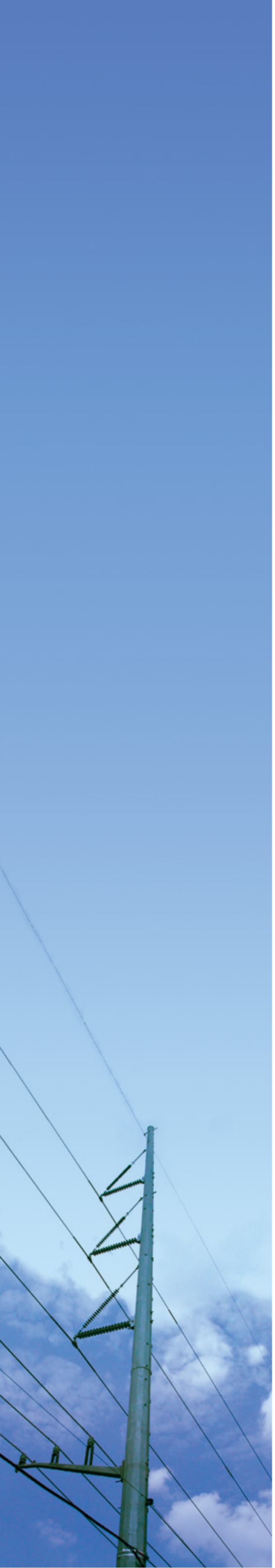

Impact Cluster Study for Generation Interconnection Requests

Southwest Power Pool
Engineering Department
Tariff Studies – Generation Interconnection

(ICS-2008-001)
July 2009

SPP RESTRICTED

Executive Summary

Pursuant to the Federal Energy Regulatory Commission's (FERC) order in Docket No. ER09-262-000, Southwest Power Pool has conducted this Impact Study for certain generation interconnection requests in the SPP Generation Interconnection Queue. These interconnection requests have been clustered together for the following Impact Cluster Study. This Impact Cluster Study analyzes the interconnecting of multiple generation interconnection requests associated with new generation totaling 12,744 MW of new generation which would be located within the transmission systems of American Electric Power West (AEPW), Empire District Electric (EMDE), Midwest Energy Inc. (MIDW), Missouri Public Service (MIPU), Mid-Kansas Electric Power LLC (MKEC), Oklahoma Gas and Electric (OKGE), Southwestern Public Service (SPS), Sunflower Electric Power Corporation (SUNC), Westar Energy (WERE) and/or Western Farmers Electric Cooperative (WFEC). The various generation interconnection requests have differing proposed in-service dates1. The generation interconnection requests included in this Impact Cluster Study are listed in Appendix A by their queue number, amount, area, requested interconnection point, proposed interconnection point, and the requested in-service date.

This Impact Cluster Study report also includes Impact Studies for several generation interconnection requests associated with new generation totaling 550MW, which are electrically isolated from the generation that has been clustered together. These new generation projects will be located within the transmission systems of Empire District Electric (EMDE), Missouri Public Service (MIPU), and Mid-Kansas Electric Company LLC (MKEC). The Impact Studies for the electrically isolated new generation are included in Appendix J.

Power flow analysis has indicated that for the powerflow cases studied, 12,744 MW of nameplate generation may be interconnected with transmission system reinforcements within the SPP transmission system. Dynamic Stability 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 Interconnection Facilities to the Impact Cluster Study Generation Interconnection Customers. Certain issues will need to be addressed during the Facility Study stage including the following items:

- Possible observed instability in Nebraska Public Power District for faults at Gentlemen Power Station and faults within the SPP footprint involving Groups 3 and Groups 4 as described in the stability study for these groups.
- GEN-2007-019 interconnection request on the Lamar – Finney 345kV line will need to have additional analysis performed with regards to harmonics and a possible sub-synchronous resonance study (SSR) to determine interactions with the Lamar HVDC tie.
- The proposed 345kV lines out of Xcel (Southwestern Public Service) will require an electrical switching transients study (EMTP study) to determine the need and size of transmission line reactors.

[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 completion of the Facility Study.

- GEN-2008-001 interconnection request – determine whether oscillations of the wind turbines observed during certain simulations are actual behavior or are modeling issues.

The total estimated minimum cost for interconnecting the studied generation interconnection request is $1,705,000,000. These costs are shown in Appendix F and G. 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 that were identified are shown in Appendix I.

Network Constraints listed in Appendix I are in the local area of the new generation when this generation is injected throughout the SPP footprint for the Energy Resource (ER) Interconnection Request. 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 F and G 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.

Based on the SPP Tariff Attachment O, transmission facilities that are part of the SPP Transmission Expansion Plan (STEP) including Sponsored Economic Upgrades or the Balanced Portfolio that may be approved by the SPP Board of Directors will receive notifications to construct. These projects will then be considered construction pending projects and would not be assignable to the Impact Cluster Study Generation Interconnection Requests.

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Introduction

Generation Interconnection Requests in the Southwest Power Pool (SPP) Generation Interconnection Queue have been clustered together for the following Impact Cluster Study. This Impact Cluster Study analyzes multiple generation interconnection requests associated with new generation totaling 12,744 MW which would be located within the transmission systems of American Electric Power West (AEPW), Empire District Electric (EMDE), Midwest Energy Inc. (MIDW), Missouri Public Service (MIPU), Mid-Kansas Electric Power LLC (MKEC), Oklahoma Gas and Electric (OKGE), Southwestern Public Service (SPS), Sunflower Electric Power Corporation (SUNC), Westar Energy (WERE) and/or Western Farmers Electric Cooperative (WFEC). The various generation interconnection requests have differing proposed in-service dates. The generation interconnection requests included in this Impact Cluster Study are listed in Appendix A by their queue number, amount, area, requested interconnection point, proposed interconnection point, and the requested in-service date.

This Impact Study also analyzes the interconnection of three generation interconnection requests totaling 500 MW of new generation which are electrically isolated to the Cluster. These new generation projects will be located within the transmission systems of Empire District Electric (EMDE), Missouri Public Service (MIPU), and/or Mid-Kansas Electric Company LLC (MKEC). The Impact Studies for the electrically isolated new generation are included in Appendix S.

The primary objective of this Impact Cluster 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.

Model Development

Interconnection Requests Included in the Cluster

SPP has included the following interconnection requests to be analyzed in this cluster study. The interconnection requests are listed in Appendix A.

All interconnection requests with a queue date prior to March 17, 2008 that have not yet executed a Facility Study Agreement (all queue positions through GEN-2008-020 without executed Facility Study Agreements).

Two interconnection requests listed below had executed Facility Study Agreements that were given the option to be studied in the Impact Cluster study and chose to be included in this Impact Cluster Study.

- GEN-2006-006
- GEN-2007-008

Electrically Isolated Interconnection Requests – There were three interconnection requests that were determined to be electrically isolated in that they did not share common electrical constraints/impacts with the rest of the cluster interconnection studies. These interconnection requests total 500 MW and are denoted in Appendix A with a footnote. These studies are posted in Appendix S. Interconnection request GEN-2007-053 was not able to be completed at this time due to modeling issues with the Customer requested wind turbines. SPP is currently working with the manufacturer to finalize this study. The delay of this study did not affect the remainder of the cluster.

Previous Queued Projects

The previous queued projects included in this study are listed in Appendix B. In addition to the Base Case Upgrades, the previous queued projects 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.

Development of Base Cases

Powerflow - The 2008 series Transmission Service Request (TSR) Models 2010 spring and 2012 summer and winter peak scenario 0 peak cases were used for this study. The 2010 spring case was created using the 2009 spring case. The load in each of SPP's control areas were scaled up approximately 2% for each year for a total of 2% total load scaling. After the 2010 spring and the 2012 summer peak cases were developed, each of the control areas' resources were then re-dispatched using current dispatch orders.

Stability – The 2008 series SPP Model Development Working Group (MDWG) Models 2010 winter and 2010 summer were used for this study.

Base Case Upgrades

The following facilities have been previously assigned or are in construction stages and were assumed to be in-service at the time of dispatch and added to the base case models.

- Woodward – Northwest 345kV line and associated upgrades to be built by OKGE for 2009 in-service[2].
- Hitchland 345/230/115kV upgrades to be built by SPS for 2010/2011 in-service[3].
- Hitchland – Pringle 230kV line
- Hitchland – Moore County 230kV line
- Hitchland – Ochiltree 230kV line
- Hitchland – Texas County 115kV line
- Hitchland – Hansford County 115kV line
- Hitchland – Sherman County Tap 115kV line
- Valliant – Hugo – Sunnyside 345kV – assigned to Aggregate Study AG3-2006 Customers for 2011 in-service
- Wichita – Reno County – Summit 345kV to be built by WERE for 2011 in-service[4].
- Rose Hill – Sooner 345kV to be built by WERE/OKGE for 2010 in-service.
- Finney – Holcomb 345kV Ckt #2 line assigned to GEN-2006-044 interconnection customer for possible 2010 in-service[5].

[2] Approved based on an order of the Corporation Commission of the State of Oklahoma, Cause No. PUD 200800148 Order No. 55935

[3] Approved 230kV upgrades are based on SPP 2007 STEP. Upgrades may need to be re-evaluated in the system impact study.

[4] Approved based on an order of the Kansas Corporation Commission issued in Docket no. 07-WSEE-715-MIS

- Hitchland – Woodward 345kV line assigned to GEN-2006-049 interconnection customer for in service date yet to be determined

Potential Upgrades Not in the Base Case
Any potential upgrades that do not have a Notification to Construct (NTC) to construct 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.

The recently approved Balanced Portfolio projects were issued NTCs at a time that those projects could not be incorporated into this study. During the Facility Study phase for these interconnection requests, the Balanced Portfolio projects will be added to the base case and the interconnection requests facilities and cost allocation will be re-evaluated at that time.

Regional Groupings
The interconnection requests listed in Appendix A were grouped together in eight different regional groups based on geographical and electrical impacts. These groupings are shown in Appendix C.

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

Powerflow - 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 eight 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. 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.

Peaking units were not dispatched in the 2010 spring model. To study peaking units' impacts, the 2012 summer peak model was chosen and peaking units were modeled at 100% of the nameplate rating and wind generating facilities were modeled at 10% of the nameplate rating.

Stability - For each group, all interconnection requests (wind and non-wind) were modeled at 100% nameplate of maximum generation in both winter and summer seasonal models. The wind interconnection requests in the other areas were modeled at 20% nameplate of maximum generation while fossil units were modeled at 100% in the other areas. This process created eight different scenarios with each group being studied at 100% nameplate rating. These projects were dispatched as Energy Resources with equal distribution across the SPP footprint.

[5] Based on Facility Study Posting November 2008

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.

Determination of Cost Allocated Network Upgrades

Cost Allocated Network Upgrades of wind generation interconnection requests were determined using the 2010 spring model. Cost Allocated Network Upgrades of peaking units was determined using the 2012 summer peak model. Once a determination of the required Network Upgrades was made, a powerflow model of the 2010 spring case was developed with all cost allocated Network Upgrades in-service. A MUST FCITC analysis was performed to determine the Power Transfer Distribution Factors (PTDF), defined as a distribution factor with system intact conditions 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:

  Request X Impact Factor on Upgrade Project 1 = PTDF(%)(X) * MW(X) = X1

  Request Y Impact Factor on Upgrade Project 1 = PTDF(%)(Y) * MW(Y) = Y1

  Request Z Impact Factor on Upgrade Project 1 = PTDF(%)(Z) * MW(Z) = Z1

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

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

- Repeat previous for each responsible GI request for each Project

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

Credits for Amounts Advanced for Network Upgrades

Interconnection Customer shall be entitled to credits in accordance with Attachment Z1 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.

Interconnection Facilities

The requirement to interconnect the 12,744 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 G. Interconnection Facilities specific to each generation interconnection request are listed in Appendix F. Appendix G lists the costs by upgrade.

Other Network Constraints in the AEPW, MIDW, OKGE, SPS, SUNC, SWPA, MKEC, WERE, AND WFEC transmission systems that were identified are shown in Appendix I. 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.

A preliminary one-line drawing for each generation interconnection request are listed in Appendix D. Figure 1 depicts the major transmission line Network Upgrades needed to support the interconnection of the generation amounts requested in this study.

Powerflow

Powerflow 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 contingencies in portions or all of the modeled control areas of AEPW, EMDE, Grand River Dam Authority (GRDA), Kansas City Power & Light (KCPL), MIDW, MIPU, OKGE, SPS, SUNC, WERE, WFEC and other control areas were applied and the resulting scenarios analyzed. This satisfies the “more probable” contingency testing criteria mandated by NERC and the SPP criteria.

Powerflow Analysis

A powerflow analysis was conducted for each Interconnection Customer’s facility using modified versions of the 2010 spring peak and the 2012 summer 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. The available seasonal models used were through the 2012 Summer Peak.

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

Cluster Group 1 (Woodward Area)

The Woodward area contained approximately 2,769 MW of new interconnection requests in addition to the 739MW of prior queued interconnection requests The major constraints in the Woodward area consists of the proposed Woodward – Northwest 345kV line, the Mooreland – Elk City 138kV line, and the Roman Nose – El Reno 138kV line. To mitigate these constraints, an additional 345kV line was modeled and all new interconnection requests along the Roman Nose – El Reno path were modeled at the 345kV voltage level. In addition, a 345kV line was modeled from Woodward to Comanche County, Kansas and a 345kV transmission line from Comanche County to Wichita, Kansas to alleviate constraints that were impacted by the Woodward group.

Cluster Group 2 (Hitchland Area)

The Hitchland area contained 2,195 MW of interconnection request in addition to the 2,068 MW of previous queued generation interconnection requests. GEN-2006-049 Interconnection Customer was included in the Feasibility Study for Cluster 1. Because GEN-2006-049 had already had an Impact Study posted and completed, this customer had the option not be included in the Cluster and exercised that option. In the separate Impact Study conducted solely for GEN-2006-049, the Customer has been assigned the 345kV line from Hitchland to Woodward. The major constraints for the Hitchland area included all Southwestern Public Service tie lines to both American Electric Power West and Sunflower Electric Power Corporation as well as the 345kV line to Nebraska. Due to approximately 1,300 MW withdrawing after the Feasibility Cluster Study and because the Hitchland-Woodward 345kV line was previously assigned to GEN-2006-049, a solution set was able to be obtained without the need for 765kV facilities. The resulting solution may also act as a collector system for the various interconnection requests.

These 345kV lines include a line from Hitchland to a new substation in Beaver County, Oklahoma. The new Beaver County substation will have a second line that traverses northwest to a point in Stevens County, Kansas where it will intersect and tap the Hitchland – Finney 345kV line. This substation is intended to be the proposed interconnection point of both GEN-2003-013 and GEN-2006-049. A third line will connect to the Beaver County substation that will terminate at the Woodward 345kV substation. Also necessary for the Hitchland area group of interconnection requests was an additional line out of the Stevens County, Kansas substation that terminates to a new substation on the Holcomb – Spearville 345kV line in Gray County, Kansas that is the proposed interconnection point for GEN-2007-040.

The Hitchland group interconnection requests also utilized proposed upgrades in the Woodward, Amarillo, and Spearville areas.

Cluster Group 3 (Spearville Area)

The Spearville area contained 2,686 MW of interconnection requests and 660 MW of previous queued interconnection requests. The major constraints caused by the Spearville area cluster included the Spearville – Mullergren 230kV line, the Spearville 345/230kV transformer, the Holcomb – Setab – Mingo – Red Willow 345kV line, and the Hitchland – Finney 345kV line. To mitigate these constraints, two connections to Wichita are necessary, one via Comanche substation, and one that traverse on a more direct path from Spearville to Wichita, both at 345kV. It was seen, however, that with both of these 345kV paths to the east that the Spearville – Mullergren 230kV line may overload. This, however, is not a stability issue, and it may be possible that the loading could be brought under control with the addition of a series line reactor at Spearville to limit loading on Spearville – Mullergren and also to force through flow to stay on the 345kV system. Also, to alleviate loadings on the Mingo – Red Willow 345kV line, a Mingo – Knoll 345kV line was modeled which is used primarily by the Mingo/NW Kansas group but was also allocated to this group to reduce overloads on the Mingo – Red Willow line.

Cluster Group 4 (Mingo/NW Kansas Group)

The Mingo/NW Kansas group had 1,004 MW in addition to the 715 MW of previously queued generation in the area. The major constraints that were caused by this grouping of interconnection requests were very similar to the Spearville group. As such, the same mitigations were used for this group as the Spearville group.

Cluster Group 5 (Amarillo Area)

The Amarillo group had 1,401 MW of interconnection requests in addition to the 1,606 MW of previously queued interconnection requests in this area. The major constraints were all of the SPS area tie lines. The solution set for this area varied slightly from the Feasibility Study. It was determined that a Grapevine – Lawton Eastside (LES) 345kV line proved to be a better solution than terminating the LES line at Beckham. This solution lessens the loading on a Grapevine – Beckham 345kV line. The resulting solution set was a single line 345kV line from Potter – Grapevine; from Grapevine two lines including the 345kV line to LES and another to Anadarko via Beckham County. In addition, to lower the flows on the Nichols – Grapevine – Elk City 230kV line, part of the mitigation involves disconnecting certain previous queued projects from the 230kV line and reconnecting them to the proposed 345kV system at Beckham County. It is recommended that the new 345kV system not tie into the 230kV system at any point between Potter and Anadarko/Lawton. The 345kV buses at Grapevine and Beckham County do not have interconnections to the 230kV system. This results in a higher than expected cost allocation for the generation interconnection requests along this corridor because the interconnection requests are entirely using these new lines and are not using the existing system in the area to any extent. These interconnection requests include GEN-2007-008, GEN-2007-030, and GEN-2007-045.

Cluster Group 6 (South Panhandle/New Mexico)

This group had 1,230 MW of interconnection requests in addition to the 870 MW of previously queued interconnection requests. The major constraints in this area were all SPS tie lines. As a result, the solution set of network upgrades was similar to the Amarillo group. Another major constraint in this area included a corridor between Tuco and Grassland. When the Tuco – Grassland 230kV circuit was outaged, the result was an overload of the 115kV system.

Cluster Group 7 (Southwestern Oklahoma)

This group had 660 MW of interconnection requests in addition to the 947 MW of previous queued generation in the area. Since most of the generation in this area had requested points of interconnection into relatively strong places on the existing transmission system, most constraints were on the local system. It was seen that the 345kV line from Beckham County – Anadarko relieved most of these local constraints.

Cluster Group 8 (South Central Kansas)

GEN-2007-025 had been grouped in the Spearville group in the Facility Study. For the Impact Study, GEN-2007-025 was broken out of Group 3 due to is geographical distance from the Kansas – Colorado border and because it had few common impacts with the requests west of Spearville. The result was that GEN-2007-025 was assigned portions of the 345kV lines along a corridor from Wichita – Comanche – Woodward – Oklahoma City.

Stability Analysis

A stability analysis was conducted for each Interconnection Customer's facility using modified versions of the 2010 winter peak and the 2010 summer peak models. The stability analysis was conducted with all upgrades in service that were identified in the powerflow 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)

The Group 1 stability study was conducted by S&C Consulting Services (S&C). The Woodward area contained saw system stability issues due potential voltage stability issues at the Tatonga substation. GEN-2008-019 interconnection request was initially requested to step down to 138kV at Tatonga and include a 138kV line to its generating facility. Due to stability issues for the Mitsubishi turbines, it was determined that the GEN-2008-019 interconnection request will need to have a 345kV transmission line to its generating facility and step down to 138kV a that point.

It was determined that all interconnection requests in the Woodward area will have a power factor requirement as listed in the study for Group 1 at the point of interconnection in accordance with FERC Order #661A in order to maintain a reliable and stable system. With the power factor requirements and all network upgrades in service, all interconnection request in Group 1 will meet FERC Order #661A low voltage ride through (LVRT) requirements.

Cluster Group 2 (Hitchland Area)

The Group 2 stability study was conducted by Power Technologies Inc (PTI). The Hitchland area was seen to have stability issues that were primarily due to the addition of GEN-2007-056. It was determined that a second 345kV line is necessary to be built for the GEN-2007-056 interconnection request to connect to Hitchland. In addition, lower impedence transformers are required for GEN-2007-056.

It was determined that all interconnection requests in the Hitchland area will have a power factor requirement as listed in the study for Group 2 at the point of interconnection in accordance with FERC Order #661A in order to maintain a reliable and stable system.

With the power factor requirements and all network upgrades in service, all interconnection request in Group 2 will meet FERC Order #661A low voltage ride through (LVRT) requirements.

Cluster Group 3 (Spearville Area)
The Group 3 stability study was conducted by S&C. The Spearville area analysis determined there may be possible interactions with generators in Nebraska Public Power District (NPPD) that may cause instability. SPP will work with NPPD during the Facility Study to determine the effects upon NPPD. It was determined that all interconnection requests in the Spearville area will have a power factor requirement as listed in the study for Group 3 at the point of interconnection in accordance with FERC Order #661A.

Further analysis is required for the GEN-2007-019 interconnection request on the Lamar – Finney 345kV line to determine what harmonic or sub-synchronous resonance (SSR) interactions may affect the Lamar HVDC tie.

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

Cluster Group 4 (Mingo Area)
The Group 4 stability study was conducted by ABB Consulting Inc. (ABB). The Mingo area stability analysis observed some sustained oscillations due to the addition of Gamesa G87 wind turbines for GEN-2008-001. Further consultation is needed with the manufacturer to determine whether this issue is a modeling inaccuracy or a real system problem. It was determined that all interconnection requests in the Mingo area required to provide varying power factors that depending on the wind turbines used by the requests could results in the need for additional capacitor banks in accordance with FERC Order #661A.. It was also observed that possible instability in NPPD may occur for faults on the Gentleman – Red Willow 345kV line even with the addition of the Mingo – Knoll 345kV line. SPP will work with NPPD during the Facility Study to determine whether additional facilities need to be added as to not degrade reliability in this area. The recently approved Balanced Portfolio project, Spearville – Knoll – Axtell will also have to evaluated to determine the effects on both Group 4 and NPPD.

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

Cluster Group 5 (Amarillo Area)
The Group 5 stability study was conducted by Excel Engineering Inc. (Excel) The Amarillo area stability analysis determined that prolonged oscillations of Suzlon S88 wind turbines were prevalent in this area. However, the system was stable and the oscillations died out within 20-30 seconds. It was determined that all interconnection requests in the Amarillo area are required to provide 95% leading/lagging power factor at the point of interconnection in accordance with FERC Order #661A.

With the power factor requirements and all network upgrades in service, all interconnection request in Group 5 will meet FERC Order #661A low voltage ride through (LVRT) requirements.

Cluster Group 6 (South Panhandle Area)

The Group 6 stability study was conducted by Power Technologies Inc. (PTI). Stability issues were associated with the GEN-2007-027 interconnection request. However, it was determined that several of these issues were due to in service generation. It was determined that all interconnection requests in the New Mexico / south panhandle area are required to provide 95% leading/lagging power factor at the point of interconnection in accordance with FERC Order #661A.

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

Cluster Group 7 (Southwest Oklahoma)

The Group 7 stability analysis was conducted by AMEC Earth and Environmental (AMEC). The Southwest Oklahoma stability analysis revealed no stability issues with the study requests. It was determined that all interconnection requests in the southwest Oklahoma area will have power factor requirements as denoted in the study.

With the power factor requirements and all network upgrades in service, all interconnection request in Group 7 will meet FERC Order #661A low voltage ride through (LVRT) requirements.

Cluster Group 8 (South Central Kansas)

The Group 8 stability analysis was conducted by Pterra Consulting (Pterra). The GEN-2007-025 stability analysis revealed no stability issues with the study requests. It was determined that GEN-2007-025 will need to meet a +/-95% power factor at the point of interconnection. With the power factor requirements and all network upgrades in service, GEN-2007-025 will meet FERC Order #661A low voltage ride through (LVRT) requirements.

Additional Analysis to be Performed during Facility Study

Transient Switching Studies - 345kV transmission lines that have been proposed by this Cluster Study to be installed and constructed in the Southwestern Public Service territory will need to have transient switching studies performed during the Facility Study stage to determine the need and size of line reactors (switched or fixed).

Short Circuit Studies – Each Transmission Owner will be asked to conduct a short circuit analysis of circuit breakers and other equipment within their transmission systems during the Facility Study to determine if the addition of the ICS-2008-001 generation and the additional transmission lines will cause short circuit duty ratings to be exceeded on any existing equipment.

Regional Map with Proposed Upgrades

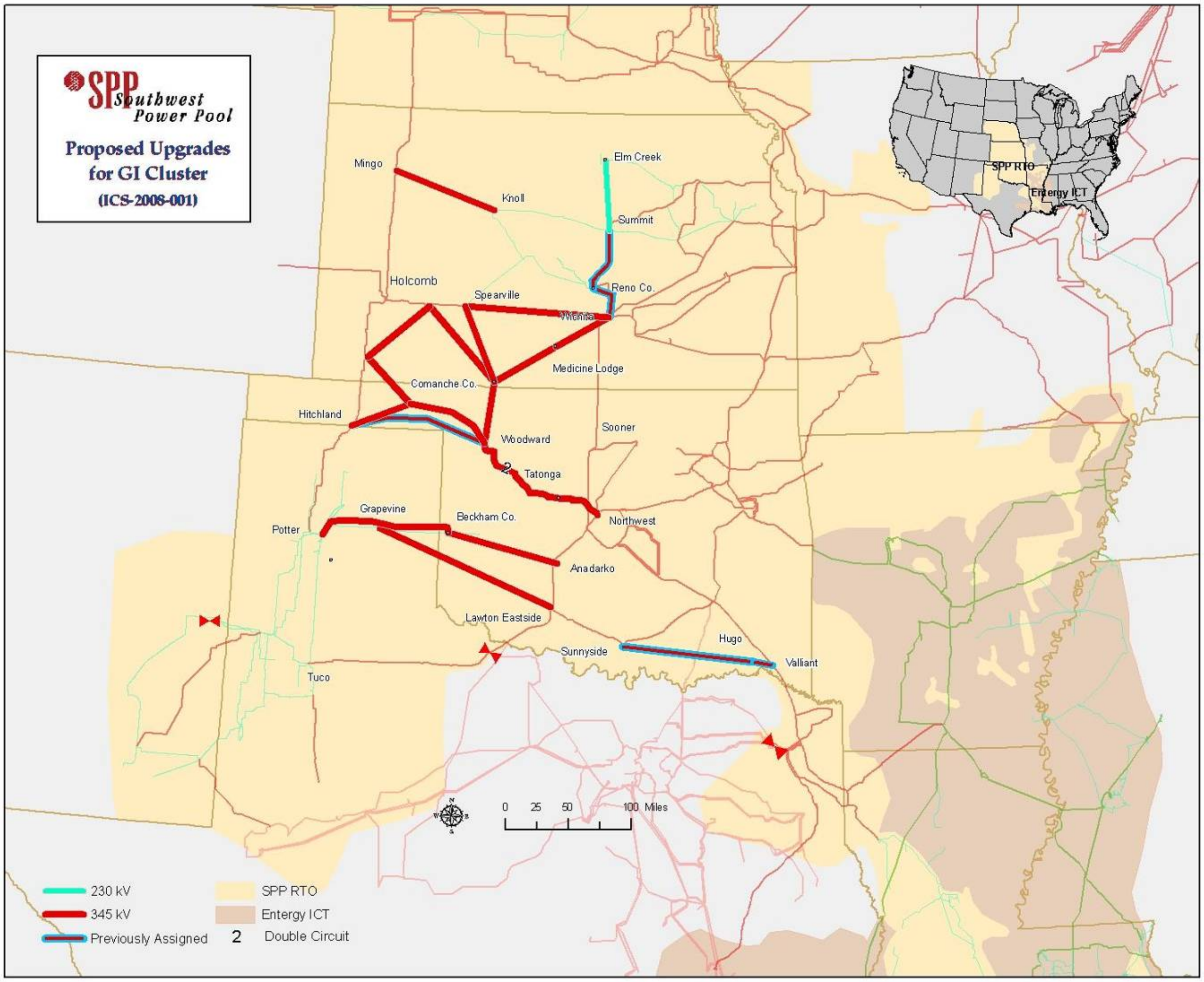


Figure 1 - Proposed Major Line Upgrades

Conclusion

The minimum cost of interconnecting all of the interconnection requests included in this Impact Cluster Study is estimated at $1,705,000,000 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 I which are Network Constraints.

These interconnection costs do not include any cost of Network Upgrades determined to be required by short circuit analysis or the additional analysis to be conducted during the Facility study. These studies will be performed if the Interconnection Customer executes the Interconnection System Facility Study Agreement and provides the required data along with a $100,000 deposit.

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

Request	Amount	Area	Requested Point of Interconnection	Proposed Point of Interconnection	Requested In-Service Date
GEN-2006-006	205	MKEC	Spearville 230kV	Spearville 230kV	12/31/2010
GEN-2007-005	200	SPS	Pringle 115kV	Pringle 115kV	12/1/2008
GEN-2007-008	300	SPS	Grapevine 230kV	^Grapevine 345kV	12/1/2009
GEN-2007-010	200	SPS	Potter County - Plant X 230kV	Potter County - Plant X 230kV	9/20/2010
GEN-2007-012	300	SUNC	Mingo - Red Willow 345kV	Mingo - Red Willow 345kV	10/15/2010
GEN-2007-019	375	SPS	Lamar - Finney 345kV	Lamar - Finney 345kV	8/30/2008
GEN-2007-021	201	OKGE	Dewey 138kV	*Tatonga 345kV	8/1/2009
GEN-2007-025	300	WERE	Wichita – Woodring 345kV	*Comanche - Wichita 345kV	10/1/2009
GEN-2007-026	130	SPS	Potter County - Plant X 230kV	Potter County - Plant X 230kV	12/31/2009
GEN-2007-027	60	SPS	Curry County - Norton 115kV	Curry County - Norton 115kV	12/1/2009
GEN-2007-028***	200	MKEC	Concordia – East Manhattan 230kV	Concordia - East Manhattan 230kV	12/1/2010
GEN-2007-030	200	SPS	Grapevine 230kV	^Grapevine 345kV	3/1/2009
GEN-2007-032	150	WFEC	Clinton Junction - Clinton 138kV	Clinton Junction - Clinton 138kV	12/31/2010
GEN-2007-033	200	SPS	Pringle – Harrington-Nichols 230kV	Pringle - Harrington-Nichols 230kV	8/1/2009
GEN-2007-034	150	SPS	Tolk - Eddy County 345kV	Tolk - Eddy County 345kV	8/15/2010
GEN-2007-036	200	SUNC	Spearville 345kV	Spearville 345kV	12/31/2012
GEN-2007-037	200	SUNC	Spearville 345kV	Spearville 345kV	12/31/2012
GEN-2007-038	200	SUNC	Spearville 345kV	Spearville 345kV	12/31/2012
GEN-2007-040	500	SUNC	Holcomb - Spearville 345kV	Holcomb - Spearville 345kV	12/15/2010
GEN-2007-041	600	SPS	*Hitchland 345kV	*Hitchland 345kV	12/31/2010
GEN-2007-042	360	SPS	*Hitchland 345kV	*Hitchland 345kV	9/30/2010
GEN-2007-043	300	AEPW	Lawton Eastside - Cimarron 345kV	Lawton Eastside - Cimarron 345kV	12/1/2009
GEN-2007-044	300	OKGE	Roman Nose 138kV	*Tatonga 345kV	12/1/2009
GEN-2007-045	171	SPS	Conway 115kV	^Grapevine 345kV	12/31/2011
GEN-2007-046	200	SPS	Texas County - *Hitchland 115kV	*Hitchland 115kV	12/31/2011
GEN-2007-047	204	SUNC	Mingo 115kV	Mingo 345kV	7/1/2009
GEN-2007-048	400	SPS	Amarillo South - Swisher County 230kV	Amarillo South - Swisher County 230kV	11/1/2009
GEN-2007-049	60	WFEC	Carter Junction 69kV	Carter Junction 69kV	12/31/2009
GEN-2007-050	200	OKGE	Woodward 138kV	*Woodward EHV 138kV	10/1/2009
GEN-2007-051	200	WFEC	Mooreland 138kV	Mooreland 138kV	11/7/2007
GEN-2007-052	150	WFEC	Anadarko 138kV	Anadarko 138kV	5/1/2008
GEN-2007-053***	150	MIPU	Maryville 161kV	Maryville 161kV	1/30/2010
GEN-2007-055	250	SPS	Tolk - Eddy County 345kV	Tolk - Eddy County 345kV	12/30/2010
GEN-2007-056	600	SPS	*Hitchland 345kV	*Hitchland 345kV	12/1/2009
GEN-2007-057	35	SPS	Valero 115kV	Moore County East 115kV	5/1/2009
GEN-2007-060	202	OKGE	Mooreland - Northwest 345kV	*Tatonga 345kV	12/1/2012
GEN-2007-061	200	OKGE	Woodward 138kV	*Woodward 345kV	12/31/2011
GEN-2007-062	765	OKGE	*Woodward 345kV	*Woodward 345kV	12/31/2011
GEN-2008-001	200	MIDW	^Knoll 230kV	^Knoll 345kV	12/1/2010
GEN-2008-003	101	OKGE	Woodward 138kV	*Woodward EHV 138kV	8/31/2009
GEN-2008-007	102	SPS	Grassland - Jones 230kV	Grassland - Jones 230kV	12/1/2009
GEN-2008-008	60	SPS	Graham 69kV	Graham 115kV	12/31/2010
GEN-2008-009	60	SPS	San Juan Mesa 230kV	San Juan Mesa 230kV	3/1/2012
GEN-2008-011	600	SUNC	Holcomb 345kV	Holcomb 345kV	10/1/2010
GEN-2008-012***	150	EMDE	Decatur - Noel 161kV	Decatur - Noel 161kV	10/1/2010
GEN-2008-013	300	OKGE	Wichita – Woodring 345kV	Wichita - Woodring 345kV	10/1/2010
GEN-2008-014	150	SPS	TUCO - Oklaunion 345kV	TUCO - Oklaunion 345kV	12/1/2010
GEN-2008-015	150	SPS	TUCO - Oklaunion 345kV	TUCO - Oklaunion 345kV	12/1/2011

Request	Amount	Area	Requested Point of Interconnection	Proposed Point of Interconnection	Requested In-Service Date
GEN-2008-016	248	SPS	Grassland 230kV	Grassland 230kV	12/1/2009
GEN-2008-017	300	SUNC	Setab 345kV	Setab 345kV	3/1/2012
GEN-2008-018	405	SUNC	Holcomb - Spearville 345kV	Finney 345kV	12/31/2012
GEN-2008-019	300	OKGE	Dewey 138kV	*Tatonga 345kV	12/31/2012
GROUPED TOTAL	**12,744**				

***** Planned Facility
^ Proposed Facility
******* Electrically Remote Interconnection Requests

B: Prior Queued Interconnection Requests

Request	Amount	Area	Requested/Proposed Point of Interconnection	Status or In-Service Date
GEN-2001-014	96	WFEC	Fort Supply 138kV	On-Line
GEN-2001-026	74	WFEC	Washita 138kV	On-Line
GEN-2001-033	180	SPS	San Juan Mesa Tap 230kV	On-Line
GEN-2001-036	80	SPS	Caprock Tap 115kV	On-Line
GEN-2001-037	103	OKGE	Windfarm Switching 138kV	On-Line
GEN-2001-039A	105	MKEC	Greensburg - Judson-Large 115kV	On Suspension
GEN-2001-039M	100	SUNC	Leoti – City Services 115kV	IA Executed/On Schedule
GEN-2002-005	120	WFEC	Morewood - Elk City 138kV	IA Executed/On Schedule
GEN-2002-006	150	SPS	Texas County 115kV	IA Executed/On Schedule 12/31/2010
GEN-2002-008	120	SPS	*Hitchland 345kV	On-Line
GEN-2002-009	80	SPS	Hansford County 115kV	On-Line
GEN-2002-022	240	SPS	Bushland 230kV	On-Line
GEN-2002-025A	150	MKEC	Spearville 230kV	On-Line
GEN-2003-004	100	WFEC	Washita 138kV	On-Line
GEN-2003-005	100	WFEC	Anadarko - Paradise 138kV	12/31/2009
GEN-2003-013**	198	SPS	*Hitchland - Finney 345kV	On Suspension
GEN-2003-020	160	SPS	Carson County 115kV	On-Line
GEN-2003-022	120	AEPW	Washita 138kV	On-Line
GEN-2004-003	240	SPS	Conway 115kV	On Suspension
GEN-2004-014	155	MKEC	Spearville 230kV	12/31/2009
GEN-2004-020	27	AEPW	Washita 138kV	On-Line
GEN-2004-023	21	WFEC	Washita 138kV	On-Line
GEN-2005-002	80	SPS	Pringle - Riverview 230kV	On Suspension
GEN-2005-003	31	WFEC	Washita 138kV	On-Line
GEN-2005-008	120	OKGE	Woodward 138kV	On-Line
GEN-2005-010	160	SPS	Roosevelt County - Tolk West 230kV (Single Ckt Tap)	On Suspension
GEN-2005-012	250	SUNC	Spearville 345kV	IA Executed/On Schedule 10/1/2011
GEN-2005-015	150	SPS	TUCO - Oklaunion 345kV	On Suspension
GEN-2005-017	340	SPS	*Hitchland - Potter County 345kV	On Suspension
GEN-2005-021	86	SPS	Kirby 115kV	On Suspension
GEN-2006-002	150	AEPW	Grapevine - Elk City 230kV	On Suspension
GEN-2006-020	20	SPS	*Hitchland - Sherman County Tap	IA Executed/On Schedule 12/31/2009
GEN-2006-032	200	MIDW	South Hays 230kV	4/30/2012
GEN-2006-034	81	SUNC	Kanarado - Sharon Springs 115kV	On Suspension
GEN-2006-035	225	AEPW	Grapevine - Elk City 230kV	10/1/2010
GEN-2006-039	400	SPS	Tap and Tie both Potter County - Plant X 230kV and Bushland - Deaf Smith 230kV	On Suspension
GEN-2006-040	100	SUNC	Mingo 115kV	6/30/2010
GEN-2006-043	99	AEPW	Grapevine - Elk City 230kV	12/31/2009
GEN-2006-044	400	SPS	*Hitchland 345kV	11/1/2011
GEN-2006-045	240	SPS	Tap and Tie both Potter County - Plant X 230kV and Bushland - Deaf Smith 230kV	12/31/2010
GEN-2006-046	130	OKGE	Dewey 138kV	IA Executed/On Schedule 12/31/2009
GEN-2006-047	240	SPS	Tap and Tie both Potter County - Plant X 230kV and Bushland - Deaf Smith 230kV	12/31/2013

Request	Amount	Area	Requested/Proposed Point of Interconnection	Status or In-Service Date
GEN-2006-049	400	SPS	***Hitchland - Finney 345kV	Facility Study In Progress
GEN-2007-002	160	SPS	Grapevine 115kV	10/1/2011
GEN-2007-004	150	SPS	Amoco Switching - Yoakum County 230kV	IA Pending
GEN-2007-006	160	OKGE	Roman Nose 138kV	On Suspension
GEN-2007-011	135	SUNC	Syracuse 115kV	12/31/2010
GEN-2007-013	99	SUNC	Selkirk 115kV	IA Pending
GROUPED TOTAL	**7,325**			

