line, ckt1, near Spearville. a. Apply fault at the Spearville 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
18	FLT20-1PH	Single phase fault and sequence like previous
19	FLT23-3PH	3 phase fault on the Spearville (531469) to G11-017 (576704) 345kV line, ckt1, near Spearville. a. Apply fault at the Spearville 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
20	FLT24-1PH	Single phase fault and sequence like previous
21	FLT25-3PH	3 phase fault on the G12_002-TAP (562110) to Scott City (531433) 115kV line, near G12_002-TAP. a. Apply fault at the G12_002-TAP 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
22	FLT26-1PH	Single phase fault and sequence like previous
23	FLT27-3PH	3 phase fault on the G12_002-TAP (562110) to Pile (531432) 115kV line, near G12_002-TAP. a. Apply fault at the G12_002-TAP 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
24	FLT28-1PH	Single phase fault and sequence like previous
25	FLT29-3PH	3 phase fault on the Scott City (531433) to Manning Tap (531362) 115kV line, near Scott City. a. Apply fault at the Scott City 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
26	FLT30-1PH	Single phase fault and sequence like previous
27	FLT31-3PH	3 phase fault on the Scott City (531433) to Setab (531464) 115kV line, near Scott City. a. Apply fault at the Scott City 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
28	FLT32-1PH	Single phase fault and sequence like previous

Cont. No.	Contingency Name	Contingency Description
29	FLT33-3PH	3 phase fault on the Setab (531464) to Central Plains (531485) 115kV line, near Setab. a. Apply fault at the Setab 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
30	FLT34-1PH	Single phase fault and sequence like previous
31	FLT35-3PH	3 phase fault on the Tribune Switch (531438) to Palmer (531431) 115kV line, near Tribune Switch. a. Apply fault at the Tribune Switch 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
32	FLT36-1PH	Single phase fault and sequence like previous
33	FLT37-3PH	3 phase fault on the Tribune Switch (531438) to Tribune (531439) 115kV line, near Tribune Switch. a. Apply fault at the Tribune Switch 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
34	FLT38-1PH	Single phase fault and sequence like previous
35	FLT39-3PH	3 phase fault on the Ness City (531456) to Ransom (531359) 115kV line, near Ness City. a. Apply fault at the Ness City 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
36	FLT40-1PH	Single phase fault and sequence like previous
37	FLT41-3PH	3 phase fault on the Ness City (531456) to Ness City (530607) 115kV line, near Ness City (531456). a. Apply fault at the Ness City (531456) 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
38	FLT42-1PH	Single phase fault and sequence like previous
39	FLT43-3PH	3 phase fault on Pile (531432) to Dobson (531419) 115kV line, near Pile. a. Apply fault at the Pile 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
40	FLT44-1PH	Single phase fault and sequence like previous
41	FLT45-3PH	3 phase fault on Dobson (531419) to Lowe Tap (531425) 115kV line, near Dobson. a. Apply fault at the Dobson 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
42	FLT46-1PH	Single phase fault and sequence like previous

Cont. No.	Contingency Name	Contingency Description
43	FLT47-3PH	3 phase fault on Dobson (531419) to Lowe Tap (531425) 115kV line, near Dobson. a. Apply fault at the Dobson 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
44	FLT48-1PH	Single phase fault and sequence like previous
45	FLT49-3PH	3 phase fault on Dobson (531419) to Morris (531430) 115kV line, near Dobson. a. Apply fault at the Dobson 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
46	FLT50-1PH	Single phase fault and sequence like previous
47	FLT51-3PH	3 phase fault on Dobson (531419) to KSAVWTP (531480) 115kV line, near Dobson. a. Apply fault at the Dobson 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
48	FLT52-1PH	Single phase fault and sequence like previous
49	FLT53-3PH	3 phase fault on Holcomb (531448) to Fletcher (531420) 115kV line, near Holcomb. a. Apply fault at the Holcomb 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
50	FLT54-1PH	Single phase fault and sequence like previous
51	FLT55-3PH	3 phase fault on Holcomb (531448) to Plymell (531393) 115kV line, near Holcomb. a. Apply fault at the Holcomb 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
52	FLT56-1PH	Single phase fault and sequence like previous
53	FLT57-3PH	3 phase fault on the Setab 345kV (531465) to 115kV (531464) transformer, near the 345 kV bus. a. Apply fault at the Setab 345kV bus. 531259 b. Clear fault after 5 cycles by tripping the faulted transformer.
54	FLT58-3PH	3 phase fault on the Mingo 345kV (531451) to 115kV (531429) transformer, near the 345 kV bus. a. Apply fault at the Mingo 345kV bus. 531452 b. Clear fault after 5 cycles by tripping the faulted transformer.
55	FLT59-3PH	3 phase fault on the Holcomb 345kV (531449) to 115kV (531448) transformer, near the 345 kV bus. a. Apply fault at the Holcomb 345kV bus. 531450 b. Clear fault after 5 cycles by tripping the faulted transformer.
56	FLT61-3PH	3 phase fault on Spearville (531469) to Clark County (539800) 345kV line, ckt1&2, near Spearville. a. Apply fault at the Spearville 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

4. Results and Observations

4.1 Stability Analysis Results

Table 4-1 summarizes the final results. Figure 4-1 through Figure 4-2 show representative summer peak season plots for faults at the POI's of the study projects. Complete sets of plots for both summer and winter peak seasons for each fault and each project are included in Appendices A and B.

All of the simulations performed well. No plants tripped and none went unstable for any of the simulated faults.

Table 4-1. Summary of Stability Results

Cont. No.	Contingency Name	Contingency Description	Summer Peak Results	Winter Peak Results
1	FLT01-3PH	3 phase fault on the Setab (531465) to Holcomb (531449) 345kV line, near Setab.	OK	OK
2	FLT02-1PH	Single phase fault and sequence like previous	OK	OK
3	FLT03-3PH	3 phase fault on the Setab (531465) to Mingo (531451) 345kV line, near Setab.	OK	OK
4	FLT04-1PH	Single phase fault and sequence like previous	OK	OK
5	FLT05-3PH	3 phase fault on the Mingo (531451) to Red Willow (640325) 345kV line, near Mingo.	OK	OK
6	FLT06-1PH	Single phase fault and sequence like previous	OK	OK
7	FLT07-3PH	3 phase fault on the Holcomb (531449) to Gray County (579284) 345kV line, near Holcomb.	OK	OK
8	FLT08-1PH	Single phase fault and sequence like previous	OK	OK
9	FLT09-3PH	3 phase fault on the Holcomb (531449) to Finney (523853) 345kV line, ckt 1, near Finney.	OK	OK
10	FLT10-1PH	Single phase fault and sequence like previous	OK	OK
11	FLT11-3PH	3 phase fault on the Finney (523853) to Lamar (599950) 345kV line, near Finney.	OK	OK
12	FLT12-1PH	Single phase fault and sequence like previous	OK	OK
13	FLT13-3PH	3 phase fault on the Finney (523853) to Stevens (560029) 345kV line, near Finney.	OK	OK
14	FLT14-1PH	Single phase fault and sequence like previous	OK	OK
15	FLT15-3PH	3 phase fault on the Gray County (579284) to Spearville (531469) 345kV line, near Gray County.	OK	OK
16	FLT16-1PH	Single phase fault and sequence like previous	OK	OK
17	FLT19-3PH	3 phase fault on the Spearville (531469) to Clark County (539800) 345kV line, ckt1, near Spearville.	OK	OK

Cont. No.	Contingency Name	Contingency Description	Summer Peak Results	Winter Peak Results
18	FLT20-1PH	Single phase fault and sequence like previous	OK	OK
19	FLT23-3PH	3 phase fault on the Spearville (531469) to G11-017 (576704) 345kV line, ckt1, near Spearville.	OK	OK
20	FLT24-1PH	Single phase fault and sequence like previous	OK	OK
21	FLT25-3PH	3 phase fault on the G12_002-TAP (562110) to Scott City (531433) 115kV line, near G12_002-TAP.	OK	OK
22	FLT26-1PH	Single phase fault and sequence like previous	OK	OK
23	FLT27-3PH	3 phase fault on the G12_002-TAP (562110) to Pile (531432) 115kV line, near G12_002-TAP.	OK	OK
24	FLT28-1PH	Single phase fault and sequence like previous	OK	OK
25	FLT29-3PH	3 phase fault on the Scott City (531433) to Manning Tap (531362) 115kV line, near Scott City.	OK	OK
26	FLT30-1PH	Single phase fault and sequence like previous	OK	OK
27	FLT31-3PH	3 phase fault on the Scott City (531433) to Setab (531464) 115kV line, near Scott City.	OK	OK
28	FLT32-1PH	Single phase fault and sequence like previous	OK	OK
29	FLT33-3PH	3 phase fault on the Setab (531464) to Central Plains (531485) 115kV line, near Setab.	OK	OK
30	FLT34-1PH	Single phase fault and sequence like previous	OK	OK
31	FLT35-3PH	3 phase fault on the Tribune Switch (531438) to Palmer (531431) 115kV line, near Tribune Switch.	OK	OK
32	FLT36-1PH	Single phase fault and sequence like previous	OK	OK
33	FLT37-3PH	3 phase fault on the Tribune Switch (531438) to Tribune (531439) 115kV line, near Tribune Switch.	OK	OK
34	FLT38-1PH	Single phase fault and sequence like previous	OK	OK
35	FLT39-3PH	3 phase fault on the Ness City (531456) to Ransom (531359) 115kV line, near Ness City.	OK	OK
36	FLT40-1PH	Single phase fault and sequence like previous	OK	OK
37	FLT41-3PH	3 phase fault on the Ness City (531456) to Ness City (530607) 115kV line, near Ness City (531456).	OK	OK
38	FLT42-1PH	Single phase fault and sequence like previous	OK	OK
39	FLT43-3PH	3 phase fault on Pile (531432) to Dobson (531419) 115kV line, near Pile.	OK	OK
40	FLT44-1PH	Single phase fault and sequence like previous	OK	OK
41	FLT45-3PH	3 phase fault on Dobson (531419) to Lowe Tap (531425) 115kV line, near Dobson.	OK	OK
42	FLT46-1PH	Single phase fault and sequence like previous	OK	OK
43	FLT47-3PH	3 phase fault on Dobson (531419) to Lowe Tap (531425) 115kV line, near Dobson.	OK	OK
44	FLT48-1PH	Single phase fault and sequence like previous	OK	OK

Cont. No.	Contingency Name	Contingency Description	Summer Peak Results	Winter Peak Results
45	FLT49-3PH	3 phase fault on Dobson (531419) to Morris (531430) 115kV line, near Dobson.	OK	OK
46	FLT50-1PH	Single phase fault and sequence like previous	OK	OK
47	FLT51-3PH	3 phase fault on Dobson (531419) to KSAVWTP (531480) 115kV line, near Dobson.	OK	OK
48	FLT52-1PH	Single phase fault and sequence like previous	OK	OK
49	FLT53-3PH	3 phase fault on Holcomb (531448) to Fletcher (531420) 115kV line, near Holcomb.	OK	OK
50	FLT54-1PH	Single phase fault and sequence like previous	OK	OK
51	FLT55-3PH	3 phase fault on Holcomb (531448) to Plymell (531393) 115kV line, near Holcomb.	OK	OK
52	FLT56-1PH	Single phase fault and sequence like previous	OK	OK
53	FLT57-3PH	3 phase fault on the Setab 345kV (531465) to 115kV (531464) transformer, near the 345 kV bus.	OK	OK
54	FLT58-3PH	3 phase fault on the Mingo 345kV (531451) to 115kV (531429) transformer, near the 345 kV bus.	OK	OK
55	FLT59-3PH	3 phase fault on the Holcomb 345kV (531449) to 115kV (531448) transformer, near the 345 kV bus.	OK	OK
56	FLT61-3PH	3 phase fault on Spearville (531469) to Clark County (539800) 345kV line, ckt1&2, near Spearville.	OK	OK

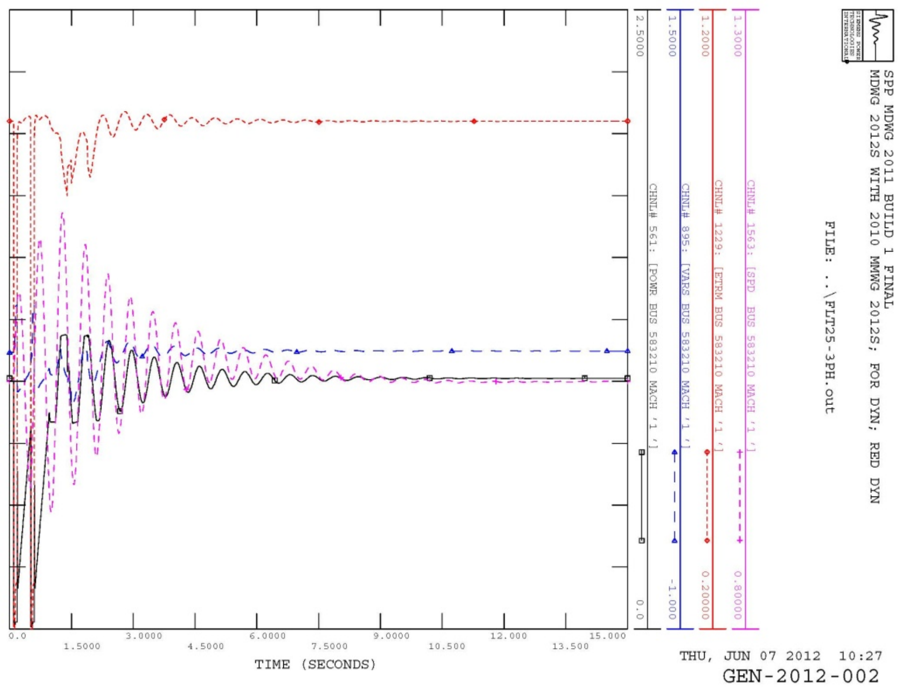

Figure 4-1. GEN-2012-002 Plot for Fault 25 – 3-Phase Fault on the G12_002-TAP (562110) to Scott City (531433) 115 kV line, near G12_002-TAP

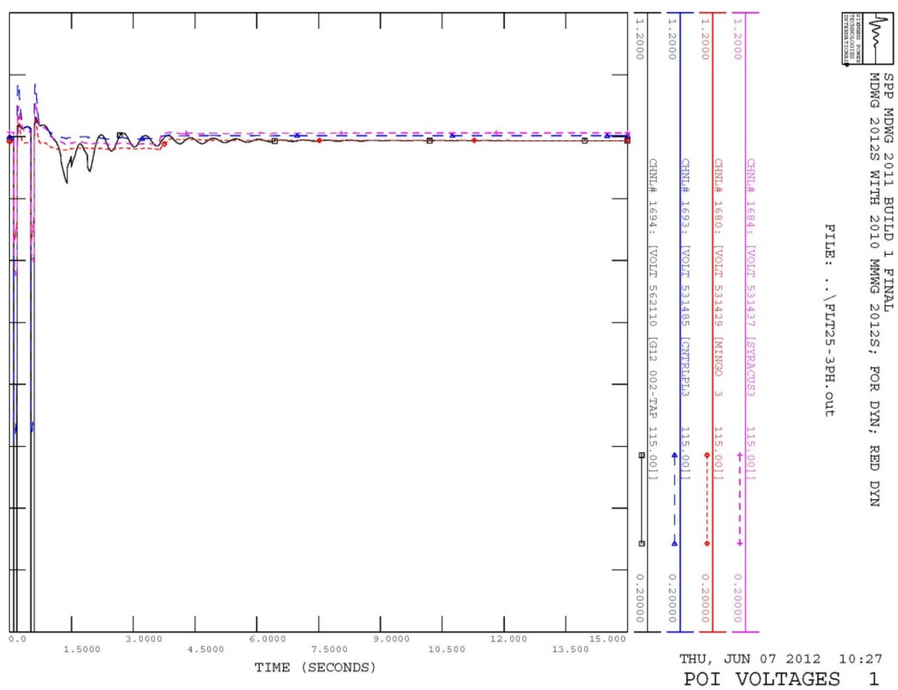

Figure 4-2. POI Voltages for Fault 25 – 3-Phase Fault on the G12_002-TAP (562110) to Scott City (531433) 115 kV line, near G12_002-TAP

4.2 Power Factor Requirements

All stability faults were tested as power flow contingencies to determine the power factor requirements for the wind farm study projects to maintain scheduled voltage at their respective points of interconnection (POI). The voltage schedules are set equal to the voltages at the POIs before the projects are added, with a minimum of 1.0 per unit. Fictitious reactive power sources were added to the study projects to maintain scheduled voltage during all studied contingencies. The MW and Mvar injections from the study projects at the POIs were recorded and the resulting power factors were calculated for all contingencies for summer peak and winter peak cases. The most leading and most lagging power factors determine the minimum power factor range capability that the study projects must install before commercial operation.

If more than one study project shared a single POI, the projects were grouped together and a common power factor requirement was determined for those study projects. This ensures that none of the study projects is required to provide more or less than its fair share of the reactive power requirements at a single POI. *Prior-queued* projects at the same POI, if any, were not grouped with the study projects because their interconnection requirements were determined in previous studies. The voltage schedules of prior-queued and study projects at the same POI were coordinated.

Per FERC and SPP Tariff requirements, if the power factor needed to maintain scheduled voltage is less than 0.95 lagging, then the requirement is limited to 0.95 lagging. The lower limit for leading power factor requirement is also 0.95. If a project never operated leading under any contingency, then the leading requirement is set to 1.0. The same applies on the lagging side.

The final power factor requirements are shown in Table 4-2 below. These are only the minimum power factor ranges based on steady-state analysis.

The full details for each contingency in summer and winter peak cases are given in Appendix C.

Table 4-2. Power Factor Requirements [a]

Request	Size (MW)	Generator Model	Point of Interconnection	Final PF Requirement	
				Lagging [b]	Leading [c]
GEN-2012-002	101.2	Siemens 2.3MW	Tap on Pile – Scott City 115kV (562110)	0.95 [d]	0.997

Notes:

a. For each plant, the table shows the minimum required power factor capability at the point of interconnection that must be designed and installed with the plant. The power factor capability at the POI includes the net effect of the generators, transformers, line impedances, and any reactive compensation devices installed on the plant side of the meter. Installing more capability than the minimum requirement is acceptable.

b. Lagging is when the generating plant is supplying reactive power to the transmission grid. In this situation, the alternating current sinusoid "lags" behind the alternating voltage sinusoid, meaning that the current peaks shortly after the voltage.

c. Leading is when the generating plant is taking reactive power from the transmission grid. In this situation, the alternating current sinusoid "leads" the alternating voltage sinusoid, meaning that the current peaks shortly before the voltage.

d. Electrical need is lower, but PF requirement limited to 0.95 by FERC order.

5. Conclusions

The DISIS-2012-001 Group 4 Definitive Impact Study evaluated the impacts of interconnecting the projects shown below.

Table 5-1. Interconnection Requests Evaluated in this Study

Request	Size	Generator Type	Point of Interconnection	Gen Buses
GEN-2012-002	101.2	Siemens 2.3MW	Tap on Pile – Scott City 115kV (562110)	583210

No stability problems were found for any of the simulated faults. All study projects and prior-queued projects remained stable and on-line following all faults.

Final power factor and capacitor requirements for the Group 4 projects are listed in Table 4-2.

With the assumptions and upgrades described in this report, DISIS-2012-001 Group 4 should be able to connect without causing any stability problems on the SPP transmission grid.

Any change in system or wind farm models or assumptions could change these results.

Appendix A – Summer Peak Plots

Appendix B – Winter Peak Plots

Appendix C – Power Factor Details

Appendix D – Project Model Data

Appendix E – SPP Transmission One-line Diagrams

K: Group 6 Dynamic Stability Analysis Report

See next page.