***** Planned Facility

******Certain Cluster requests are alternate to GEN-2003-013

C: Study Groupings

Cluster	Request	Amount	Area	Proposed Point of Interconnection
Prior Queued	GEN-2001-014	96	WFEC	Fort Supply 138kV
	GEN-2001-037	103	OKGE	Windfarm Switching 138kV
	GEN-2002-005	120	WFEC	Morewood - Elk City 138kV
	GEN-2005-008	130	OKGE	Woodward 138kV
	GEN-2006-046	130	OKGE	Dewey 138kV
	GEN-2007-006	160	OKGE	Roman Nose 138kV
	PRIOR QUEUED SUBTOTAL	**739**		
Cluster	**Request**	**Amount**	**Area**	**Proposed Point of Interconnection**
Woodward	GEN-2007-021	201	OKGE	*Tatonga 345kV
	GEN-2007-044	300	OKGE	*Tatonga 345kV
	GEN-2007-050	200	OKGE	*Woodward 138kV
	GEN-2007-051	200	WFEC	Mooreland 138kV
	GEN-2007-060	202	OKGE	*Tatonga 345kV
	GEN-2007-061	200	OKGE	*Woodward 345kV
	GEN-2007-062	765	OKGE	*Woodward 345kV
	GEN-2008-003	101	OKGE	*Woodward EHV 138kV
	GEN-2008-013	300	OKGE	Wichita - Woodring 345kV
	GEN-2008-019	300	OKGE	*Tatonga 345kV
	WOODWARD SUBTOTAL	**2,769**		
	AREA SUBTOTAL	**3,508**		

Cluster	Request	Amount	Area	Proposed Point of Interconnection
Prior Queued	GEN-2002-006	150	SPS	Texas County 115kV
	GEN-2002-008	240	SPS	*Hitchland 345kV
	GEN-2002-009	80	SPS	Hansford County 115kV
	GEN-2003-013	198	SPS	*Hitchland - Finney 345kV
	GEN-2003-020	160	SPS	Carson County 115kV
	GEN-2005-002	80	SPS	Pringle - Riverview 230kV
	GEN-2005-017	340	SPS	*Hitchland - Potter County 345kV
	GEN-2006-020	20	SPS	*Hitchland - Sherman County Tap
	GEN-2006-044	400	SPS	*Hitchland 345kV
	GEN-2006-049	400	SPS	*Hitchland - Finney 345kV
	PRIOR QUEUED SUBTOTAL	**2,068**		
Cluster	**Request**	**Amount**	**Area**	**Proposed Point of Interconnection**
Hitchland	GEN-2007-005	200	SPS	Pringle 115kV
	GEN-2007-033	200	SPS	Pringle - Harrington-Nichols 230kV
	GEN-2007-041	600	SPS	*Hitchland 345kV
	GEN-2007-042	360	SPS	*Hitchland 345kV
	GEN-2007-046	200	SPS	*Hitchland 115kV
	GEN-2007-056	600	SPS	*Hitchland 345kV
	GEN-2007-057	35	SPS	Moore County East 115kV
	HITCHLAND SUBTOTAL	**2,195**		
	AREA SUBTOTAL	**4,263**		

Cluster	Request	Amount	Area	Proposed Point of Interconnection
Prior Queued	GEN-2001-039A	105	MKEC	Greensburg - Judson-Large 115kV
	GEN-2002-025A	150	MKEC	Spearville 230kV
	GEN-2004-014	155	MKEC	Spearville 230kV
	GEN-2005-012	250	SUNC	Spearville 345kV
	PRIOR QUEUED SUBTOTAL	**660**		
Cluster	**Request**	**Amount**	**Area**	**Proposed Point of Interconnection**
Spearville	GEN-2006-006	205	MKEC	Spearville 230kV
	GEN-2007-019	375	SPS	Lamar - Finney 345kV
	GEN-2007-025	300	WERE	*Comanche - Wichita 345kV
	GEN-2007-036	200	SUNC	Spearville 345kV
	GEN-2007-037	200	SUNC	Spearville 345kV
	GEN-2007-038	200	SUNC	Spearville 345kV
	GEN-2007-040	500	SUNC	Holcomb - Spearville 345kV
	GEN-2008-011	600	SUNC	Holcomb 345kV
	GEN-2008-018	405	SUNC	Finney 345kV
	SPEARVILLE SUBTOTAL	**2,985**		
	AREA SUBTOTAL	**3,645**		

Cluster	Request	Amount	Area	Proposed Point of Interconnection
Prior Queued	GEN-2001-039M	100	SUNC	Leoti - City Services 115kV
	GEN-2006-032	200	MIDW	South Hays 230kV
	GEN-2006-034	81	SUNC	Kanarado - Sharon Springs 115kV
	GEN-2006-040	100	SUNC	Mingo 115kV
	GEN-2007-011	135	SUNC	Syracuse 115kV
	GEN-2007-013	99	SUNC	Selkirk 115kV
	PRIOR QUEUED SUBTOTAL	**715**		
Cluster	**Request**	**Amount**	**Area**	**Proposed Point of Interconnection**
Mingo/ NW Kansas	GEN-2007-012	300	SUNC	Mingo - Red Willow 345kV
	GEN-2007-047	204	SUNC	Mingo 345kV
	GEN-2008-001	200	MIDW	^Knoll 345kV
	GEN-2008-017	300	SUNC	Setab 345kV
	MINGO/NW KANSAS SUBTOTAL	**1,004**		
	AREA SUBTOTAL	**1,719**		

Cluster	Request	Amount	Area	Proposed Point of Interconnection
Prior Queued	GEN-2002-022	240	SPS	Bushland 230kV
	GEN-2004-003	240	SPS	Conway 115kV
	GEN-2005-021	86	SPS	Kirby 115kV
	GEN-2006-039	400	SPS	Tap and Tie both Potter County - Plant X 230kV and Bushland - Deaf Smith 230kV
	GEN-2006-045	240	SPS	Dewey 138kV
	GEN-2006-047	240	SPS	Tap and Tie both Potter County - Plant X 230kV and Bushland - Deaf Smith 230kV
	GEN-2007-002	160	SPS	Grapevine 115kV
	PRIOR QUEUED SUBTOTAL	**1,606**		
Cluster	**Request**	**Amount**	**Area**	**Proposed Point of Interconnection**
Amarillo	GEN-2007-008	300	SPS	^Grapevine 345kV
	GEN-2007-010	200	SPS	Potter County - Plant X 230kV
	GEN-2007-026	130	SPS	Potter County - Plant X 230kV
	GEN-2007-030	200	SPS	^Grapevine 345kV
	GEN-2007-045	171	SPS	^Grapevine 345kV
	GEN-2007-048	400	SPS	Amarillo South - Swisher County 230kV
	AMARILLO SUBTOTAL	**1,401**		
	AREA SUBTOTAL	**3,007**		

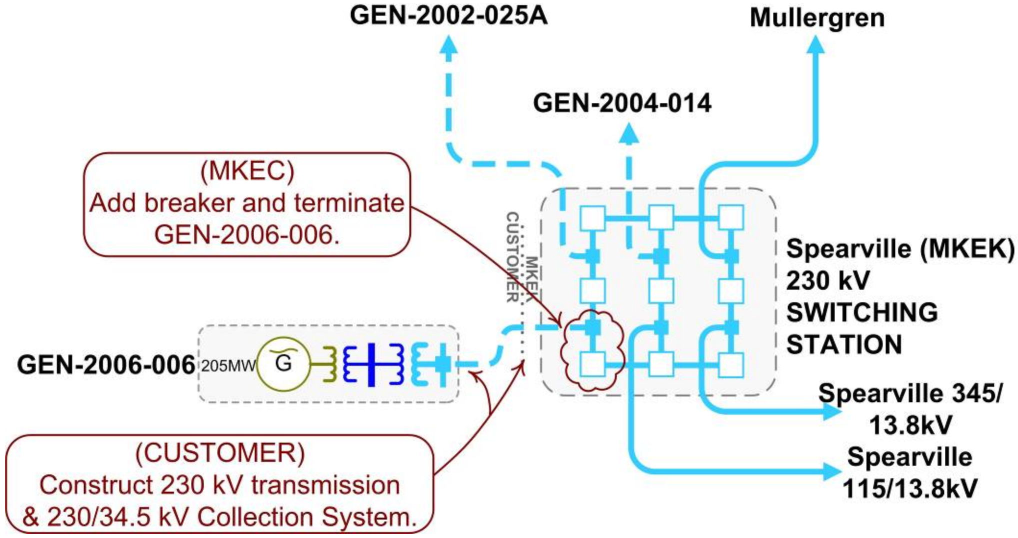
Cluster	Request	Amount	Area	Proposed Point of Interconnection
Prior Queued	GEN-2001-033	180	SPS	San Juan Mesa Tap 230kV
	GEN-2001-036	80	SPS	Caprock Tap 115kV
	GEN-2005-010	160	SPS	Roosevelt County - Tolk West 230kV (Single Ckt Tap)
	GEN-2005-015	150	SPS	TUCO - Oklaunion 345kV
	GEN-2007-004	150	SPS	Amoco Switching - Yoakum County 230kV
	PRIOR QUEUED SUBTOTAL	**720**		
Cluster	**Request**	**Amount**	**Area**	**Proposed Point of Interconnection**
South Panhandle/ New Mexico	GEN-2007-027	60	SPS	Curry County - Norton 115kV
	GEN-2007-034	150	SPS	Tolk - Eddy County 345kV
	GEN-2007-055	250	SPS	Tolk - Eddy County 345kV
	GEN-2008-007	102	SPS	Grassland 230kV
	GEN-2008-008	60	SPS	Graham 115kV
	GEN-2008-009	60	SPS	San Juan Mesa 230kV
	GEN-2008-014	150	SPS	TUCO - Oklaunion 345kV
	GEN-2008-015	150	SPS	TUCO - Oklaunion 345kV
	GEN-2008-016	248	SPS	Grassland 230kV
	SOUTH PANHANDLE/NM SUBTOTAL	**1,230**		
	AREA SUBTOTAL	**1,950**		

Cluster	Request	Amount	Area	Proposed Point of Interconnection
Prior Queued	GEN-2001-026	74	WFEC	Fort Supply 138kV
	GEN-2003-004	101	WFEC	Washita 138kV
	GEN-2003-005	100	WFEC	Anadarko - Paradise 138kV
	GEN-2003-022	120	AEPW	Washita 138kV
	GEN-2004-020	27	AEPW	Washita 138kV
	GEN-2004-023	21	WFEC	Washita 138kV
	GEN-2005-003	31	WFEC	Washita 138kV
	GEN-2006-002	150	AEPW	Grapevine - Elk City 230kV
	GEN-2006-035	225	AEPW	Grapevine - Elk City 230kV
	GEN-2006-043	99	AEPW	Grapevine - Elk City 230kV
	PRIOR QUEUED SUBTOTAL	**948**		
Cluster	**Request**	**Amount**	**Area**	**Proposed Point of Interconnection**
SW Oklahoma	GEN-2007-032	150	WFEC	Clinton Junction - Clinton 138kV
	GEN-2007-043	300	AEPW	Lawton Eastside - Cimarron 345kV
	GEN-2007-049	60	WFEC	Carter Junction 69kV
	GEN-2007-052	150	WFEC	Anadarko 138kV
	SW OKLAHOMA SUBTOTAL	**660**		
	AREA SUBTOTAL	**1,608**		
	*****CLUSTERED TOTAL (w/o PRIOR QUEUED)**	**12,244**		
	*****CLUSTERED TOTAL (w/PRIOR QUEUED)**	**19,700**		

***** Planned Facility
^ Proposed Facility
****** Alternate requests - counted as one request for study purpose
*** Electrically Remote Interconnection Requests included in total

D: Proposed Point of Interconnection One line Diagrams

GEN-2006-006



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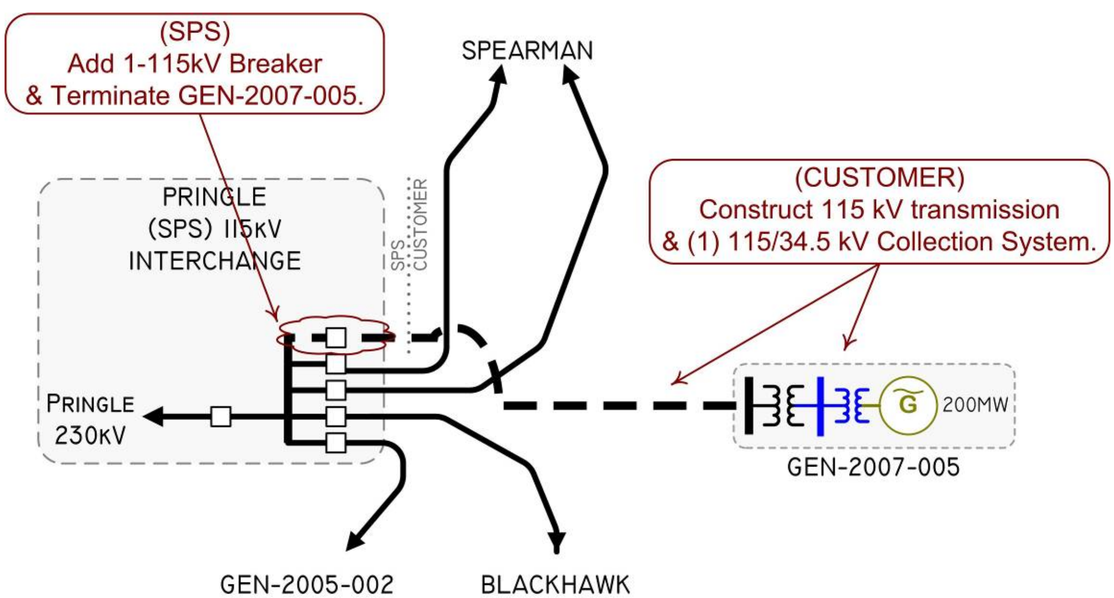
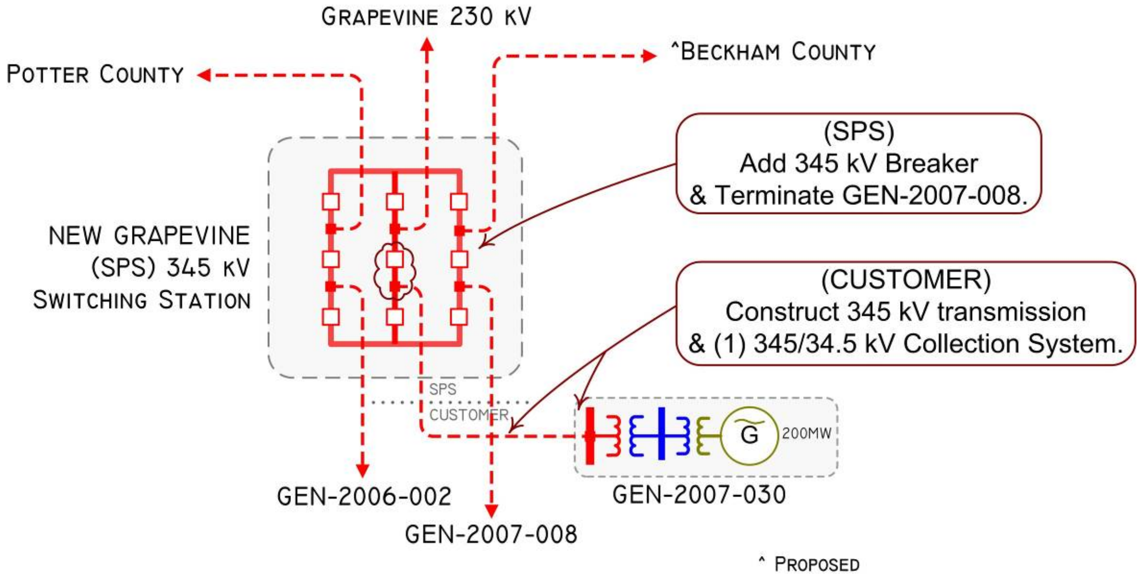
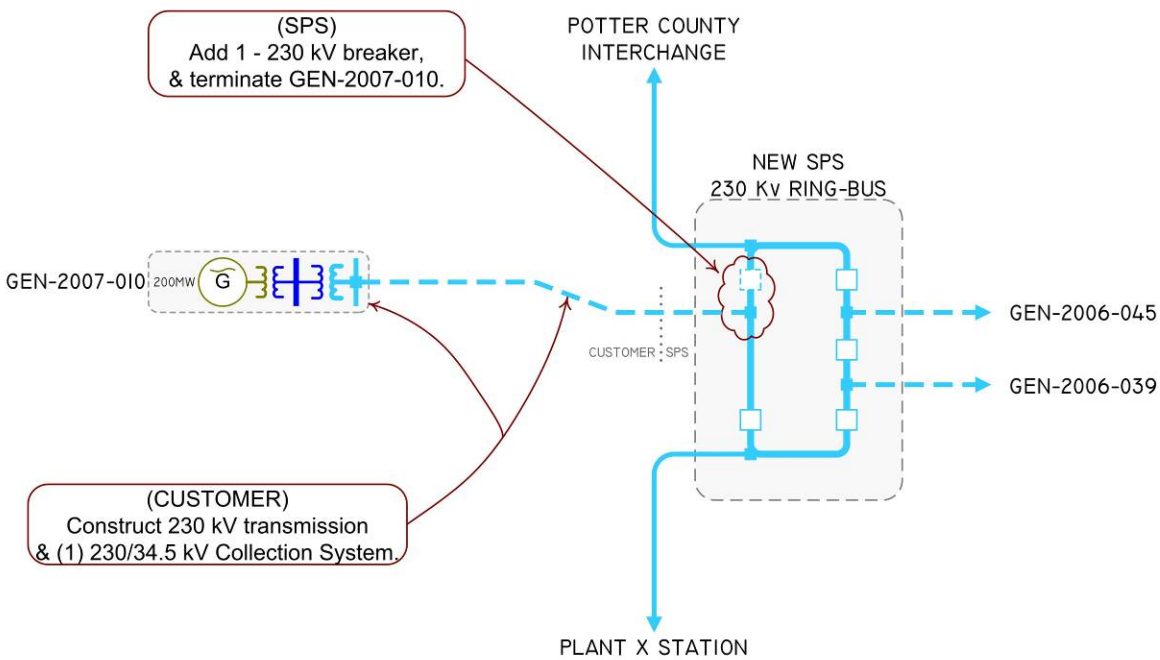


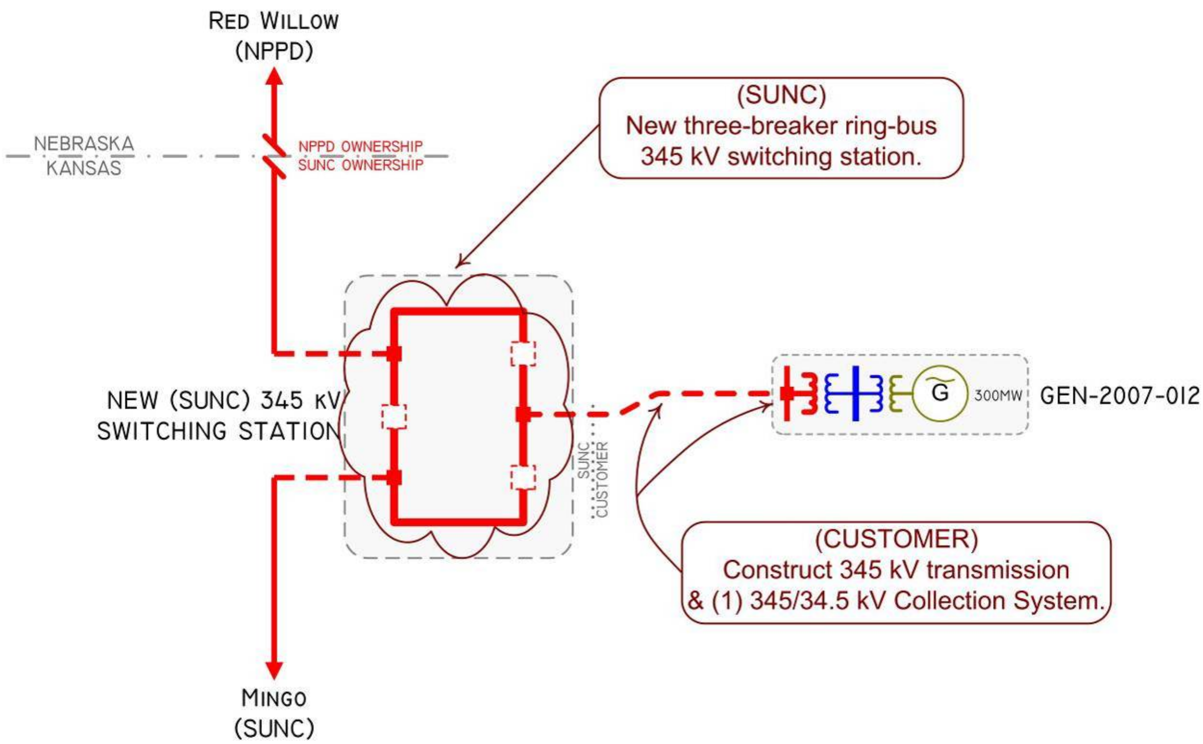
GEN-2007-008



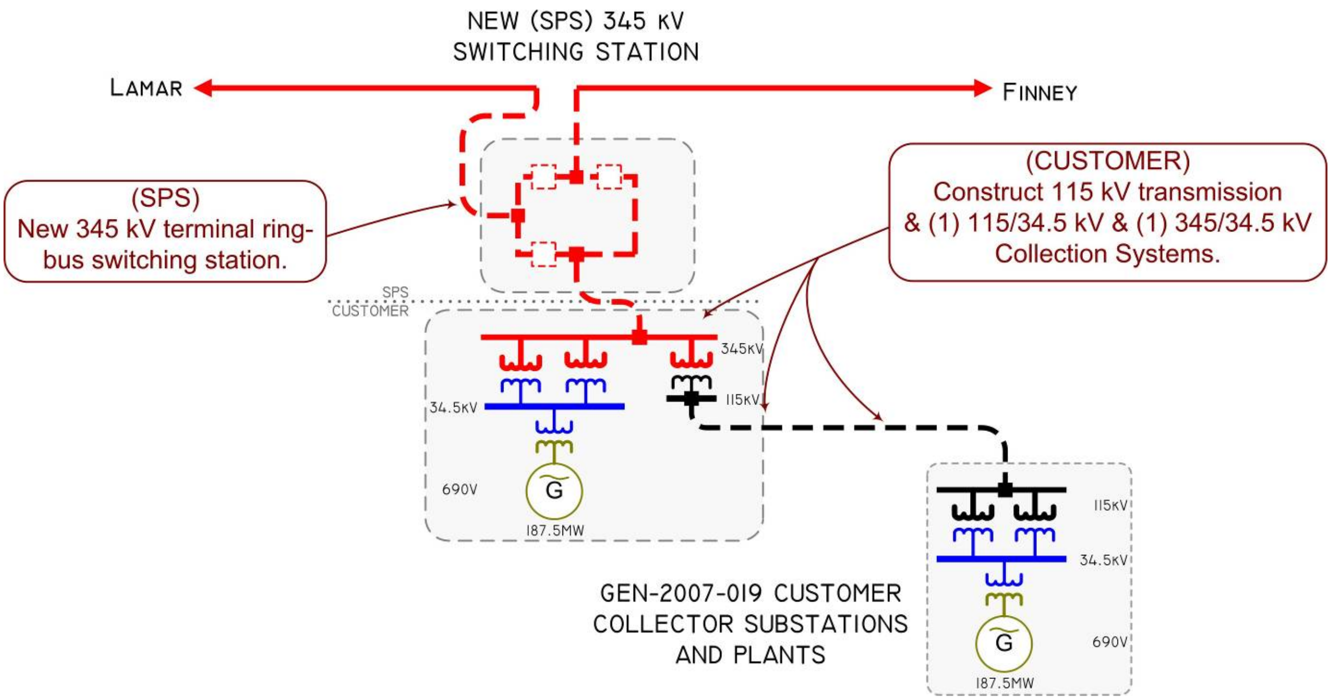
GEN-2007-010



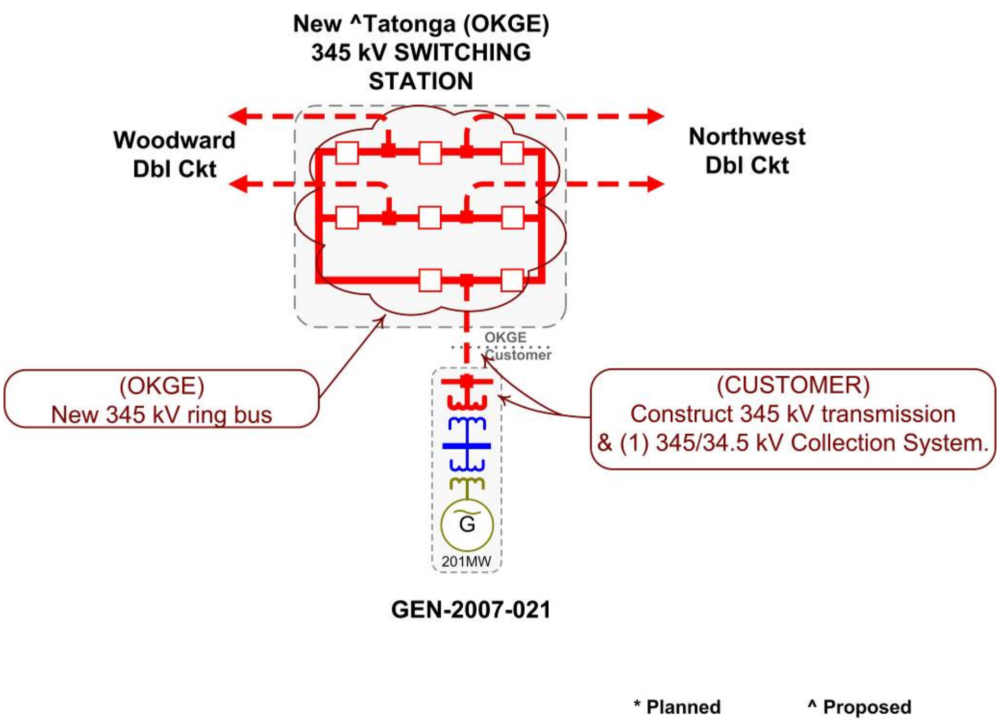
GEN-2007-012



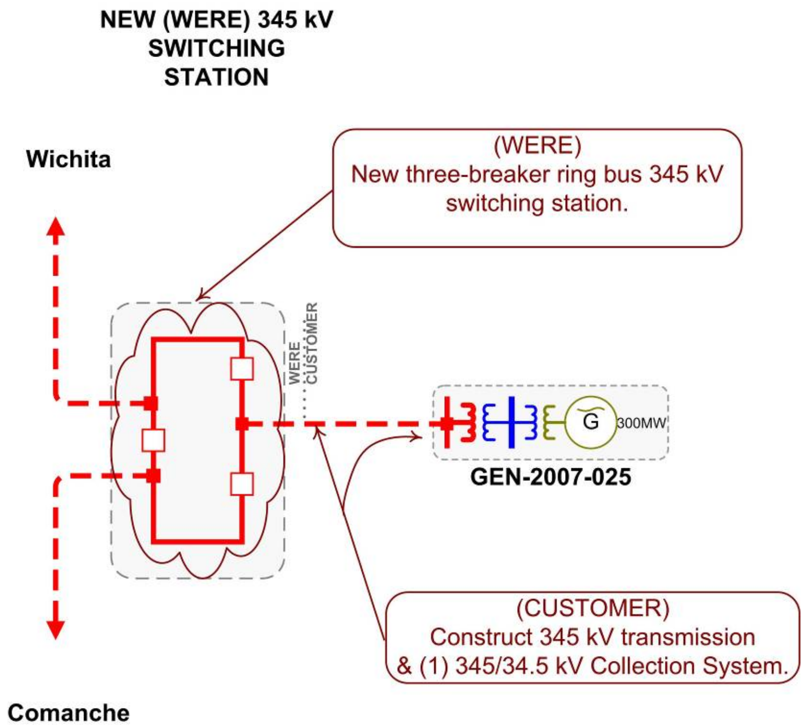
GEN-2007-019


NEW (SPS) 345 KV
SWITCHING STATION
LAMAR
FINNEY
(SPS)
New 345 kV terminal ring-bus switching station.
(CUSTOMER)
Construct 115 kV transmission & (1) 115/34.5 kV & (1) 345/34.5 kV Collection Systems.
SPS
CUSTOMER
345KV
115KV
34.5KV
690V
G
187.5MW
115KV
34.5KV
690V
G
187.5MW
GEN-2007-019 CUSTOMER
COLLECTOR SUBSTATIONS
AND PLANTS

GEN-2007-021

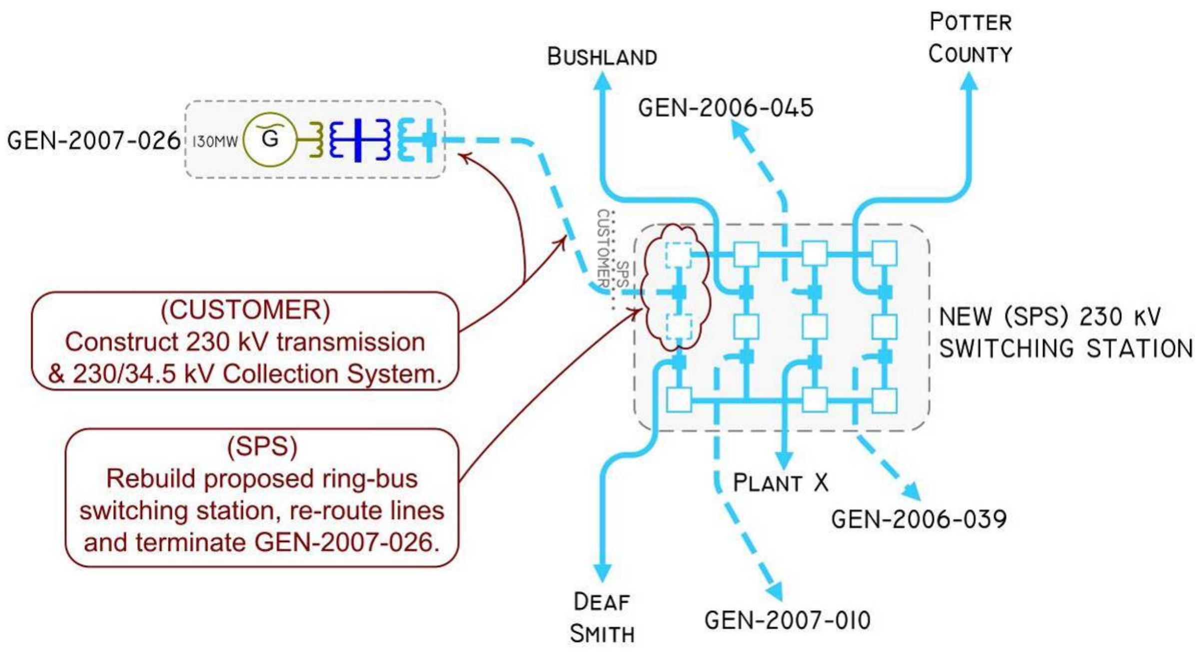


GEN-2007-025



NEW (WERE) 345 kV
SWITCHING
STATION
Wichita
(WERE)
New three-breaker ring bus 345 kV
switching station.
WERE
CUSTOMER
G
300MW
GEN-2007-025
(CUSTOMER)
Construct 345 kV transmission
& (1) 345/34.5 kV Collection System.
Comanche

GEN-2007-026



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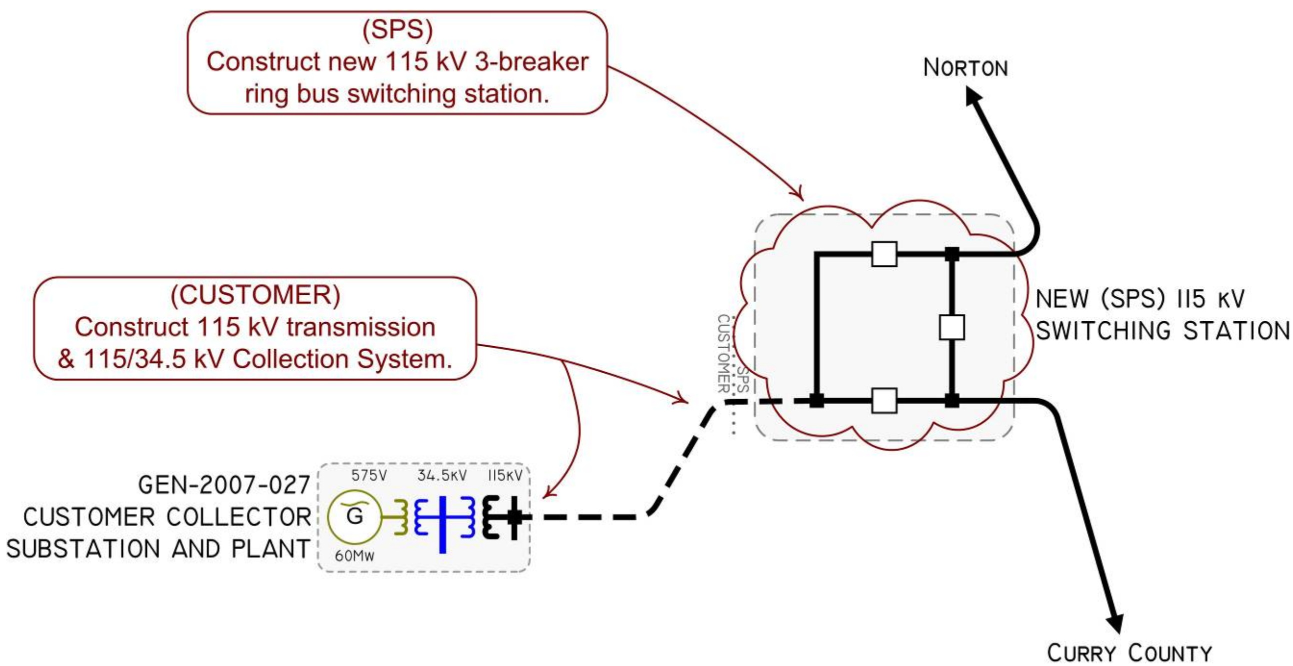
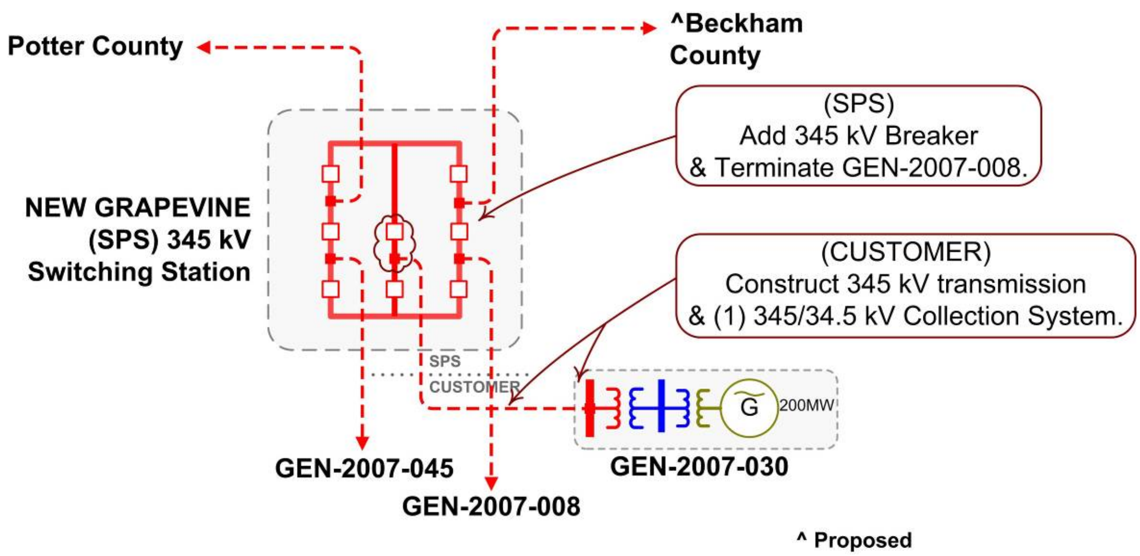


GEN-2007-028***

See GEN-2008-028 Impact Study report in Appendix J

GEN-2007-030



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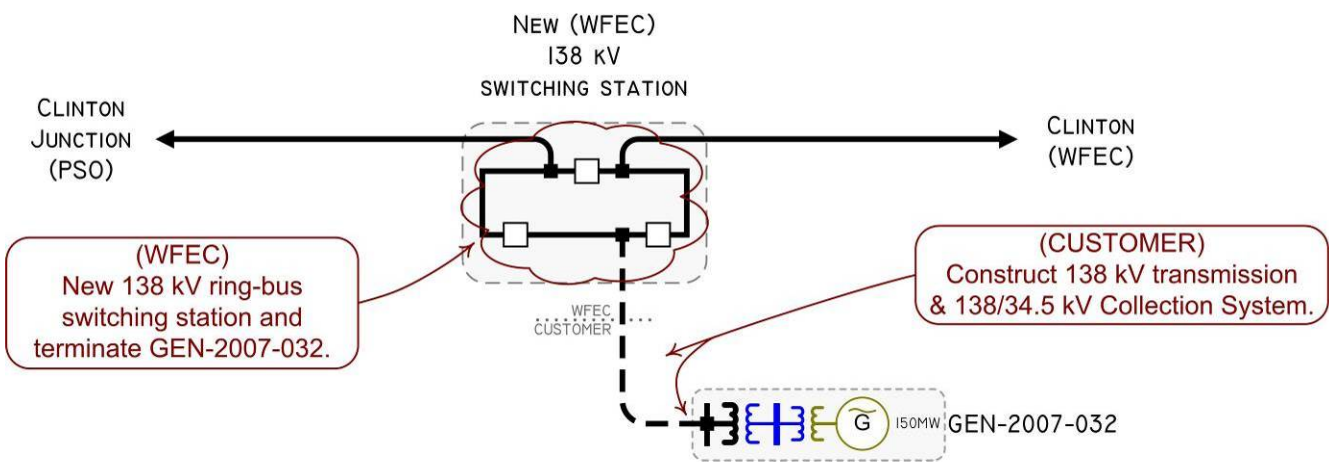