Final Report

For

Southwest Power Pool

From

S&C Electric Company

DEFINITIVE IMPACT STUDY
DISIS-2012-001 (Group 6)

S&C Project No. 6397

July 20, 2012

S&C Electric Company

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TABLE OF CONTENTS

Report Revision History:

Date of Report	Issue	Comments
July 17, 2012	Rev. A	Preliminary report issued for review and approval
July 20, 2012	Rev. 0	Final report issued

Prepared by:	Reviewed by:
Saeed Kamalinia Project Engineer S&C Electric Company	George S. Tsai Li Senior Engineer S&C Electric Company

EXECUTIVE SUMMARY

S&C Electric Company has performed an interconnection impact study for the Definitive Impact Study DISIS-2012-001 (Group 6) in response to a request through the Southwest Power Pool (SPP) tariff studies. Group 6 includes four generation interconnection projects. One of the aforementioned interconnection projects, i.e. GEN-2012-001, is a new wind farm project and the other three, i.e. GEN-2012-008, GEN-2012-009, and GEN-2012-010, are generation expansion in the existing thermal power plants.

Group 6 and prior-queued projects in the Southwestern Public Service (SPS) area were studied at 100% output power using “SPP MDWG 2011 Build 1 Final” summer and winter peak loading cases provided by SPP.

SPP requires that interconnection request projects meet a voltage schedule at the point of interconnection (POI) consistent with the voltage in the SPP base case or nominal voltage, whichever is higher. The power factor requirements for wind-farm interconnection projects are for N-1 (or N-2 contingencies if applicable) contingencies specified by SPP. Power Factor analysis for the wind generation study project revealed that the generating facility must meet the following requirements to maintain nominal voltage at the POI:

- GEN-2012-001 is required to maintain a power factor of up to 95% lagging (capacitive) at the POI. No leading (inductive) power factor requirement was identified for this project.

Transient stability simulation case did not converge for contingencies involved a 3-ph fault on Jones 230-kV bus. The issue has been discussed with SPP and an addition of a 24-Mvar capacitor bank was considered at 34.5-kV bus at GEN-2012-001 project and the study was repeated. Transient stability analysis indicated that Group 6 is expected to successfully ride-through each N-1 fault contingency specified by SPP and the nearby areas will retain angular, frequency and voltage stability. Group 6 is expected to successfully interconnect into the transmission system at the desired location without reduction in output power. Prior-queued project GEN-2001-033 tripped due to undervoltage protection when a 3-phase fault occurs on the Eddy County to Chaves County 230-kV line, near Eddy County, followed by tripping and re-closing of this line. The simulation was repeated with voltage protection disabled, as specified in the scope of work by SPP, and the case did successfully ride through the aforementioned contingency.

1. INTRODUCTION

S&C Electric Company has performed an interconnection impact study for the Definitive Impact Study DISIS-2012-001 (Group 6) in response to a request through the Southwest Power Pool (SPP) Tariff studies. Group 6 includes projects as follows.

Table 1.1: Study Projects in Group 6

Project	Size (MW)	Wind Turbine Model	Point of Interconnection
GEN-2012-001	61.2	CCWE 3.6 MW (WT4)	Tap Grassland to Borden 230-kV line
GEN-2012-008	40	GENROU	Mustang 115-kV bus
GEN-2012-009	15	GENROU	Mustang 230-kV bus
GEN-2012-010	15	GENROU	Mustang 230-kV bus

One of the aforementioned interconnection projects, i.e. GEN-2012-001, is a new wind farm project and the other three, i.e. GEN-2012-008, GEN-2012-009, and GEN-2012-010, are generation expansion in the existing thermal power plants.

Group 6 and prior-queued projects in the Southwestern Public Service (SPS) area were studied at 100% output power using 2010/2011 summer and winter peak loading cases provided by SPP.

2. TRANSMISSION SYSTEM AND STUDY AREA

The wind generation projects in Group 6 will interconnect into SPS. In addition to the SPS area, the following areas were monitored:

AEP West (AEPW)

Sunflower Electric Power Company (SUNC)

Western Farmers Electric Cooperative (WFEC)

Westar Energy, Inc. (WERE)

Midwest Energy, Inc. (MIDW)

Oklahoma Gas and Electric (OKGE)

3. POWER FLOW BASE CASES

The following power flow base cases were provided by SPP:

MDWG_2011_2012SP_G6 – Summer peak 2012, which includes aggregate representation of interconnect requests for Definitive Impact Study DISIS-2012-001 (Group 6) and prior-queued projects at 100% output power.

MDWG_2011_2012WP_G6 – Winter peak 2012, which includes aggregate representation of interconnect requests for Definitive Impact Study DISIS-2012-001 (Group 6) and prior-queued projects at 100% output power.

4. POWER FLOW MODEL

Definitive Impact Study DISIS-2012-001 (Group 6) and prior-queued projects were modeled as aggregates of generating units. The aggregate models were part of the base case supplied by SPP. Figure1 depicts a simplified one-line diagram for GEN-2012-001, 61.2 MW wind farm project.

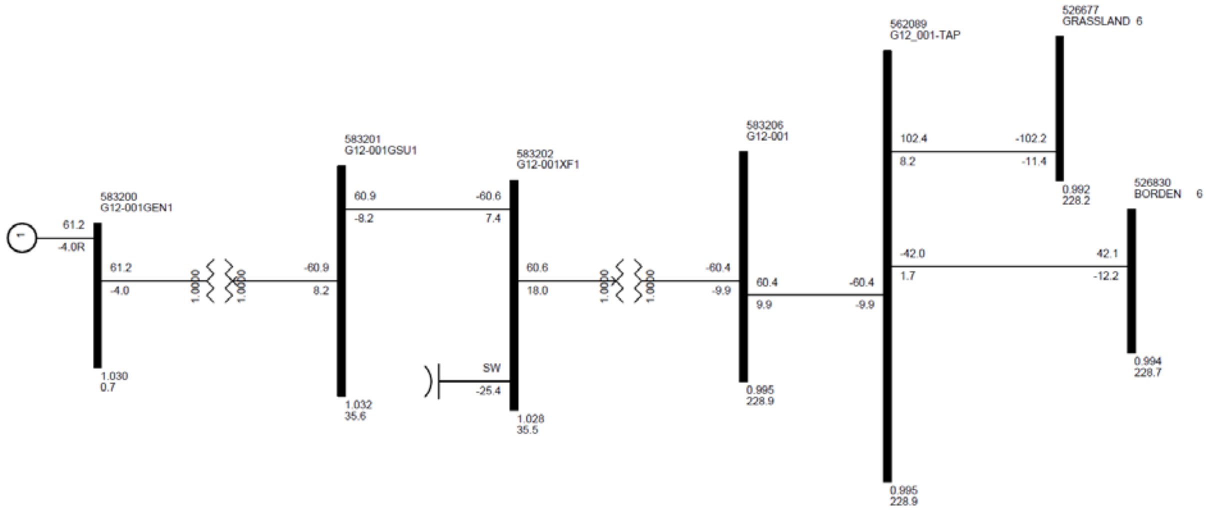

Fig. 1. A simplified one-line diagram for GEN-2012-001

4.1 CCWE 3.6 MW Wind Turbine Generator

CCWE 3.6 MW wind turbine employing a permanent-magnet synchronous machine connected to the grid via a full size power converter. CCWE applies Siemens PTI's PSS®E WT4 generic model to simulate the wind turbine with parameters adjusted to fit the nameplate data.

The key parameters needed for power-flow setup are provided in Table 4.1.

Table 4.1: Power-Flow Parameters for CCWE 3.6 MW Wind Turbine Model

Converter rating (MVA)	4.21
Pmax (MW)	3.6
Pmin (MW)	0.05
Qmax (Mvar)	1.18
Qmin (Mvar)	-1.18
Terminal voltage for 60 Hz (V)	690
Source reactance, Xsource (p.u.)	99999
Unit transformer rating (MVA)	4.0
Unit transformer impedance, R+jX (% of transformer rating)	0.587+j8.093

5. Power Factor Requirements at the Point of Interconnection

SPP has specific voltage requirements for interconnecting wind farm requests. Such projects are required to meet a voltage schedule at the POI consistent with the voltage in the SPP base case or nominal voltage, whichever is higher, for single (or N-2, if applicable) transmission facility outage contingencies specified by SPP.

5.1 Facility Outage Contingencies

The base case voltages at the point of interconnection for summer and winter are listed in Table 5.1.

Transmission facility outage contingencies specified by SPP are listed in Table 5.2.

Table 5.1: Base Case Voltage at the Point of Interconnection

Point of Interconnection	Summer Peak (pu)	Winter Peak (pu)
Tap Grassland to Borden 230-kV line	0.995	0.998

Table 5.2: List of Outages for Power-Factor Analysis

Cont. No.	Description
0	System Intact
1	Outage of the Jones_Bus2 (526338) to Lubbock_STH (526269) 230kV line
2	Outage of the Jones_Bus2 (526338) to Jones_Bus1 (626337) 230kV line
3	Outage of the Jones_Bus2 (526338) to Grassland (526677) 230kV line
4	Outage of the Lubbock_STH (526269) to Jones_Bus1 (526337) 230kV line
5	Outage of the Lubbock_STH (526269) to Wolfforth (526525) 230kV line
6	Outage of the Wolfforth (526525) to Sundown (526435) 230kV line
7	Outage of the Lubbock_EST (526299) to LP-Wadswrth (522888) 230kV line
8	Outage of the Jones_Bus1 (526337) to Tuco_Int (525830) 230kV line
9	Outage of the Grassland (526677) to Wolfforth (526525) 230kV line
10	Outage of the G12_001-TAP (562089) to Borden (526830) 230kV line