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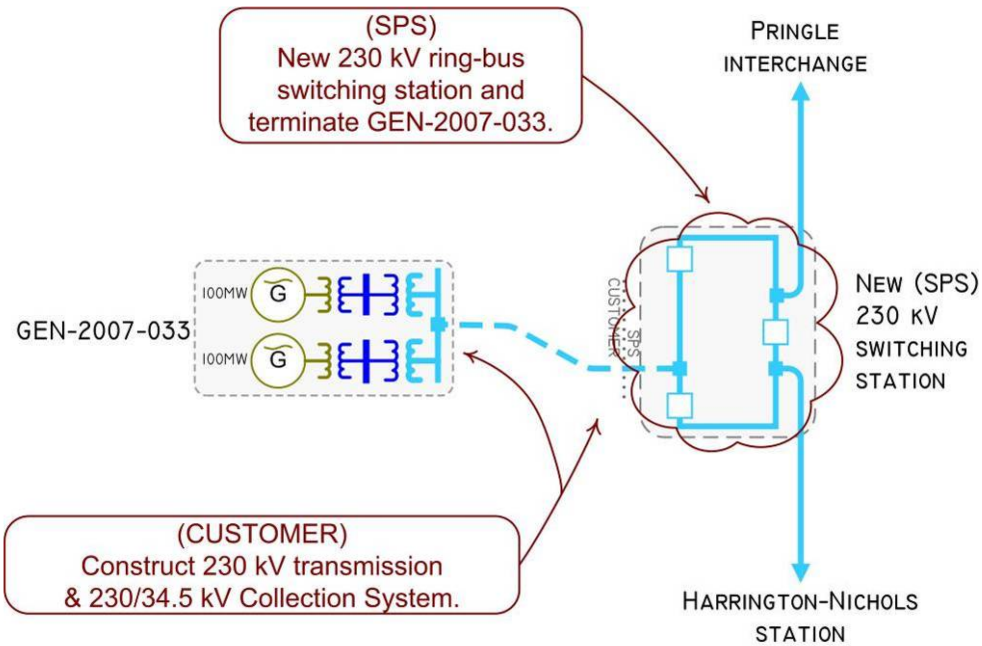

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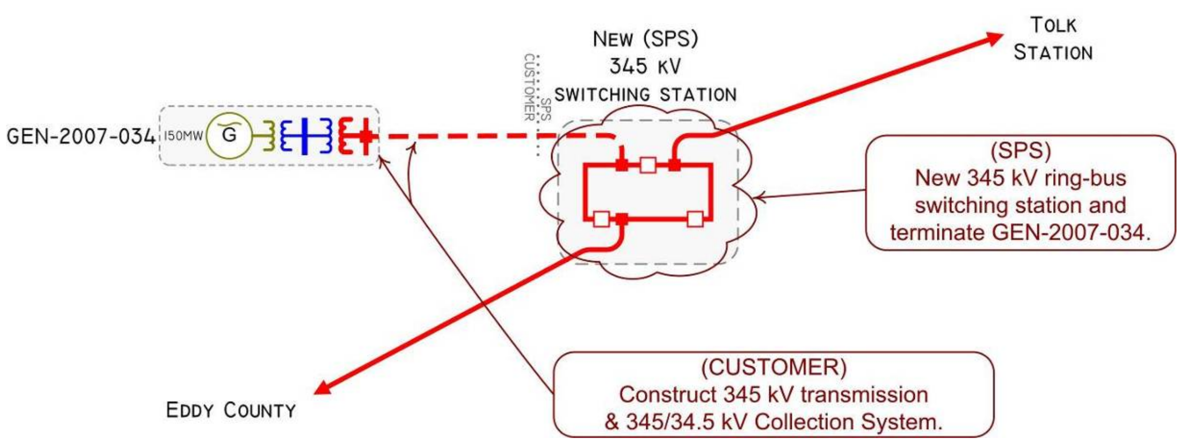

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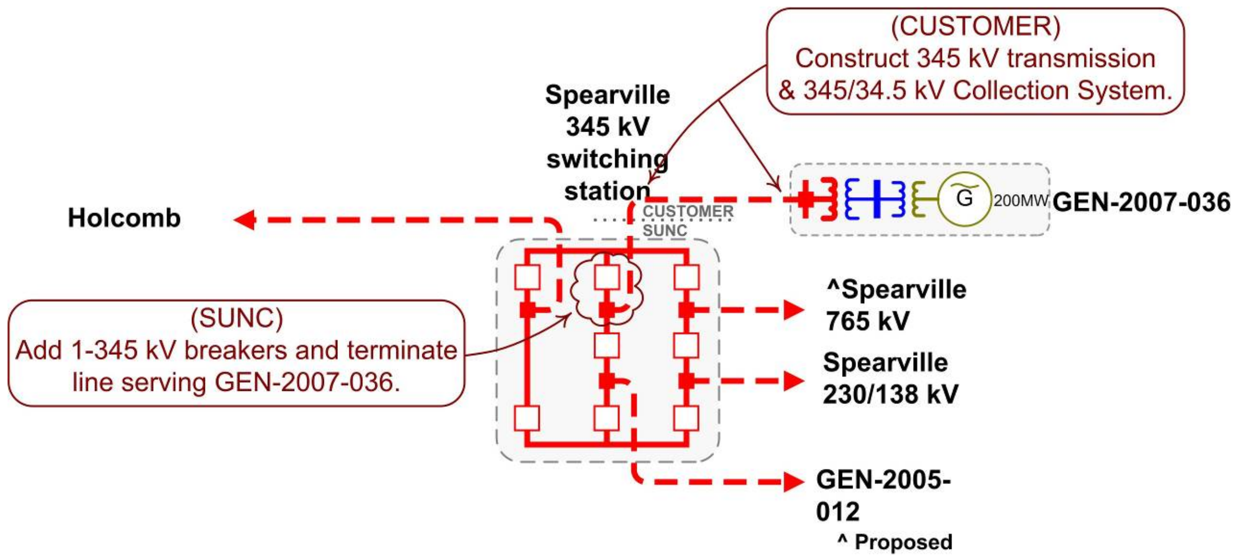

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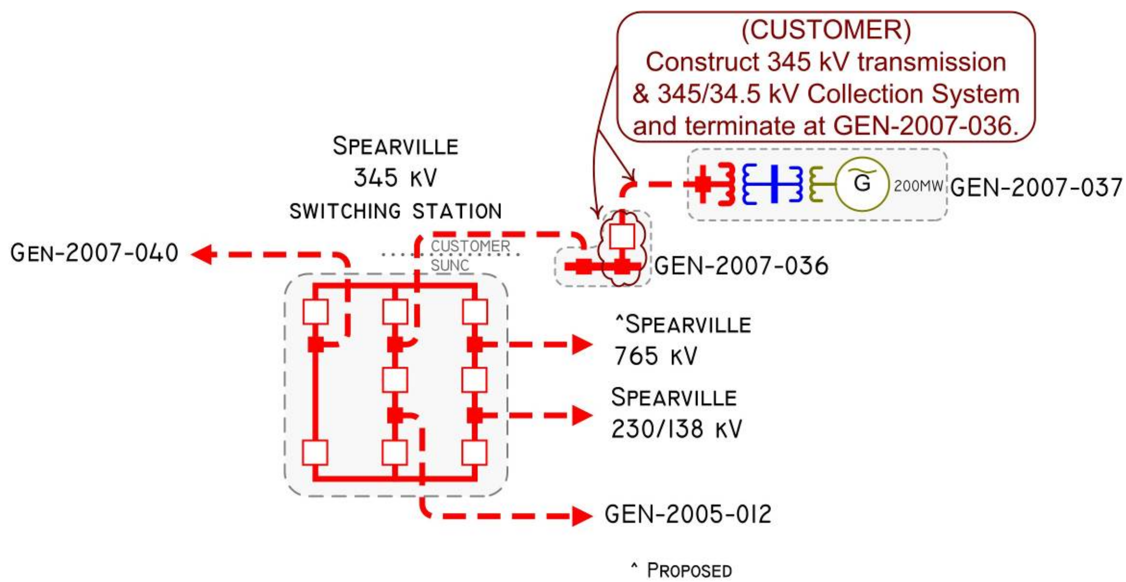
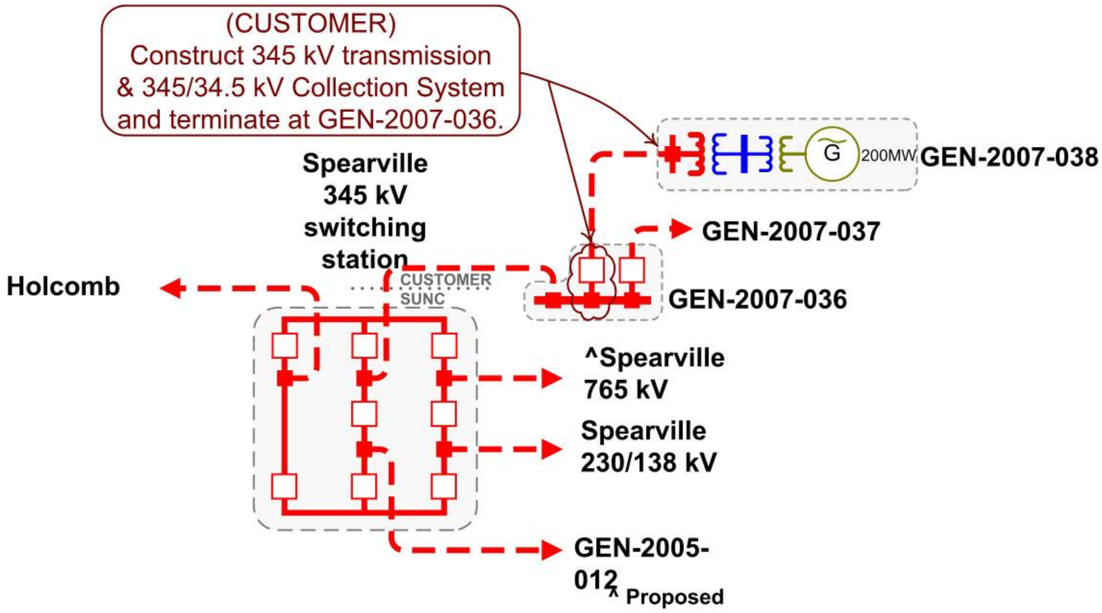


GEN-2007-038



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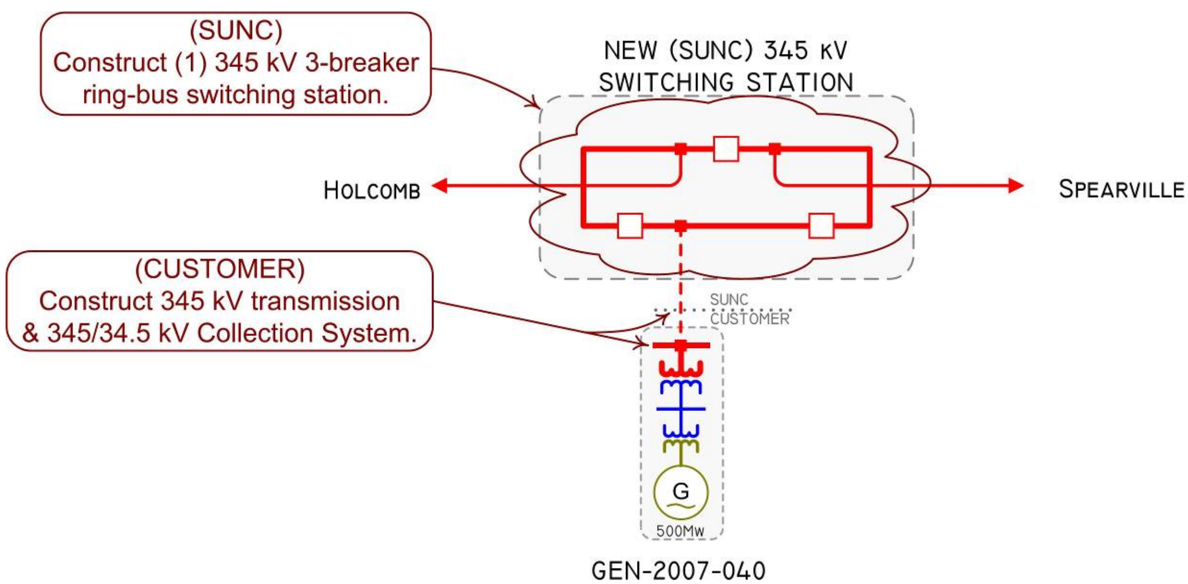

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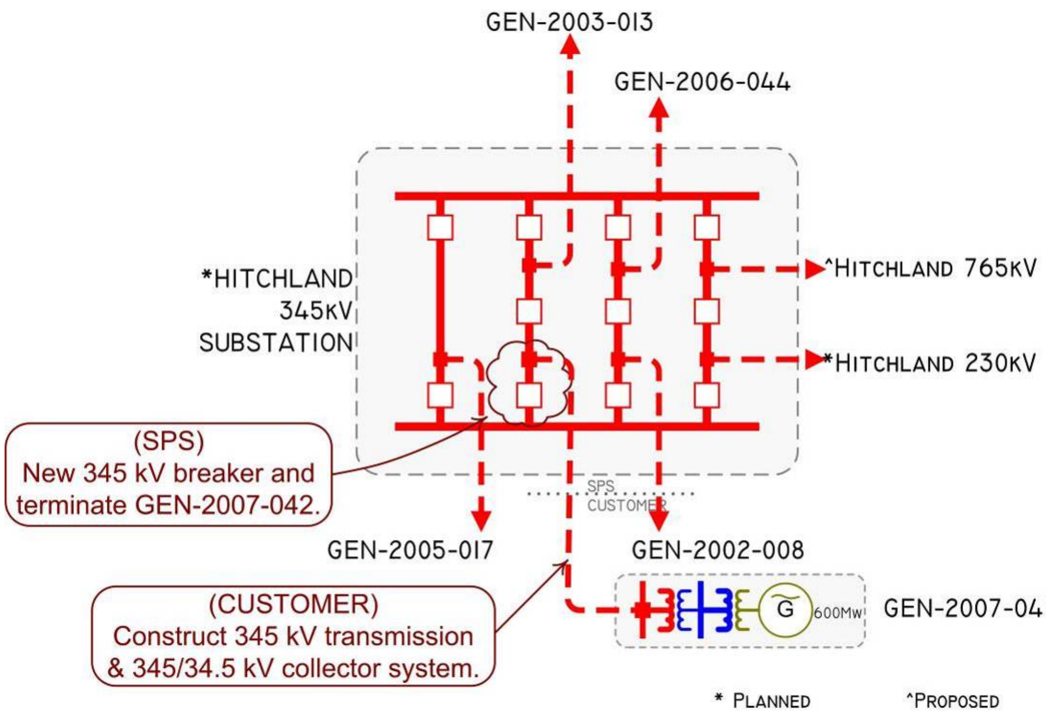

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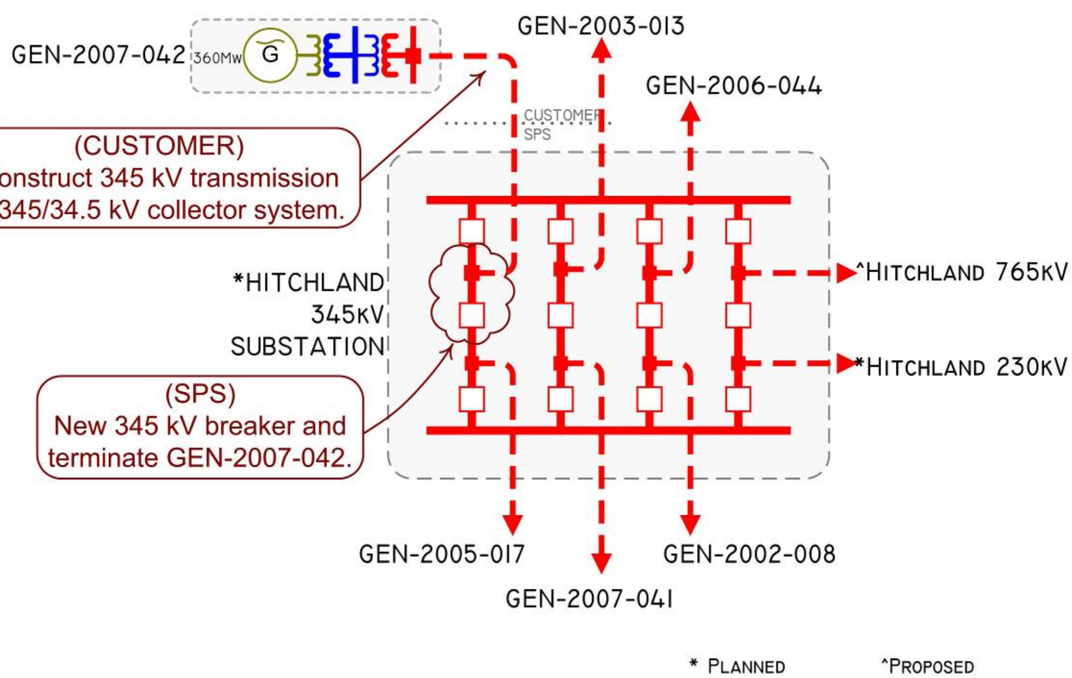

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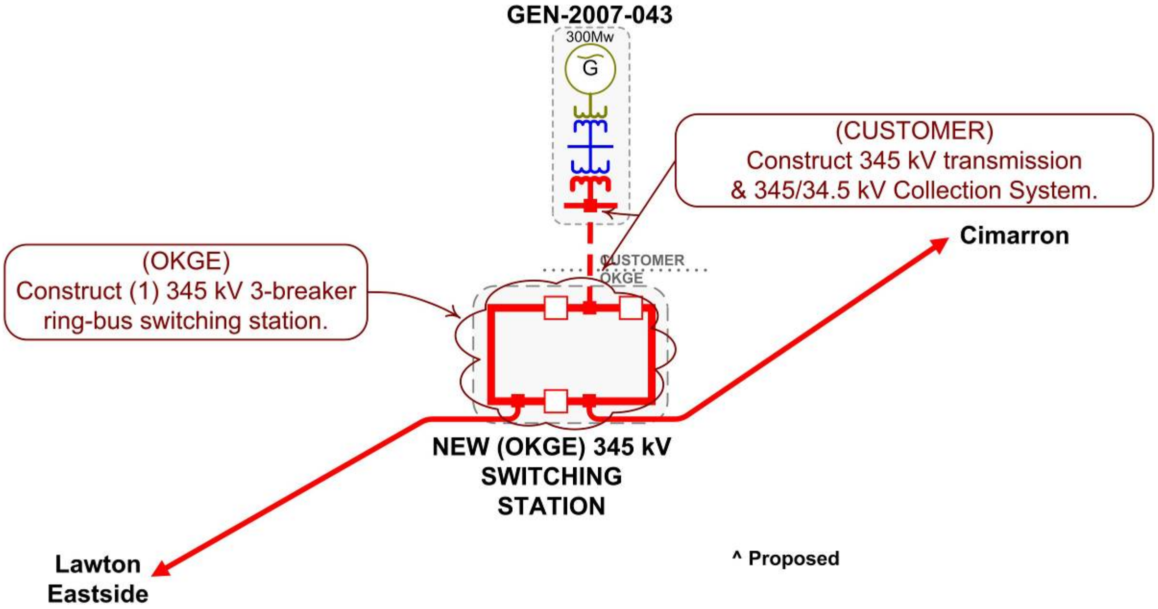

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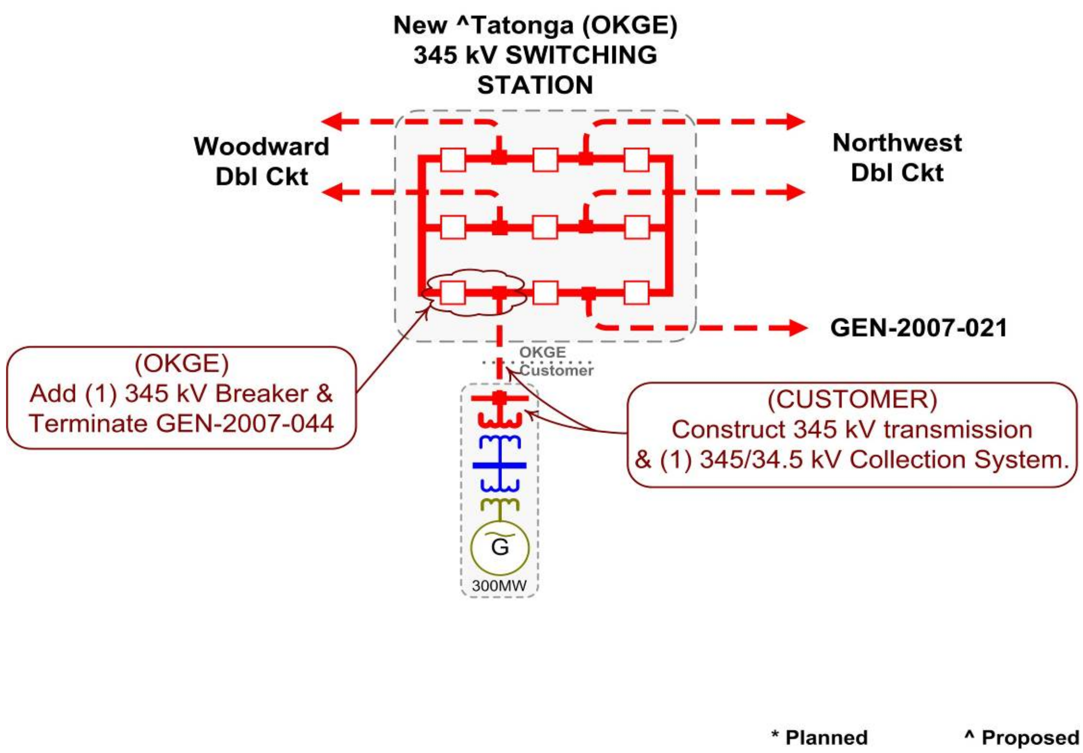

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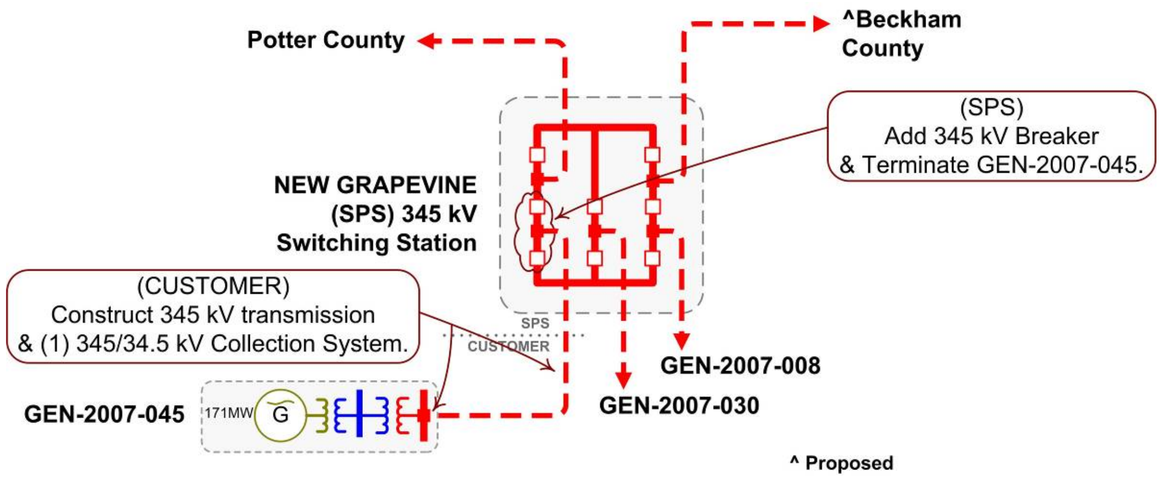

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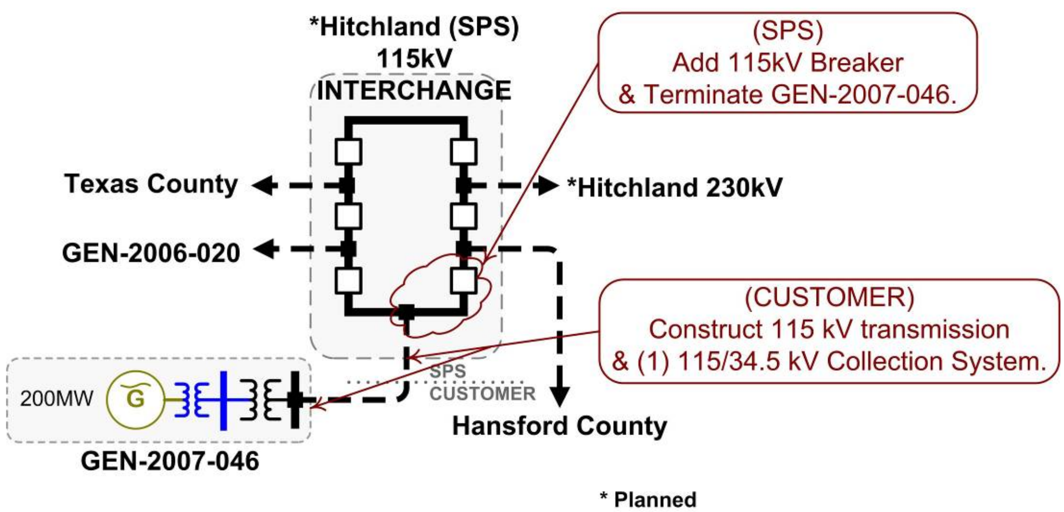

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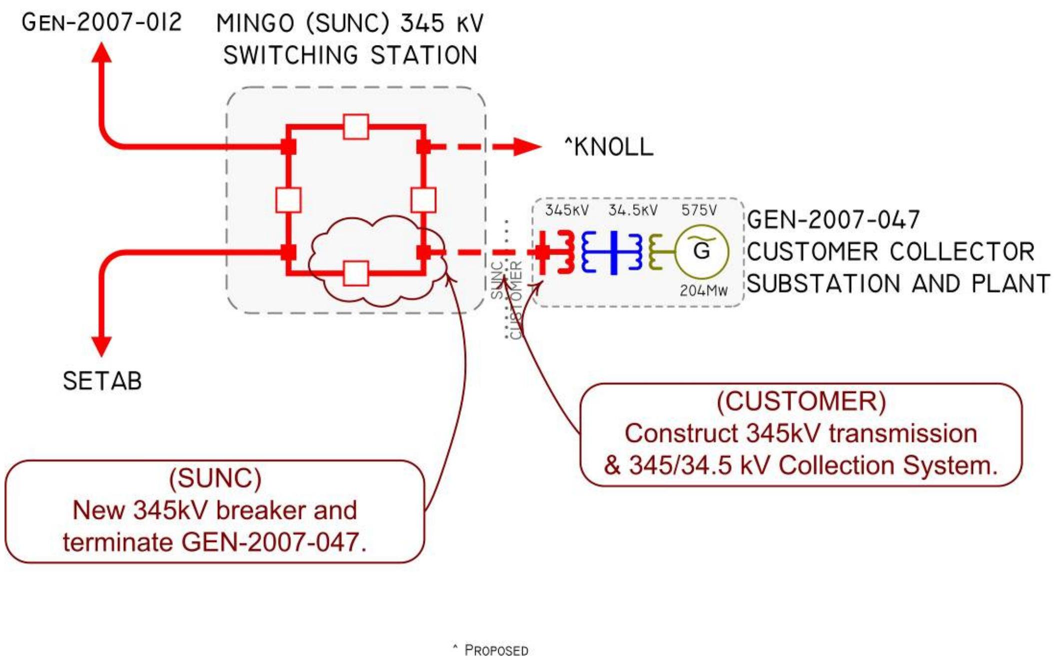

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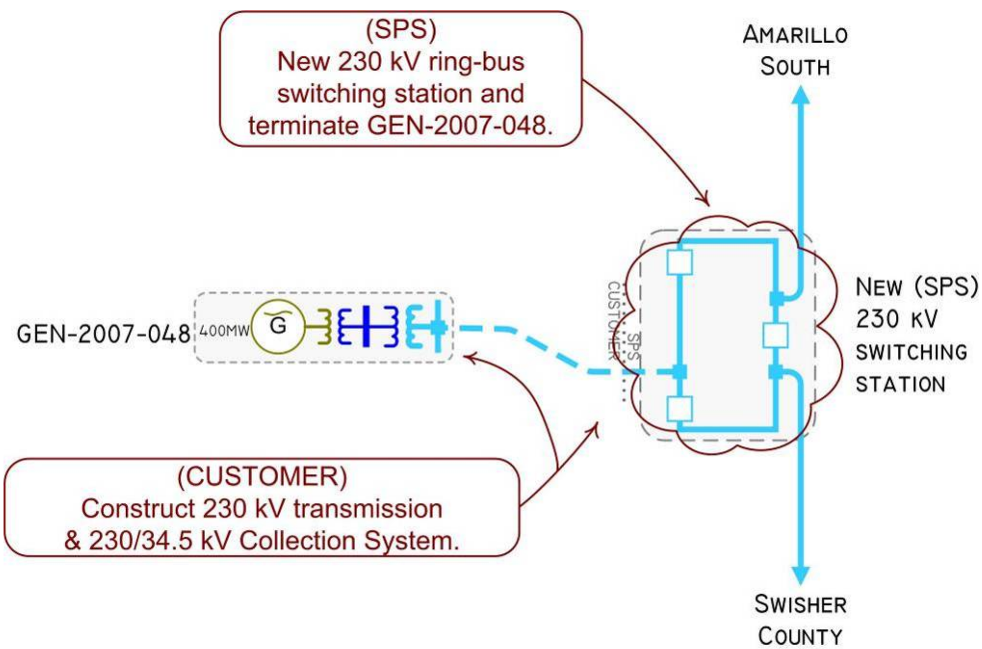

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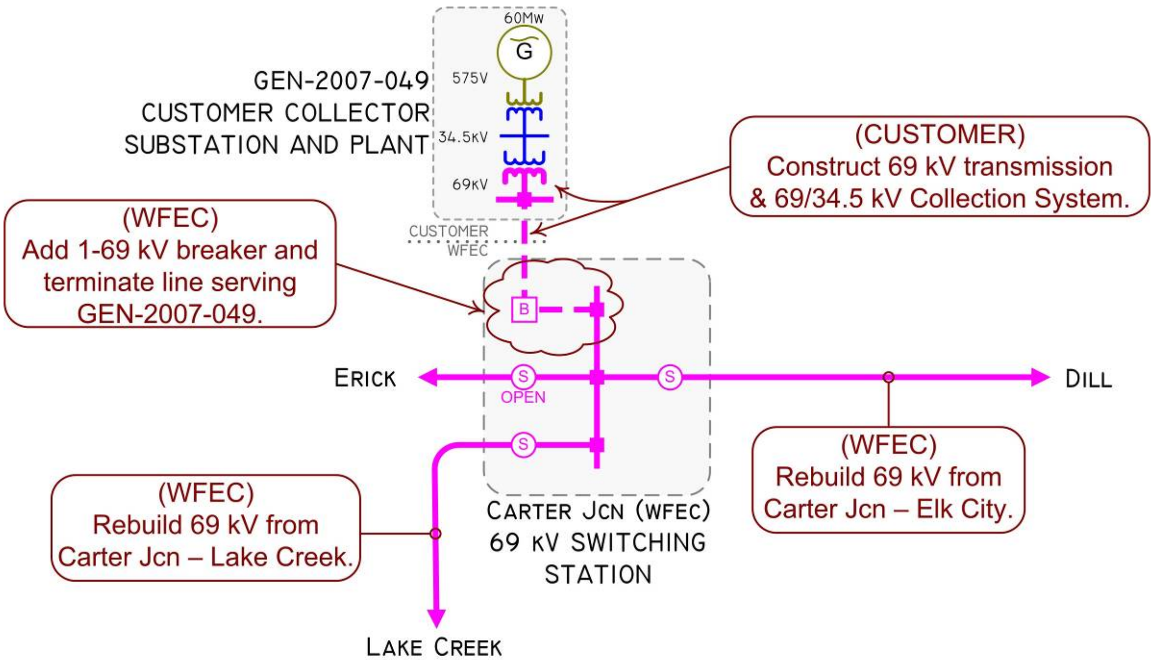

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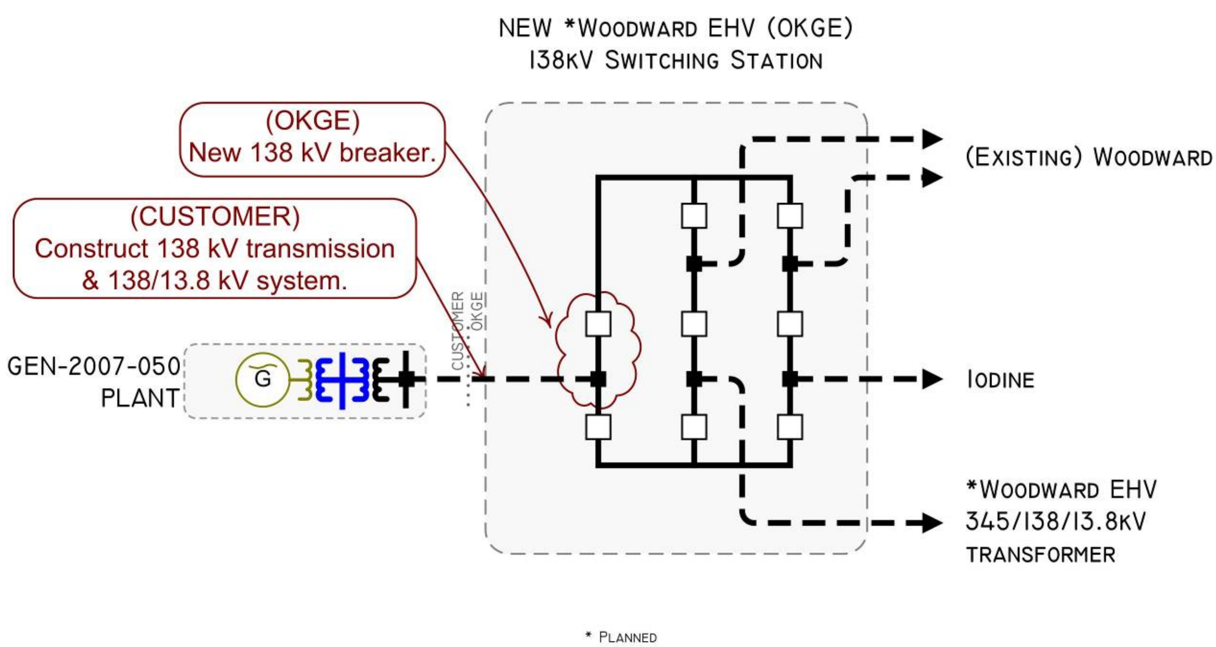

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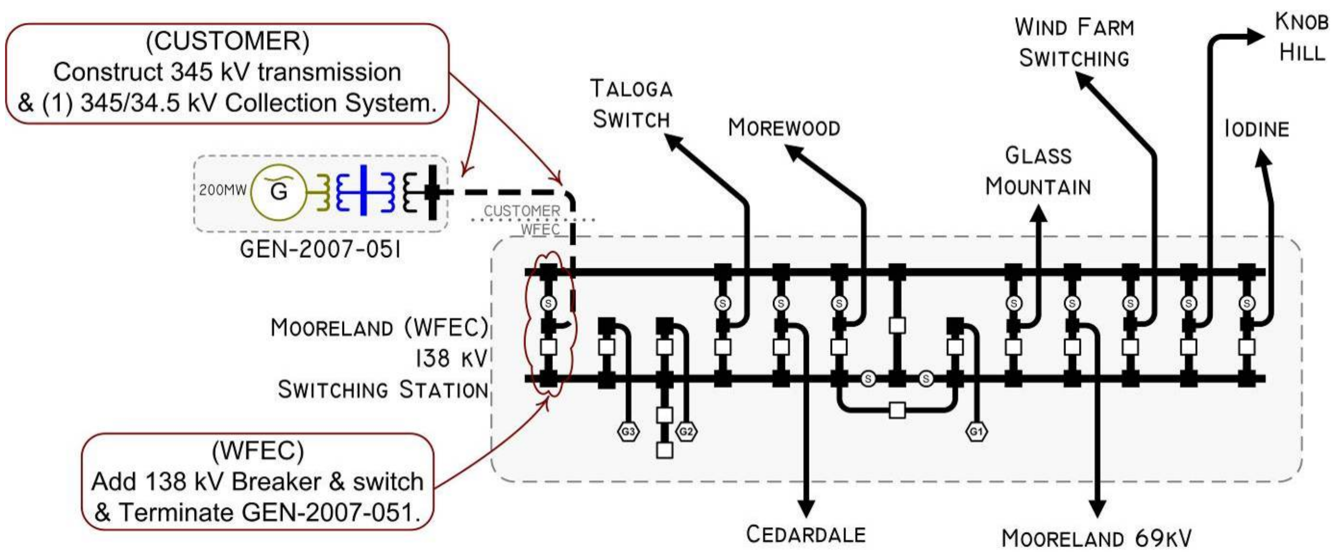

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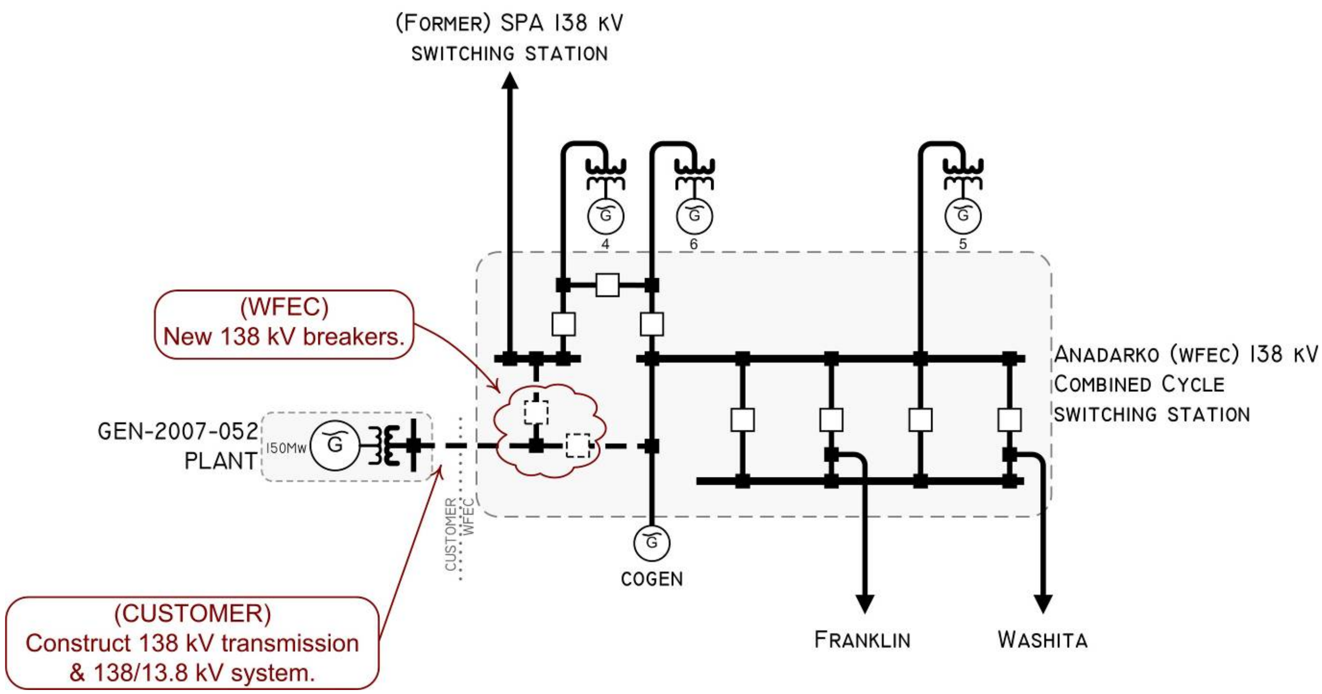
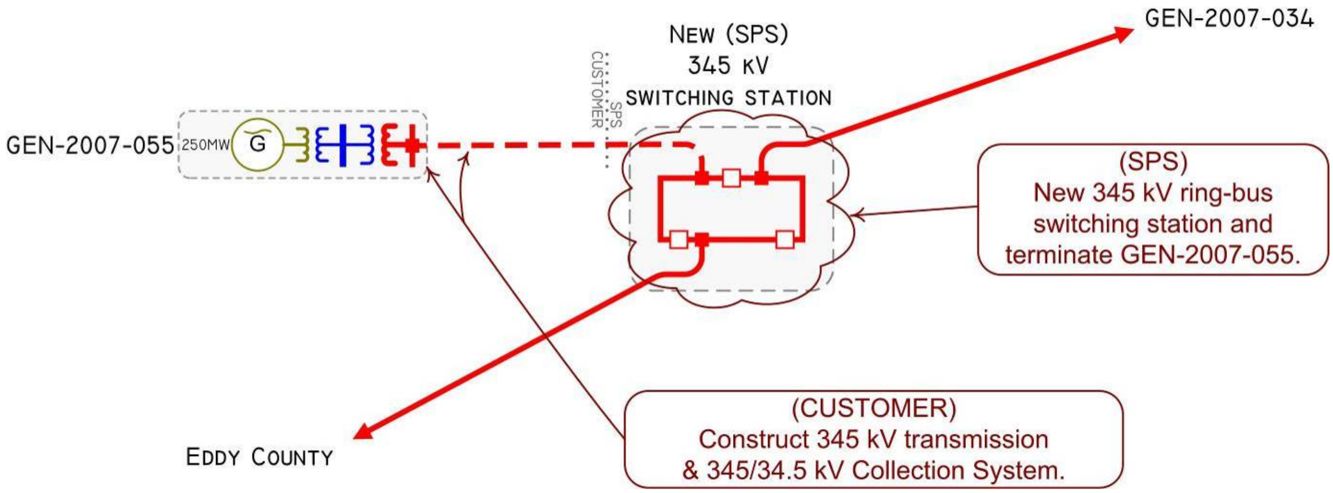


GEN-2007-053***

See GEN-2007-053 Impact Study report in Appendix J.