Cont. No.	Description
11	Outage of the Eddy County (527800) to Cunningham (527865) 230kV line
12	Outage of the Eddy County (527800) to Chaves County (527483) 230kV line
13	Outage of the Eddy County (527802) to GEN-2008-022 (577104) 345kV line
14	Outage of the Tolk (525549) to GEN-2008-022 (577104) 345kV line
15	Outage of the Chaves County (527483) to San Juan (524885) 230kV line
16	Outage of the Hobbs (527894) to Midland (527914) 230kV line
17	Outage of the Mustang (527149) to Amocowasson (526784) 230kV line
18	Outage of the Mustang (527149) to Yoakum (526935) 230kV line
19	Outage of the Mustang (527149) to Seminole (527276) 230kV line
20	Outage of the Amocowasson (526784) to Yoakum (526935) 230kV line
21	Outage of the Yoakum (526935) to Tolk_West (525531) 230kV line
22	Outage of the Yoakum (526935) to Amoco_SS (526460) 230kV line
23	Outage of the Yoakum (526935) to Lea_Cnty (527849) 230kV line
24	Outage of the Mustang (527146) to Denver_N (527130) 115kV line
25	Outage of the Mustang (527146) to Denver_S (527136) 115kV line, Ckt 2
26	Outage of the Mustang (527146) to Seagraves (527202) 115kV line
27	Outage of the Border (523775) to Tuco_Int (525832) 345kV line
28	Outage of the Grassland (526676) to Lynn County (526656) 115kV line
29	Outage of the Tuco_Int (525832) to G08-014-POI (560813) 345kV line
30	Outage of the Grassland 230kV (526677) to Grassland 115kV (526676) transformer
31	Outage of the Borden 230kV (526830) to CR-Vealmoor 138kV (522896) transformer
32	Outage of the Mustang 230kV (527149) to Mustang 115kV (527146) transformer
33	Outage of the Yoakum 230kV (526935) to Yoakum 115kV (526934) transformer
34	Outage of the Seminole 230kV (527276) to Seminole 115kV (527275) transformer, Ckt 2
35	Outage of the Tuco 345kV (525832) to Tuco 230kV (525830)/Tuco 13.2kV (525824) transformer

Table 5.3: Power Factor Requirements at the POI for Outages in Table 5.2 for GEN-2012-001

Cont. No.	Summer				Winter			
	P (MW)	Q (Mvar)	Power Factor		P (MW)	Q (Mvar)	Power Factor	
0	-61.2	-23.6	93.30%	lagging	-61.2	-15.7	96.86%	lagging
1	-61.2	-25.8	92.15%	lagging	-61.2	-17.4	96.19%	lagging
2	-61.2	-22.8	93.71%	lagging	-61.2	-16.6	96.51%	lagging
3	-61.2	-23.2	93.51%	lagging	-61.2	-14.8	97.20%	lagging
4	-61.2	-25.9	92.09%	lagging	-61.2	-17.5	96.15%	lagging
5	-61.2	-40.9	83.14%	lagging	-61.2	-32.3	88.44%	lagging
6	-61.2	-22.8	93.71%	lagging	-61.2	-12.3	98.04%	lagging
7	-61.2	-23.6	93.30%	lagging	-61.2	-15.8	96.83%	lagging
8	-61.2	-22.6	93.81%	lagging	-61.2	-19.5	95.28%	lagging
9	-61.2	-9.8	98.74%	lagging	-61.2	-3.0	99.88%	lagging
10	-61.2	-23.6	93.30%	lagging	-61.2	-20.8	94.68%	lagging
11	-61.2	-25.6	92.25%	lagging	-61.2	-16.8	96.43%	lagging
12	-61.2	-24.3	92.94%	lagging	-61.2	-15.9	96.79%	lagging
13	-61.2	-20.6	94.78%	lagging	-61.2	-13.5	97.65%	lagging
14	-61.2	-30.4	89.56%	lagging	-61.2	-21.4	94.40%	lagging
15	-61.2	-22.2	94.01%	lagging	-61.2	-14.6	97.27%	lagging
16	-61.2	-5.2	99.64%	lagging	-61.2	-2.4	99.92%	lagging
17	-61.2	-24.7	92.73%	lagging	-61.2	-16.6	96.51%	lagging
18	-61.2	-24.5	92.84%	lagging	-61.2	-16.5	96.55%	lagging
19	-61.2	-23.3	93.46%	lagging	-61.2	-15.5	96.94%	lagging
20	-61.2	-24.5	92.84%	lagging	-61.2	-16.4	96.59%	lagging
21	-61.2	-25.7	92.20%	lagging	-61.2	-18.0	95.94%	lagging
22	-61.2	-35.1	86.75%	lagging	-61.2	-25.8	92.15%	lagging
23	-61.2	-27.0	91.49%	lagging	-61.2	-16.8	96.43%	lagging
24	-61.2	-23.7	93.25%	lagging	-61.2	-15.7	96.86%	lagging
25	-61.2	-23.7	93.25%	lagging	-61.2	-15.7	96.86%	lagging
26	-61.2	-25.0	92.57%	lagging	-61.2	-16.3	96.63%	lagging
27	-61.2	-23.0	93.61%	lagging	-61.2	-16.2	96.67%	lagging

Cont. No.	Summer				Winter			
	P (MW)	Q (Mvar)	Power Factor		P (MW)	Q (Mvar)	Power Factor	
28	-61.2	-23.4	93.41%	lagging	-61.2	-17.7	96.06%	lagging
29	-61.2	-22.0	94.10%	lagging	-61.2	-13.9	97.52%	lagging
30	-61.2	-23.6	93.30%	lagging	-61.2	-15.7	96.86%	lagging
31	-61.2	-23.6	93.30%	lagging	-61.2	-15.7	96.86%	lagging
32	-61.2	-23.6	93.30%	lagging	-61.2	-15.7	96.86%	lagging
33	-61.2	-24.0	93.10%	lagging	-61.2	-15.9	96.79%	lagging
34	-61.2	-23.6	93.30%	lagging	-61.2	-15.7	96.86%	lagging
35	-61.2	-22.9	93.66%	lagging	-61.2	-15.1	97.09%	lagging

The power factor required to maintain a voltage schedule at the POI of 1.0 per unit voltage in accordance with SPP requirements for each of the power flow contingencies in Table 5.2 is listed in Tables 5.3. Contingency cases in which required power factor exceed 95% were highlighted in the table. Wind farms are not typically required according to FERC 661-A to operate at the POI beyond a power factor range of ±95% for voltages from 95 to 105% of nominal. To deliver additional capacitive reactive power in order to meet the schedule at the POI of 1.0 per unit voltage, external sources of reactive power such as capacitor banks could be needed. In addition, stability analysis identified the need for an additional capacitor bank of approximately 24 Mvar.

Power Factor analysis indicates the following,

- GEN-2012-001 is required to maintain a power factor of up to 95% lagging (capacitive) at the POI. No leading (inductive) power factor requirement was identified for this project. Additional reactive power equipment was identified as being required in the stability portion of this report.

6. Transient Stability Analysis

Transient stability analysis was performed for the fault contingencies in Table 6.1, which were specified by SPP. For the purpose of the transient stability analysis, each of the interconnection request projects was studied with the required lagging power factor at the POI from power factor analysis.

Table 6.1: SPP fault contingencies

Cont. No.	Cont. Name	Description
1	FLT01-3PH	3 phase fault on the Jones_Bus2 (526338) to Lubbock_STH (526269) 230kV line, near Jones_Bus2. a. Apply fault at the Jones_Bus2 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
2	FLT02-1PH	*Single phase fault and sequence like previous*
3	FLT03-3PH	3 phase fault on the Jones_Bus2 (526338) to Jones_Bus1 (626337 230kV line, near Jones_Bus2. a. Apply fault at the Jones_Bus2 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
4	FLT04-1PH	*Single phase fault and sequence like previous*
5	FLT05-3PH	3 phase fault on the Jones_Bus2 (526338) to Grassland (526677) 230kV line, near Jones_Bus2. a. Apply fault at the Jones_Bus2 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
6	FLT06-1PH	*Single phase fault and sequence like previous*

Cont. No.	**Cont. Name**	**Description**
7	FLT07-3PH	3 phase fault on the Lubbock_STH (526269) to Jones_Bus1 (526337) 230kV line, near Lubbock_STH. a. Apply fault at the Lubbock_STH 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
8	FLT08-1PH	*Single phase fault and sequence like previous*
9	FLT09-3PH	3 phase fault on the Lubbock_STH (526269) to Wolfforth (526525) 230kV line, near Lubbock_STH. a. Apply fault at the Lubbock_STH 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
10	FLT10-1PH	*Single phase fault and sequence like previous*
11	FLT11-3PH	3 phase fault on the Wolfforth (526525) to Sundown (526435) 230kV line, near Wolfforth. a. Apply fault at the Wolfforth 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
12	FLT12-1PH	*Single phase fault and sequence like previous*
13	FLT13-3PH	3 phase fault on the Lubbock_EST (526299) to LP-Wadswrth (522888) 230kV line, near Lubbock_ EST. a. Apply fault at the Lubbock_ EST 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
14	FLT14-1PH	*Single phase fault and sequence like previous*

Cont. No.	Cont. Name	Description
15	FLT15-3PH	3 phase fault on the Jones_Bus1 (526337) to Tuco_Int (525830) 230kV line, near Jones_Bus1. a. Apply fault at the Jones_Bus1 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
16	FLT16-1PH	*Single phase fault and sequence like previous*
17	FLT17-3PH	3 phase fault on the Grassland (526677) to Wolfforth (526525) 230kV line, near Grassland. a. Apply fault at the Grassland 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
18	FLT18-1PH	*Single phase fault and sequence like previous*
19	FLT19-3PH	3 phase fault on the G12_001-TAP (562089) to Borden (526830) 230kV line, near G12_001-TAP. a. Apply fault at the G12_001-TAP30kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
20	FLT20-1PH	*Single phase fault and sequence like previous*
21	FLT23-3PH	3 phase fault on the Eddy County (527800) to Cunningham (527865) 230kV line, near Eddy County. a. Apply fault at the Eddy County 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
22	FLT24-1PH	*Single phase fault and sequence like previous*

Cont. No.	Cont. Name	Description
23	FLT25-3PH	3 phase fault on the Eddy County (527800) to Chaves County (527483) 230kV line, near Eddy County. a. Apply fault at the Eddy County 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
24	FLT26-1PH	*Single phase fault and sequence like previous*
25	FLT27-3PH	3 phase fault on the Eddy County (527802) to GEN-2008-022 (577104) 345kV line, near Eddy County. a. Apply fault at the Eddy County 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
26	FLT28-1PH	*Single phase fault and sequence like previous*
27	FLT29-3PH	3 phase fault on the Tolk (525549) to GEN-2008-022 (577104) 345kV line, near Tolk. a. Apply fault at the Tolk 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
28	FLT30-1PH	*Single phase fault and sequence like previous*
29	FLT31-3PH	3 phase fault on the Chaves County (527483) to San Juan (524885) 230kV line, near Eddy County. a. Apply fault at the Chaves County 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
30	FLT32-1PH	*Single phase fault and sequence like previous*