GEN-2007-055



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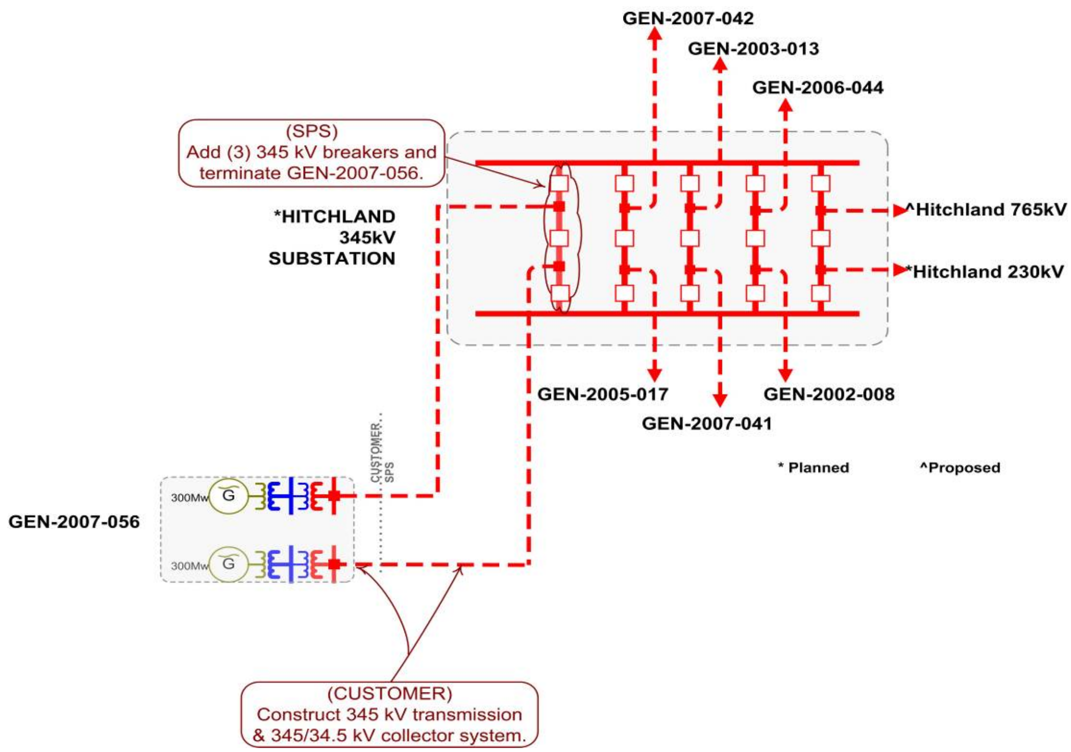

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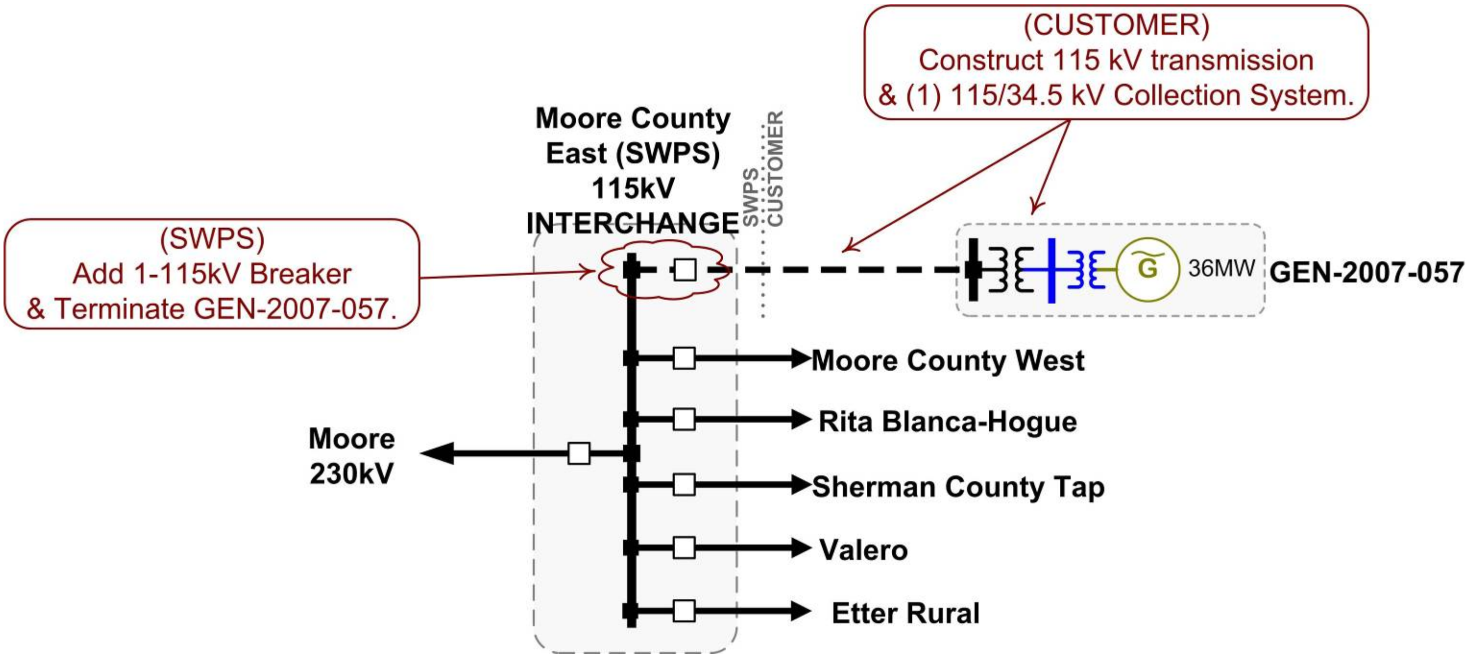
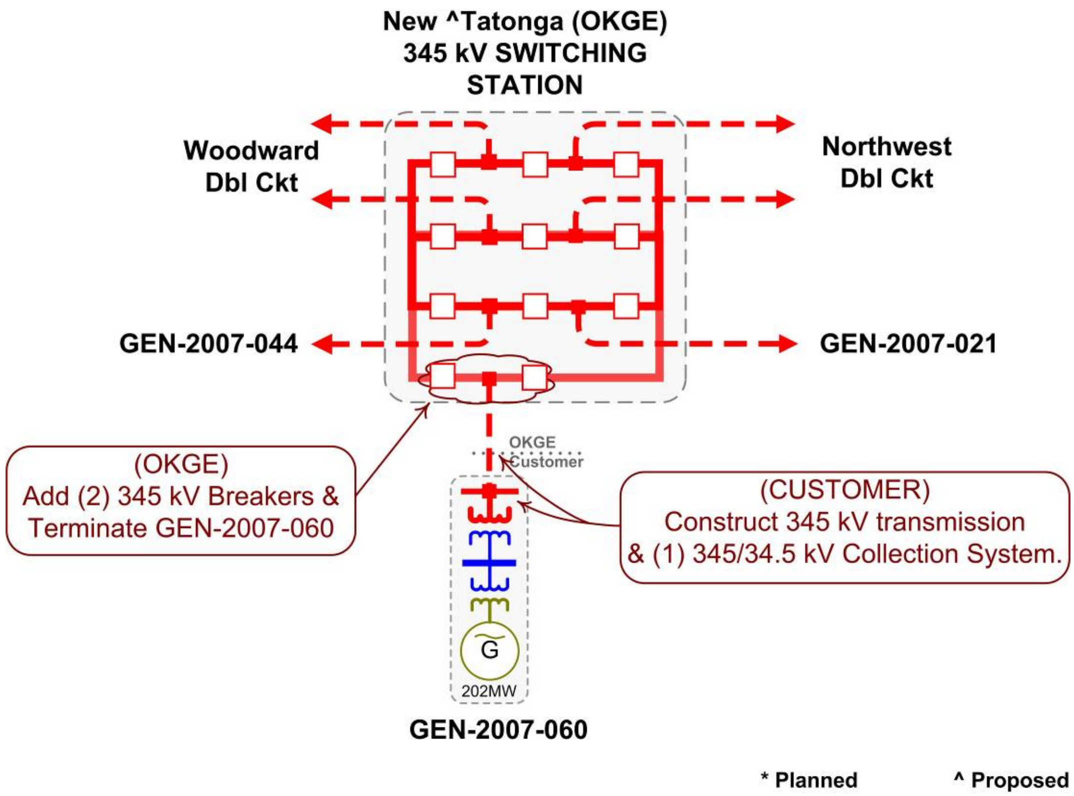
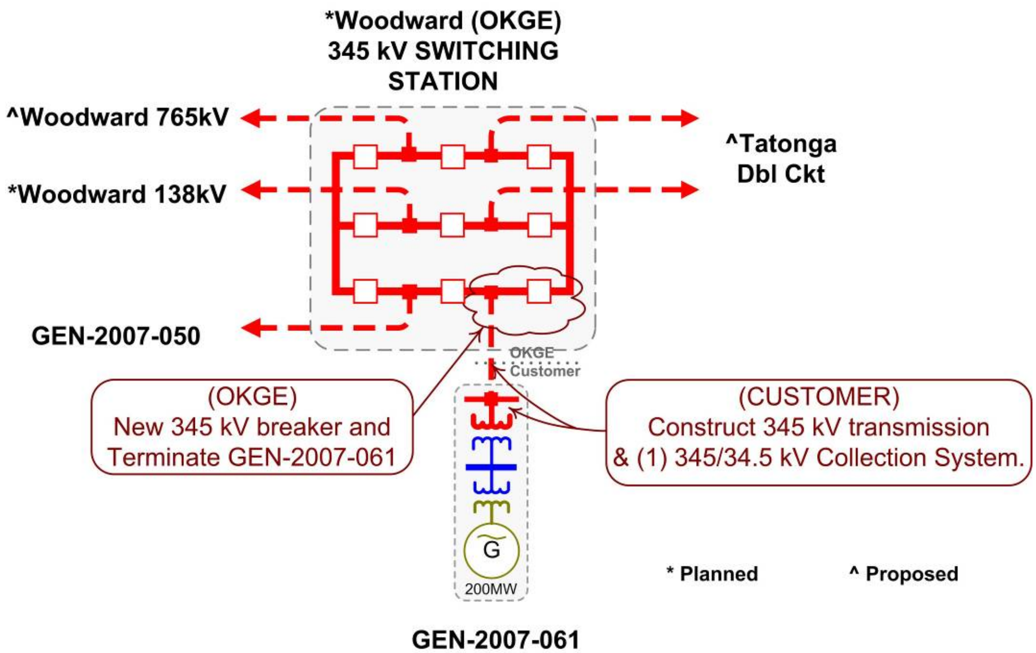


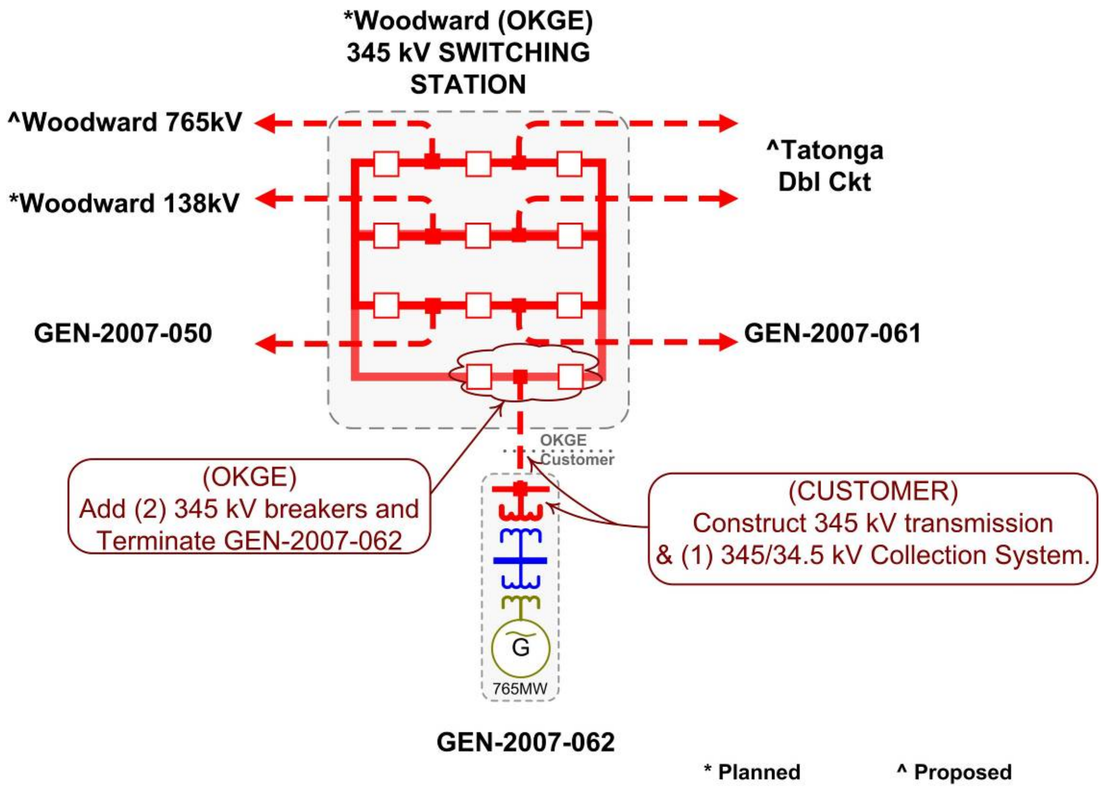
GEN-2007-060


New ^Tatonga (OKGE)
345 kV SWITCHING
STATION
Woodward
Dbl Ckt
Northwest
Dbl Ckt
GEN-2007-044
GEN-2007-021
OKGE
Customer
(OKGE)
Add (2) 345 kV Breakers &
Terminate GEN-2007-060
(CUSTOMER)
Construct 345 kV transmission
& (1) 345/34.5 kV Collection System.
G
202MW
GEN-2007-060
* Planned
^ Proposed

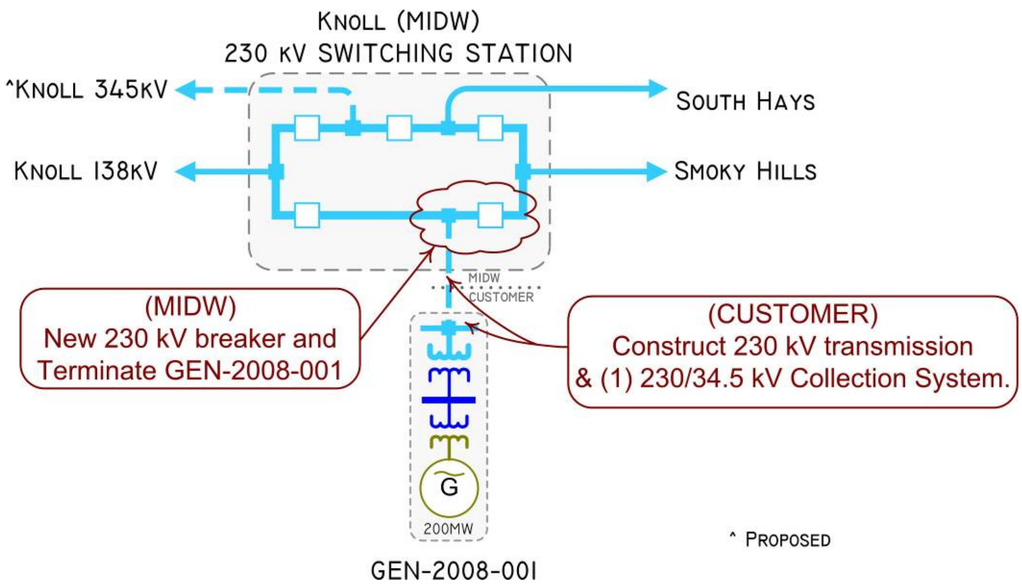
GEN-2007-061



GEN-2007-062


*Woodward (OKGE)
345 kV SWITCHING
STATION
^Woodward 765kV
*Woodward 138kV
GEN-2007-050
^Tatonga
Dbl Ckt
GEN-2007-061
OKGE
Customer
(OKGE)
Add (2) 345 kV breakers and
Terminate GEN-2007-062
(CUSTOMER)
Construct 345 kV transmission
& (1) 345/34.5 kV Collection System.
G
765MW
GEN-2007-062
* Planned
^ Proposed

GEN-2008-001



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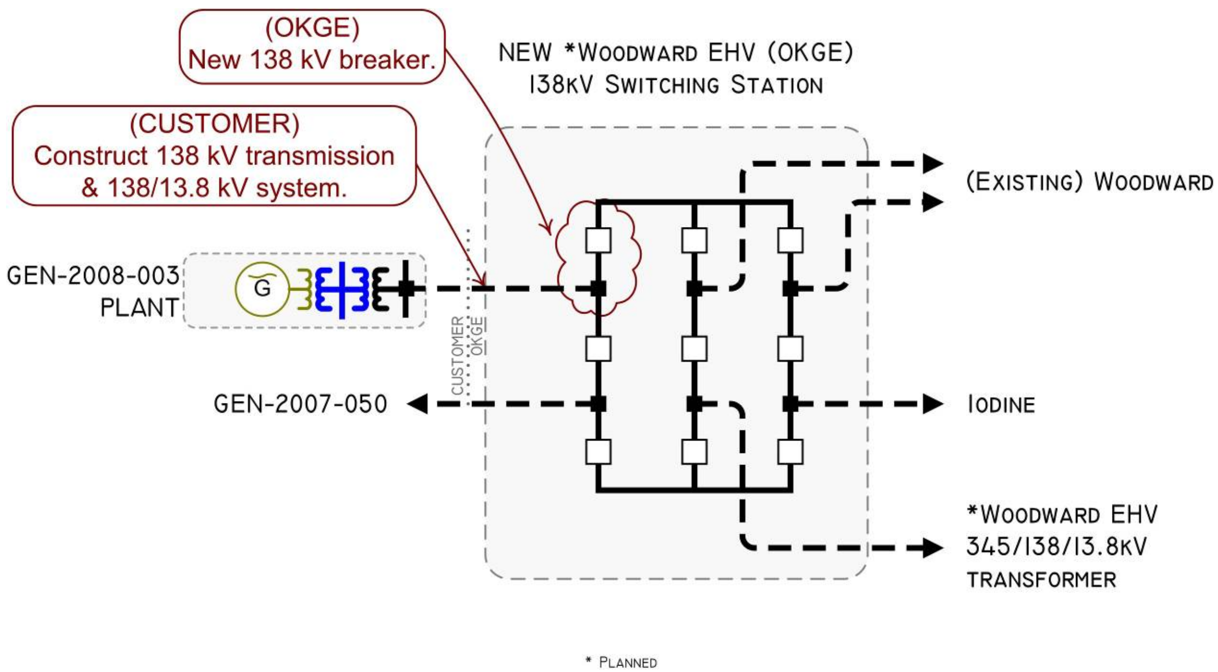

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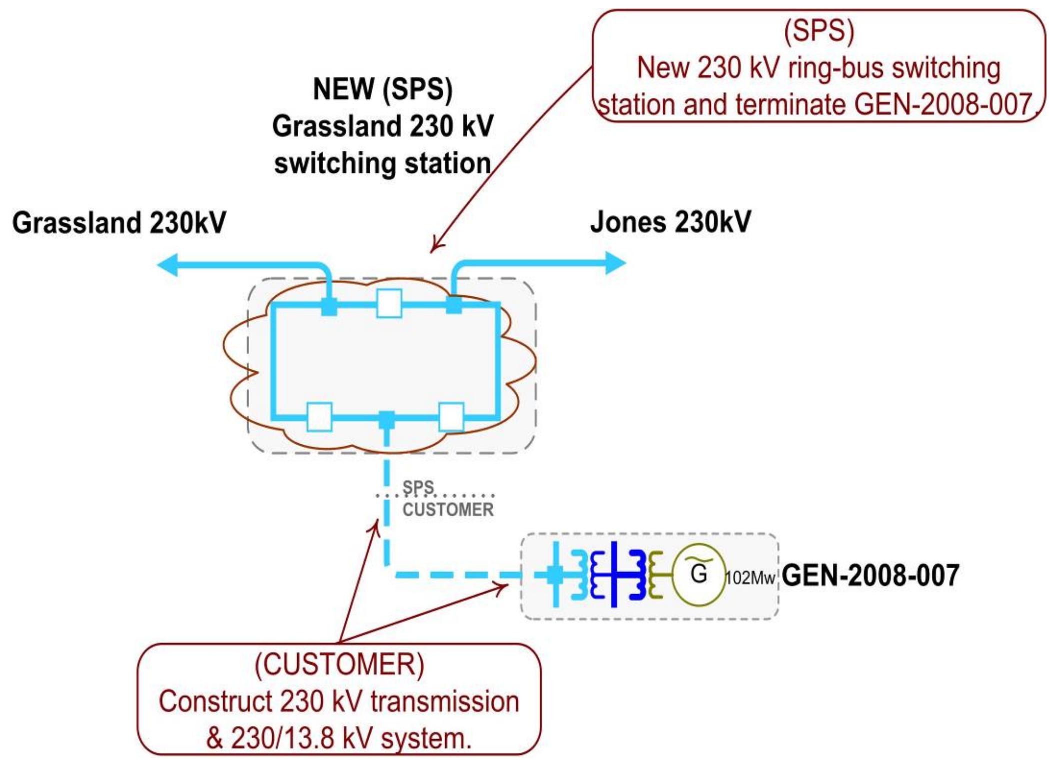

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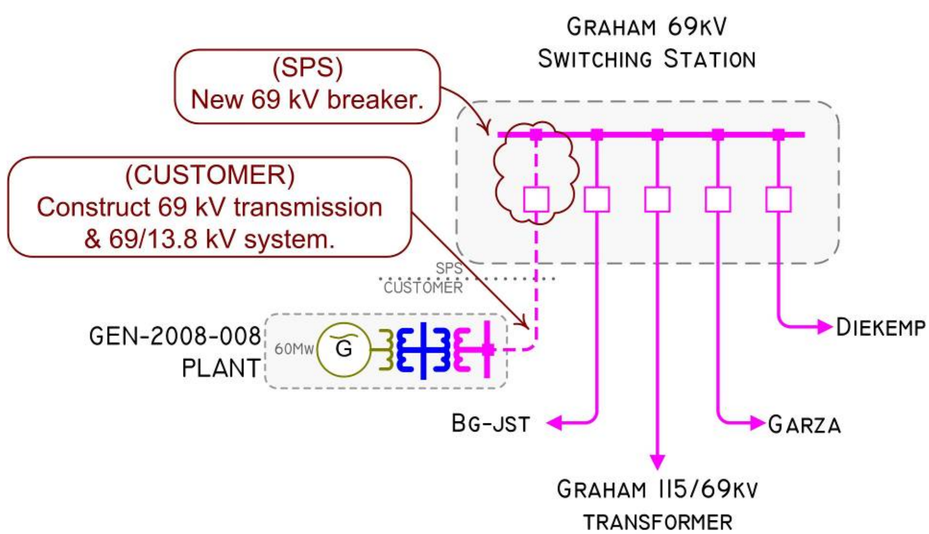

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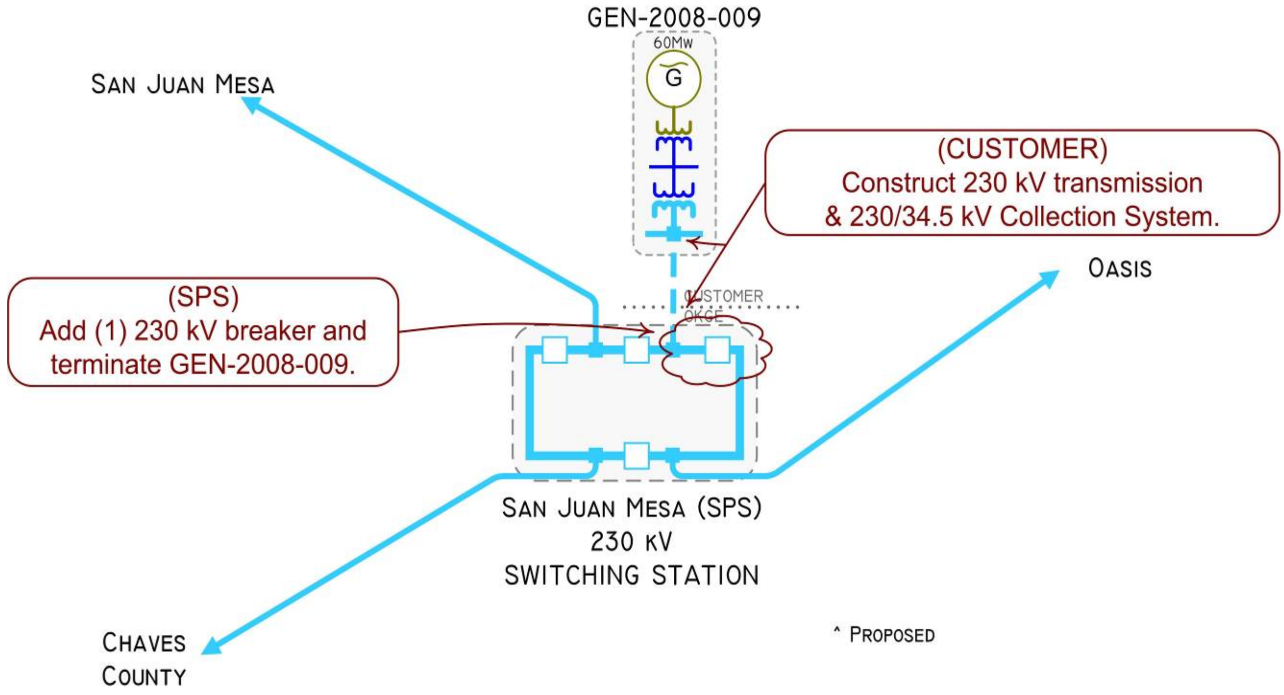
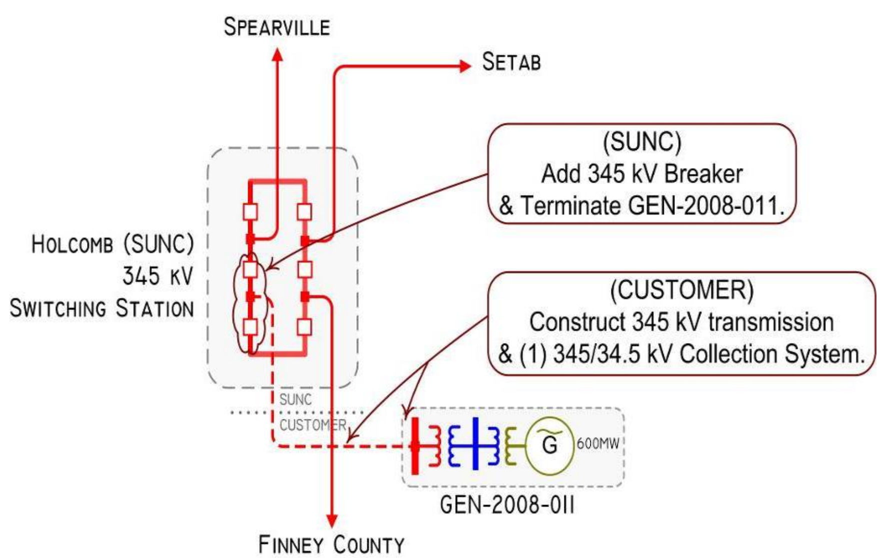


GEN-2008-010***

See GEN-2008-010 Impact Study report in Appendix J

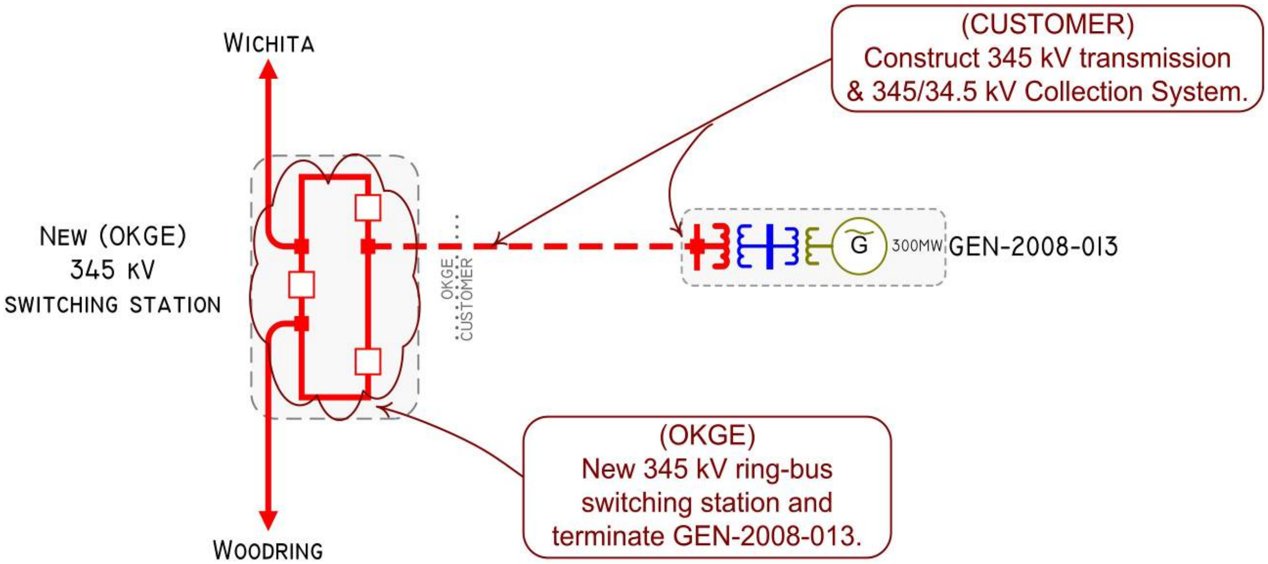
GEN-2008-011



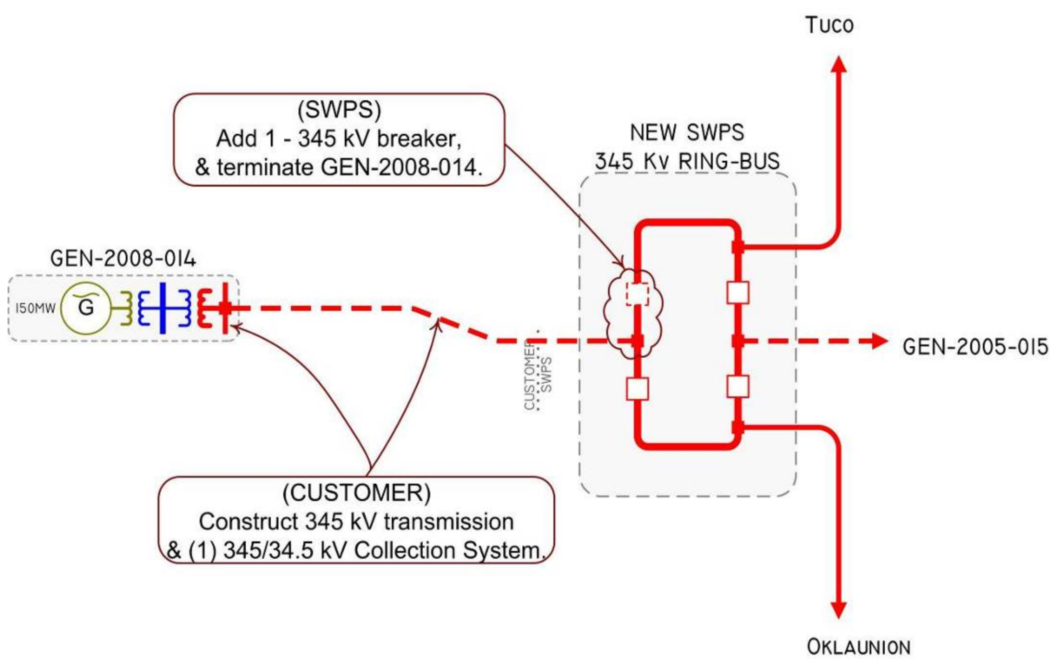
GEN-2008-012***

See GEN-2008-012 Impact Study Report in Appendix J

GEN-2008-013



GEN-2008-014



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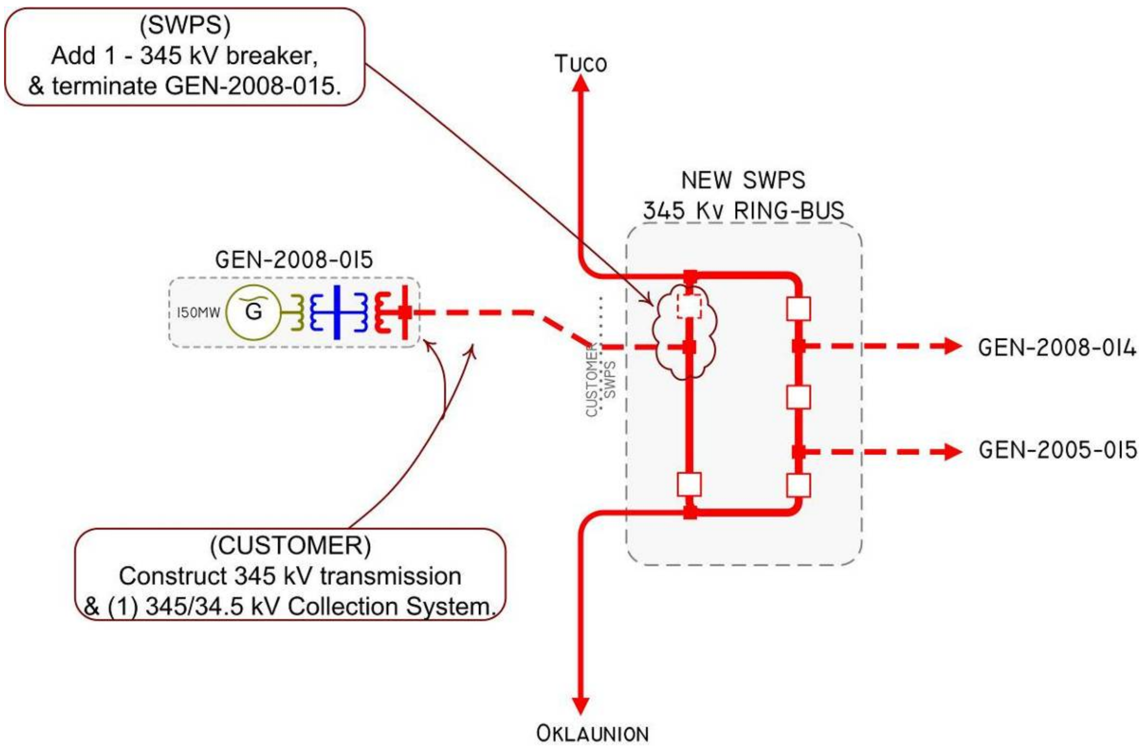

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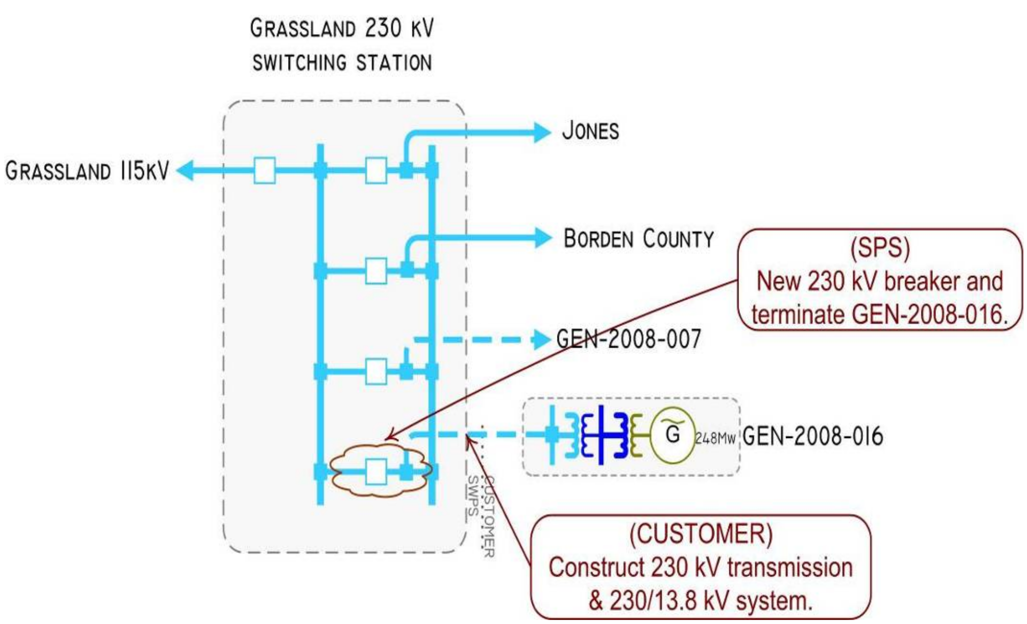

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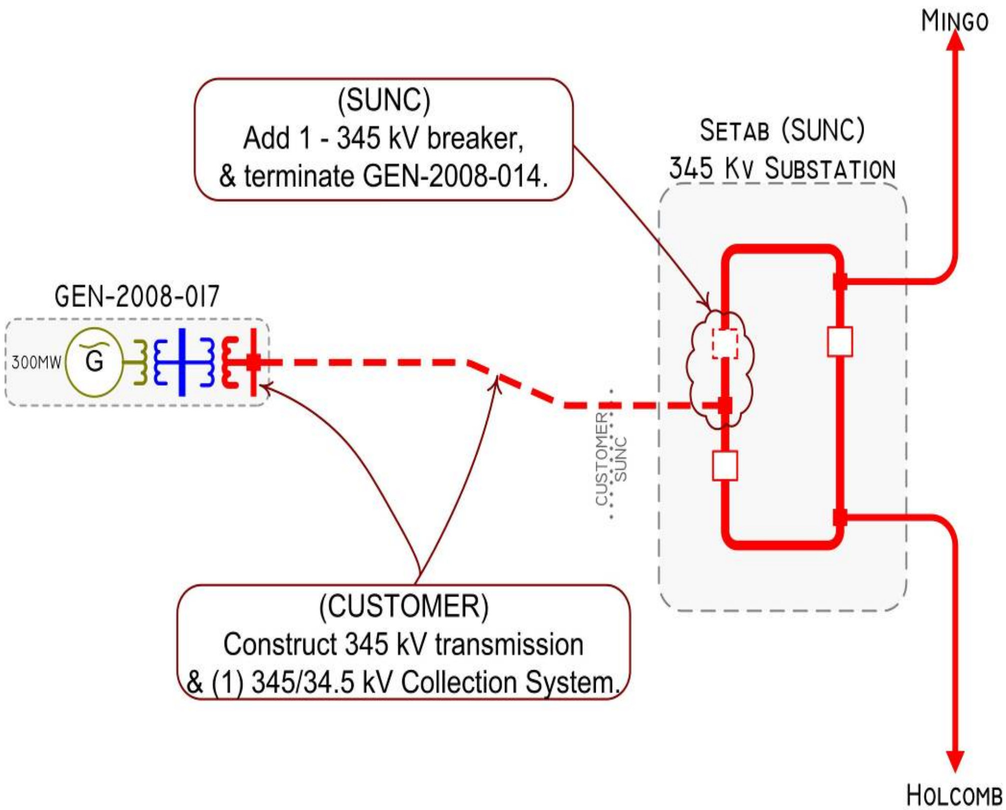

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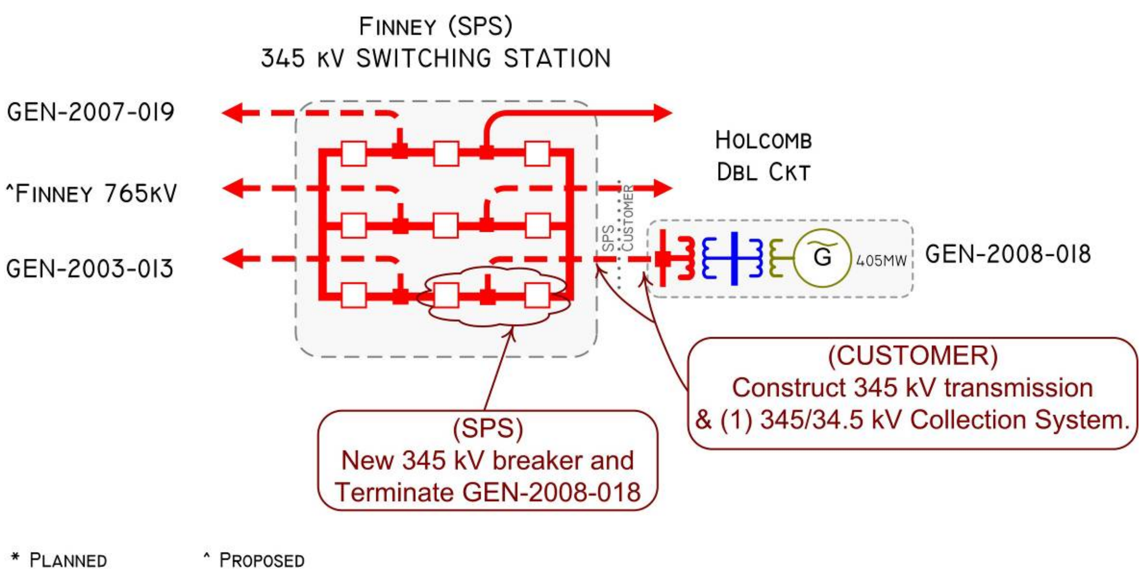
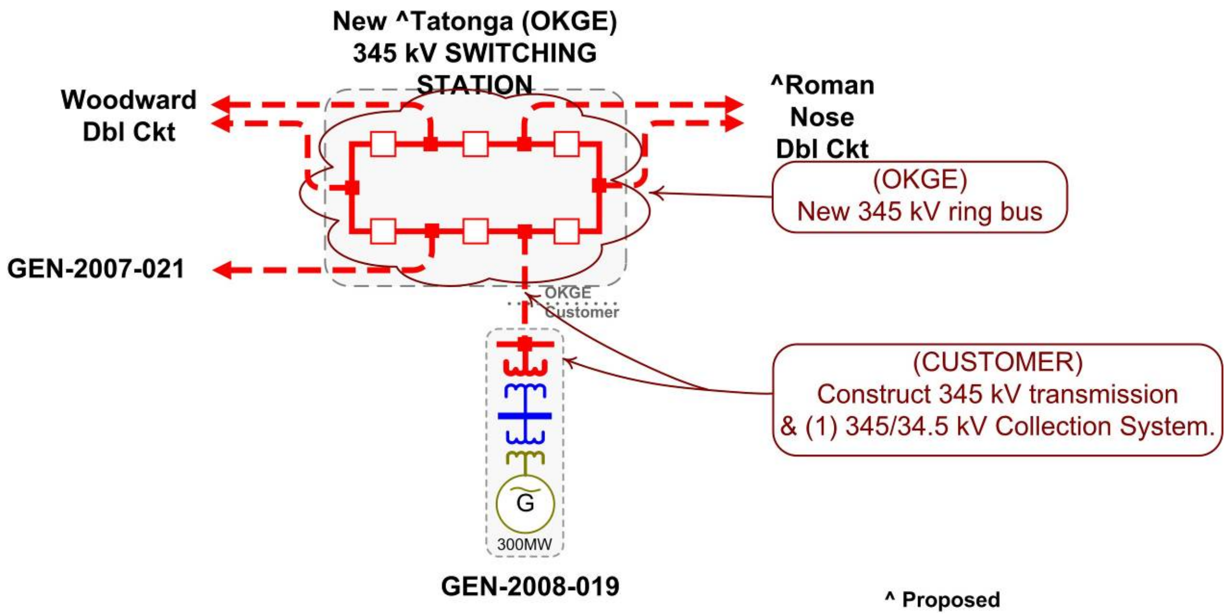


GEN-2008-019


New ^Tatonga (OKGE)
345 kV SWITCHING
STATION
Woodward
Dbl Ckt
^Roman
Nose
Dbl Ckt
(OKGE)
New 345 kV ring bus
GEN-2007-021
OKGE
Customer
(CUSTOMER)
Construct 345 kV transmission
& (1) 345/34.5 kV Collection System.
G
300MW
GEN-2008-019
^ Proposed

E: Cost Allocation per Interconnection Request

Appendix E.

Generation Interconnection Cost Allocation

Interconnection Request	Allocated Costs
G06-06	$35,762,672.86
G07-05	$44,386,298.93
G07-08	$74,729,148.21
G07-10	$30,191,028.03
G07-12	$39,663,031.77
G07-19	$62,914,837.88
G07-21	$14,226,868.45
G07-25	$38,742,718.73
G07-26	$20,418,668.93
G07-27	$11,375,025.17
G07-30	$52,045,675.73
G07-32	$2,608,320.56
G07-33	$40,570,904.77
G07-34	$26,768,034.03
G07-36	$33,821,475.68
G07-37	$30,821,475.68
G07-38	$30,821,475.68
G07-40	$96,460,222.78
G07-41	$111,777,785.32
G07-42	$67,767,165.40
G07-43	$6,955,892.94
G07-44	$20,187,490.23
G07-45	$44,861,552.75
G07-46	$37,704,881.88
G07-47	$27,769,747.88
G07-48	$59,338,991.58
G07-49	$734,360.17
G07-50	$18,744,325.52
G07-51	$14,461,885.22
G07-52	$763,482.31
G07-55	$39,997,017.60
G07-56	$112,277,785.32
G07-57	$8,930,741.27
G07-60	$13,487,076.75
G07-61	$20,724,905.30
G07-62	$66,484,637.78

Interconnection Request	Allocated Costs
G08-01	$33,000,630.47
G08-03	$9,875,884.39
G08-07	$12,836,895.43
G08-08	$8,496,824.83
G08-09	$8,938,165.94
G08-11	$92,882,843.90
G08-13	$8,908,728.36
G08-14	$9,588,424.22
G08-15	$10,588,424.22
G08-16	$34,198,642.26
G08-17	$33,236,723.76
G08-18	$63,252,024.91
G08-19	$20,187,490.23
All Upgrades Total	**$1,705,289,312.00**

F: Cost Allocation per Interconnection Request with Detail

Appendix F.
Generation Interconnection Cost Allocation

Interconnection Request		E + C Cost	Allocated Costs
G06-06			
	Beaver County - Stevens County 345kV	$42,000,000.00	$960,049.07
	Beaver County - Woodward 345kV ckt 1	$109,230,000.00	$1,133,971.08
	Cimarron - Matthewson 345kV ckt #2	$13,800,000.00	$257,391.07
	Comanche - Medicine Lodge 345kV ckt 1	$60,000,000.00	$1,031,203.29
	Comanche - Woodward 345kV ckt1	$80,000,000.00	$2,860,262.79
	GEN06-006 Interconnection Cost	$5,447,481.00	$5,447,481.00
	GEN07-043 - Cimarron 345kV ckt1	$250,000.00	$1,452.48
	Gray County - Comanche 345kV ckt 1	$71,000,000.00	$2,153,374.10
	Gray County - Stevens County 345kV ckt	$58,200,000.00	$3,016,558.73
	Knoll 345/230kV Transformer	$10,000,000.00	$86,252.16
	Medicine Lodge - Wichita 345kV ckt 1	$90,000,000.00	$1,445,287.85
	Mingo - Knoll 345kV ckt 1	$110,000,000.00	$948,773.74
	Mullergren - Circle 230kV ckt1	$200,000.00	$11,985.32
	Spearville - Comanche 345kV ckt 1	$50,000,000.00	$5,089,883.72
	Spearville - Wichita 345kV ckt 1	$150,000,000.00	$8,720,069.59
	Tatonga - Matthewson 345kV ckt #2	$87,500,000.00	$1,202,072.26
	Woodward - Tatonga 345kV ckt 2	$83,848,000.00	$1,396,604.61
G06-06	**Total**		**$35,762,672.86**
G07-05			
	Beaver County - Hitchland 345kV ckt 1	$54,900,000.00	$2,757,136.52
	Beaver County - Stevens County 345kV	$42,000,000.00	$1,027,108.18
	Beaver County - Woodward 345kV ckt 1	$109,230,000.00	$3,216,651.96
	Beckham 345/230kV Transformer	$6,000,000.00	$219,172.43
	Beckham County - Anadarko 345kV ckt 1	$150,000,000.00	$5,352,948.63
	Comanche - Medicine Lodge 345kV ckt 1	$60,000,000.00	$798,853.90
	Comanche - Woodward 345kV ckt1	$80,000,000.00	$925,322.60
	GEN07-005 Interconnection Cost	$600,000.00	$600,000.00
	GEN07-043 - Cimarron 345kV ckt1	$250,000.00	$4,408.21
	Grapevine - Beckham 345kV ckt 1	$50,000,000.00	$1,826,436.95
	Grapevine - LES 345kV ckt1	$180,000,000.00	$6,737,381.14
	Gray County - Stevens County 345kV ckt	$58,200,000.00	$2,382,651.50

Interconnection Request		E + C Cost	Allocated Costs
	Hutchinson - Riverview 115kV ckt1	$4,250,000.00	$3,298,556.94
	Knoll 345/230kV Transformer	$10,000,000.00	$106,017.95
	Medicine Lodge - Wichita 345kV ckt 1	$90,000,000.00	$1,119,637.47
	Mingo - Knoll 345kV ckt 1	$110,000,000.00	$1,166,197.43
	Mullergren - Circle 230kV ckt1	$200,000.00	$3,271.91
	Potter - Grapevine 345kV ckt 1	$60,000,000.00	$3,561,190.36
	Pringle - Hutchinson 115kV ckt1	$4,250,000.00	$4,250,000.00
	SmokyHills - Summit 230kV ckt1	$200,000.00	$4,269.29
	Spearville - Comanche 345kV ckt 1	$50,000,000.00	$213,309.22
	Spearville - Wichita 345kV ckt 1	$150,000,000.00	$2,888,993.86
	Sunnyside - LES 345kV ckt1	$500,000.00	$14,115.99
	Tatonga - Matthewson 345kV ckt #2	$87,500,000.00	$884,743.83
	Woodward - Tatonga 345kV ckt 2	$83,848,000.00	$1,027,922.66
G07-05	**Total**		**$44,386,298.93**
G07-08			
	Beaver County - Hitchland 345kV ckt 1	$54,900,000.00	$1,461,672.59
	Beaver County - Woodward 345kV ckt 1	$109,230,000.00	$2,348,437.16
	Beckham 345/230kV Transformer	$6,000,000.00	$951,770.18
	Beckham County - Anadarko 345kV ckt 1	$150,000,000.00	$24,943,274.72
	Cimarron - Matthewson 345kV ckt #2	$13,800,000.00	$392,570.35
	GEN07-008 Interconnection Cost	$2,500,000.00	$2,500,000.00
	GEN07-043 - Cimarron 345kV ckt1	$250,000.00	$15,656.75
	Grapevine - Beckham 345kV ckt 1	$50,000,000.00	$7,931,418.19
	Grapevine - LES 345kV ckt1	$180,000,000.00	$32,326,488.03
	Sunnyside - LES 345kV ckt1	$500,000.00	$35,388.31
	Tatonga - Matthewson 345kV ckt #2	$87,500,000.00	$843,022.45
	Woodward - Tatonga 345kV ckt 2	$83,848,000.00	$979,449.47
G07-08	**Total**		**$74,729,148.21**
G07-10			
	Beaver County - Hitchland 345kV ckt 1	$54,900,000.00	$1,635,910.64
	Beaver County - Woodward 345kV ckt 1	$109,230,000.00	$2,628,381.61
	Beckham 345/230kV Transformer	$6,000,000.00	$260,338.39
	Beckham County - Anadarko 345kV ckt 1	$150,000,000.00	$6,470,543.99
	Bushland Line Trap	$400,000.00	$91,783.58
	Cimarron - Matthewson 345kV ckt #2	$13,800,000.00	$126,048.30
	Curry County - Deaf Smith	$1,000,000.00	$123,845.06

Interconnection Request		E + C Cost	Allocated Costs
	Deaf Smith - Plant X 230kV Line Trap	$400,000.00	$37,436.89
	GEN07-010 Interconnection Cost-1	$250,000.00	$250,000.00
	GEN07-010 Interconnection Cost-2	$250,000.00	$250,000.00
	GEN07-043 - Cimarron 345kV ckt1	$250,000.00	$6,770.03
	GEN07-048 - Swisher 230kV ckt1 Line Tr	$200,000.00	$1,369.87
	Grapevine - Beckham 345kV ckt 1	$50,000,000.00	$2,169,486.54
	Grapevine - LES 345kV ckt1	$180,000,000.00	$7,537,396.13
	Potter - Bushland 230kV ckt1 Line Trap	$200,000.00	$40,825.11
	Potter - Grapevine 345kV ckt 1	$60,000,000.00	$4,115,299.43
	Potter - Replace 345/115kV Auto with (2	$20,000,000.00	$2,287,528.85
	Sunnyside - LES 345kV ckt1	$500,000.00	$19,480.00
	Tatonga - Matthewson 345kV ckt #2	$87,500,000.00	$989,246.51
	Woodward - Tatonga 345kV ckt 2	$83,848,000.00	$1,149,337.10
G07-10	**Total**		**$30,191,028.03**
G07-12			
	Comanche - Medicine Lodge 345kV ckt 1	$60,000,000.00	$429,807.30
	Comanche - Woodward 345kV ckt1	$80,000,000.00	$1,781,215.87
	GEN07-012 Interconnection Cost	$9,843,070.00	$9,843,070.00
	GEN07-043 - Cimarron 345kV ckt1	$250,000.00	$1,460.13
	Knoll 345/230kV Transformer	$10,000,000.00	$1,542,237.25
	Medicine Lodge - Wichita 345kV ckt 1	$90,000,000.00	$602,398.46
	Mingo - Knoll 345kV ckt 1	$110,000,000.00	$16,964,609.76
	Mullergren - Circle 230kV ckt1	$200,000.00	$13,589.12
	SmokyHills - Summit 230kV ckt1	$200,000.00	$32,998.44
	South Hays - Mullergren 230kV ckt1	$100,000.00	$22,798.61
	Spearville - Comanche 345kV ckt 1	$50,000,000.00	$3,506,281.26
	Spearville - Wichita 345kV ckt 1	$150,000,000.00	$4,922,565.58
G07-12	**Total**		**$39,663,031.77**
G07-19			
	Beaver County - Stevens County 345kV	$42,000,000.00	$5,675,499.00
	Beaver County - Woodward 345kV ckt 1	$109,230,000.00	$6,703,669.61
	Cimarron - Matthewson 345kV ckt #2	$13,800,000.00	$438,406.93
	Comanche - Medicine Lodge 345kV ckt 1	$60,000,000.00	$2,018,923.94
	Comanche - Woodward 345kV ckt1	$80,000,000.00	$2,876,289.63
	GEN07-019 Interconnection Cost-1	$3,100,000.00	$3,100,000.00
	GEN07-019 Interconnection Cost-2	$3,100,000.00	$3,100,000.00

Interconnection Request		E + C Cost	Allocated Costs
	GEN07-043 - Cimarron 345kV ckt1	$250,000.00	$2,049.96
	Gray County - Comanche 345kV ckt 1	$71,000,000.00	$10,074,062.68
	Gray County - Stevens County 345kV ckt	$58,200,000.00	$439,423.43
	Knoll 345/230kV Transformer	$10,000,000.00	$623,112.20
	Medicine Lodge - Wichita 345kV ckt 1	$90,000,000.00	$2,829,632.40
	Mingo - Knoll 345kV ckt 1	$110,000,000.00	$6,854,234.17
	Mullergren - Circle 230kV ckt1	$200,000.00	$13,225.43
	Spearville - Comanche 345kV ckt 1	$50,000,000.00	$2,611,949.69
	Spearville - Wichita 345kV ckt 1	$150,000,000.00	$10,232,663.30
	Tatonga - Matthewson 345kV ckt #2	$87,500,000.00	$2,461,661.40
	Woodward - Tatonga 345kV ckt 2	$83,848,000.00	$2,860,034.11
G07-19	**Total**		**$62,914,837.88**
G07-21			
	Cimarron - Matthewson 345kV ckt #2	$13,800,000.00	$532,831.94
	Comanche - Medicine Lodge 345kV ckt 1	$60,000,000.00	$1,656,527.82
	Comanche - Woodward 345kV ckt1	$80,000,000.00	$1,640,380.63
	GEN07-021 Interconnection Cost	$2,125,000.00	$2,125,000.00
	GEN07-043 - Cimarron 345kV ckt1	$250,000.00	$3,381.68
	Medicine Lodge - Wichita 345kV ckt 1	$90,000,000.00	$2,321,714.40
	Sunnyside - LES 345kV ckt1	$500,000.00	$2,920.67
	Tatonga - Matthewson 345kV ckt #2	$87,500,000.00	$4,337,494.78
	Woodward - Tatonga 345kV ckt 2	$83,848,000.00	$1,606,616.54
G07-21	**Total**		**$14,226,868.45**
G07-25			
	Cimarron - Matthewson 345kV ckt #2	$13,800,000.00	$561,270.99
	Comanche - Medicine Lodge 345kV ckt 1	$60,000,000.00	$6,193,441.90
	Comanche - Woodward 345kV ckt1	$80,000,000.00	$6,133,070.63
	GEN07-025 Interconnection Cost	$6,000,000.00	$6,000,000.00
	GEN07-043 - Cimarron 345kV ckt1	$250,000.00	$4,493.31
	Medicine Lodge - Wichita 345kV ckt 1	$90,000,000.00	$14,587,163.67
	Tatonga - Matthewson 345kV ckt #2	$87,500,000.00	$2,434,639.26
	Woodward - Tatonga 345kV ckt 2	$83,848,000.00	$2,828,638.96
G07-25	**Total**		**$38,742,718.73**
G07-26			
	Beaver County - Hitchland 345kV ckt 1	$54,900,000.00	$1,063,341.92
	Beaver County - Woodward 345kV ckt 1	$109,230,000.00	$1,708,448.04

Interconnection Request		E + C Cost	Allocated Costs
	Beckham 345/230kV Transformer	$6,000,000.00	$169,219.95
	Beckham County - Anadarko 345kV ckt 1	$150,000,000.00	$4,205,853.60
	Bushland Line Trap	$400,000.00	$59,659.33
	Cimarron - Matthewson 345kV ckt #2	$13,800,000.00	$81,931.40
	Deaf Smith - Plant X 230kV Line Trap	$400,000.00	$24,333.98
	GEN07-026 Interconnection Cost	$1,200,000.00	$1,200,000.00
	GEN07-043 - Cimarron 345kV ckt1	$250,000.00	$4,400.52
	GEN07-048 - Swisher 230kV ckt1 Line Tr	$200,000.00	$890.42
	Grapevine - Beckham 345kV ckt 1	$50,000,000.00	$1,410,166.25
	Grapevine - LES 345kV ckt1	$180,000,000.00	$4,899,307.48
	Potter - Bushland 230kV ckt1 Line Trap	$200,000.00	$26,536.32
	Potter - Grapevine 345kV ckt 1	$60,000,000.00	$2,674,944.63
	Potter - Replace 345/115kV Auto with (2	$20,000,000.00	$1,486,893.75
	Sunnyside - LES 345kV ckt1	$500,000.00	$12,662.00
	Tatonga - Matthewson 345kV ckt #2	$87,500,000.00	$643,010.23
	Woodward - Tatonga 345kV ckt 2	$83,848,000.00	$747,069.11
G07-26	**Total**		**$20,418,668.93**
G07-27			
	Amarillo South - Swisher 230kV Line Tra	$100,000.00	$3,612.17
	Beaver County - Hitchland 345kV ckt 1	$54,900,000.00	$464,420.69
	Beaver County - Woodward 345kV ckt 1	$109,230,000.00	$746,174.50
	Beckham 345/230kV Transformer	$6,000,000.00	$64,319.29
	Beckham County - Anadarko 345kV ckt 1	$150,000,000.00	$1,566,814.18
	Bushland Line Trap	$400,000.00	$16,459.90
	Cimarron - Matthewson 345kV ckt #2	$13,800,000.00	$50,147.70
	Comanche - Woodward 345kV ckt1	$80,000,000.00	$102,056.19
	Curry County - Deaf Smith	$1,000,000.00	$544,468.97
	Deaf Smith - Plant X 230kV Line Trap	$400,000.00	$15,033.17
	GEN07-027 Interconnection Cost	$2,500,000.00	$2,500,000.00
	GEN07-043 - Cimarron 345kV ckt1	$250,000.00	$2,251.10
	GEN07-048 - Swisher 230kV ckt1 Line Tr	$200,000.00	$4,445.64
	Grapevine - Beckham 345kV ckt 1	$50,000,000.00	$535,994.07
	Grapevine - LES 345kV ckt1	$180,000,000.00	$1,610,383.11
	Gray County - Comanche 345kV ckt 1	$71,000,000.00	$314,408.50
	Plant X - Tolk 230kV #1 Reconductor to	$5,000,000.00	$387,406.54
	Plant X - Tolk 230kV #2 Reconductor to	$5,000,000.00	$387,406.54

Interconnection Request		E + C Cost	Allocated Costs
	Potter - Bushland 230kV ckt1 Line Trap	$200,000.00	$7,946.88
	Potter - Grapevine 345kV ckt 1	$60,000,000.00	$954,634.20
	Potter - Replace 345/115kV Auto with (2	$20,000,000.00	$566,584.85
	Sunnyside - LES 345kV ckt1	$500,000.00	$6,442.76
	Swisher - Tuco 230kV Line Trap	$400,000.00	$12,347.53
	Tatonga - Matthewson 345kV ckt #2	$87,500,000.00	$236,497.08
	Woodward - Tatonga 345kV ckt 2	$83,848,000.00	$274,769.60
G07-27	**Total**		**$11,375,025.17**
G07-30			
	Beaver County - Hitchland 345kV ckt 1	$54,900,000.00	$974,448.39
	Beaver County - Woodward 345kV ckt 1	$109,230,000.00	$1,565,624.78
	Beckham 345/230kV Transformer	$6,000,000.00	$634,513.46
	Beckham County - Anadarko 345kV ckt 1	$150,000,000.00	$16,628,849.81
	Cimarron - Matthewson 345kV ckt #2	$13,800,000.00	$261,713.57
	Deaf Smith - Plant X 230kV Line Trap	$400,000.00	$7,710.16
	GEN07-030 Interconnection Cost	$2,500,000.00	$2,500,000.00
	GEN07-043 - Cimarron 345kV ckt1	$250,000.00	$10,437.83
	GEN07-048 - Swisher 230kV ckt1 Line Tr	$200,000.00	$2,577.24
	Grapevine - Beckham 345kV ckt 1	$50,000,000.00	$5,287,612.13
	Grapevine - LES 345kV ckt1	$180,000,000.00	$21,550,992.02
	Potter - Replace 345/115kV Auto with (2	$20,000,000.00	$1,382,622.86
	Sunnyside - LES 345kV ckt1	$500,000.00	$23,592.21
	Tatonga - Matthewson 345kV ckt #2	$87,500,000.00	$562,014.96
	Woodward - Tatonga 345kV ckt 2	$83,848,000.00	$652,966.31
G07-30	**Total**		**$52,045,675.73**
G07-32			
	Beckham County - Anadarko 345kV ckt 1	$150,000,000.00	$447,946.76
	Clinton Jct Switches	$150,000.00	$150,000.00
	GEN07-032 Interconnection Cost	$2,000,000.00	$2,000,000.00
	GEN07-043 - Cimarron 345kV ckt1	$250,000.00	$1,565.03
	Sunnyside - LES 345kV ckt1	$500,000.00	$8,808.77
G07-32	**Total**		**$2,608,320.56**
G07-33			
	Beaver County - Hitchland 345kV ckt 1	$54,900,000.00	$2,682,141.90
	Beaver County - Stevens County 345kV	$42,000,000.00	$1,018,152.11
	Beaver County - Woodward 345kV ckt 1	$109,230,000.00	$3,106,738.29

Interconnection Request		E + C Cost	Allocated Costs
	Beckham 345/230kV Transformer	$6,000,000.00	$226,178.45
	Beckham County - Anadarko 345kV ckt 1	$150,000,000.00	$5,543,151.85
	Cimarron - Matthewson 345kV ckt #2	$13,800,000.00	$37,366.68
	Comanche - Medicine Lodge 345kV ckt 1	$60,000,000.00	$784,908.82
	Comanche - Woodward 345kV ckt1	$80,000,000.00	$921,377.13
	GEN07-033 Interconnection Cost	$3,221,000.00	$3,221,000.00
	GEN07-043 - Cimarron 345kV ckt1	$250,000.00	$4,635.51
	Grapevine - Beckham 345kV ckt 1	$50,000,000.00	$1,884,820.46
	Grapevine - LES 345kV ckt1	$180,000,000.00	$6,939,737.87
	Gray County - Stevens County 345kV ckt	$58,200,000.00	$2,326,436.97
	Hutchinson - Riverview 115kV ckt1	$4,250,000.00	$951,443.06
	Knoll 345/230kV Transformer	$10,000,000.00	$103,595.28
	Medicine Lodge - Wichita 345kV ckt 1	$90,000,000.00	$1,100,092.67
	Mingo - Knoll 345kV ckt 1	$110,000,000.00	$1,139,548.11
	Mullergren - Circle 230kV ckt1	$200,000.00	$3,200.75
	Potter - Grapevine 345kV ckt 1	$60,000,000.00	$3,671,818.76
	SmokyHills - Summit 230kV ckt1	$200,000.00	$4,171.54
	Spearville - Comanche 345kV ckt 1	$50,000,000.00	$228,980.92
	Spearville - Wichita 345kV ckt 1	$150,000,000.00	$2,820,732.90
	Sunnyside - LES 345kV ckt1	$500,000.00	$14,544.44
	Tatonga - Matthewson 345kV ckt #2	$87,500,000.00	$849,340.42
	Woodward - Tatonga 345kV ckt 2	$83,848,000.00	$986,789.88
G07-33	**Total**		**$40,570,904.77**
G07-34			
	Amarillo South - Swisher 230kV Line Tra	$100,000.00	$10,268.68
	Beaver County - Hitchland 345kV ckt 1	$54,900,000.00	$1,138,408.81
	Beaver County - Woodward 345kV ckt 1	$109,230,000.00	$1,829,056.37
	Beckham 345/230kV Transformer	$6,000,000.00	$156,079.20
	Beckham County - Anadarko 345kV ckt 1	$150,000,000.00	$3,789,375.17
	Bushland Line Trap	$400,000.00	$39,899.76
	Cimarron - Matthewson 345kV ckt #2	$13,800,000.00	$129,333.49
	Comanche - Woodward 345kV ckt1	$80,000,000.00	$257,606.39
	Deaf Smith - Plant X 230kV Line Trap	$400,000.00	$53,251.78
	GEN07-034 Interconnection Cost	$6,200,000.00	$6,200,000.00
	GEN07-043 - Cimarron 345kV ckt1	$250,000.00	$5,708.30
	GEN07-048 - Swisher 230kV ckt1 Line Tr	$200,000.00	$12,638.07

Interconnection Request		E + C Cost	Allocated Costs
	Grapevine - Beckham 345kV ckt 1	$50,000,000.00	$1,300,659.99
	Grapevine - LES 345kV ckt1	$180,000,000.00	$3,801,247.69
	Gray County - Comanche 345kV ckt 1	$71,000,000.00	$793,618.11
	Plant X - Tolk 230kV #1 Reconductor to	$5,000,000.00	$1,131,950.58
	Plant X - Tolk 230kV #2 Reconductor to	$5,000,000.00	$1,131,950.58
	Potter - Bushland 230kV ckt1 Line Trap	$200,000.00	$19,208.95
	Potter - Grapevine 345kV ckt 1	$60,000,000.00	$2,290,269.15
	Potter - Replace 345/115kV Auto with (2	$20,000,000.00	$1,378,969.00
	Sunnyside - LES 345kV ckt1	$500,000.00	$16,336.76
	Swisher - Tuco 230kV Line Trap	$400,000.00	$36,330.74
	Tatonga - Matthewson 345kV ckt #2	$87,500,000.00	$576,301.55
	Woodward - Tatonga 345kV ckt 2	$83,848,000.00	$669,564.91
G07-34	**Total**		**$26,768,034.03**
G07-36			
	Beaver County - Stevens County 345kV	$42,000,000.00	$926,407.02
	Beaver County - Woodward 345kV ckt 1	$109,230,000.00	$1,094,234.45
	Cimarron - Matthewson 345kV ckt #2	$13,800,000.00	$254,445.78
	Comanche - Medicine Lodge 345kV ckt 1	$60,000,000.00	$1,134,421.23
	Comanche - Woodward 345kV ckt1	$80,000,000.00	$2,962,391.32
	GEN07-036 Interconnection Cost	$3,000,000.00	$3,000,000.00
	GEN07-043 - Cimarron 345kV ckt1	$250,000.00	$1,403.39
	Gray County - Comanche 345kV ckt 1	$71,000,000.00	$2,132,859.22
	Gray County - Stevens County 345kV ckt	$58,200,000.00	$3,177,572.45
	Medicine Lodge - Wichita 345kV ckt 1	$90,000,000.00	$1,589,953.45
	Mullergren - Circle 230kV ckt1	$200,000.00	$7,425.94
	Spearville - Comanche 345kV ckt 1	$50,000,000.00	$5,424,322.98
	Spearville - Wichita 345kV ckt 1	$150,000,000.00	$9,430,381.02
	Tatonga - Matthewson 345kV ckt #2	$87,500,000.00	$1,242,306.93
	Woodward - Tatonga 345kV ckt 2	$83,848,000.00	$1,443,350.49
G07-36	**Total**		**$33,821,475.68**
G07-37			
	Beaver County - Stevens County 345kV	$42,000,000.00	$926,407.02
	Beaver County - Woodward 345kV ckt 1	$109,230,000.00	$1,094,234.45
	Cimarron - Matthewson 345kV ckt #2	$13,800,000.00	$254,445.78
	Comanche - Medicine Lodge 345kV ckt 1	$60,000,000.00	$1,134,421.23
	Comanche - Woodward 345kV ckt1	$80,000,000.00	$2,962,391.32

Interconnection Request		E + C Cost	Allocated Costs
	GEN07-043 - Cimarron 345kV ckt1	$250,000.00	$1,403.39
	Gray County - Comanche 345kV ckt 1	$71,000,000.00	$2,132,859.22
	Gray County - Stevens County 345kV ckt	$58,200,000.00	$3,177,572.45
	Medicine Lodge - Wichita 345kV ckt 1	$90,000,000.00	$1,589,953.45
	Mullergren - Circle 230kV ckt1	$200,000.00	$7,425.94
	Spearville - Comanche 345kV ckt 1	$50,000,000.00	$5,424,322.98
	Spearville - Wichita 345kV ckt 1	$150,000,000.00	$9,430,381.02
	Tatonga - Matthewson 345kV ckt #2	$87,500,000.00	$1,242,306.93
	Woodward - Tatonga 345kV ckt 2	$83,848,000.00	$1,443,350.49
G07-37	**Total**		**$30,821,475.68**
G07-38			
	Beaver County - Stevens County 345kV	$42,000,000.00	$926,407.02
	Beaver County - Woodward 345kV ckt 1	$109,230,000.00	$1,094,234.45
	Cimarron - Matthewson 345kV ckt #2	$13,800,000.00	$254,445.78
	Comanche - Medicine Lodge 345kV ckt 1	$60,000,000.00	$1,134,421.23
	Comanche - Woodward 345kV ckt1	$80,000,000.00	$2,962,391.32
	GEN07-043 - Cimarron 345kV ckt1	$250,000.00	$1,403.39
	Gray County - Comanche 345kV ckt 1	$71,000,000.00	$2,132,859.22
	Gray County - Stevens County 345kV ckt	$58,200,000.00	$3,177,572.45
	Medicine Lodge - Wichita 345kV ckt 1	$90,000,000.00	$1,589,953.45
	Mullergren - Circle 230kV ckt1	$200,000.00	$7,425.94
	Spearville - Comanche 345kV ckt 1	$50,000,000.00	$5,424,322.98
	Spearville - Wichita 345kV ckt 1	$150,000,000.00	$9,430,381.02
	Tatonga - Matthewson 345kV ckt #2	$87,500,000.00	$1,242,306.93
	Woodward - Tatonga 345kV ckt 2	$83,848,000.00	$1,443,350.49
G07-38	**Total**		**$30,821,475.68**
G07-40			
	Beaver County - Stevens County 345kV	$42,000,000.00	$5,313,023.97
	Beaver County - Woodward 345kV ckt 1	$109,230,000.00	$6,275,528.77
	Cimarron - Matthewson 345kV ckt #2	$13,800,000.00	$617,027.36
	Comanche - Medicine Lodge 345kV ckt 1	$60,000,000.00	$3,135,152.93
	Comanche - Woodward 345kV ckt1	$80,000,000.00	$5,856,284.87
	GEN07-040 Interconnection Cost	$6,275,000.00	$6,275,000.00
	GEN07-043 - Cimarron 345kV ckt1	$250,000.00	$3,041.04
	Gray County - Comanche 345kV ckt 1	$71,000,000.00	$18,487,368.46
	Gray County - Stevens County 345kV ckt	$58,200,000.00	$12,412,722.28

Interconnection Request		E + C Cost	Allocated Costs
	Knoll 345/230kV Transformer	$10,000,000.00	$412,511.47
	Medicine Lodge - Wichita 345kV ckt 1	$90,000,000.00	$4,394,088.43
	Mingo - Knoll 345kV ckt 1	$110,000,000.00	$4,537,626.13
	Mullergren - Circle 230kV ckt1	$200,000.00	$16,384.39
	Spearville - Comanche 345kV ckt 1	$50,000,000.00	$4,784,221.18
	Spearville - Wichita 345kV ckt 1	$150,000,000.00	$16,568,403.53
	Tatonga - Matthewson 345kV ckt #2	$87,500,000.00	$3,409,997.62
	Woodward - Tatonga 345kV ckt 2	$83,848,000.00	$3,961,840.37
G07-40	**Total**		**$96,460,222.78**
G07-41			
	Beaver County - Hitchland 345kV ckt 1	$54,900,000.00	$10,930,266.20
	Beaver County - Stevens County 345kV	$42,000,000.00	$3,389,325.93
	Beaver County - Woodward 345kV ckt 1	$109,230,000.00	$13,558,083.50
	Beckham 345/230kV Transformer	$6,000,000.00	$466,882.13
	Beckham County - Anadarko 345kV ckt 1	$150,000,000.00	$10,883,379.88
	Cimarron - Matthewson 345kV ckt #2	$13,800,000.00	$319,341.94
	Comanche - Medicine Lodge 345kV ckt 1	$60,000,000.00	$2,879,991.15
	Comanche - Woodward 345kV ckt1	$80,000,000.00	$2,899,263.78
	Curry County - Deaf Smith	$1,000,000.00	$165,842.99
	GEN07-041 Interconnection Cost	$2,000,000.00	$2,000,000.00
	GEN07-043 - Cimarron 345kV ckt1	$250,000.00	$5,953.98
	Grapevine - Beckham 345kV ckt 1	$50,000,000.00	$3,890,684.43
	Grapevine - LES 345kV ckt1	$180,000,000.00	$15,117,930.31
	Gray County - Stevens County 345kV ckt	$58,200,000.00	$9,132,089.86
	Knoll 345/230kV Transformer	$10,000,000.00	$402,267.80
	Medicine Lodge - Wichita 345kV ckt 1	$90,000,000.00	$4,036,465.24
	Mingo - Knoll 345kV ckt 1	$110,000,000.00	$4,424,945.85
	Mullergren - Circle 230kV ckt1	$200,000.00	$12,337.94
	Potter - Grapevine 345kV ckt 1	$60,000,000.00	$7,774,933.59
	SmokyHills - Summit 230kV ckt1	$200,000.00	$16,165.64
	Spearville - Wichita 345kV ckt 1	$150,000,000.00	$11,062,163.56
	Sunnyside - LES 345kV ckt1	$500,000.00	$28,387.50
	Tatonga - Matthewson 345kV ckt #2	$87,500,000.00	$3,876,844.57
	Woodward - Tatonga 345kV ckt 2	$83,848,000.00	$4,504,237.54
G07-41	**Total**		**$111,777,785.32**
G07-42			