Cont. No.	Cont. Name	Description
31	FLT33-3PH	3 phase fault on the Hobbs (527894) to Midland (527914) 230kV line, near Hobb. a. Apply fault at the Hobbs 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
32	FLT34-1PH	*Single phase fault and sequence like previous*
33	FLT35-3PH	3 phase fault on the Mustang (527149) to Amocowasson (526784) 230kV line, near Mustang. a. Apply fault at the Mustang 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
34	FLT36-1PH	*Single phase fault and sequence like previous*
35	FLT37-3PH	3 phase fault on the Mustang (527149) to Yoakum (526935) 230kV line, near Mustang. a. Apply fault at the Mustang 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
36	FLT38-1PH	*Single phase fault and sequence like previous*
37	FLT39-3PH	3 phase fault on the Mustang (527149) to Seminole (527276) 230kV line, near Mustang. a. Apply fault at the Mustang 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
38	FLT40-1PH	*Single phase fault and sequence like previous*

Cont. No.	Cont. Name	Description
39	FLT41-3PH	3 phase fault on the Amocowasson (526784) to Yoakum (526935) 230kV line, near Amocowasson. a. Apply fault at the Amocowasson 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
40	FLT42-1PH	*Single phase fault and sequence like previous*
41	FLT43-3PH	3 phase fault on the Yoakum (526935) to Tolk_West (525531) 230kV line, near Yoakum. a. Apply fault at the Yoakum 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
42	FLT44-1PH	*Single phase fault and sequence like previous*
43	FLT45-3PH	3 phase fault on the Yoakum (526935) to Amoco_SS (526460) 230kV line, near Yoakum. a. Apply fault at the Yoakum 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
44	FLT46-1PH	*Single phase fault and sequence like previous*
45	FLT47-3PH	3 phase fault on the Yoakum (526935) to Lea_Cnty (527849) 230kV line, near Yoakum. a. Apply fault at the Yoakum 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
46	FLT48-1PH	*Single phase fault and sequence like previous*

Cont. No.	Cont. Name	Description
47	FLT49-3PH	3 phase fault on the Mustang (527146) to Denver_N (527130) 115kV line, near Mustang. a. Apply fault at the Mustang 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
48	FLT50-1PH	*Single phase fault and sequence like previous*
49	FLT51-3PH	3 phase fault on the Mustang (527146) to Denver_S (527136) 115kV line, ckt2, near Mustang. a. Apply fault at the Mustang 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
50	FLT52-1PH	*Single phase fault and sequence like previous*
51	FLT53-3PH	3 phase fault on the Mustang (527146) to Seagraves (527202) 115kV line, near Mustang. a. Apply fault at the Mustang 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
52	FLT54-1PH	*Single phase fault and sequence like previous*
53	FLT55-3PH	3 phase fault on the Border (523775) to Tuco_Int (525832) 345kV line, near Border. a. Apply fault at the Border 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
54	FLT56-1PH	*Single phase fault and sequence like previous*

Cont. No.	Cont. Name	Description
55	FLT61-3PH	3 phase fault on the Grassland (526676) to Lynn County (526656) 115kV line, ckt1, near Grassland. a. Apply fault at the Grassland 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
56	FLT62-1PH	*Single phase fault and sequence like previous*
57	FLT63-3PH	3 phase fault on the Tuco_Int (525832) to G08-014-POI (560813) 345kV line, near Tuco. a. Apply fault at the Tuco 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
58	FLT64-3PH	3 phase fault on the Grassland 230kV (526677) to Grassland 115kV (526676) transformer, near the 230kV bus. a. Apply fault at the Grassland 230kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
59	FLT65-3PH	3 phase fault on the Borden 230kV (526830) to CR-Vealmoor 138kV (522896) transformer, near the 230kV bus. a. Apply fault at the Borden 230kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
60	FLT66-3PH	3 phase fault on the Mustang 230kV (527149) to Mustang 115kV (527146transformer, near the 230kV bus. a. Apply fault at the Mustang 230kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
61	FLT67-3PH	3 phase fault on the Yoakum 230kV (526935) to Yoakum 115kV (526934) transformer, ckt2, near the 230kV bus. a. Apply fault at the Yoakum 230kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.

Cont. No.	Cont. Name	Description
62	FLT68-3PH	3 phase fault on the Seminole 230kV (527276) to Seminole 115kV (527275) transformer, ckt2, near the 230kV bus. a. Apply fault at the Seminole 230kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
63	FLT69-3PH	3 phase fault on the Tuco 345kV (525832) to Tuco 230kV (525830)/Tuco 13.2kV (525824) transformer, near the 345kV bus. a. Apply fault at the Tuco 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.

Single line to ground faults were simulated in a manner consistent with currently accepted practices, that is to assume that a single line to ground will cause a voltage drop at the fault location to 60% of nominal.

The prior-queued projects monitored are listed in Table 6.2.

Table 6.2: Prior queued wind farm projects monitored

Request	Size (MW)	Generator Model	Point of Interconnection
GEN-2001-033	180	Mitsubishi 1000	San Juan Mesa 230kV (524885)
GEN-2001-036	80	CIMTR	Norton 115kV (524502)
GEN-2006-018	167.4	GENSAL	Tuco 230kV (525830)
GEN-2008-008	60	GE 1.5MW	Graham 69kV (526693)
GEN-2008-009	60	GE 1.5MW	San Juan Mesa 230kV (524885)
GEN-2008-014	149.4	Vestas V90 1.8MW	Tap on Tuco – Oklaunion 345kV line (G08-014-POI, 560813)
GEN-2008-016	248.4	Vestas V90 1.8MW	Grassland 230kV (526677)
GEN-2008-022	300	GE 2.5MW	Tap on Eddy County – Tolk 345kV line (G08-022-POI, 577104)
GEN-2009-067S	20	STCNPG (usrmdl)	Seven Rivers 69kV (528093)
GEN-2010-006	205Winter 180Summer	GENROU	Jones_bus2 230kV(526338)

Request	Size (MW)	Generator Model	Point of Interconnection
ASGI-2010-010	42	GENSAL	Lovington 115kV (528334)
ASGI-2010-020	50	Nordex 2.5MW	Tap LE-Tatum to LE-Crsroads 69kV (AS10-020-POI, 580084)
GEN-2010-020	20	STCNPG	Roswell 69kV (527563)
ASGI-2010-021	36.6	Vestas V90 1.8/ Mitsubishi MPS-1000A 1.0MW	Tap LE-Saundrtp to LE-Anderson 69kV (ASGI-021-POI, 580090)
GEN-2010-046	56	GENSAL	Tuco 230kV (525830)
GEN-2010-058	20	STCNPG	Chaves County 115kV (527482)
ASGI-2011-003	10	Sany 2.0MW	Hendricks 69kV (525943)
ASGI-2011-001	28.8	Mitsubishi 2.4MW	Lovington 115kV (528334)
GEN-2011-025	80	GE 1.6MW	Tap on Floyd County - Crosby County 115kV line (G11-025-POI, 581137)
GEN-2011-045	205 Winter 180 Summer	GENROU	Jones_bus2 230kV (526338)
GEN-2011-046	27 Winter 23 Summer	GENROU	Tucumcari 115kV (524477)
GEN-2011-048	175 Winter 165 Summer	GENROU	Mustang 230kV (527151)
ASGI-2011-004	19.2MW	GE 1.6MW	Crosby 69kV (525925)

Table 6.3 lists protection relay settings were used to evaluate fault ride-through capability of WTGs in transient stability analysis.

Table 6.3: CCWE 3.6 MW Protection Settings (Implemented with PSS®E WT4 Generic Model)

Relay Type	Trip Setting	Time Setting (sec)
Undervoltage	0.90 (pu)	3.0
Undervoltage	0.65 (pu)	1.73
Undervoltage	0.43 (pu)	1.23

Undervoltage	0.28 (pu)	0.95
Undervoltage	0.10 (pu)	0.75
Overvoltage	1.15 (pu)	0.5
Underfrequency	57.5 (Hz)	1.0
Overfrequency	62.5 (Hz)	1.0

6.1 Stability Criteria

Disturbances including three-phase and single-phase to ground faults should not cause synchronous and asynchronous plants to become unstable or disconnect from the transmission grid.

The criterion for synchronous generator stability as defined by NERC is:

"Power system stability is defined as that condition in which the difference of the angular positions of synchronous machine rotor becomes constant following an aperiodic system disturbance."

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

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

6.2 Transient Stability Results

Undisturbed runs of 20 seconds were performed with the summer and winter peak cases to verify proper initialization of dynamic models.

Transient stability simulation case did not converge for contingencies 1, 3 and 5. The issue has been discussed with SPP and an addition of a 24-Mvar capacitor bank was considered at 34.5-kV bus at GEN-2012-001 project and the study was repeated. Transient stability analysis indicated that Group 6 will successfully ride-through each N-1 fault contingency specified by SPP and the nearby areas will retain angular, frequency and voltage stability. Group 6 can successfully interconnect into the transmission system at the desired location without reduction in output power (See Appendices A and B).

Summary results of transient stability analysis are listed in Table 6.4. GEN-2001-033 tripped due to undervoltage protection in contingency #15 in winter peak case and in contingency #23 in summer and winter peak cases. The simulations were repeated with voltage protection disabled for this prior-queued project, as specified in the scope of work by SPP, and the case could successfully ride through the aforementioned contingencies (See Appendix C).

Table 6.4: Summary of Transient Stability Results

Cont. No.	Cont. Name	Summer Peak 2010/2011	Winter Peak 2010/2011
1	FLT01-3PH	STABLE	STABLE
2	FLT02-1PH	STABLE	STABLE
3	FLT03-3PH	STABLE	STABLE
4	FLT04-1PH	STABLE	STABLE
5	FLT05-3PH	STABLE	STABLE
6	FLT06-1PH	STABLE	STABLE
7	FLT07-3PH	STABLE	STABLE
8	FLT08-1PH	STABLE	STABLE
9	FLT09-3PH	STABLE	STABLE
10	FLT10-1PH	STABLE	STABLE
11	FLT11-3PH	STABLE	STABLE
12	FLT12-1PH	STABLE	STABLE
13	FLT13-3PH	STABLE	STABLE
14	FLT14-1PH	STABLE	STABLE
15	FLT15-3PH	STABLE	GEN-2001-033 Tripped on Undervoltage Protection
16	FLT16-1PH	STABLE	STABLE
17	FLT17-3PH	STABLE	STABLE
18	FLT18-1PH	STABLE	STABLE
19	FLT19-3PH	STABLE	STABLE
20	FLT20-1PH	STABLE	STABLE
21	FLT23-3PH	STABLE	STABLE

Cont. No.	Cont. Name	Summer Peak 2010/2011	Winter Peak 2010/2011
22	FLT24-1PH	STABLE	STABLE
23	FLT25-3PH	GEN-2001-033 Tripped on Undervoltage Protection	GEN-2001-033 Tripped on Undervoltage Protection
24	FLT26-1PH	STABLE	STABLE
25	FLT27-3PH	STABLE	STABLE
26	FLT28-1PH	STABLE	STABLE
27	FLT29-3PH	STABLE	STABLE
28	FLT30-1PH	STABLE	STABLE
29	FLT31-3PH	STABLE	STABLE
30	FLT32-1PH	STABLE	STABLE
31	FLT33-3PH	STABLE	STABLE
32	FLT34-1PH	STABLE	STABLE
33	FLT35-3PH	STABLE	STABLE
34	FLT36-1PH	STABLE	STABLE
35	FLT37-3PH	STABLE	STABLE
36	FLT38-1PH	STABLE	STABLE
37	FLT39-3PH	STABLE	STABLE
38	FLT40-1PH	STABLE	STABLE
39	FLT41-3PH	STABLE	STABLE
40	FLT42-1PH	STABLE	STABLE
41	FLT43-3PH	STABLE	STABLE
42	FLT44-1PH	STABLE	STABLE
43	FLT45-3PH	STABLE	STABLE
44	FLT46-1PH	STABLE	STABLE
45	FLT47-3PH	STABLE	STABLE
46	FLT48-1PH	STABLE	STABLE
47	FLT49-3PH	STABLE	STABLE
48	FLT50-1PH	STABLE	STABLE
49	FLT51-3PH	STABLE	STABLE
50	FLT52-1PH	STABLE	STABLE
51	FLT53-3PH	STABLE	STABLE
52	FLT54-1PH	STABLE	STABLE
53	FLT55-3PH	STABLE	STABLE

Cont. No.	Cont. Name	Summer Peak 2010/2011	Winter Peak 2010/2011
54	FLT56-1PH	STABLE	STABLE
55	FLT61-3PH	STABLE	STABLE
56	FLT62-1PH	STABLE	STABLE
57	FLT63-3PH	STABLE	STABLE
58	FLT64-3PH	STABLE	STABLE
59	FLT65-3PH	STABLE	STABLE
60	FLT66-3PH	STABLE	STABLE
61	FLT67-3PH	STABLE	STABLE
62	FLT68-3PH	STABLE	STABLE
63	FLT69-3PH	STABLE	STABLE

7. Conclusions and Recommendations

Group 6 and prior-queued projects in the Southwestern Public Service (SPS) area were studied at 100% output power using summer and winter peak loading cases provided by SPP.

The results of power factor analysis indicated that GEN-2012-001 is required to maintain power factor of 95% lagging (capacitive) at the POI, while no leading (inductive) power factor requirement was identified for this project.

Transient stability simulation case did not converge for contingencies 1, 3 and 5. The issue has been discussed with SPP and an addition of a 24-Mvar capacitor bank was considered at 34.5-kV bus for GEN-2012-001 project and the study was repeated. Transient stability analysis indicated that Group 6 will successfully ride-through each N-1 fault contingency specified by SPP and the nearby areas will retain angular, frequency and voltage stability. Group 6 can successfully interconnect into the transmission system at the desired location without reduction in output power. Furthermore, GEN-2001-033 tripped due to undervoltage protection in contingency #23. The simulation was repeated with voltage protection disabled for this prior-queued project, as specified in the scope of work by SPP, and the case did successfully ride through the aforementioned contingency.

L: Group 14 Dynamic Stability Analysis Report

See next page.

Southwest Power Pool Inc.

Definitive Impact Study
DISIS-2012-001 (Group 14)

Report Submitted to
Southwest Power Pool Inc.
July 2012

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Table of Contents

Executive Summary

This report presents the results of impact study comprising of power factor and stability analyses of the proposed interconnection projects under Southwest Power Pool Inc. (SPP) DISIS-2012-001 Group 14 (the Project) as described in the following Table.

Interconnection Request

Request	Size (MW)	Wind Turbine Model	Point of Interconnection
GEN-2012-004	41.4	Siemens 2.3MW	Bus # 562038 (2011-040TP) 138.00kV
Note: This is a 41.4MW increase to the existing GEN-2011-040 110.4MW for a total of 151.8MW			

Power factor analysis and transient stability simulations were performed for the Project in service at its full output. SPP provided two base cases for summer and winter conditions respectively, each comprising of a power flow and corresponding dynamics database. The previous queued request projects are already modeled in the base cases.

The power factor analysis indicates the GEN-2012-004 interconnection request is required to maintain a 96.7% lagging (supplying vars) and 96.2% leading (absorbing vars) power factor at the point of interconnection (the 2011-040TP 138kV transmission bus).

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

1.0 Introduction

1.1. Project Overview and Assumptions

The DISIS-**2012-001** Group 14 Impact Study is a generation interconnection study performed by POWER-tek Global Inc. for Southwest Power Pool (SPP). This report presents the results of impact study comprising of power factor and stability analyses of the proposed interconnection projects under DISIS-2012-001 Group 14 ("The Project") as described in Table 1.1 below:

Table 1.1: Interconnection Request

Request	Size (MW)	Wind Turbine Model	Point of Interconnection
GEN-2012-004	41.4	Siemens 2.3MW	Bus # 562038 (2011-040TP) 138.0kV
Note: This is a 41.4MW increase to the existing GEN-2011-040 110.4MW for a total of 151.8MW			

Figure 1.1 shows the single line diagram for the interconnection of the Project to present and planned system of SPP. This arrangement was modeled and studied in power flow cases for this Project.

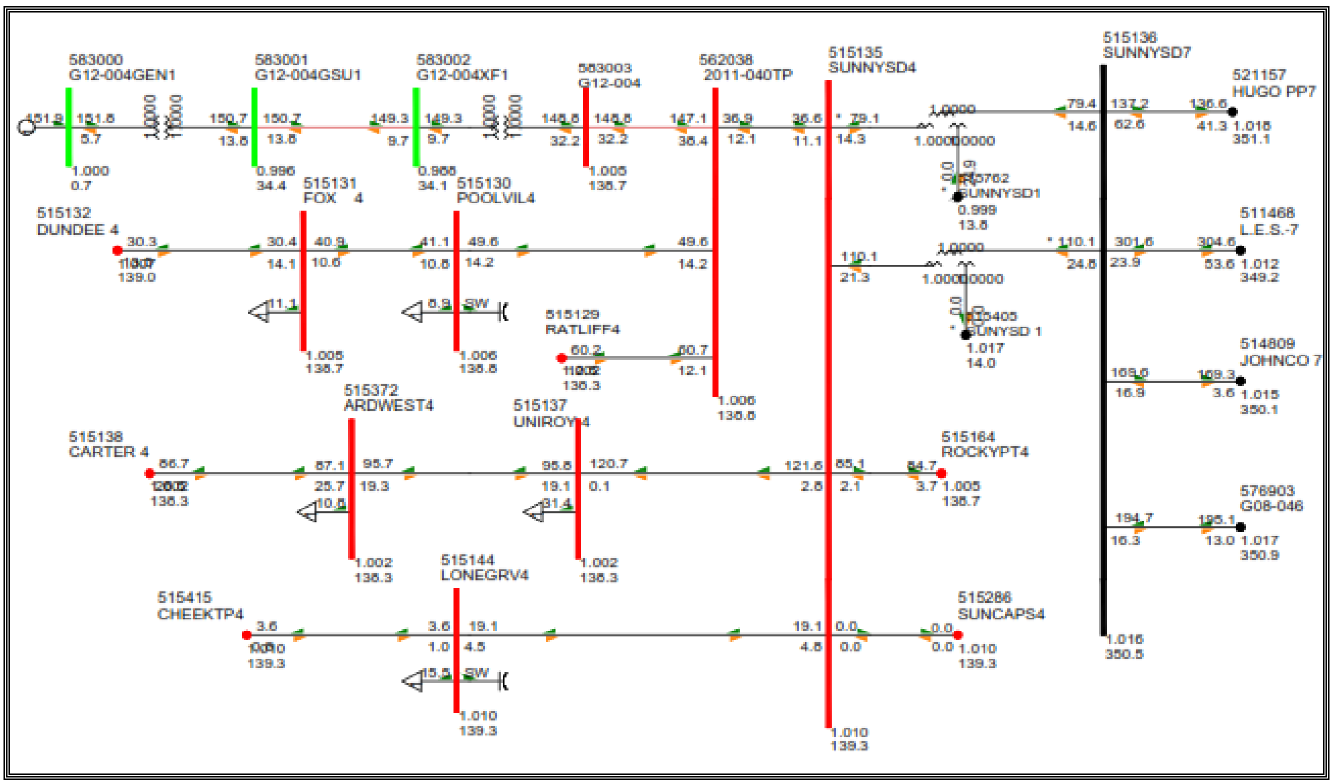

Figure 1.1: Power flow single line diagram for Gen-2012-001 and surrounding system components

Appendix-C contains the machine, interconnection, and machine user model parameters.

Table 1.2 below shows the list of prior queued projects modeled in the base case.

Table 1.2: List of previous queued request projects

Request	Size (MW)	Wind Turbine Model	Point of Interconnection
GEN-2008-046	198	Vestas V90 1.8MW	Sunnyside 345kV (515136)
GEN-2011-040	110.4	Siemens 2.3MW	Tap on Poolvil4 to Ratliff 138kV (562038)
GEN-2011-050	109.8	Vestas V90 1.8MW	Tap on the Rushspt4 to Ommarlo4 138kV line (G11_050-TAP 138kV, 562081)

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

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

1.2. Objectives

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

1.3. Models and Simulations Tools Used

Version 30.3.3 of the Siemens, PSS/E power system simulation program was used in this study.