Interconnection Request		E + C Cost	Allocated Costs
	Beaver County - Hitchland 345kV ckt 1	$54,900,000.00	$6,558,159.72
	Beaver County - Stevens County 345kV	$42,000,000.00	$2,033,595.56
	Beaver County - Woodward 345kV ckt 1	$109,230,000.00	$8,134,850.10
	Beckham 345/230kV Transformer	$6,000,000.00	$280,129.28
	Beckham County - Anadarko 345kV ckt 1	$150,000,000.00	$6,530,027.93
	Cimarron - Matthewson 345kV ckt #2	$13,800,000.00	$191,605.16
	Comanche - Medicine Lodge 345kV ckt 1	$60,000,000.00	$1,727,994.69
	Comanche - Woodward 345kV ckt1	$80,000,000.00	$1,739,558.27
	GEN07-042 Interconnection Cost	$2,000,000.00	$2,000,000.00
	GEN07-043 - Cimarron 345kV ckt1	$250,000.00	$3,572.39
	Grapevine - Beckham 345kV ckt 1	$50,000,000.00	$2,334,410.66
	Grapevine - LES 345kV ckt1	$180,000,000.00	$9,070,758.19
	Gray County - Stevens County 345kV ckt	$58,200,000.00	$5,479,253.92
	Knoll 345/230kV Transformer	$10,000,000.00	$241,360.68
	Medicine Lodge - Wichita 345kV ckt 1	$90,000,000.00	$2,421,879.15
	Mingo - Knoll 345kV ckt 1	$110,000,000.00	$2,654,967.51
	Mullergren - Circle 230kV ckt1	$200,000.00	$7,402.77
	Potter - Grapevine 345kV ckt 1	$60,000,000.00	$4,664,960.16
	SmokyHills - Summit 230kV ckt1	$200,000.00	$9,699.39
	Spearville - Wichita 345kV ckt 1	$150,000,000.00	$6,637,298.13
	Sunnyside - LES 345kV ckt1	$500,000.00	$17,032.50
	Tatonga - Matthewson 345kV ckt #2	$87,500,000.00	$2,326,106.74
	Woodward - Tatonga 345kV ckt 2	$83,848,000.00	$2,702,542.52
G07-42	**Total**		**$67,767,165.40**
G07-43			
	Beckham County - Anadarko 345kV ckt 1	$150,000,000.00	$895,893.52
	GEN07-043 - Cimarron 345kV ckt1	$250,000.00	$37,210.74
	GEN07-043 Interconnection Cost	$6,000,000.00	$6,000,000.00
	Sunnyside - LES 345kV ckt1	$500,000.00	$22,788.68
G07-43	**Total**		**$6,955,892.94**
G07-44			
	Cimarron - Matthewson 345kV ckt #2	$13,800,000.00	$795,271.55
	Comanche - Medicine Lodge 345kV ckt 1	$60,000,000.00	$2,472,429.58
	Comanche - Woodward 345kV ckt1	$80,000,000.00	$2,448,329.29
	GEN07-043 - Cimarron 345kV ckt1	$250,000.00	$5,047.28
	GEN07-044 Interconnection Cost	$2,125,000.00	$2,125,000.00

Interconnection Request		E + C Cost	Allocated Costs
	Medicine Lodge - Wichita 345kV ckt 1	$90,000,000.00	$3,465,245.38
	Sunnyside - LES 345kV ckt1	$500,000.00	$4,359.21
	Tatonga - Matthewson 345kV ckt #2	$87,500,000.00	$6,473,872.80
	Woodward - Tatonga 345kV ckt 2	$83,848,000.00	$2,397,935.13
G07-44	**Total**		**$20,187,490.23**
G07-45			
	Beaver County - Hitchland 345kV ckt 1	$54,900,000.00	$833,153.37
	Beaver County - Woodward 345kV ckt 1	$109,230,000.00	$1,338,609.18
	Beckham 345/230kV Transformer	$6,000,000.00	$542,509.00
	Beckham County - Anadarko 345kV ckt 1	$150,000,000.00	$14,217,666.59
	Cimarron - Matthewson 345kV ckt #2	$13,800,000.00	$223,765.10
	Deaf Smith - Plant X 230kV Line Trap	$400,000.00	$6,592.18
	GEN07-043 - Cimarron 345kV ckt1	$250,000.00	$8,924.35
	GEN07-045 Interconnection Cost	$2,500,000.00	$2,500,000.00
	GEN07-048 - Swisher 230kV ckt1 Line Tr	$200,000.00	$2,203.54
	Grapevine - Beckham 345kV ckt 1	$50,000,000.00	$4,520,908.37
	Grapevine - LES 345kV ckt1	$180,000,000.00	$18,426,098.18
	Potter - Replace 345/115kV Auto with (2	$20,000,000.00	$1,182,142.55
	Sunnyside - LES 345kV ckt1	$500,000.00	$20,171.34
	Tatonga - Matthewson 345kV ckt #2	$87,500,000.00	$480,522.79
	Woodward - Tatonga 345kV ckt 2	$83,848,000.00	$558,286.20
G07-45	**Total**		**$44,861,552.75**
G07-46			
	Beaver County - Hitchland 345kV ckt 1	$54,900,000.00	$3,088,269.12
	Beaver County - Stevens County 345kV	$42,000,000.00	$1,065,116.86
	Beaver County - Woodward 345kV ckt 1	$109,230,000.00	$3,703,781.09
	Beckham 345/230kV Transformer	$6,000,000.00	$197,529.63
	Beckham County - Anadarko 345kV ckt 1	$150,000,000.00	$4,765,378.17
	Comanche - Medicine Lodge 345kV ckt 1	$60,000,000.00	$858,729.20
	Comanche - Woodward 345kV ckt1	$80,000,000.00	$940,118.12
	GEN07-043 - Cimarron 345kV ckt1	$250,000.00	$3,526.50
	GEN07-046 Interconnection Cost	$1,200,000.00	$1,200,000.00
	Grapevine - Beckham 345kV ckt 1	$50,000,000.00	$1,646,080.25
	Grapevine - LES 345kV ckt1	$180,000,000.00	$6,180,507.96
	Gray County - Stevens County 345kV ckt	$58,200,000.00	$2,629,414.81
	Knoll 345/230kV Transformer	$10,000,000.00	$116,445.94

Interconnection Request		E + C Cost	Allocated Costs
	Medicine Lodge - Wichita 345kV ckt 1	$90,000,000.00	$1,203,555.98
	Mingo - Knoll 345kV ckt 1	$110,000,000.00	$1,280,905.38
	Mullergren - Circle 230kV ckt1	$200,000.00	$3,584.71
	Potter - Grapevine 345kV ckt 1	$60,000,000.00	$3,236,267.76
	SmokyHills - Summit 230kV ckt1	$200,000.00	$4,687.18
	Spearville - Comanche 345kV ckt 1	$50,000,000.00	$142,612.45
	Spearville - Wichita 345kV ckt 1	$150,000,000.00	$3,186,231.45
	Sunnyside - LES 345kV ckt1	$500,000.00	$12,409.81
	Tatonga - Matthewson 345kV ckt #2	$87,500,000.00	$1,036,033.66
	Woodward - Tatonga 345kV ckt 2	$83,848,000.00	$1,203,695.85
G07-46	**Total**		**$37,704,881.88**
G07-47			
	Comanche - Medicine Lodge 345kV ckt 1	$60,000,000.00	$417,349.70
	Comanche - Woodward 345kV ckt1	$80,000,000.00	$1,304,234.70
	GEN07-043 - Cimarron 345kV ckt1	$250,000.00	$937.93
	GEN07-047 Interconnection Cost	$3,807,109.00	$3,807,109.00
	Knoll 345/230kV Transformer	$10,000,000.00	$1,226,588.16
	Medicine Lodge - Wichita 345kV ckt 1	$90,000,000.00	$584,938.45
	Mingo - Knoll 345kV ckt 1	$110,000,000.00	$13,492,469.80
	Mullergren - Circle 230kV ckt1	$200,000.00	$11,148.14
	SmokyHills - Summit 230kV ckt1	$200,000.00	$26,656.52
	South Hays - Mullergren 230kV ckt1	$100,000.00	$17,904.81
	Spearville - Comanche 345kV ckt 1	$50,000,000.00	$2,728,839.66
	Spearville - Wichita 345kV ckt 1	$150,000,000.00	$4,151,571.01
G07-47	**Total**		**$27,769,747.88**
G07-48			
	Beaver County - Hitchland 345kV ckt 1	$54,900,000.00	$3,253,193.06
	Beaver County - Woodward 345kV ckt 1	$109,230,000.00	$5,226,833.67
	Beckham 345/230kV Transformer	$6,000,000.00	$490,599.97
	Beckham County - Anadarko 345kV ckt 1	$150,000,000.00	$12,123,335.28
	Cimarron - Matthewson 345kV ckt #2	$13,800,000.00	$246,664.12
	GEN07-043 - Cimarron 345kV ckt1	$250,000.00	$13,232.49
	GEN07-048 - Swisher 230kV ckt1 Line Tr	$200,000.00	$69,884.95
	GEN07-048 Interconnection Cost	$3,500,000.00	$3,500,000.00
	Grapevine - Beckham 345kV ckt 1	$50,000,000.00	$4,088,333.06
	Grapevine - LES 345kV ckt1	$180,000,000.00	$13,951,633.95

Interconnection Request		E + C Cost	Allocated Costs
	Potter - Bushland 230kV ckt1 Line Trap	$200,000.00	$9,844.43
	Potter - Grapevine 345kV ckt 1	$60,000,000.00	$7,692,929.32
	Potter - Harrington East 230kV ckt1 Line	$200,000.00	$166,032.08
	Potter - Replace 345/115kV Auto with (2	$20,000,000.00	$4,172,028.84
	Sunnyside - LES 345kV ckt1	$500,000.00	$38,575.77
	Tatonga - Matthewson 345kV ckt #2	$87,500,000.00	$1,987,144.67
	Woodward - Tatonga 345kV ckt 2	$83,848,000.00	$2,308,725.94
G07-48	**Total**		**$59,338,991.58**
G07-49			
	Beckham County - Anadarko 345kV ckt 1	$150,000,000.00	$179,178.70
	Carter Jct. - Lake Creek	$50,000.00	$50,000.00
	GEN07-043 - Cimarron 345kV ckt1	$250,000.00	$996.08
	GEN07-049 Interconnection Cost	$500,000.00	$500,000.00
	Sunnyside - LES 345kV ckt1	$500,000.00	$4,185.39
G07-49	**Total**		**$734,360.17**
G07-50			
	Cimarron - Matthewson 345kV ckt #2	$13,800,000.00	$398,847.07
	Comanche - Medicine Lodge 345kV ckt 1	$60,000,000.00	$2,444,262.73
	Comanche - Woodward 345kV ckt1	$80,000,000.00	$2,420,437.00
	GEN07-043 - Cimarron 345kV ckt1	$250,000.00	$2,764.32
	Medicine Lodge - Wichita 345kV ckt 1	$90,000,000.00	$3,425,768.00
	Sunnyside - LES 345kV ckt1	$500,000.00	$3,323.92
	Tatonga - Matthewson 345kV ckt #2	$87,500,000.00	$3,005,078.19
	Woodward - Tatonga 345kV ckt 2	$83,848,000.00	$3,491,392.49
	Woodward 345/138kV Transformer #2	$7,875,000.00	$3,552,451.80
G07-50	**Total**		**$18,744,325.52**
G07-51			
	Cimarron - Matthewson 345kV ckt #2	$13,800,000.00	$291,445.40
	Comanche - Medicine Lodge 345kV ckt 1	$60,000,000.00	$1,897,859.05
	Comanche - Woodward 345kV ckt1	$80,000,000.00	$1,879,359.46
	GEN07-043 - Cimarron 345kV ckt1	$250,000.00	$2,124.18
	GEN07-051 Interconnection Cost	$750,000.00	$750,000.00
	Medicine Lodge - Wichita 345kV ckt 1	$90,000,000.00	$2,659,953.35
	Sunnyside - LES 345kV ckt1	$500,000.00	$4,379.04
	Tatonga - Matthewson 345kV ckt #2	$87,500,000.00	$2,057,609.98
	Woodward - Tatonga 345kV ckt 2	$83,848,000.00	$2,390,594.71

Interconnection Request		E + C Cost	Allocated Costs
	Woodward 345/138kV Transformer #2	$7,875,000.00	$2,528,560.04
G07-51	**Total**		**$14,461,885.22**
G07-52			
	GEN07-043 - Cimarron 345kV ckt1	$250,000.00	$3,176.63
	GEN07-052 Interconnection Cost-1	$750,000.00	$750,000.00
	Sunnyside - LES 345kV ckt1	$500,000.00	$10,305.68
G07-52	**Total**		**$763,482.31**
G07-55			
	Amarillo South - Swisher 230kV Line Tra	$100,000.00	$17,435.01
	Beaver County - Hitchland 345kV ckt 1	$54,900,000.00	$1,890,523.02
	Beaver County - Woodward 345kV ckt 1	$109,230,000.00	$3,037,461.71
	Beckham 345/230kV Transformer	$6,000,000.00	$258,681.71
	Beckham County - Anadarko 345kV ckt 1	$150,000,000.00	$6,276,252.01
	Bushland Line Trap	$400,000.00	$65,642.47
	Cimarron - Matthewson 345kV ckt #2	$13,800,000.00	$216,748.75
	Comanche - Woodward 345kV ckt1	$80,000,000.00	$430,028.97
	Deaf Smith - Plant X 230kV Line Trap	$400,000.00	$86,839.04
	GEN07-043 - Cimarron 345kV ckt1	$250,000.00	$9,536.58
	GEN07-048 - Swisher 230kV ckt1 Line Tr	$200,000.00	$21,457.97
	GEN07-055 Interconnection Cost	$6,200,000.00	$6,200,000.00
	Grapevine - Beckham 345kV ckt 1	$50,000,000.00	$2,155,680.89
	Grapevine - LES 345kV ckt1	$180,000,000.00	$6,266,784.08
	Gray County - Comanche 345kV ckt 1	$71,000,000.00	$1,324,807.09
	Plant X - Tolk 230kV #1 Reconductor to	$5,000,000.00	$1,738,416.33
	Plant X - Tolk 230kV #2 Reconductor to	$5,000,000.00	$1,738,416.33
	Potter - Bushland 230kV ckt1 Line Trap	$200,000.00	$31,664.18
	Potter - Grapevine 345kV ckt 1	$60,000,000.00	$3,787,620.79
	Potter - Replace 345/115kV Auto with (2	$20,000,000.00	$2,286,276.10
	Sunnyside - LES 345kV ckt1	$500,000.00	$27,292.74
	Swisher - Tuco 230kV Line Trap	$400,000.00	$62,236.37
	Tatonga - Matthewson 345kV ckt #2	$87,500,000.00	$956,233.69
	Woodward - Tatonga 345kV ckt 2	$83,848,000.00	$1,110,981.78
G07-55	**Total**		**$39,997,017.60**
G07-56			
	Beaver County - Hitchland 345kV ckt 1	$54,900,000.00	$10,930,266.20
	Beaver County - Stevens County 345kV	$42,000,000.00	$3,389,325.93

Interconnection Request		E + C Cost	Allocated Costs
	Beaver County - Woodward 345kV ckt 1	$109,230,000.00	$13,558,083.50
	Beckham 345/230kV Transformer	$6,000,000.00	$466,882.13
	Beckham County - Anadarko 345kV ckt 1	$150,000,000.00	$10,883,379.88
	Cimarron - Matthewson 345kV ckt #2	$13,800,000.00	$319,341.94
	Comanche - Medicine Lodge 345kV ckt 1	$60,000,000.00	$2,879,991.15
	Comanche - Woodward 345kV ckt1	$80,000,000.00	$2,899,263.78
	Curry County - Deaf Smith	$1,000,000.00	$165,842.99
	GEN07-043 - Cimarron 345kV ckt1	$250,000.00	$5,953.98
	GEN07-056 Interconnection Cost	$2,500,000.00	$2,500,000.00
	Grapevine - Beckham 345kV ckt 1	$50,000,000.00	$3,890,684.43
	Grapevine - LES 345kV ckt1	$180,000,000.00	$15,117,930.31
	Gray County - Stevens County 345kV ckt	$58,200,000.00	$9,132,089.86
	Knoll 345/230kV Transformer	$10,000,000.00	$402,267.80
	Medicine Lodge - Wichita 345kV ckt 1	$90,000,000.00	$4,036,465.24
	Mingo - Knoll 345kV ckt 1	$110,000,000.00	$4,424,945.85
	Mullergren - Circle 230kV ckt1	$200,000.00	$12,337.94
	Potter - Grapevine 345kV ckt 1	$60,000,000.00	$7,774,933.59
	SmokyHills - Summit 230kV ckt1	$200,000.00	$16,165.64
	Spearville - Wichita 345kV ckt 1	$150,000,000.00	$11,062,163.56
	Sunnyside - LES 345kV ckt1	$500,000.00	$28,387.50
	Tatonga - Matthewson 345kV ckt #2	$87,500,000.00	$3,876,844.57
	Woodward - Tatonga 345kV ckt 2	$83,848,000.00	$4,504,237.54
G07-56	**Total**		**$112,277,785.32**
G07-57			
	Beaver County - Hitchland 345kV ckt 1	$54,900,000.00	$467,913.48
	Beaver County - Stevens County 345kV	$42,000,000.00	$177,909.03
	Beaver County - Woodward 345kV ckt 1	$109,230,000.00	$541,647.35
	Beckham 345/230kV Transformer	$6,000,000.00	$40,369.96
	Beckham County - Anadarko 345kV ckt 1	$150,000,000.00	$991,464.58
	Cimarron - Matthewson 345kV ckt #2	$13,800,000.00	$6,911.73
	Comanche - Medicine Lodge 345kV ckt 1	$60,000,000.00	$136,991.05
	Comanche - Woodward 345kV ckt1	$80,000,000.00	$160,991.67
	GEN07-043 - Cimarron 345kV ckt1	$250,000.00	$822.39
	GEN07-057 Interconnection Cost	$2,500,000.00	$2,500,000.00
	Grapevine - Beckham 345kV ckt 1	$50,000,000.00	$336,416.37
	Grapevine - LES 345kV ckt1	$180,000,000.00	$1,242,591.91

Interconnection Request		E + C Cost	Allocated Costs
	Gray County - Stevens County 345kV ckt	$58,200,000.00	$405,971.83
	Knoll 345/230kV Transformer	$10,000,000.00	$18,083.09
	Medicine Lodge - Wichita 345kV ckt 1	$90,000,000.00	$192,000.45
	Mingo - Knoll 345kV ckt 1	$110,000,000.00	$198,914.00
	Mullergren - Circle 230kV ckt1	$200,000.00	$558.39
	Potter - Grapevine 345kV ckt 1	$60,000,000.00	$656,343.65
	SmokyHills - Summit 230kV ckt1	$200,000.00	$727.88
	Spearville - Comanche 345kV ckt 1	$50,000,000.00	$40,254.50
	Spearville - Wichita 345kV ckt 1	$150,000,000.00	$492,040.54
	Sunnyside - LES 345kV ckt1	$500,000.00	$2,561.82
	Tatonga - Matthewson 345kV ckt #2	$87,500,000.00	$147,678.34
	Woodward - Tatonga 345kV ckt 2	$83,848,000.00	$171,577.25
G07-57	**Total**		**$8,930,741.27**
G07-60			
	Cimarron - Matthewson 345kV ckt #2	$13,800,000.00	$535,482.84
	Comanche - Medicine Lodge 345kV ckt 1	$60,000,000.00	$1,664,769.25
	Comanche - Woodward 345kV ckt1	$80,000,000.00	$1,648,541.72
	GEN07-043 - Cimarron 345kV ckt1	$250,000.00	$3,398.50
	GEN07-060 Interconnection Cost	$1,325,000.00	$1,325,000.00
	Medicine Lodge - Wichita 345kV ckt 1	$90,000,000.00	$2,333,265.22
	Sunnyside - LES 345kV ckt1	$500,000.00	$2,935.20
	Tatonga - Matthewson 345kV ckt #2	$87,500,000.00	$4,359,074.35
	Woodward - Tatonga 345kV ckt 2	$83,848,000.00	$1,614,609.65
G07-60	**Total**		**$13,487,076.75**
G07-61			
	Cimarron - Matthewson 345kV ckt #2	$13,800,000.00	$449,427.90
	Comanche - Medicine Lodge 345kV ckt 1	$60,000,000.00	$2,661,296.88
	Comanche - Woodward 345kV ckt1	$80,000,000.00	$2,635,355.59
	GEN07-043 - Cimarron 345kV ckt1	$250,000.00	$2,992.33
	GEN07-061 Interconnection Cost	$3,925,000.00	$3,925,000.00
	Medicine Lodge - Wichita 345kV ckt 1	$90,000,000.00	$3,729,953.24
	Sunnyside - LES 345kV ckt1	$500,000.00	$2,936.64
	Tatonga - Matthewson 345kV ckt #2	$87,500,000.00	$3,385,067.25
	Woodward - Tatonga 345kV ckt 2	$83,848,000.00	$3,932,875.48
G07-61	**Total**		**$20,724,905.30**
G07-62			

Interconnection Request		E + C Cost	Allocated Costs
	Cimarron - Matthewson 345kV ckt #2	$13,800,000.00	$1,719,061.71
	Comanche - Medicine Lodge 345kV ckt 1	$60,000,000.00	$10,179,460.55
	Comanche - Woodward 345kV ckt1	$80,000,000.00	$10,080,235.13
	GEN07-043 - Cimarron 345kV ckt1	$250,000.00	$11,445.67
	GEN07-062 Interconnection Cost	$2,225,000.00	$2,225,000.00
	Medicine Lodge - Wichita 345kV ckt 1	$90,000,000.00	$14,267,071.14
	Sunnyside - LES 345kV ckt1	$500,000.00	$11,232.64
	Tatonga - Matthewson 345kV ckt #2	$87,500,000.00	$12,947,882.21
	Woodward - Tatonga 345kV ckt 2	$83,848,000.00	$15,043,248.73
G07-62	**Total**		**$66,484,637.78**
G08-01			
	Comanche - Medicine Lodge 345kV ckt 1	$60,000,000.00	$136,351.90
	Comanche - Woodward 345kV ckt1	$80,000,000.00	$1,439,549.02
	GEN07-043 - Cimarron 345kV ckt1	$250,000.00	$1,171.81
	GEN08-001 Interconnection Cost	$2,000,000.00	$2,000,000.00
	Knoll 345/230kV Transformer	$10,000,000.00	$1,979,581.04
	Medicine Lodge - Wichita 345kV ckt 1	$90,000,000.00	$191,104.65
	Mingo - Knoll 345kV ckt 1	$110,000,000.00	$21,775,391.42
	Mullergren - Circle 230kV ckt1	$200,000.00	$18,329.01
	SmokyHills - Summit 230kV ckt1	$200,000.00	$56,720.27
	South Hays - Mullergren 230kV ckt1	$100,000.00	$46,880.76
	Spearville - Comanche 345kV ckt 1	$50,000,000.00	$2,501,551.28
	Spearville - Wichita 345kV ckt 1	$150,000,000.00	$2,853,999.31
G08-01	**Total**		**$33,000,630.47**
G08-03			
	Cimarron - Matthewson 345kV ckt #2	$13,800,000.00	$201,417.77
	Comanche - Medicine Lodge 345kV ckt 1	$60,000,000.00	$1,234,352.68
	Comanche - Woodward 345kV ckt1	$80,000,000.00	$1,222,320.69
	GEN07-043 - Cimarron 345kV ckt1	$250,000.00	$1,395.98
	GEN08-003 Interconnection Cost	$410,000.00	$410,000.00
	Medicine Lodge - Wichita 345kV ckt 1	$90,000,000.00	$1,730,012.84
	Sunnyside - LES 345kV ckt1	$500,000.00	$1,678.58
	Tatonga - Matthewson 345kV ckt #2	$87,500,000.00	$1,517,564.49
	Woodward - Tatonga 345kV ckt 2	$83,848,000.00	$1,763,153.21
	Woodward 345/138kV Transformer #2	$7,875,000.00	$1,793,988.16
G08-03	**Total**		**$9,875,884.39**

Interconnection Request		E + C Cost	Allocated Costs
G08-07			
	Amarillo South - Swisher 230kV Line Tra	$100,000.00	$10,203.86
	Beaver County - Hitchland 345kV ckt 1	$54,900,000.00	$707,369.56
	Beaver County - Woodward 345kV ckt 1	$109,230,000.00	$1,136,515.10
	Beckham 345/230kV Transformer	$6,000,000.00	$91,625.37
	Beckham County - Anadarko 345kV ckt 1	$150,000,000.00	$2,182,890.90
	Bushland Line Trap	$400,000.00	$19,274.65
	Cimarron - Matthewson 345kV ckt #2	$13,800,000.00	$99,553.20
	Comanche - Woodward 345kV ckt1	$80,000,000.00	$182,326.80
	Deaf Smith - Plant X 230kV Line Trap	$400,000.00	$25,850.61
	GEN07-043 - Cimarron 345kV ckt1	$250,000.00	$4,110.76
	GEN07-048 - Swisher 230kV ckt1 Line Tr	$200,000.00	$12,558.30
	GEN08-007 Interconnection Cost	$1,000,000.00	$1,000,000.00
	Grapevine - Beckham 345kV ckt 1	$50,000,000.00	$763,544.73
	Grapevine - LES 345kV ckt1	$180,000,000.00	$1,901,235.62
	Grassland - Lynn 115kV ckt1	$2,130,000.00	$152,722.75
	Grassland 230/115kV Transformer	$5,000,000.00	$678,577.62
	Gray County - Comanche 345kV ckt 1	$71,000,000.00	$561,701.32
	Plant X - Tolk 230kV #1 Reconductor to	$5,000,000.00	$201,624.37
	Plant X - Tolk 230kV #2 Reconductor to	$5,000,000.00	$201,624.37
	Potter - Bushland 230kV ckt1 Line Trap	$200,000.00	$9,789.15
	Potter - Grapevine 345kV ckt 1	$60,000,000.00	$1,263,049.57
	Potter - Harrington East 230kV ckt1 Line	$200,000.00	$5,404.83
	Potter - Replace 345/115kV Auto with (2	$20,000,000.00	$818,406.31
	Sunnyside - LES 345kV ckt1	$500,000.00	$11,771.53
	Swisher - Tuco 230kV Line Trap	$400,000.00	$41,981.61
	Tatonga - Matthewson 345kV ckt #2	$87,500,000.00	$348,400.33
	Woodward - Tatonga 345kV ckt 2	$83,848,000.00	$404,782.24
G08-07	**Total**		**$12,836,895.43**
G08-08			
	Amarillo South - Swisher 230kV Line Tra	$100,000.00	$5,994.74
	Beaver County - Hitchland 345kV ckt 1	$54,900,000.00	$416,629.68
	Beaver County - Woodward 345kV ckt 1	$109,230,000.00	$669,389.74
	Beckham 345/230kV Transformer	$6,000,000.00	$54,011.07
	Beckham County - Anadarko 345kV ckt 1	$150,000,000.00	$1,287,142.76
	Bushland Line Trap	$400,000.00	$11,358.98

Interconnection Request		E + C Cost	Allocated Costs
	Cimarron - Matthewson 345kV ckt #2	$13,800,000.00	$58,472.61
	Comanche - Woodward 345kV ckt1	$80,000,000.00	$107,185.30
	Deaf Smith - Plant X 230kV Line Trap	$400,000.00	$15,212.77
	GEN07-043 - Cimarron 345kV ckt1	$250,000.00	$2,416.17
	GEN07-048 - Swisher 230kV ckt1 Line Tr	$200,000.00	$7,377.97
	GEN08-008 Interconnection Cost	$1,000,000.00	$1,000,000.00
	Grapevine - Beckham 345kV ckt 1	$50,000,000.00	$450,092.22
	Grapevine - LES 345kV ckt1	$180,000,000.00	$1,123,550.46
	Grassland - Lynn 115kV ckt1	$2,130,000.00	$1,004,684.72
	Gray County - Comanche 345kV ckt 1	$71,000,000.00	$330,209.96
	Plant X - Tolk 230kV #1 Reconductor to	$5,000,000.00	$120,685.60
	Plant X - Tolk 230kV #2 Reconductor to	$5,000,000.00	$120,685.60
	Potter - Bushland 230kV ckt1 Line Trap	$200,000.00	$5,769.61
	Potter - Grapevine 345kV ckt 1	$60,000,000.00	$745,291.21
	Potter - Harrington East 230kV ckt1 Line	$200,000.00	$3,180.62
	Potter - Replace 345/115kV Auto with (2	$20,000,000.00	$482,310.30
	Sunnyside - LES 345kV ckt1	$500,000.00	$6,918.94
	Swisher - Tuco 230kV Line Trap	$400,000.00	$24,393.10
	Tatonga - Matthewson 345kV ckt #2	$87,500,000.00	$205,317.03
	Woodward - Tatonga 345kV ckt 2	$83,848,000.00	$238,543.66
G08-08	**Total**		**$8,496,824.83**
G08-09			
	Amarillo South - Swisher 230kV Line Tra	$100,000.00	$4,016.46
	Beaver County - Hitchland 345kV ckt 1	$54,900,000.00	$456,905.17
	Beaver County - Woodward 345kV ckt 1	$109,230,000.00	$734,099.47
	Beckham 345/230kV Transformer	$6,000,000.00	$62,746.28
	Beckham County - Anadarko 345kV ckt 1	$150,000,000.00	$1,524,291.04
	Bushland Line Trap	$400,000.00	$15,977.05
	Cimarron - Matthewson 345kV ckt #2	$13,800,000.00	$51,469.11
	Comanche - Woodward 345kV ckt1	$80,000,000.00	$102,878.16
	Deaf Smith - Plant X 230kV Line Trap	$400,000.00	$19,314.21
	GEN07-043 - Cimarron 345kV ckt1	$250,000.00	$2,277.65
	GEN07-048 - Swisher 230kV ckt1 Line Tr	$200,000.00	$4,943.22
	GEN08-009 Interconnection Cost	$750,000.00	$750,000.00
	Grapevine - Beckham 345kV ckt 1	$50,000,000.00	$522,885.68
	Grapevine - LES 345kV ckt1	$180,000,000.00	$1,535,558.18

Interconnection Request		E + C Cost	Allocated Costs
	Gray County - Comanche 345kV ckt 1	$71,000,000.00	$316,940.79
	Plant X - Tolk 230kV #1 Reconductor to	$5,000,000.00	$414,169.77
	Plant X - Tolk 230kV #2 Reconductor to	$5,000,000.00	$414,169.77
	Potter - Bushland 230kV ckt1 Line Trap	$200,000.00	$7,706.68
	Potter - Grapevine 345kV ckt 1	$60,000,000.00	$922,548.09
	Potter - Replace 345/115kV Auto with (2	$20,000,000.00	$554,021.52
	Sunnyside - LES 345kV ckt1	$500,000.00	$6,518.70
	Swisher - Tuco 230kV Line Trap	$400,000.00	$14,167.48
	Tatonga - Matthewson 345kV ckt #2	$87,500,000.00	$231,545.16
	Woodward - Tatonga 345kV ckt 2	$83,848,000.00	$269,016.30
G08-09	**Total**		**$8,938,165.94**
G08-11			
	Beaver County - Stevens County 345kV	$42,000,000.00	$9,042,134.40
	Beaver County - Woodward 345kV ckt 1	$109,230,000.00	$10,680,203.02
	Cimarron - Matthewson 345kV ckt #2	$13,800,000.00	$701,451.09
	Comanche - Medicine Lodge 345kV ckt 1	$60,000,000.00	$3,228,618.17
	Comanche - Woodward 345kV ckt1	$80,000,000.00	$4,622,448.34
	GEN07-043 - Cimarron 345kV ckt1	$250,000.00	$3,285.28
	GEN08-011 Interconnection Cost	$2,000,000.00	$2,000,000.00
	Gray County - Comanche 345kV ckt 1	$71,000,000.00	$16,147,874.79
	Gray County - Stevens County 345kV ckt	$58,200,000.00	$836,092.15
	Knoll 345/230kV Transformer	$10,000,000.00	$999,507.51
	Medicine Lodge - Wichita 345kV ckt 1	$90,000,000.00	$4,525,085.08
	Mingo - Knoll 345kV ckt 1	$110,000,000.00	$10,994,582.66
	Mullergren - Circle 230kV ckt1	$200,000.00	$21,185.52
	Spearville - Comanche 345kV ckt 1	$50,000,000.00	$4,193,746.42
	Spearville - Wichita 345kV ckt 1	$150,000,000.00	$16,380,037.85
	Tatonga - Matthewson 345kV ckt #2	$87,500,000.00	$3,934,901.61
	Woodward - Tatonga 345kV ckt 2	$83,848,000.00	$4,571,690.00
G08-11	**Total**		**$92,882,843.90**
G08-13			
	Cimarron - Matthewson 345kV ckt #2	$13,800,000.00	$812,560.06
	GEN07-043 - Cimarron 345kV ckt1	$250,000.00	$5,187.52
	GEN08-013 Interconnection Cost	$7,500,000.00	$7,500,000.00
	Sunnyside - LES 345kV ckt1	$500,000.00	$3,750.85
	Tatonga - Matthewson 345kV ckt #2	$87,500,000.00	$587,229.94

Interconnection Request		E + C Cost	Allocated Costs
G08-13	Total		**$8,908,728.36**
G08-14			
	Amarillo South - Swisher 230kV Line Tra	$100,000.00	$11,917.79
	Beaver County - Hitchland 345kV ckt 1	$54,900,000.00	$733,004.23
	Beaver County - Woodward 345kV ckt 1	$109,230,000.00	$1,177,701.76
	Beckham 345/230kV Transformer	$6,000,000.00	$71,404.52
	Beckham County - Anadarko 345kV ckt 1	$150,000,000.00	$1,490,127.15
	Bushland Line Trap	$400,000.00	$16,323.71
	Cimarron - Matthewson 345kV ckt #2	$13,800,000.00	$200,855.07
	Comanche - Woodward 345kV ckt1	$80,000,000.00	$300,677.79
	Deaf Smith - Plant X 230kV Line Trap	$400,000.00	$22,520.91
	GEN07-043 - Cimarron 345kV ckt1	$250,000.00	$7,147.02
	GEN07-048 - Swisher 230kV ckt1 Line Tr	$200,000.00	$14,667.70
	GEN08-014 Interconnection Cost	$1,500,000.00	$1,500,000.00
	Grapevine - Beckham 345kV ckt 1	$50,000,000.00	$595,037.65
	Gray County - Comanche 345kV ckt 1	$71,000,000.00	$926,309.84
	Plant X - Tolk 230kV #1 Reconductor to	$5,000,000.00	$248,382.83
	Plant X - Tolk 230kV #2 Reconductor to	$5,000,000.00	$248,382.83
	Potter - Bushland 230kV ckt1 Line Trap	$200,000.00	$8,363.66
	Potter - Grapevine 345kV ckt 1	$60,000,000.00	$562,377.19
	Potter - Harrington East 230kV ckt1 Line	$200,000.00	$6,283.23
	Potter - Replace 345/115kV Auto with (2	$20,000,000.00	$702,705.53
	Sunnyside - LES 345kV ckt1	$500,000.00	$20,431.82
	Swisher - Tuco 230kV Line Trap	$400,000.00	$53,802.69
	Tatonga - Matthewson 345kV ckt #2	$87,500,000.00	$309,922.17
	Woodward - Tatonga 345kV ckt 2	$83,848,000.00	$360,077.13
G08-14	Total		**$9,588,424.22**
G08-15			
	Amarillo South - Swisher 230kV Line Tra	$100,000.00	$11,917.79
	Beaver County - Hitchland 345kV ckt 1	$54,900,000.00	$733,004.23
	Beaver County - Woodward 345kV ckt 1	$109,230,000.00	$1,177,701.76
	Beckham 345/230kV Transformer	$6,000,000.00	$71,404.52
	Beckham County - Anadarko 345kV ckt 1	$150,000,000.00	$1,490,127.15
	Bushland Line Trap	$400,000.00	$16,323.71
	Cimarron - Matthewson 345kV ckt #2	$13,800,000.00	$200,855.07
	Comanche - Woodward 345kV ckt1	$80,000,000.00	$300,677.79

Interconnection Request		E + C Cost	Allocated Costs
	Deaf Smith - Plant X 230kV Line Trap	$400,000.00	$22,520.91
	GEN07-043 - Cimarron 345kV ckt1	$250,000.00	$7,147.02
	GEN07-048 - Swisher 230kV ckt1 Line Tr	$200,000.00	$14,667.70
	GEN08-015 Interconnection Cost	$2,500,000.00	$2,500,000.00
	Grapevine - Beckham 345kV ckt 1	$50,000,000.00	$595,037.65
	Gray County - Comanche 345kV ckt 1	$71,000,000.00	$926,309.84
	Plant X - Tolk 230kV #1 Reconductor to	$5,000,000.00	$248,382.83
	Plant X - Tolk 230kV #2 Reconductor to	$5,000,000.00	$248,382.83
	Potter - Bushland 230kV ckt1 Line Trap	$200,000.00	$8,363.66
	Potter - Grapevine 345kV ckt 1	$60,000,000.00	$562,377.19
	Potter - Harrington East 230kV ckt1 Line	$200,000.00	$6,283.23
	Potter - Replace 345/115kV Auto with (2	$20,000,000.00	$702,705.53
	Sunnyside - LES 345kV ckt1	$500,000.00	$20,431.82
	Swisher - Tuco 230kV Line Trap	$400,000.00	$53,802.69
	Tatonga - Matthewson 345kV ckt #2	$87,500,000.00	$309,922.17
	Woodward - Tatonga 345kV ckt 2	$83,848,000.00	$360,077.13
G08-15	**Total**		**$10,588,424.22**
G08-16			
	Amarillo South - Swisher 230kV Line Tra	$100,000.00	$24,633.49
	Beaver County - Hitchland 345kV ckt 1	$54,900,000.00	$1,723,861.51
	Beaver County - Woodward 345kV ckt 1	$109,230,000.00	$2,769,690.34
	Beckham 345/230kV Transformer	$6,000,000.00	$223,633.08
	Beckham County - Anadarko 345kV ckt 1	$150,000,000.00	$5,330,705.76
	Bushland Line Trap	$400,000.00	$47,296.86
	Cimarron - Matthewson 345kV ckt #2	$13,800,000.00	$241,322.67
	Comanche - Woodward 345kV ckt1	$80,000,000.00	$442,896.68
	Deaf Smith - Plant X 230kV Line Trap	$400,000.00	$63,383.36
	GEN07-043 - Cimarron 345kV ckt1	$250,000.00	$9,981.07
	GEN07-048 - Swisher 230kV ckt1 Line Tr	$200,000.00	$30,317.41
	GEN08-016 Interconnection Cost	$2,000,000.00	$2,000,000.00
	Grapevine - Beckham 345kV ckt 1	$50,000,000.00	$1,863,609.02
	Grapevine - LES 345kV ckt1	$180,000,000.00	$4,662,487.36
	Grassland - Lynn 115kV ckt1	$2,130,000.00	$972,592.53
	Grassland 230/115kV Transformer	$5,000,000.00	$4,321,422.38
	Gray County - Comanche 345kV ckt 1	$71,000,000.00	$1,364,449.16
	Plant X - Tolk 230kV #1 Reconductor to	$5,000,000.00	$508,981.15

Interconnection Request		E + C Cost	Allocated Costs
	Plant X - Tolk 230kV #2 Reconductor to	$5,000,000.00	$508,981.15
	Potter - Bushland 230kV ckt1 Line Trap	$200,000.00	$23,981.39
	Potter - Grapevine 345kV ckt 1	$60,000,000.00	$3,088,211.36
	Potter - Harrington East 230kV ckt1 Line	$200,000.00	$12,816.01
	Potter - Replace 345/115kV Auto with (2	$20,000,000.00	$1,996,804.02
	Sunnyside - LES 345kV ckt1	$500,000.00	$28,581.26
	Swisher - Tuco 230kV Line Trap	$400,000.00	$100,937.78
	Tatonga - Matthewson 345kV ckt #2	$87,500,000.00	$849,773.00
	Woodward - Tatonga 345kV ckt 2	$83,848,000.00	$987,292.47
G08-16	**Total**		**$34,198,642.26**
G08-17			
	Comanche - Medicine Lodge 345kV ckt 1	$60,000,000.00	$1,074,601.27
	Comanche - Woodward 345kV ckt1	$80,000,000.00	$1,997,559.21
	GEN07-043 - Cimarron 345kV ckt1	$250,000.00	$1,080.11
	GEN08-017 Interconnection Cost	$2,252,652.00	$2,252,652.00
	Knoll 345/230kV Transformer	$10,000,000.00	$1,067,210.48
	Medicine Lodge - Wichita 345kV ckt 1	$90,000,000.00	$1,506,112.49
	Mingo - Knoll 345kV ckt 1	$110,000,000.00	$11,739,315.29
	Mullergren - Circle 230kV ckt1	$200,000.00	$14,897.39
	SmokyHills - Summit 230kV ckt1	$200,000.00	$27,738.19
	South Hays - Mullergren 230kV ckt1	$100,000.00	$12,415.82
	Spearville - Comanche 345kV ckt 1	$50,000,000.00	$4,864,495.10
	Spearville - Wichita 345kV ckt 1	$150,000,000.00	$8,678,646.42
G08-17	**Total**		**$33,236,723.76**
G08-18			
	Beaver County - Stevens County 345kV	$42,000,000.00	$6,129,538.92
	Beaver County - Woodward 345kV ckt 1	$109,230,000.00	$7,239,963.18
	Cimarron - Matthewson 345kV ckt #2	$13,800,000.00	$473,479.48
	Comanche - Medicine Lodge 345kV ckt 1	$60,000,000.00	$2,180,437.85
	Comanche - Woodward 345kV ckt1	$80,000,000.00	$3,106,392.80
	GEN07-043 - Cimarron 345kV ckt1	$250,000.00	$2,213.95
	GEN08-018 Interconnection Cost	$2,000,000.00	$2,000,000.00
	Gray County - Comanche 345kV ckt 1	$71,000,000.00	$10,879,987.69
	Gray County - Stevens County 345kV ckt	$58,200,000.00	$474,577.31
	Knoll 345/230kV Transformer	$10,000,000.00	$672,961.17
	Medicine Lodge - Wichita 345kV ckt 1	$90,000,000.00	$3,056,003.00

Interconnection Request		E + C Cost	Allocated Costs
	Mingo - Knoll 345kV ckt 1	$110,000,000.00	$7,402,572.90
	Mullergren - Circle 230kV ckt1	$200,000.00	$14,283.47
	Spearville - Comanche 345kV ckt 1	$50,000,000.00	$2,820,905.66
	Spearville - Wichita 345kV ckt 1	$150,000,000.00	$11,051,276.36
	Tatonga - Matthewson 345kV ckt #2	$87,500,000.00	$2,658,594.32
	Woodward - Tatonga 345kV ckt 2	$83,848,000.00	$3,088,836.84
G08-18	**Total**		**$63,252,024.91**
G08-19			
	Cimarron - Matthewson 345kV ckt #2	$13,800,000.00	$795,271.55
	Comanche - Medicine Lodge 345kV ckt 1	$60,000,000.00	$2,472,429.58
	Comanche - Woodward 345kV ckt1	$80,000,000.00	$2,448,329.29
	GEN07-043 - Cimarron 345kV ckt1	$250,000.00	$5,047.28
	GEN08-019 Interconnection Cost	$2,125,000.00	$2,125,000.00
	Medicine Lodge - Wichita 345kV ckt 1	$90,000,000.00	$3,465,245.38
	Sunnyside - LES 345kV ckt1	$500,000.00	$4,359.21
	Tatonga - Matthewson 345kV ckt #2	$87,500,000.00	$6,473,872.80
	Woodward - Tatonga 345kV ckt 2	$83,848,000.00	$2,397,935.13
G08-19	**Total**		**$20,187,490.23**
All Upgrades Total			**$1,705,289,312.00**

G: Cost Allocation per Proposed Network Upgrade

Appendix G. - Cost Allocation per Upgrade

Amarillo South - Swisher 230kV Line Trap	**$100,000.00**
Replace Line Traps	
G07-55	$17,435.01
G08-16	$24,633.49
G07-27	$3,612.17
G08-08	$5,994.74
G07-34	$10,268.68
G08-15	$11,917.79
G08-14	$11,917.79
G08-09	$4,016.46
G08-07	$10,203.86
Upgrade Total	**$100,000.00**

Beaver County - Hitchland 345kV ckt 1	**$54,900,000.00**
This line was assumed to be approximately 61 miles long, have 3000 amp equipment, and be insulated at 345kV.	
G08-08	$416,629.68
G07-08	$1,461,672.59
G07-56	$10,930,266.20
G07-05	$2,757,136.52
G07-57	$467,913.48
G08-07	$707,369.56
G08-14	$733,004.23
G08-15	$733,004.23
G08-09	$456,905.17
G07-10	$1,635,910.64
G08-16	$1,723,861.51
G07-26	$1,063,341.92
G07-33	$2,682,141.90
G07-30	$974,448.39
G07-55	$1,890,523.02
G07-42	$6,558,159.72
G07-45	$833,153.37
G07-48	$3,253,193.06
G07-34	$1,138,408.81
G07-41	$10,930,266.20
G07-27	$464,420.69
G07-46	$3,088,269.12
Upgrade Total	**$54,900,000.00**

Beaver County - Stevens County 345kV ckt	**$42,000,000.00**
This line was assumed to be approximately 47 miles long, have 3000 amp equipment, and be insulated at 345kV.	
G07-37	$926,407.02

G07-46	$1,065,116.86
G06-06	$960,049.07
G07-38	$926,407.02
G07-05	$1,027,108.18
G08-11	$9,042,134.40
G07-36	$926,407.02
G07-41	$3,389,325.93
G07-42	$2,033,595.56
G07-40	$5,313,023.97
G07-56	$3,389,325.93
G07-19	$5,675,499.00
G08-18	$6,129,538.92
G07-57	$177,909.03
G07-33	$1,018,152.11
Upgrade Total	**$42,000,000.00**

Beaver County - Woodward 345kV ckt 1 **$109,230,000.00**

This line was assumed to be approximately 69 miles long, have 3000 amp equipment, and be insulated at 345kV.

G07-26	$1,708,448.04
G08-07	$1,136,515.10
G07-37	$1,094,234.45
G08-18	$7,239,963.18
G08-15	$1,177,701.76
G07-10	$2,628,381.61
G07-08	$2,348,437.16
G07-05	$3,216,651.96
G08-08	$669,389.74
G08-09	$734,099.47
G07-38	$1,094,234.45
G07-56	$13,558,083.50
G07-57	$541,647.35
G08-14	$1,177,701.76
G07-46	$3,703,781.09
G07-41	$13,558,083.50
G07-36	$1,094,234.45
G07-34	$1,829,056.37
G07-33	$3,106,738.29
G06-06	$1,133,971.08
G07-45	$1,338,609.18
G07-40	$6,275,528.77
G07-42	$8,134,850.10
G07-48	$5,226,833.67
G08-11	$10,680,203.02
G07-55	$3,037,461.71

G07-27	$746,174.50
G07-19	$6,703,669.61
G07-30	$1,565,624.78
G08-16	$2,769,690.34
Upgrade Total	$109,230,000.00

Beckham 345/230kV Transformer	$6,000,000.00
G08-09	$62,746.28
G07-41	$466,882.13
G07-56	$466,882.13
G07-46	$197,529.63
G07-08	$951,770.18
G07-48	$490,599.97
G07-27	$64,319.29
G08-08	$54,011.07
G07-05	$219,172.43
G07-45	$542,509.00
G07-10	$260,338.39
G08-07	$91,625.37
G07-42	$280,129.28
G07-33	$226,178.45
G07-26	$169,219.95
G07-55	$258,681.71
G08-14	$71,404.52
G07-30	$634,513.46
G07-34	$156,079.20
G07-57	$40,369.96
G08-15	$71,404.52
G08-16	$223,633.08
Upgrade Total	$6,000,000.00

Beckham County - Anadarko 345kV ckt 1	$150,000,000.00

This line was assumed to be approximately 100 miles long, have 3000 amp equipment, and be insulated at 345kV.

G07-55	$6,276,252.01
G07-10	$6,470,543.99
G08-09	$1,524,291.04
G07-57	$991,464.58
G07-08	$24,943,274.72
G08-07	$2,182,890.90
G07-56	$10,883,379.88
G07-46	$4,765,378.17
G07-05	$5,352,948.63
G07-49	$179,178.70
G07-33	$5,543,151.85

G08-15	$1,490,127.15
G07-43	$895,893.52
G07-26	$4,205,853.60
G07-42	$6,530,027.93
G08-16	$5,330,705.76
G07-45	$14,217,666.59
G08-08	$1,287,142.76
G07-34	$3,789,375.17
G07-32	$447,946.76
G07-48	$12,123,335.28
G07-41	$10,883,379.88
G07-27	$1,566,814.18
G08-14	$1,490,127.15
G07-30	$16,628,849.81
Upgrade Total	$150,000,000.00

Bushland Line Trap $400,000.00

G08-08	$11,358.98
G07-10	$91,783.58
G08-14	$16,323.71
G08-07	$19,274.65
G07-26	$59,659.33
G07-55	$65,642.47
G08-16	$47,296.86
G07-34	$39,899.76
G08-15	$16,323.71
G07-27	$16,459.90
G08-09	$15,977.05
Upgrade Total	$400,000.00

Carter Jct. - Lake Creek $50,000.00

Replace CTs

G07-49	$50,000.00
Upgrade Total	$50,000.00

Cimarron - Matthewson 345kV ckt #2 $13,800,000.00

Build new substation where Cimarron-Woodring crosses Woodward-NW

G07-41	$319,341.94
G07-37	$254,445.78
G08-15	$200,855.07
G08-07	$99,553.20
G07-30	$261,713.57
G07-38	$254,445.78
G08-03	$201,417.77
G07-10	$126,048.30

G07-21	$532,831.94
G07-56	$319,341.94
G07-34	$129,333.49
G07-62	$1,719,061.71
G07-44	$795,271.55
G07-19	$438,406.93
G07-26	$81,931.40
G07-57	$6,911.73
G07-51	$291,445.40
G08-11	$701,451.09
G07-55	$216,748.75
G08-09	$51,469.11
G07-42	$191,605.16
G07-36	$254,445.78
G07-08	$392,570.35
G07-61	$449,427.90
G07-45	$223,765.10
G07-25	$561,270.99
G07-50	$398,847.07
G08-14	$200,855.07
G07-48	$246,664.12
G06-06	$257,391.07
G07-27	$50,147.70
G07-33	$37,366.68
G08-08	$58,472.61
G08-18	$473,479.48
G07-40	$617,027.36
G08-19	$795,271.55
G08-13	$812,560.06
G07-60	$535,482.84
G08-16	$241,322.67
Upgrade Total	**$13,800,000.00**

Clinton Jct Switches **$150,000.00**

Replace 600 A switches at Clinton Jct

G07-32	$150,000.00
Upgrade Total	**$150,000.00**

Comanche - Medicine Lodge 345kV ckt 1 **$60,000,000.00**

This line was assumed to be approximately 55 miles long, have 3000 amp equipment, and be insulated at 345kV. No step down at Medicine Lodge.

G07-19	$2,018,923.94
G07-60	$1,664,769.25
G08-11	$3,228,618.17
G07-33	$784,908.82
G07-51	$1,897,859.05

G07-50	$2,444,262.73
G07-47	$417,349.70
G06-06	$1,031,203.29
G07-41	$2,879,991.15
G07-40	$3,135,152.93
G08-03	$1,234,352.68
G07-36	$1,134,421.23
G07-21	$1,656,527.82
G07-25	$6,193,441.90
G07-37	$1,134,421.23
G07-57	$136,991.05
G07-05	$798,853.90
G07-44	$2,472,429.58
G07-62	$10,179,460.55
G07-38	$1,134,421.23
G07-12	$429,807.30
G08-01	$136,351.90
G08-17	$1,074,601.27
G07-56	$2,879,991.15
G08-19	$2,472,429.58
G07-42	$1,727,994.69
G07-46	$858,729.20
G07-61	$2,661,296.88
G08-18	$2,180,437.85
Upgrade Total	**$60,000,000.00**

Comanche - Woodward 345kV ckt1 **$80,000,000.00**

This line was assumed to be approximately 60 miles long, have 3000 amp equipment, and be insulated at 345kV.

G07-44	$2,448,329.29
G07-61	$2,635,355.59
G07-40	$5,856,284.87
G06-06	$2,860,262.79
G07-57	$160,991.67
G08-19	$2,448,329.29
G07-38	$2,962,391.32
G08-17	$1,997,559.21
G07-25	$6,133,070.63
G07-41	$2,899,263.78
G07-62	$10,080,235.13
G07-21	$1,640,380.63
G07-50	$2,420,437.00
G08-14	$300,677.79
G07-36	$2,962,391.32
G08-08	$107,185.30

G07-37	$2,962,391.32
G08-11	$4,622,448.34
G07-56	$2,899,263.78
G07-60	$1,648,541.72
G07-55	$430,028.97
G07-46	$940,118.12
G07-51	$1,879,359.46
G08-01	$1,439,549.02
G07-33	$921,377.13
G07-34	$257,606.39
G07-47	$1,304,234.70
G07-05	$925,322.60
G07-12	$1,781,215.87
G08-09	$102,878.16
G07-27	$102,056.19
G08-03	$1,222,320.69
G07-19	$2,876,289.63
G08-18	$3,106,392.80
G08-07	$182,326.80
G08-16	$442,896.68
G07-42	$1,739,558.27
G08-15	$300,677.79
Upgrade Total	$80,000,000.00

Curry County - Deaf Smith	$1,000,000.00
G07-41	$165,842.99
G07-10	$123,845.06
G07-56	$165,842.99
G07-27	$544,468.97
Upgrade Total	$1,000,000.00

Deaf Smith - Plant X 230kV Line Trap	$400,000.00
G07-26	$24,333.98
G07-30	$7,710.16
G07-10	$37,436.89
G07-34	$53,251.78
G07-55	$86,839.04
G08-07	$25,850.61
G08-09	$19,314.21
G08-08	$15,212.77
G07-27	$15,033.17
G08-14	$22,520.91
G07-45	$6,592.18
G08-15	$22,520.91

G08-16	$63,383.36
Upgrade Total	**$400,000.00**
GEN06-006 Interconnection Cost	**$5,447,481.00**
See one-line diagram	
G06-06	$5,447,481.00
Upgrade Total	**$5,447,481.00**
GEN07-005 Interconnection Cost	**$600,000.00**
See one-line diagram	
G07-05	$600,000.00
Upgrade Total	**$600,000.00**
GEN07-008 Interconnection Cost	**$2,500,000.00**
See one-line diagram	
G07-08	$2,500,000.00
Upgrade Total	**$2,500,000.00**
GEN07-010 Interconnection Cost-1	**$250,000.00**
See one-line diagram	
G07-10	$250,000.00
Upgrade Total	**$250,000.00**
GEN07-010 Interconnection Cost-2	**$250,000.00**
See one-line diagram	
G07-10	$250,000.00
Upgrade Total	**$250,000.00**
GEN07-012 Interconnection Cost	**$9,843,070.00**
See one-line diagram	
G07-12	$9,843,070.00
Upgrade Total	**$9,843,070.00**
GEN07-019 Interconnection Cost-1	**$3,100,000.00**
See one-line diagram	
G07-19	$3,100,000.00
Upgrade Total	**$3,100,000.00**
GEN07-019 Interconnection Cost-2	**$3,100,000.00**
See one-line diagram	
G07-19	$3,100,000.00
Upgrade Total	**$3,100,000.00**
GEN07-021 Interconnection Cost	**$2,125,000.00**
See one-line diagram	
G07-21	$2,125,000.00
Upgrade Total	**$2,125,000.00**

GEN07-025 Interconnection Cost	$6,000,000.00
See one-line diagram	
G07-25	$6,000,000.00
Upgrade Total	**$6,000,000.00**
GEN07-026 Interconnection Cost	$1,200,000.00
See one-line diagram	
G07-26	$1,200,000.00
Upgrade Total	**$1,200,000.00**
GEN07-027 Interconnection Cost	$2,500,000.00
See one-line diagram	
G07-27	$2,500,000.00
Upgrade Total	**$2,500,000.00**
GEN07-030 Interconnection Cost	$2,500,000.00
See one-line diagram	
G07-30	$2,500,000.00
Upgrade Total	**$2,500,000.00**
GEN07-032 Interconnection Cost	$2,000,000.00
See one-line diagram	
G07-32	$2,000,000.00
Upgrade Total	**$2,000,000.00**
GEN07-033 Interconnection Cost	$3,221,000.00
See one-line diagram	
G07-33	$3,221,000.00
Upgrade Total	**$3,221,000.00**
GEN07-034 Interconnection Cost	$6,200,000.00
See one-line diagram	
G07-34	$6,200,000.00
Upgrade Total	**$6,200,000.00**
GEN07-036 Interconnection Cost	$3,000,000.00
See one-line diagram	
G07-36	$3,000,000.00
Upgrade Total	**$3,000,000.00**
GEN07-040 Interconnection Cost	$6,275,000.00
See one-line diagram	
G07-40	$6,275,000.00
Upgrade Total	**$6,275,000.00**
GEN07-041 Interconnection Cost	$2,000,000.00
See one-line diagram	
G07-41	$2,000,000.00

Upgrade Total	**$2,000,000.00**
GEN07-042 Interconnection Cost	**$2,000,000.00**
See one-line diagram	
G07-42	$2,000,000.00
Upgrade Total	**$2,000,000.00**
GEN07-043 - Cimarron 345kV ckt1	**$250,000.00**
Replace switch at Cimarron	
G07-26	$4,400.52
G07-46	$3,526.50
G07-57	$822.39
G08-18	$2,213.95
G07-44	$5,047.28
G07-05	$4,408.21
G07-37	$1,403.39
G07-32	$1,565.03
G08-16	$9,981.07
G07-60	$3,398.50
G07-62	$11,445.67
G07-50	$2,764.32
G07-61	$2,992.33
G07-10	$6,770.03
G07-08	$15,656.75
G08-08	$2,416.17
G08-14	$7,147.02
G07-27	$2,251.10
G06-06	$1,452.48
G07-43	$37,210.74
G07-41	$5,953.98
G07-40	$3,041.04
G07-52	$3,176.63
G07-56	$5,953.98
G07-34	$5,708.30
G08-11	$3,285.28
G08-09	$2,277.65
G07-45	$8,924.35
G07-51	$2,124.18
G08-01	$1,171.81
G07-47	$937.93
G07-33	$4,635.51
G07-42	$3,572.39
G07-36	$1,403.39
G07-19	$2,049.96
G07-21	$3,381.68
G08-19	$5,047.28

G08-07	$4,110.76
G07-49	$996.08
G08-15	$7,147.02
G08-17	$1,080.11
G07-25	$4,493.31
G07-55	$9,536.58
G08-03	$1,395.98
G07-48	$13,232.49
G07-30	$10,437.83
G07-38	$1,403.39
G08-13	$5,187.52
G07-12	$1,460.13
Upgrade Total	**$250,000.00**

GEN07-043 Interconnection Cost	**$6,000,000.00**
See one-line diagram	
G07-43	$6,000,000.00
Upgrade Total	**$6,000,000.00**

GEN07-044 Interconnection Cost	**$2,125,000.00**
See one-line diagram	
G07-44	$2,125,000.00
Upgrade Total	**$2,125,000.00**

GEN07-045 Interconnection Cost	**$2,500,000.00**
See one-line diagram	
G07-45	$2,500,000.00
Upgrade Total	**$2,500,000.00**

GEN07-046 Interconnection Cost	**$1,200,000.00**
See one-line diagram	
G07-46	$1,200,000.00
Upgrade Total	**$1,200,000.00**

GEN07-047 Interconnection Cost	**$3,807,109.00**
See one-line diagram	
G07-47	$3,807,109.00
Upgrade Total	**$3,807,109.00**

GEN07-048 - Swisher 230kV ckt1 Line Trap	**$200,000.00**
G08-16	$30,317.41
G08-09	$4,943.22
G08-08	$7,377.97
G07-26	$890.42
G08-15	$14,667.70
G08-14	$14,667.70

G07-45	$2,203.54
G07-30	$2,577.24
G07-55	$21,457.97
G07-27	$4,445.64
G07-10	$1,369.87
G08-07	$12,558.30
G07-48	$69,884.95
G07-34	$12,638.07
Upgrade Total	**$200,000.00**
GEN07-048 Interconnection Cost	**$3,500,000.00**
See one-line diagram	
G07-48	$3,500,000.00
Upgrade Total	**$3,500,000.00**
GEN07-049 Interconnection Cost	**$500,000.00**
See one-line diagram	
G07-49	$500,000.00
Upgrade Total	**$500,000.00**
GEN07-051 Interconnection Cost	**$750,000.00**
See one-line diagram	
G07-51	$750,000.00
Upgrade Total	**$750,000.00**
GEN07-052 Interconnection Cost-1	**$750,000.00**
See one-line diagram	
G07-52	$750,000.00
Upgrade Total	**$750,000.00**
GEN07-055 Interconnection Cost	**$6,200,000.00**
See one-line diagram	
G07-55	$6,200,000.00
Upgrade Total	**$6,200,000.00**
GEN07-056 Interconnection Cost	**$2,500,000.00**
See one-line diagram	
G07-56	$2,500,000.00
Upgrade Total	**$2,500,000.00**
GEN07-057 Interconnection Cost	**$2,500,000.00**
See one-line diagram	
G07-57	$2,500,000.00
Upgrade Total	**$2,500,000.00**
GEN07-060 Interconnection Cost	**$1,325,000.00**
See one-line diagram	
G07-60	$1,325,000.00

Upgrade Total	$1,325,000.00
GEN07-061 Interconnection Cost	$3,925,000.00
See one-line diagram	
G07-61	$3,925,000.00
Upgrade Total	$3,925,000.00
GEN07-062 Interconnection Cost	$2,225,000.00
See one-line diagram	
G07-62	$2,225,000.00
Upgrade Total	$2,225,000.00
GEN08-001 Interconnection Cost	$2,000,000.00
See one-line diagram	
G08-01	$2,000,000.00
Upgrade Total	$2,000,000.00
GEN08-003 Interconnection Cost	$410,000.00
See one-line diagram	
G08-03	$410,000.00
Upgrade Total	$410,000.00
GEN08-007 Interconnection Cost	$1,000,000.00
See one-line diagram	
G08-07	$1,000,000.00
Upgrade Total	$1,000,000.00
GEN08-008 Interconnection Cost	$1,000,000.00
See one-line diagram	
G08-08	$1,000,000.00
Upgrade Total	$1,000,000.00
GEN08-009 Interconnection Cost	$750,000.00
See one-line diagram	
G08-09	$750,000.00
Upgrade Total	$750,000.00
GEN08-011 Interconnection Cost	$2,000,000.00
See one-line diagram	
G08-11	$2,000,000.00
Upgrade Total	$2,000,000.00
GEN08-013 Interconnection Cost	$7,500,000.00
See one-line diagram	
G08-13	$7,500,000.00
Upgrade Total	$7,500,000.00
GEN08-014 Interconnection Cost	$1,500,000.00
See one-line diagram	

G08-14	$1,500,000.00
Upgrade Total	**$1,500,000.00**

GEN08-015 Interconnection Cost	**$2,500,000.00**
See one-line diagram	
G08-15	$2,500,000.00
Upgrade Total	**$2,500,000.00**

GEN08-016 Interconnection Cost	**$2,000,000.00**
See one-line diagram	
G08-16	$2,000,000.00
Upgrade Total	**$2,000,000.00**

GEN08-017 Interconnection Cost	**$2,252,652.00**
See one-line diagram	
G08-17	$2,252,652.00
Upgrade Total	**$2,252,652.00**

GEN08-018 Interconnection Cost	**$2,000,000.00**
See one-line diagram	
G08-18	$2,000,000.00
Upgrade Total	**$2,000,000.00**

GEN08-019 Interconnection Cost	**$2,125,000.00**
See one-line diagram	
G08-19	$2,125,000.00
Upgrade Total	**$2,125,000.00**

Grapevine - Beckham 345kV ckt 1 **$50,000,000.00**

This line was assumed to be approximately 60 miles long, have 3000 amp equipment, and be insulated at 345kV.

G08-15	$595,037.65
G07-57	$336,416.37
G07-56	$3,890,684.43
G08-14	$595,037.65
G08-16	$1,863,609.02
G08-08	$450,092.22
G07-42	$2,334,410.66
G07-05	$1,826,436.95
G07-48	$4,088,333.06
G07-26	$1,410,166.25
G08-07	$763,544.73
G07-55	$2,155,680.89
G07-30	$5,287,612.13
G07-41	$3,890,684.43
G07-08	$7,931,418.19
G07-10	$2,169,486.54
G07-45	$4,520,908.37

G07-46	$1,646,080.25
G07-33	$1,884,820.46
G07-34	$1,300,659.99
G08-09	$522,885.68
G07-27	$535,994.07
Upgrade Total	$50,000,000.00

Grapevine - LES 345kV ckt1 **$180,000,000.00**

This line was assumed to be approximately 180 miles long, have 3000 amp equipment, and be insulated at 345kV.

G07-41	$15,117,930.31
G07-45	$18,426,098.18
G07-05	$6,737,381.14
G07-57	$1,242,591.91
G07-55	$6,266,784.08
G07-30	$21,550,992.02
G07-33	$6,939,737.87
G07-34	$3,801,247.69
G07-42	$9,070,758.19
G07-26	$4,899,307.48
G07-08	$32,326,488.03
G08-08	$1,123,550.46
G07-10	$7,537,396.13
G08-09	$1,535,558.18
G07-48	$13,951,633.95
G07-27	$1,610,383.11
G07-46	$6,180,507.96
G08-16	$4,662,487.36
G08-07	$1,901,235.62
G07-56	$15,117,930.31
Upgrade Total	$180,000,000.00

Grassland - Lynn 115kV ckt1 **$2,130,000.00**

Reconductor

G08-16	$972,592.53
G08-08	$1,004,684.72
G08-07	$152,722.75
Upgrade Total	$2,130,000.00

Grassland 230/115kV Transformer **$5,000,000.00**

New Xfmr

G08-16	$4,321,422.38
G08-07	$678,577.62
Upgrade Total	$5,000,000.00

Gray County - Comanche 345kV ckt 1	**$71,000,000.00**

This line was assumed to be approximately 80 miles long, have 3000 amp equipment, and be insulated at 345kV

G07-40	$18,487,368.46
G07-19	$10,074,062.68
G07-38	$2,132,859.22
G08-16	$1,364,449.16
G07-37	$2,132,859.22
G07-36	$2,132,859.22
G06-06	$2,153,374.10
G08-18	$10,879,987.69
G07-27	$314,408.50
G08-08	$330,209.96
G08-11	$16,147,874.79
G08-09	$316,940.79
G08-07	$561,701.32
G08-15	$926,309.84
G08-14	$926,309.84
G07-55	$1,324,807.09
G07-34	$793,618.11
Upgrade Total	**$71,000,000.00**

Gray County - Stevens County 345kV ckt 1	**$58,200,000.00**

This line was assumed to be approximately 65 miles long, have 3000 amp equipment, and be insulated at 345kV

G07-42	$5,479,253.92
G07-37	$3,177,572.45
G07-05	$2,382,651.50
G07-46	$2,629,414.81
G07-19	$439,423.43
G07-56	$9,132,089.86
G08-18	$474,577.31
G07-38	$3,177,572.45
G07-57	$405,971.83
G08-11	$836,092.15
G07-36	$3,177,572.45
G07-33	$2,326,436.97
G06-06	$3,016,558.73
G07-40	$12,412,722.28
G07-41	$9,132,089.86
Upgrade Total	**$58,200,000.00**

Hutchinson - Riverview 115kV ckt1	**$4,250,000.00**
G07-05	$3,298,556.94
G07-33	$951,443.06

Upgrade Total	$4,250,000.00

Knoll 345/230kV Transformer	$10,000,000.00
440 MVA unit	
G07-33	$103,595.28
G07-42	$241,360.68
G07-05	$106,017.95
G07-19	$623,112.20
G07-41	$402,267.80
G07-57	$18,083.09
G07-40	$412,511.47
G08-18	$672,961.17
G07-56	$402,267.80
G06-06	$86,252.16
G07-47	$1,226,588.16
G07-12	$1,542,237.25
G08-11	$999,507.51
G07-46	$116,445.94
G08-17	$1,067,210.48
G08-01	$1,979,581.04
Upgrade Total	$10,000,000.00

Medicine Lodge - Wichita 345kV ckt 1 $90,000,000.00

This line was assumed to be approximately 75 miles long, have 3000 amp equipment, and be insulated at 345kV. No step down at Medicine Lodge.

G07-41	$4,036,465.24
G07-61	$3,729,953.24
G06-06	$1,445,287.85
G07-60	$2,333,265.22
G07-21	$2,321,714.40
G07-51	$2,659,953.35
G07-33	$1,100,092.67
G07-57	$192,000.45
G08-19	$3,465,245.38
G07-42	$2,421,879.15
G07-44	$3,465,245.38
G08-03	$1,730,012.84
G07-56	$4,036,465.24
G07-50	$3,425,768.00
G07-19	$2,829,632.40
G07-05	$1,119,637.47
G07-46	$1,203,555.98
G07-62	$14,267,071.14
G07-47	$584,938.45
G08-01	$191,104.65
G07-38	$1,589,953.45

G07-36	$1,589,953.45
G08-17	$1,506,112.49
G08-11	$4,525,085.08
G07-40	$4,394,088.43
G08-18	$3,056,003.00
G07-25	$14,587,163.67
G07-12	$602,398.46
G07-37	$1,589,953.45
Upgrade Total	**$90,000,000.00**

Mingo - Knoll 345kV ckt 1 **$110,000,000.00**

This line was assumed to be approximately 90 miles long, have 3000 amp equipment, and be insulated at 345kV.

G07-57	$198,914.00
G07-56	$4,424,945.85
G07-12	$16,964,609.76
G08-11	$10,994,582.66
G07-05	$1,166,197.43
G08-01	$21,775,391.42
G07-47	$13,492,469.80
G07-40	$4,537,626.13
G07-33	$1,139,548.11
G08-18	$7,402,572.90
G06-06	$948,773.74
G07-19	$6,854,234.17
G07-42	$2,654,967.51
G08-17	$11,739,315.29
G07-46	$1,280,905.38
G07-41	$4,424,945.85
Upgrade Total	**$110,000,000.00**

Mullergren - Circle 230kV ckt1 **$200,000.00**

Change relays

G07-33	$3,200.75
G07-57	$558.39
G07-56	$12,337.94
G07-19	$13,225.43
G07-12	$13,589.12
G08-11	$21,185.52
G07-41	$12,337.94
G08-17	$14,897.39
G07-42	$7,402.77
G07-47	$11,148.14
G07-46	$3,584.71
G07-40	$16,384.39
G07-05	$3,271.91

G08-18	$14,283.47
G06-06	$11,985.32
G07-38	$7,425.94
G08-01	$18,329.01
G07-36	$7,425.94
G07-37	$7,425.94
Upgrade Total	**$200,000.00**
Plant X - Tolk 230kV #1 Reconductor to 2-7	**$5,000,000.00**
Rebuild line with bundled 795MCM ACSR	
G07-55	$1,738,416.33
G08-08	$120,685.60
G08-14	$248,382.83
G08-16	$508,981.15
G08-09	$414,169.77
G07-34	$1,131,950.58
G08-07	$201,624.37
G08-15	$248,382.83
G07-27	$387,406.54
Upgrade Total	**$5,000,000.00**
Plant X - Tolk 230kV #2 Reconductor to 2-7	**$5,000,000.00**
Rebuild line with bundled 2-795 MCM ACSR	
G07-55	$1,738,416.33
G07-27	$387,406.54
G07-34	$1,131,950.58
G08-08	$120,685.60
G08-07	$201,624.37
G08-14	$248,382.83
G08-15	$248,382.83
G08-09	$414,169.77
G08-16	$508,981.15
Upgrade Total	**$5,000,000.00**
Potter - Bushland 230kV ckt1 Line Trap	**$200,000.00**
G07-27	$7,946.88
G08-09	$7,706.68
G08-15	$8,363.66
G07-34	$19,208.95
G08-14	$8,363.66
G08-08	$5,769.61
G08-16	$23,981.39
G07-55	$31,664.18
G07-10	$40,825.11
G08-07	$9,789.15

G07-26	$26,536.32
G07-48	$9,844.43
Upgrade Total	**$200,000.00**

Potter - Grapevine 345kV ckt 1 **$60,000,000.00**

This line was assumed to be approximately 60 miles long, have 3000 amp equipment, and be insulated at 345kV.

G08-14	$562,377.19
G08-16	$3,088,211.36
G07-48	$7,692,929.32
G07-41	$7,774,933.59
G08-15	$562,377.19
G07-46	$3,236,267.76
G07-26	$2,674,944.63
G07-10	$4,115,299.43
G07-27	$954,634.20
G07-57	$656,343.65
G08-07	$1,263,049.57
G07-05	$3,561,190.36
G07-55	$3,787,620.79
G07-56	$7,774,933.59
G07-42	$4,664,960.16
G07-34	$2,290,269.15
G08-08	$745,291.21
G08-09	$922,548.09
G07-33	$3,671,818.76
Upgrade Total	**$60,000,000.00**

Potter - Harrington East 230kV ckt1 Line Tr **$200,000.00**

G08-07	$5,404.83
G08-08	$3,180.62
G08-16	$12,816.01
G08-15	$6,283.23
G08-14	$6,283.23
G07-48	$166,032.08
Upgrade Total	**$200,000.00**

Potter - Replace 345/115kV Auto with (2) 7 **$20,000,000.00**

Replace the 560MVA auto at Potter with two 750MVA units

G08-16	$1,996,804.02
G07-10	$2,287,528.85
G07-55	$2,286,276.10
G08-09	$554,021.52
G07-26	$1,486,893.75
G08-15	$702,705.53

G07-45	$1,182,142.55
G08-08	$482,310.30
G08-07	$818,406.31
G07-27	$566,584.85
G08-14	$702,705.53
G07-34	$1,378,969.00
G07-48	$4,172,028.84
G07-30	$1,382,622.86
Upgrade Total	$20,000,000.00

Pringle - Hutchinson 115kV ckt1	$4,250,000.00
G07-05	$4,250,000.00
Upgrade Total	$4,250,000.00

SmokyHills - Summit 230kV ckt1	$200,000.00
G07-12	$32,998.44
G07-46	$4,687.18
G08-17	$27,738.19
G07-41	$16,165.64
G08-01	$56,720.27
G07-33	$4,171.54
G07-47	$26,656.52
G07-56	$16,165.64
G07-05	$4,269.29
G07-42	$9,699.39
G07-57	$727.88
Upgrade Total	$200,000.00

South Hays - Mullergren 230kV ckt1	$100,000.00
G07-47	$17,904.81
G07-12	$22,798.61
G08-17	$12,415.82
G08-01	$46,880.76
Upgrade Total	$100,000.00

Spearville - Comanche 345kV ckt 1 $50,000,000.00

This line was assumed to be approximately 55 miles long, have 3000 amp equipment, and be insulated at 345kV.

G07-05	$213,309.22
G07-40	$4,784,221.18
G07-46	$142,612.45
G06-06	$5,089,883.72
G07-19	$2,611,949.69
G07-33	$228,980.92

G07-12	$3,506,281.26
G08-18	$2,820,905.66
G07-38	$5,424,322.98
G07-47	$2,728,839.66
G08-01	$2,501,551.28
G08-11	$4,193,746.42
G07-37	$5,424,322.98
G07-57	$40,254.50
G08-17	$4,864,495.10
G07-36	$5,424,322.98
Upgrade Total	$50,000,000.00

Spearville - Wichita 345kV ckt 1 $150,000,000.00

This line was assumed to be approximately 150 miles long, have 3000 amp equipment, and be insulated at 345kV.

G07-47	$4,151,571.01
G07-05	$2,888,993.86
G07-37	$9,430,381.02
G07-12	$4,922,565.58
G07-56	$11,062,163.56
G08-18	$11,051,276.36
G07-38	$9,430,381.02
G07-40	$16,568,403.53
G08-11	$16,380,037.85
G08-01	$2,853,999.31
G08-17	$8,678,646.42
G07-36	$9,430,381.02
G07-41	$11,062,163.56
G07-46	$3,186,231.45
G07-57	$492,040.54
G07-42	$6,637,298.13
G07-19	$10,232,663.30
G07-33	$2,820,732.90
G06-06	$8,720,069.59
Upgrade Total	$150,000,000.00

Sunnyside - LES 345kV ckt1 $500,000.00

Replace Line Trap, Switches CTs at LES

G07-42	$17,032.50
G08-03	$1,678.58
G07-62	$11,232.64
G07-21	$2,920.67
G08-09	$6,518.70
G07-43	$22,788.68
G07-60	$2,935.20
G07-55	$27,292.74

G07-49	$4,185.39
G08-08	$6,918.94
G08-13	$3,750.85
G07-52	$10,305.68
G08-07	$11,771.53
G07-48	$38,575.77
G07-57	$2,561.82
G07-05	$14,115.99
G07-61	$2,936.64
G07-10	$19,480.00
G08-19	$4,359.21
G08-14	$20,431.82
G07-45	$20,171.34
G07-33	$14,544.44
G07-50	$3,323.92
G07-30	$23,592.21
G07-34	$16,336.76
G07-27	$6,442.76
G08-15	$20,431.82
G07-26	$12,662.00
G07-41	$28,387.50
G08-16	$28,581.26
G07-08	$35,388.31
G07-32	$8,808.77
G07-56	$28,387.50
G07-51	$4,379.04
G07-44	$4,359.21
G07-46	$12,409.81
Upgrade Total	$500,000.00

Swisher - Tuco 230kV Line Trap	$400,000.00
G08-09	$14,167.48
G07-27	$12,347.53
G08-08	$24,393.10
G08-14	$53,802.69
G08-15	$53,802.69
G08-16	$100,937.78
G08-07	$41,981.61
G07-34	$36,330.74
G07-55	$62,236.37
Upgrade Total	$400,000.00

Tatonga - Matthewson 345kV ckt #2	$87,500,000.00
Build new substation where Cimarron-Woodring crosses Woodward-NW	
G07-44	$6,473,872.80

G07-62	$12,947,882.21
G07-51	$2,057,609.98
G07-37	$1,242,306.93
G07-19	$2,461,661.40
G08-14	$309,922.17
G08-09	$231,545.16
G07-60	$4,359,074.35
G08-15	$309,922.17
G07-38	$1,242,306.93
G06-06	$1,202,072.26
G07-61	$3,385,067.25
G07-25	$2,434,639.26
G08-16	$849,773.00
G07-50	$3,005,078.19
G07-21	$4,337,494.78
G07-36	$1,242,306.93
G07-57	$147,678.34
G07-05	$884,743.83
G07-45	$480,522.79
G08-18	$2,658,594.32
G07-55	$956,233.69
G07-41	$3,876,844.57
G07-27	$236,497.08
G07-46	$1,036,033.66
G07-56	$3,876,844.57
G07-30	$562,014.96
G08-07	$348,400.33
G07-48	$1,987,144.67
G08-19	$6,473,872.80
G08-11	$3,934,901.61
G08-13	$587,229.94
G07-26	$643,010.23
G08-08	$205,317.03
G07-08	$843,022.45
G07-33	$849,340.42
G08-03	$1,517,564.49
G07-34	$576,301.55
G07-10	$989,246.51
G07-42	$2,326,106.74
G07-40	$3,409,997.62
Upgrade Total	$87,500,000.00

Woodward - Tatonga 345kV ckt 2 $83,848,000.00

This line was assumed to be approximately 60 miles long, have 3000 amp equipment, and be insulated at 345kV.