SPP provided its stability database cases for both summer and winter peak seasons. The Project's PSS/E model had been developed prior to this study and was included in the power flow case and the dynamics database. Machine, interconnection and dynamic model data for the Project plant is provided in Appendix C.
Any upgrades and instructions provided by SPP were made to the base cases.

Power flow single line diagram of the project in summer peak conditions are shown in Figure 1.1. Figure 1.1 shows that wind farm model includes representation of the radial transmission line, the substation transformer from transmission voltage to 34.5kV. The remainder of each wind farm is represented by lumped equivalents including a generator, a step-up transformer, and collector system impedance.

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

All generators in Areas 531, 534, 536, 540, 541, 640, 645, 650, and 652 were monitored.

2.0 Power Factor Analysis

2.1. Methodology

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

1. Replace the wind farm by a generator at the high side bus, 345 or 138 kV bus, as applicable, with the MW of the wind farms at that point of interconnection and with no var capability.
2. Turn off the wind farm as modeled (as well as previous queued projects at the same point of interconnection).
3. Model a var generator at the Project's high voltage side, 345 or 138 kV bus, as applicable. The var generator is set to hold a voltage schedule at the POI consistent with the voltage schedule in the provided power flow cases for summer and winter or 1.0 pu voltage, whichever is higher.
4. Perform the steady state contingency analysis to determine the power factor necessary at the POI for each contingency.
5. If the required power factor at the POI is beyond the capability of the studied wind turbines to meet (at the POI) capacitor banks may be considered for the stability analysis. The preference is to locate the capacitance banks on the 34.5 kV customer side. Factors to sizing capacitor banks include:
    - 5.1. The ability of the wind farm to meet FERC Order 661A (low voltage ride through) with and without capacitor banks.
    - 5.2. The ability of the wind farm to meet FERC Order 661A (wind farm recovery to pre-fault voltage).
    - 5.3. If wind farms trips on high voltage, power factor lower than unity may be required.

2.2. Analysis

Analysis was performed for proposed Project with all prior queued projects in service. A var generator was modeled at the point of interconnection and was set to hold a voltage schedule at the POI consistent with the voltage schedule in the provided power flow cases. These voltages for this Project are summarized in Table 2.2. All upgrades and instructions were made in the base cases. No other changes were made in the base cases provided, other than the addition of the var generators. Contingency analysis was run for provided list of contingencies.

Table 2.2: POI voltages for the summer and winter peak cases

Request	Point of Interconnection	Size (MW)	Base Case Voltage (p.u.)	
			Summer Peak	Winter Peak
GEN-2012-004	Bus # 562038 (2011-040TP) 138.00kV	41.4	1.0057	1.0075

POI: (562038) - 2011-040TP 138kV line

The var generator either supplies or absorbs reactive power at different contingencies as summarized in Table 2.3. The highest values obtained are highlighted and as follows:

1. For the summer case, the maximum var generator supply is 39.7 MVARs for the outage of 511468 [L.E.S.-7 345.0] to BUS 511467 [L.E.S.-4 138.0] to BUS 411414 [LES#4-1 13.8] transformer branch. This requires maximum power factor of 0.967 lagging. The minimum var requirement is for outage of for 515136 [SUNNYSD7 345.0] to 521157 [HUGO PP7 345.0] CKT 1 requiring 27.1 MVAR at 0.984 power factor lagging.

Table 2.3: Var generator output in summer peak case for GEN-2012-004

Summer Case Power Factor Study:

Rated MW of Wind Farm OR at POI = 151.8MW Rated MVAR (lagging) of Wind Farm = 73.52 MVAR								
Cont. Name	**From Bus (# & Name)**		**To Bus (# & Name)**		**ID**	**MVAR at POI**	**% of Max MVAR**	**P.F at POI**
	Base Case MVAR Flow				N/A	39.1	53.183	0.968
FLT01-3PH	515136	SUNNYSD7 345.0	511468	L.E.S.-7 345.0	CKT 1	33.4	45.430	0.977
FLT03-3PH	515136	SUNNYSD7 345.0	514809	JOHNCO 7 345.0	CKT 1	38.3	52.095	0.970
FLT05-3PH	515136	SUNNYSD7 345.0	521157	HUGO PP7 345.0	CKT 1	27.1	36.861	0.984
FLT07-3PH	515136	SUNNYSD7 345.0	515135	SUNNYSD4 138.0	T/F	29.1	39.581	0.982
FLT08-3PH	562038	2011-040TP 138.0	515130	POOLVIL4 138.0	CKT 1	34.0	46.246	0.976
FLT10-3PH	562038	2011-040TP 138.0	515129	RATLIFF4 138.0	CKT 1	33.9	46.110	0.976
FLT12-3PH	515130	POOLVIL4 138.0	515131	FOX 4 138.0	CKT 1	35.7	48.558	0.973
FLT14-3PH	511468	L.E.S.-7 345.0	511467	L.E.S.-4 138.0	T/F	39.7	53.999	0.967
FLT15-3PH	515129	RATLIFF4 138.0	515134	PRARPNT4 138.0	CKT 1	31.5	42.845	0.979
FLT17-3PH	515131	FOX 4 138.0	515132	DUNDEE 4 138.0	CKT 1	32.9	44.750	0.977
FLT19-3PH	515138	CARTER 4 138.0	515118	JOLLYVL4 138.0	CKT 1	38.0	51.687	0.970
FLT21-3PH	521023	PAOLI 4 138.0	520822	BASELIN4 138.0	CKT 1	38.9	52.911	0.969
FLT23-3PH	511453	DUNCAN-4 138.0	511455	D.E.S.-4 138.0	CKT 1	39.2	53.319	0.968
FLT25-3PH	529304	OMDUNCN4 138.0	511494	COMMTAP4 138.0	CKT 1	38.8	52.775	0.969
FLT27-3PH	562038	2011-040TP 138.0	515135	SUNNYSD4 138.0	CKT 1	35.7	48.558	0.973
FLT29-3PH	515135	SUNNYSD4 138.0	515137	UNIROY 4 138.0	CKT 1	39.5	53.727	0.968
FLT31-3PH	515135	SUNNYSD4 138.0	515144	LONEGRV4 138.0	CKT 1	38.1	51.823	0.970
FLT33-3PH	515135	SUNNYSD4 138.0	515164	ROCKYPT4 138.0	CKT 1	38.7	52.639	0.969
FLT35-3PH	515129	RATLIFF4 138.0	515128	RATLIFF2 69.0	T/F	38.3	52.095	0.970
FLT36-3PH	515141	HLTNTAP4 138.0	515140	HLTNTAP2 69.0	T/F	38.8	52.775	0.969
FLT37-3PH	511453	DUNCAN-4 138.0	511452	DUNCAN-2 69.0	T/F	38.3	52.095	0.970
FLT38-3PH	515100	PAOLI- 4 138.0	515097	WLNUTCK4 138.0	CKT 1	39.5	53.727	0.968
FLT40-3PH	515100	PAOLI- 4 138.0	515044	SEMINOL4 138.0	CKT 1	32.5	44.206	0.978
FLT42-3PH	515100	PAOLI- 4 138.0	515124	MAYSVIL4 138.0	CKT 1	31.8	43.254	0.979
FLT44-3PH	515100	PAOLI- 4 138.0	515114	CHIGLEY4 138.0	CKT 1	38.1	51.823	0.970

2. For the winter case, the maximum var generator supply is -43.2 MVARs for the outage of 515135 [SUNNYSD4 138.0] to 515144 [LONEGRV4 138.0] CKT-1 line. This requires maximum power factor of 0.962 leading. The minimum var supply is for outage of for 515136 [SUNNYSD7 345.0] to 521157 [HUGO PP7 345.0] CKT 1 requiring -29.4 MVARs at unity power factor leading.

Table: 2.4 Var generator output in winter peak case for GEN-2012-004

Winter Case Power Factor Study

Rated MW of Wind Farm OR at POI = 151.8MW Rated MVAR (leading) of Wind Farm = -73.52 MVAR								
Cont. Name	**From Bus (# & Name)**		**To Bus (# & Name)**		**ID**	**MVAR at POI**	**% of Max MVAR**	**P.F at POI**
	Base Case MVAR Flow				N/A	-40.1	54.54	0.967
FLT01-3PH	515136	SUNNYSD7 345.0	511468	L.E.S.-7 345.0	CKT 1	-38.6	52.50	0.969
FLT03-3PH	515136	SUNNYSD7 345.0	514809	JOHNCO 7 345.0	CKT 1	-38.3	52.09	0.970
FLT05-3PH	515136	SUNNYSD7 345.0	521157	HUGO PP7 345.0	CKT 1	-29.4	39.99	0.982
FLT07-3PH	515136	SUNNYSD7 345.0	515135	SUNNYSD4 138.0	T/F	-34.3	46.65	0.975
FLT08-3PH	562038	2011-040TP 138.0	515130	POOLVIL4 138.0	CKT 1	-36.2	49.24	0.973
FLT10-3PH	562038	2011-040TP 138.0	515129	RATLIFF4 138.0	CKT 1	-31.2	42.44	0.980
FLT12-3PH	515130	POOLVIL4 138.0	515131	FOX 4 138.0	CKT 1	-34.6	47.06	0.975
FLT14-3PH	511468	L.E.S.-7 345.0	511467	L.E.S.-4 138.0	T/F	-40.0	54.41	0.967
LT15-3PH	515129	RATLIFF4 138.0	515134	PRARPNT4 138.0	CKT 1	-31.5	42.85	0.979
FLT17-3PH	515131	FOX 4 138.0	515132	DUNDEE 4 138.0	CKT 1	-32.9	44.75	0.977
FLT19-3PH	515138	CARTER 4 138.0	515118	JOLLYVL4 138.0	CKT 1	-39.3	53.45	0.968
FLT21-3PH	521023	PAOLI 4 138.0	520822	BASELIN4 138.0	CKT 1	-39.9	54.27	0.967
FLT23-3PH	511453	DUNCAN-4 138.0	511455	D.E.S.-4 138.0	CKT 1	-40.1	54.54	0.967
FLT25-3PH	529304	OMDUNCN4 138.0	511494	COMMTAP4 138.0	CKT 1	-39.9	54.27	0.967
FLT27-3PH	562038	2011-040TP 138.0	515135	SUNNYSD4 138.0	CKT 1	-38.7	52.64	0.969
FLT29-3PH	515135	SUNNYSD4 138.0	515137	UNIROY 4 138.0	CKT 1	-39.1	53.18	0.968
FLT31-3PH	515135	SUNNYSD4 138.0	515144	LONEGRV4 138.0	CKT 1	-43.2	58.76	0.962
FLT33-3PH	515135	SUNNYSD4 138.0	515164	ROCKYPT4 138.0	CKT 1	-38.9	52.91	0.969
FLT35-3PH	515129	RATLIFF4 138.0	515128	RATLIFF2 69.0	T/F	-39.3	53.45	0.968
FLT36-3PH	515141	HLTNTAP4 138.0	515140	HLTNTAP2 69.0	T/F	-41.2	56.04	0.965
FLT37-3PH	511453	DUNCAN-4 138.0	511452	DUNCAN-2 69.0	T/F	-39.5	53.73	0.968
FLT38-3PH	515100	PAOLI- 4 138.0	515097	WLNUTCK4 138.0	CKT 1	-38.8	52.77	0.969
FLT40-3PH	515100	PAOLI- 4 138.0	515044	SEMINOL4 138.0	CKT 1	-33.7	45.84	0.976
FLT42-3PH	515100	PAOLI- 4 138.0	515124	MAYSVIL4 138.0	CKT 1	-32.7	44.48	0.978
FLT44-3PH	515100	PAOLI- 4 138.0	515114	CHIGLEY4 138.0	CKT 1	-39.6	53.86	0.968

2.3. Conclusions

The power factor analysis indicates the GEN-2012-004 interconnection request is required to maintain 0.967 lagging (supplying vars) and 0.962 leading (absorbing vars) power factors at the point of interconnection (Bus # 562038 (2011-040TP) 138.0kV).

3.0 Stability Analysis

3.1 Faults Simulated

Forty five (45) faults were considered for the transient stability simulations which included three phase faults, as well as single phase line faults, at the locations defined by SPP. Single-phase line faults were simulated by applying a fault impedance to the positive sequence network at the fault location. As per the SPP current practice to compute the fault levels, the fault impedance was computed to give a positive sequence voltage at the specified fault location of approximately 60% of pre-fault voltage. Prior queued projects shown in item #10 in the study request i.e., (GEN-2008-046, GEN-2011-040, GEN-2011-050), other important neighboring machines and buses, as well as areas number 520, 524, 525, 526, 531, 534, and 536 were monitored during all the simulations. Table 3.1 shows the list of simulated contingencies. This list also shows the fault clearing time and the time delay before re-closing for all the study contingencies.

Simulations were performed with a 0.1-second steady-state run followed by the appropriate disturbance as described in Table 3.1. Simulations were run for minimum 15-second duration to confirm proper machine damping.

Table 3.1 summarizes the overall results for all faults run. Complete sets of plots for both summer and winter peak seasons for each fault are included in Appendices A and B respectively.

For each power flow case, the following faults were run (3-phase and single phase, as noted).

Table 3.1: List of simulated faults for stability analysis

Cont. #	Contingency Name	Description	Summer Results	Winter Results
1	FLT01-3PH	3 phase fault on the Sunnyside (515136) to Lawton Eastside (511468) 345kV line, near Sunnyside. a. Apply fault at Sunnyside 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable
2	FLT02-1PH	*Single phase fault and sequence like previous*	Stable	Stable
3	FLT03-3PH	3 phase fault on the Sunnyside (515136) to Johnston County (514809) 345kV line, near Sunnyside. a. Apply fault at Sunnyside 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable
4	FLT04-1PH	*Single phase fault and sequence like previous*	Stable	Stable
5	FLT05-3PH	3 phase fault on the Sunnyside (515136) to Hugo (521157) 345kV line, near Sunnyside. a. Apply fault at Sunnyside 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable
6	FLT06-1PH	*Single phase fault and sequence like previous*	Stable	Stable
7	FLT07-3PH	3 phase fault on the Sunnyside 345kv (515136) to Sunnyside 138kV (515135) / Sunnyside 13.8kV (515405) transformer on the 345kV bus. a. Apply fault at Sunnyside 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.	Stable	Stable
8	FLT08-3PH	3 phase fault on the GEN-2011-040 (562038) to Pooleville (515130) 138kV line, near GEN-2011-040. a. Apply fault at GEN-2011-040 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable
9	FLT09-1PH	*Single phase fault and sequence like previous*	Stable	Stable

Cont. #	Contingency Name	Description	Summer Results	Winter Results
10	FLT10-3PH	3 phase fault on the GEN-2011-040 (562038) to Ratliff (515129) 138kV line, near GEN-2011-040. a. Apply fault at GEN-2011-040 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable
11	FLT11-1PH	*Single phase fault and sequence like previous*	Stable	Stable
12	FLT12-3PH	3 phase fault on the Pooleville (515130) to Fox (515131) 138kV line, near Pooleville. a. Apply fault at Pooleville 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable
13	FLT13-1PH	*Single phase fault and sequence like previous*	Stable	Stable
14	FLT14-3PH	3 phase fault on one of the Lawton Eastside 345kV (511468) to138kV (511467) transformers on the 345kV bus. a. Apply fault at Lawton Eastside 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.	Stable	Stable
15	FLT15-3PH	3 phase fault on the Ratliff (515129) to Prairie Point (515134) 138kV line, near Ratliff. a. Apply fault at Ratliff 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable
16	FLT16-1PH	*Single phase fault and sequence like previous*	Stable	Stable
17	FLT17-3PH	3 phase fault on the Fox (515131) to Dundee (515132) 138kV line, near Dundee. a. Apply fault at Dundee 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable
18	FLT18-1PH	*Single phase fault and sequence like previous*	Stable	Stable
19	FLT19-3PH	3 phase fault on the Carter (515138) to Jollyville (515118) 138kV line, near Carter. a. Apply fault at Carter 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable
20	FLT20-1PH	*Single phase fault and sequence like previous*	Stable	Stable

Cont. #	Contingency Name	Description	Summer Results	Winter Results
21	FLT21-3PH	3 phase fault on the Paoli (521023) to Baseline (520822) 138kV line, near Paoli. a. Apply fault at Paoli 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable
22	FLT22-1PH	*Single phase fault and sequence like previous*	Stable	Stable
23	FLT23-3PH	3 phase fault on the Duncan (511453) to Duncan Eastside (511455) 138kV line, near Duncan. a. Apply fault at Duncan 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable
24	FLT24-1PH	*Single phase fault and sequence like previous*	Stable	Stable
25	FLT25-3PH	3 phase fault on the OMDuncan (529304) to Comanche Tap (511494) 138kV line, near OMDuncan. a. Apply fault at OMDuncan 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable
26	FLT26-1PH	*Single phase fault and sequence like previous*	Stable	Stable
27	FLT27-3PH	3 phase fault on the Sunnyside (515135) to GEN-2011-040 Tap (562038) 138kV line, near GEN-2011-040 Tap. a. Apply fault at GEN-2011-040 Tap 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable
28	FLT28-1PH	*Single phase fault and sequence like previous*	Stable	Stable
29	FLT29-3PH	3 phase fault on the Sunnyside (515135) to Uniroyal (515137) 138kV line, near Sunnyside. a. Apply fault at Sunnyside 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable
30	FLT30-1PH	*Single phase fault and sequence like previous*	Stable	Stable

Cont. #	Contingency Name	Description	Summer Results	Winter Results
31	FLT31-3PH	3 phase fault on the Sunnyside (515135) to Lone Grove (515144) 138kV line, near Sunnyside. a. Apply fault at Sunnyside 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable
32	FLT32-1PH	*Single phase fault and sequence like previous*	Stable	Stable
33	FLT33-3PH	3 phase fault on the Sunnyside (515135) to Rocky Point (515164) 138kV line, near Sunnyside. a. Apply fault at Sunnyside 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable
34	FLT34-1PH	*Single phase fault and sequence like previous*	Stable	Stable
35	FLT35-3PH	3 phase fault on the Ratliff 138kV (515129) to Healdton Tap 69kV (515128) transformer, on the 138kV bus. a. Apply fault at Ratliff 138kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.	Stable	Stable
36	FLT36-3PH	3 phase fault on the Healdton Tap 138kV (515141) to Ratliff 69kV (515140) transformer, on the 138kV bus. a. Apply fault at Healdton Tap 138kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.	Stable	Stable
37	FLT37-3PH	3 phase fault on the Duncan 138kV (511453) to Duncan 69kV (511452) transformer, on the 138kV bus. a. Apply fault at Duncan 138kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.	Stable	Stable
38	FLT38-3PH	3 phase fault on the Paoli (515100) to Walnut Creek (515097) 138kV line, near Paoli. a. Apply fault at Paoli 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable
39	FLT39-1PH	*Single phase fault and sequence like previous*	Stable	Stable
40	FLT40-3PH	3 phase fault on the Paoli (515100) to Seminole (515044) 138kV line, near Paoli. a. Apply fault at Paoli 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable

Cont. #	Contingency Name	Description	Summer Results	Winter Results
41	FLT41-1PH	*Single phase fault and sequence like previous*	Stable	Stable
42	FLT42-3PH	3 phase fault on the Paoli (515100) to Maysville (515124) 138kV line, near Paoli. a. Apply fault at Paoli 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable
43	FLT43-1PH	*Single phase fault and sequence like previous*	Stable	Stable
44	FLT44-3PH	3 phase fault on the Paoli (515100) to Chigley (515114) 138kV line, near Paoli. a. Apply fault at Paoli 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable	Stable
45	FLT45-1PH	*Single phase fault and sequence like previous*	Stable	Stable

3.2 Simulation Results

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

4.0 Conclusions

The findings of the impact study for the proposed interconnection project under DISIS-2012-001 (Group-14), Gen-2012-004, considered at 100% of their proposed installed capacity is as follows:

1. The power factor analysis indicates the GEN-2012-004 interconnection request is required to maintain 0.967 lagging (supplying vars) and 0.962 leading (absorbing vars) power factors at the point of interconnection; Bus # 562038 (2011-040TP) 138.0kV.

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