G07-46	$1,203,695.85
G07-33	$986,789.88
G07-50	$3,491,392.49
G07-48	$2,308,725.94
G07-19	$2,860,034.11
G07-44	$2,397,935.13
G07-45	$558,286.20
G07-30	$652,966.31
G08-16	$987,292.47
G07-26	$747,069.11
G07-21	$1,606,616.54
G07-08	$979,449.47
G07-42	$2,702,542.52
G07-10	$1,149,337.10
G07-41	$4,504,237.54
G07-60	$1,614,609.65
G07-40	$3,961,840.37
G07-38	$1,443,350.49
G07-62	$15,043,248.73
G08-08	$238,543.66
G08-03	$1,763,153.21
G08-09	$269,016.30
G07-57	$171,577.25
G07-61	$3,932,875.48
G08-19	$2,397,935.13
G06-06	$1,396,604.61
G07-34	$669,564.91
G07-55	$1,110,981.78
G08-15	$360,077.13
G08-18	$3,088,836.84
G08-14	$360,077.13
G07-25	$2,828,638.96
G07-37	$1,443,350.49
G07-56	$4,504,237.54
G07-51	$2,390,594.71
G07-05	$1,027,922.66
G08-07	$404,782.24
G07-36	$1,443,350.49
G07-27	$274,769.60
G08-11	$4,571,690.00
Upgrade Total	$83,848,000.00

Woodward 345/138kV Transformer #2 440 MVA unit	$7,875,000.00
G07-51	$2,528,560.04

G08-03	$1,793,988.16
G07-50	$3,552,451.80
Upgrade Total	$7,875,000.00

All Upgrades Total **$1,705,289,312.00**

H: FCITC Analysis (No Upgrades)

See Attachment

I: ACCC Analysis (Upgrades Included)

See Attachment

J: Stability Study for Group 1

Final Report

For

Southwest Power Pool

From

S&C Electric Company

CLUSTER GROUP 1 GENERATION INTERCONNECTION IMPACT STUDY

S&C Project No. 3742

June 29, 2009

S&C Electric Company

S&C Electric Company, Chicago, IL 60626-3997, Phone: (773) 338-1000

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Report Revision History:

Date of Report	Issue	Comments
June 15, 2009	Rev. A	Draft for review and comments
June 29, 2009	Rev. 0	Final report issued

Report prepared by:

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Report approved by:

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EXECUTIVE SUMMARY

S&C Electric Company has performed a grouped interconnection impact study for ten (10) wind generation projects (Cluster Group 1 projects) in response to a request through the Southwest Power Pool (SPP) Tariff studies. The projects will interconnect into areas controlled by Oklahoma Gas and Electric (OKGE), Western Farmers Electric Cooperative (WFEC), and Westar Energy, Inc. (WERE) and have an in-service year request of 2010. Studies were performed for summer and winter 2010 peak loading with Cluster Group 1 wind farms operating at rated output power. Cluster Group 1 wind generation projects consist of GEN-2007-021, GEN-2007-044, GEN-2007-050, GEN-2007-051, GEN-2007-060, GEN-2007-061, GEN-2007-062, GEN-2008-003, GEN-2008-013 and GEN-2008-019 interconnection impact requests. The wind turbine generators represented are GE 1.5 MW, Mitsubishi 2.4 MW, and Siemens 2.3 MW.

Cluster Group 1 wind projects can successfully interconnect into the transmission system at their desired locations provided that the wind farms can supply the reactive power needed to meet a voltage schedule equal to the base case voltage or nominal voltage, whichever is higher at the Point of Interconnection (POI) for single transmission facility outage contingencies. The study has identified additional capacitor bank requirements:

- One (1) 46.8 MVAR capacitor bank to be installed on the 138 kV side of the 345/138 kV transformer of GEN-2008-019
- Two (2) 39.6 MVAR capacitor banks. Each bank to be installed on one of two 34.5 kV collector buses of GEN-2007-050.
- One (1) 39.6 MVAR capacitor bank to be installed on the 34.5 kV collector bus of GEN-2008-003.
- One (1) 23.4 MVAR capacitor bank to be installed on the 34.5 kV collector bus of GEN-2007-061.
- Four (4) 23.4 MVAR capacitor banks to be installed each on one of four 34.5 kV collector buses of GEN-2007-062.

The capacitor bank requirements are based on the GE wind turbine generators being configured to provide reactive power to meet a voltage schedule at the POI through WindCONTROL, the Siemens wind turbine generators being configured to control the local voltage to nominal voltage (690 Volts), and the Mitsubishi 2.4 MW being operated at a fixed power factor of 97% leading. Ultimately, the Cluster Group 1 wind farms are required to show that they can operate at the following power factors for the worst single transmission facility outage contingency in each case:

- 98.80% leading power factor at Tatonga 345 kV POI
- 99.86% leading power factor at Woodward 138 kV POI
- 98.50% lagging power factor at Mooreland 138 kV POI
- Unity power factor at Woodward 345 kV POI
- 98.23% leading power factor at Wichita – Woodring 345 kV POI

Transient stability analysis performed for 3-phase and single-line-to-ground fault contingencies at locations specified by SPP indicate that the Cluster Group 1 wind farms and prior queued wind farms will survive, and the areas monitored will recover and becomes stable for winter peak cases. For summer peak cases, prior queued project GEN-2001-037 will trip off on undervoltage for fault contingency #63 (3 phase fault near GEN-2001-037, on the GEN-2001-037 to Woodward 138kV line with reclosing) although the Cluster Group 1 and remaining prior queued wind farm projects will survivee and the system will be stable. If GEN-2001-037 were to remain connected for fault contingency #63, the system would be stable and other prior queued projects and Cluster Group 1 would survive. The system will be stable regardless of whether GEN-2001-037 survives or trips off for fault contingency #63. SPP demands no further remedial action to keep GEN-2001-037 connected. Cluster Group 1 wind farms and prior queued wind farms will survive, and the areas monitored will recover and becomes stable for the remaining summer peak cases.

1. INTRODUCTION

S&C Electric Company has performed an interconnection impact study for ten (10) wind generation projects in response to a request through the Southwest Power Pool (SPP) Tariff studies. The wind generation projects will interconnect into Oklahoma Gas and Electric (OKGE), Western Farmers Electric Cooperatiove (WFEC), and Westar Energy, Inc. (WERE) and have an in-service year request of 2010. Studies were performed for summer and winter 2010 peak loading with wind farms at 100% output power. Seasonal power flow models including aggregate models of the projects studied were provided by SPP. Wind turbine generators represented by the projects are General Electric GE 1.5 MW, Siemens SWT 2.3 MW (SWT-2.3-93 60 Hz), and Mitsubishi MWT-95 – 2.4 MW.

Cluster Group 1 consists of the following wind generation projects:

GEN-2007-021 – GE 1.5 MW – 201 MW total rated capacity

GEN-2007-044 – GE 1.5 MW – 300 MW total rated capacity

GEN-2007-050 – Siemens 2.3 MW – 200 MW total rated capacity

GEN-2007-051 – GE 1.5 MW – 200 MW total rated capacity

GEN-2007-060 – GE 1.5 MW – 202 MW total rated capacity

GEN-2007-061 – GE 1.5 MW – 200 MW total rated capacity

GEN-2007-062 – GE 1.5 MW – 765 MW total rated capacity

GEN-2008-003 – Siemens 2.3 MW – 120 MW total rated capacity

GEN-2008-013 – GE 1.5 MW – 300 MW total rated capacity

GEN-2008-019 – GE 1.5 MW – 300 MW total rated capacity

2. TRANSMISSION SYSTEM AND STUDY AREA

The study area involves transmission facilities at 345, 230 and 138 kV. The wind generation projects will interconnect at the following locations:

345 kV Tatonga substation (OKGE): GEN-2007-021, GEN-2007-044, GEN-2007-060, and GEN-2008-019.

138 kV Woodward substation (OKGE): GEN-2007-050 and GEN-2008-003

138 kV Mooreland substation (WFEC): GEN-2007-051

345 kV Woodward substation (OKGE): GEN-2007-061 and GEN-2007-062

345 kV substation located between Wichita and Woodring (WERE): GEN-2008-013

Single outage and fault contingencies were considered for transmission facilities nearby the point of interconnection (POI) of these wind projects. Areas monitored consisted of:

- Oklahoma Gas and Electric (OKGE)
- Western Farmers Electric Cooperative (WFEC)
- AEP West (AEPW)
- Sunflower Electric Power Company (SUNC)
- Mid-Kansas Electric Company (MKEC)
- Southwestern Public Service (SPS)
- Westar Energy, Inc (WERE)

3. POWER FLOW BASE CASES

S&C received PSS/E power flow base cases for steady-state and transient stability analysis from SPP on April 2, 2009. The submittal consisted of the following base cases:

ICS08-01_G1_10SP.sav – Summer peak 2010, which includes aggregate representation of wind turbine generators for Cluster Group 1 wind farms and prior queued projects at 100% output power. Other cluster projects were also included with wind farms at 20% output power.

ICS08-01_G1_10WP.sav – Winter peak 2010, which includes aggregate representation of wind turbine generators for Cluster Group 1 wind farms and prior queued projects at 100% output power. Other cluster projects were also included with wind farms at 20% output power.

The original base cases were subsequently revised, renamed, and used for the studies by S&C with input from SPP:

ICS08-01_G1_10SP_sandc.sav – Summer peak 2010, which adds a 345 kV line from Spearville to Wichita, removes the 138 kV line in GEN-2008-019 and adds a 12 MVAR switched capacitor bank to the collector bus at GEN-2001-014.

ICS08-01_G1_10WP_sandc.sav – Winter peak 2010, which adds a 345 kV line from Spearville to Wichita, removes the 138 kV line in GEN-2008-019 and adds a 12 MVAR switched capacitor bank to the collector bus at GEN-2001-014.

4. WIND FARM MODELS

An equivalent aggregate representation of wind turbine generators and equivalent collector system impedance was developed for each 34.5/115 kV substation transformer to simplify analysis and representation in PSS/E. The equivalent collector system impedance was calculated (by others) from detailed collector cable impedance information provided by wind farm developer. The aggregate models were part of the base case supplied by SPP.

4.1 General Electric GE – 1.5 MW/60 Hz Wind Turbine Generator

The GE 1.5 MW wind turbine generator is a widely used variable-speed doubly-fed induction generator with power converter and electrical pitch control. The standard GE turbine can operate continuously between 95% leading (capacitive) to 95% lagging (inductive). With an optional upgrade, the turbines can continuously operate between 90% leading to 90% lagging. For wind farms that are required to meet a voltage schedule at the POI, the GE WindCONTROL system is available to dynamically control the power factor of each wind turbine generator as well as the switching operation of any capacitor/reactor bank. The GE controls feature local and remote voltage and power factor control.

4.2 Siemens SWT – 2.3 MW (SWT-2.3-93 60 Hz) 60 Hz Wind Turbine Generator

The SWT 2.3 MW wind turbine generator is an induction generator (squirrel cage type) with PWM control for variable reactive power output control, which can be configured to control the 0.69 kV terminal voltage. The continuous reactive output capability of the machine is dependent on the terminal voltage and the real output power of the wind turbine generator. The power curve indicates that at rated 2.3 MW output power and 1.0 p.u. voltage, the wind turbine generator is capable of operating continuously between 86% leading to 86% lagging. Leading power factor range significantly decreases at any voltage other than 1.0 p.u. Also, an increase in terminal voltage would result in higher lagging power factor capability and a decrease in terminal voltage would result in lower lagging power factor capability. For steady-state operation, the wind turbine generator features local voltage and power factor control modes of operation.

4.3 Mitsubishi MWT-95 – 2.4 MW/60 Hz Wind Turbine Generator

The MWT-95 - 2.4 MW wind turbine generator is a variable-speed doubly-fed induction generator with pitch control. At rated 2.4 MW output power, the turbines can operate at any fixed power factor setpoint between 95% leading to 90% lagging. The fixed power factor setpoint can be changed manually through software to cater various system conditions. The manufacturer also supplies a permanently connected 0.11 MVAR capacitor bank located at the terminal of the wind turbine generator.

5. Power Flow Analysis

SPP has specific voltage and power factor requirements for interconnecting wind farm projects in relation to emergency conditions. Wind generation 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 transmission facility outage contingencies specified by SPP. It may not be possible in all cases to meet the voltage requirements specified by SPP since actual requirements on the wind farm(s) may exceed a power factor of +/-95%. FERC 661A requires for LGIA that the wind farm project maintain a power factor within +/-95% measured at the high side of the substation transformer.

Voltage in the SPP base case of the various point of interconnections locations is listed in Table 5.1

Table 5.1: Base Case Voltage of Point of Interconnection Locations

Point of Interconnection	Summer Peak 2010	Winter Peak 2010
Tatonga 345 kV (515378)	343.34 kV	341.14 kV
Woodward 138kV (515376)	140.37 kV	140.22 kV
Mooreland 138kV (520999)	140.72 kV	141.20 kV
Woodward 345kV (515375)	353.73 kV	353.42 kV
Wichita – Woodring 345kV (532796-514715)	344.83 kV	346.90 kV

5.1 Facility Outage Contingencies

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

Table 5.2: List of N-1 Outage Contingencies

Cont.	Description
N-1_1	Outage of one of the Woodward (515375) to Tatonga (515378) 345kV lines
N-1_2	Outage of one of the Woodward (515375) to Hitchland (523097) 345kV lines
N-1_3	Outage of the Woodward (515375) to Comanche (531487) 345kV line
N-1_4	Outage of the Woodward 345kV (515375) to 138kV (515376) transformer
N-1_5	Outage of one of the Tatonga (515378) to Northwest (514880) 345kV lines
N-1_6	Outage of the GEN-2008-013 (210130) to Woodring (514715) 345kV line
N-1_7	Outage of the GEN-2008-013 (210130) to Wichita (532796) 345kV line
N-1_8	Outage of one of the Comanche (531487) to GEN-2007-025 (532781) 345kV lines
N-1_9	Outage of the Comanche (531487) to Spearville (531469) 345kV line
N-1_10	Outage of one of the GEN-2007-025 (532781) to Wichita (532796) 345kV lines
N-1_11	Outage of the GEN-2007-040 (210400) to Spearville (531469) 345kV line
N-1_12	Outage of the Spearville 345kV (531469) to 230kV (539695) transformer
N-1_13	Outage of the Wichita (532796) to Benton (532791) 345kV line
N-1_14	Outage of Wichita 345kV (532796) to 138kV (533040) transformer 12X
N-1_15	Outage of the Woodring (514715) to Cimarron (514901) 345kV line
N-1_16	Outage of the Woodring (514715) to Sooner (514803) 345kV line
N-1_17	Outage of the Cimarron (514901) to Draper (514934) 345kV line
N-1_18	Outage of the Northwest (514880) to Arcadia (514908) 345kV line
N-1_19	Outage of the Northwest (514880) to Spring Creek (514881) 345kV line
N-1_20	Outage of the Northwest (514880) to Cimarron (514901) 345kV line
N-1_21	Outage of Northwest 345kV (514880) to 138kV (514879) transformer T2
N-1_22	Outage of the Hitchland (523097) to GEN-2003-013 (560029) 345kV line
N-1_23	Outage of the Hitchland (523097) to GEN-2005-017 (51700) 345kV line
N-1_24	Outage of the GEN-2005-017 (51700) to Potter (523961) 345kV line
N-1_25	Outage of the Potter (523961) to Grapevine (523772) 345kV line
N-1_26	Outage of the GEN-2003-013 (560029) to Finney (523853) 345kV line
N-1_27	Outage of the Woodward EHV (515376) to Iodine (514796) 138kV line
N-1_28	Outage of the Woodward (514785) to GEN-2001-037 (515785) 138kV line
N-1_29	Outage of the GEN-2001-037 (515785) to Mooreland (520999) 138kV line
N-1_30	Outage of the Mooreland (520999) to Iodine (520957) 138kV line
N-1_31	Outage of the Mooreland (520999) to Glass Mountain (514788) 138kV line
N-1_32	Outage of the Mooreland (520999) to Cedardale (520848) 138kV line
N-1_33	Outage of the Mooreland (520999) to Morewood (521001) 138kV line
N-1_34	Outage of the Mooreland (520999) to Taloga (521065) 138kV line
N-1_35	Outage of the Taloga 138kV (521065) to 69kV (521064) transformer
N-1_36	Outage of the Taloga (521065) to Dewey (514787) 138kV line
N-1_37	Outage of the Dewey (514787) to Taloga (521065) 138kV line
N-1_38	Outage of the Dewey (514787) to Southard (514822) 138kV line
N-1_39	Outage of the Hitchland (523097) to Beaver County (523098) 345kV line
N-1_40	Outage of the GEN-2003-013 (560029) to GEN-2007-040 (210400) 345kV line
N-1_41	Outage of the GEN-2007-040 (210400) to Comanche (531487) 345kV line
N-1_42	Outage of the Woodward (515375) to Beaver County (523098) 345kV line

5.2 Power Factor Requirements at the Point of Interconnection

The power factor requirement of each interconnecting project will depend largely on the collective ability of the wind farms to deliver leading or lagging reactive power required to maintain a voltage schedule at the POI consistent with the voltage in the SPP base case or nominal voltage, whichever is higher. The collective power factor requirements are summarized in Table 5.3 for the outage contingencies that will create the greatest leading power factor demand from the interconnecting projects.

Table 5.3: Power factor requirements to maintain the base case voltage schedule at the POI

Point of Interconnection	Total Rated Capacity of Collective Projects (MW)	Worst Case Contingency (from Table 5.2)	Power Factor Requirement	
Tatonga 345 kV	1003	N-1_10 Winter Peak	98.80%	leading
Woodward 138kV	320	N-1_31 Winter Peak	99.86%	leading
Mooreland 138kV	200	N-1_5 Summer Peak	98.50%	lagging
Woodward 345kV	965	N-1_2 Summer Peak	100.00%	
Wichita – Woodring 345kV	300	N-1_8 Summer Peak	98.23%	leading

5.3 Steady-State Reactive Compensation Requirements

GE 1.5 MW wind turbine generators can be configured through WindCONTROL to control the voltage at the POI. With the exception of GEN-2007-051, outages from Table 5.2 will demand capacitive reactive power from the turbines to raise the voltage at the POI. The reactive power demanded could raise the terminal voltage at the wind turbine generators above 105%, which could have an effect on the ability of the wind turbine generator to deliver reactive power. Capacitor banks can be installed to reduce the reactive power demanded on the wind turbine generators and transformer no-load taps adjusted to reduce the voltage at the wind turbine generators. GE wind turbine generators were setup in the load flow model to control the voltage at the POI. Siemens turbines were setup to control the local voltage to nominal 690 volts and the Mitsubishi turbines were setup to operate at a fixed 97% leading power factor. Capacitor banks were then added to wind farms at 34.5 kV and 138 kV to provide reactive power support in order to meet the power factor requirements summarized in Table 5.3. Table 5.4 summarizes the control scheme for each project, location and size of cap banks required, and transformer no-load tap settings. Figures 5.1 to 5.5 show the power flow diagrams corresponding to each point of interconnection and wind farm projects for the worst contingencies in Table 5.3.

Table 5.4: Summary of wind farm control, wind turbine specifications, capacitor bank requirements and transformer tap settngs

		Wind Turbine Generator			Mechanically Switched Cap Bank Requirement		XFMR no-load tap setting (% of high side winding)				
Project Name	**Point of Interconnection**	**Model**	**Power Factor Range**	**Control Scheme and Settings**	**Size (MVAR)**	**Location**	**345/138 kV**	**138/34.5 kV and 345/34.5 kV**		**Wind Turbine Generator Step Up**	
GEN-2007-021	Tatonga 345 kV	GE 1.5 MW	+/- 90%	Meet 1.00 pu voltage at POI (requires WindCONTROL)	none			102.5		100.0	
GEN-2007-044	Tatonga 345 kV	GE 1.5MW	+/- 90%	Meet 1.00 pu voltage at POI (requires WindCONTROL)	none			102.5		100.0	
GEN-2007-050	Woodward 138 kV	Siemens 2.3MW	+/- 86%@1.00 pu voltage	Meet 1.00 pu voltage at WTG	**39.60**	34.5 kV collector bus #1		105.0	(MAIN #1)	100.0	(GSU eq #1)
					39.60	34.5 kV collector bus #2		105.0	(MAIN #2)	100.0	(GSU eq #2)
GEN-2007-051	Mooreland 138 kV	GE 1.5MW	+/- 90%	Meet 1.03 pu voltage at POI (requires WindCONTROL)	none			105.0	(MAIN #1)	100.0	(GSU eq #1)
								105.0	(MAIN #2)	100.0	(GSU eq #2)
GEN-2007-060	Tatonga 345 kV	GE 1.5MW	+/- 95%	Meet 1.00 pu voltage at POI (requires WindCONTROL)	none			105.0	(MAIN #1)	100.0	(GSU eq #1)
								105.0	(MAIN #2)	100.0	(GSU eq #2)
GEN-2007-061	Woodward 345 kV	GE 1.5MW	+/- 95% (note 1)	Meet 1.03 pu voltage at POI	**23.40**	34.5 kV collector bus		105.0		100.0	
GEN-2007-062	Woodward 345 kV	GE 1.5MW	+/- 95% (note 1)	Meet 1.03 pu voltage at POI (requires WindCONTROL)	**23.40**	34.5 kV collector bus #1		105.0	(MAIN #1)	100.0	(GSU eq #1)
					23.40	34.5 kV collector bus #2		105.0	(MAIN #2)	100.0	(GSU eq #2)
					23.40	34.5 kV collector bus #3		105.0	(MAIN #3)	100.0	(GSU eq #3)
					23.40	34.5 kV collector bus #4		105.0	(MAIN #4)	100.0	(GSU eq #4)
GEN-2008-003	Woodward 138 kV	Siemens 2.3 MW	+/- 86%@1.00 pu voltage	Meet 1.00 pu voltage at WTG	**39.60**	34.5 kV collector bus		105.0		100.0	
GEN-2008-013	Wichita – Woodring 345 kV	GE 1.5 MW	+/- 95% (note 1)	Meet 1.01 pu voltage at POI (requires WindCONTROL)	none			102.5	(MAIN #1)	100.0	(GSU eq #1)
								105.0	(MAIN #2)	100.0	(GSU eq #2)
										125.0	(GSU eq #3)
GEN-2008-019	Tatonga 345 kV	Mitsubishi 2.4 MW	-90% to +95%	Fixed 97% leading power factor	**46.8**	138 kV XFMR secondary	102.5	105.0		100.0	

Notes:

1 Assume standard reactive output capability. Wind farm developer to confirm this information.

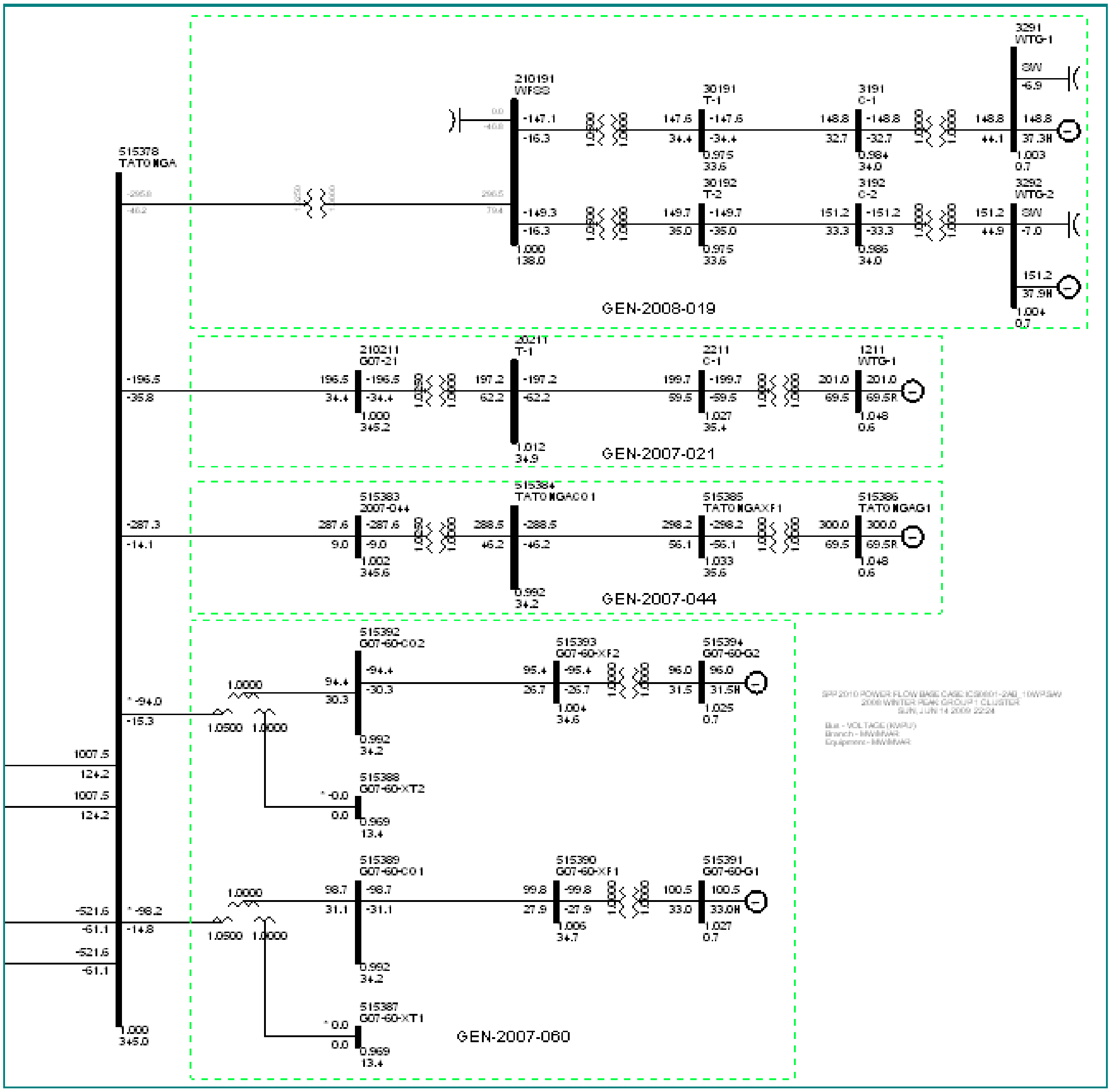

Figure 5.1: Power flow diagram of wind projects connected to Taloga 345 kV for N-1_10 winter peak outage contingency

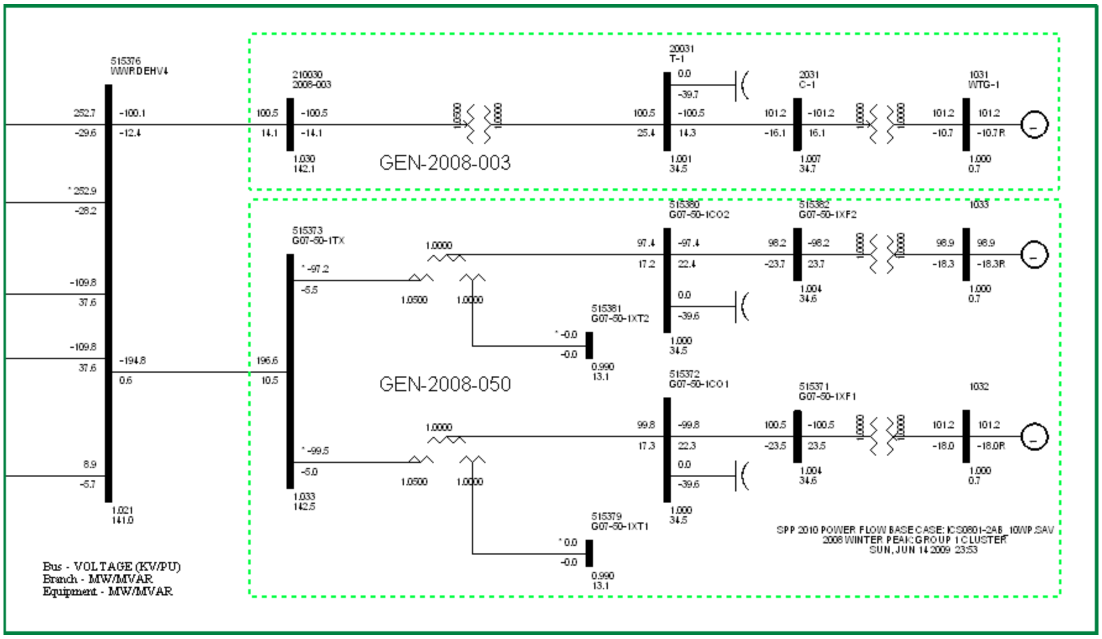

Figure 5.2: Power flow diagram of wind projects connected to Woodward 138 kV for N-1_31 winter peak outage contingency

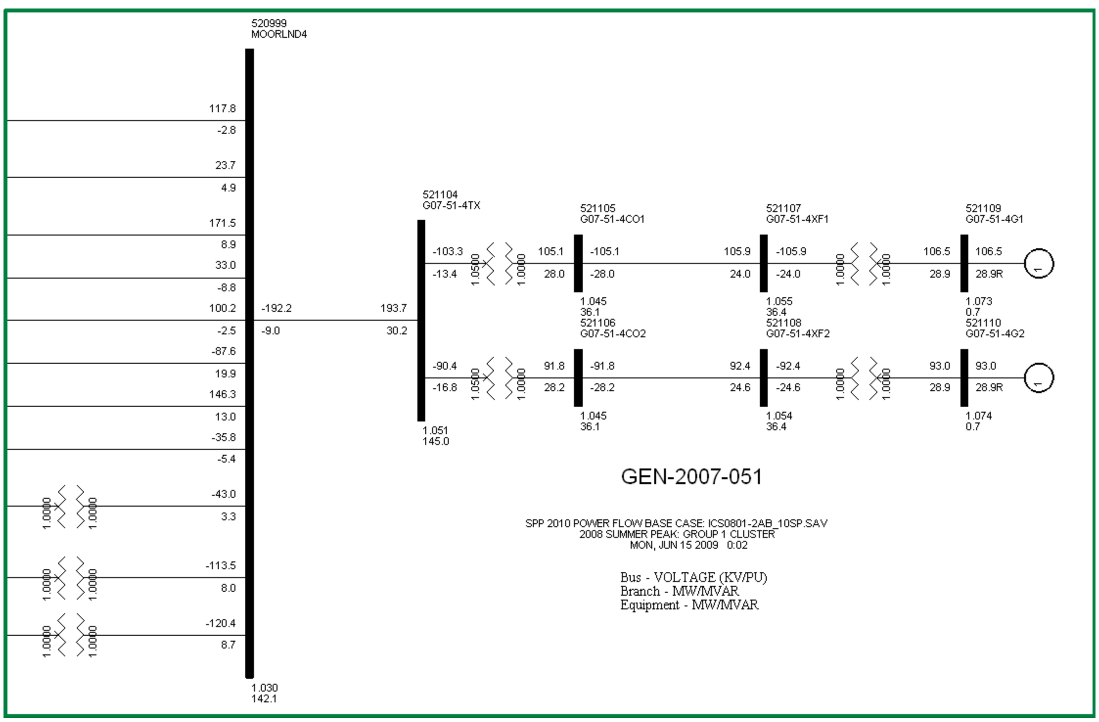

Figure 5.3: Power flow diagram of Mooreland 138 kV and GEN-2007-051 for N-1_5 summer peak outage contingency

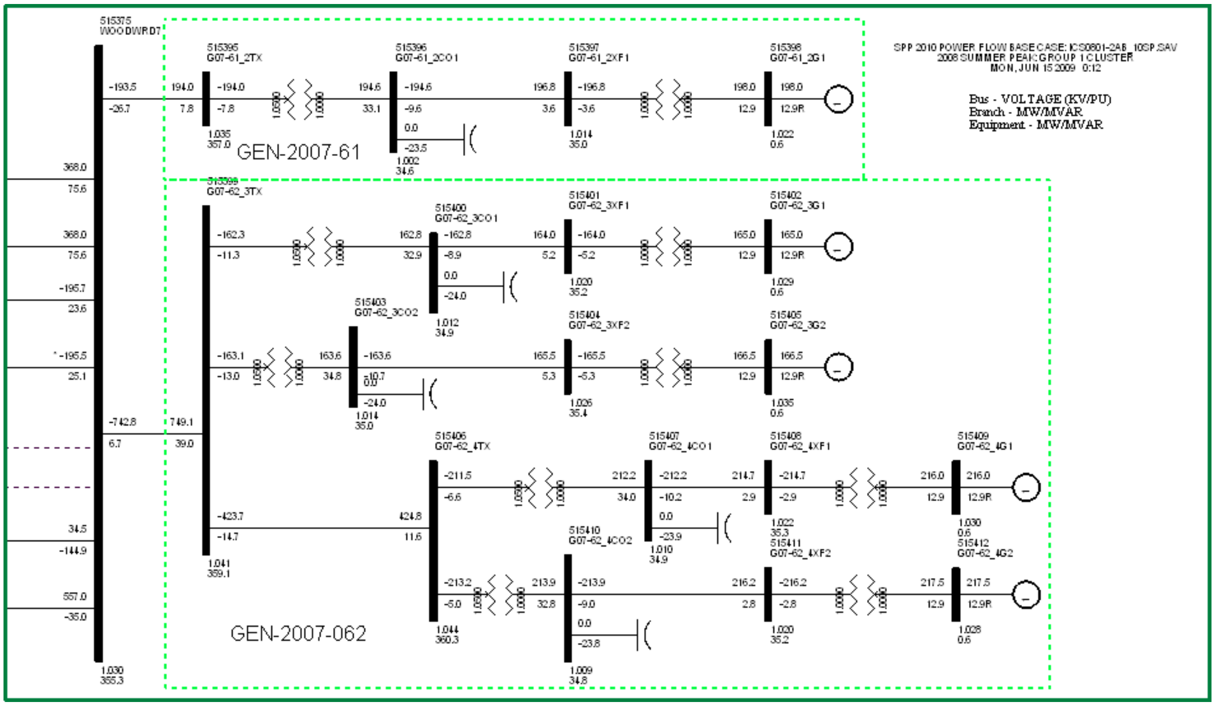

Figure 5.4: Power flow diagram of wind projects connected to Woodward 345 kV for N-1_2 summer peak outage contingency

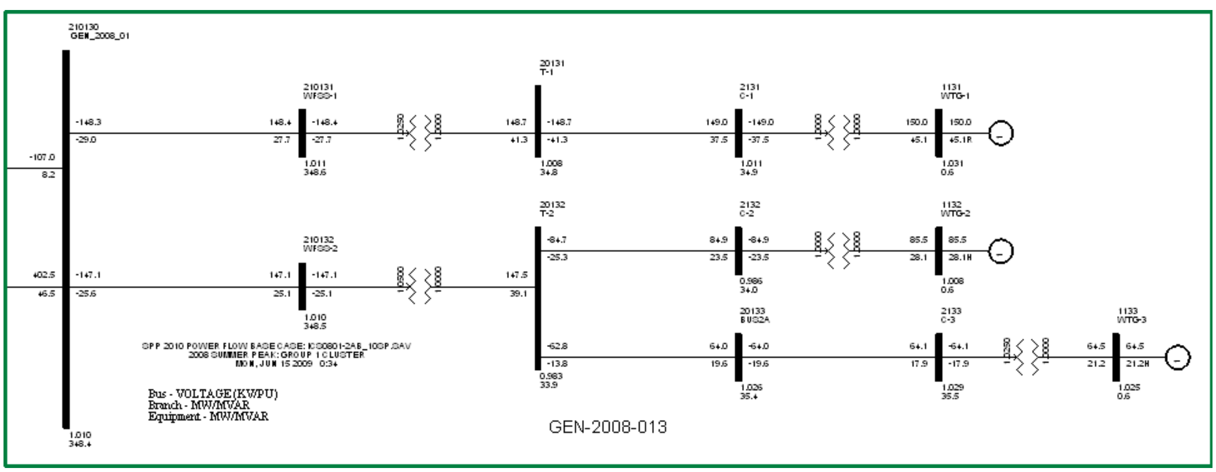

Figure 5.5: Power flow diagram of the Wichita – Woodring 345kV POI and GEN-2008-013 for N-1_8 summer peak outage contingency

6. TRANSIENT STABILITY ANALYSIS AND RESULTS

Transient stability analysis was performed for fault contingencies in Table 6.1.

Table 6.1: SPP fault contingencies

Cont. No.	Cont. Name	Description
1	FLT01-3PH	3 phase fault on one of the Woodward (515375) to Tatonga (515378) 345kV lines, near Woodward. a. Apply fault at the Woodward 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 one of the Woodward (515375) to Hitchland (523097) 345kV lines, near Woodward. a. Apply fault at the Woodward 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 Woodward (515375) to Comanche (531487) 345kV line, near Woodward. a. Apply fault at the Woodward 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 Woodward 345kV (515375) to 138kV (515376) transformer, near the 345 kV bus. a. Apply fault at the Woodward 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
8	FLT08-1PH	*Single phase fault and sequence like previous*
9	FLT09-3PH	3 phase fault on one of the Tatonga (515378) to Woodward (515375) 345kV lines, near Tatonga. a. Apply fault at the Tatonga 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 one of the Tatonga (515378) to Northwest (514880) 345kV lines, near Tatonga. a. Apply fault at the Tatonga 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*

Cont. No.	Cont. Name	Description
13	FLT13-3PH	3 phase fault on the GEN-2008-013 (210130) to Woodring (514715) 345kV line, near GEN-2008-013. a. Apply fault at the GEN-2008-013 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*
15	FLT15-3PH	3 phase fault on the GEN-2008-013 (210130) to Wichita (532796) 345kV line, near GEN-2008-013. a. Apply fault at the GEN-2008-013 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	FLT17-3PH	3 phase fault on one of the Comanche (531487) to GEN-2007-025 (532781) 345kV lines, near Comanche. a. Apply fault at the Comanche 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	FLT18-1PH	*Single phase fault and sequence like previous*
19	FLT19-3PH	3 phase fault on the Comanche (531487) to Spearville (531469) 345kV line, near Comanche. a. Apply fault at the Comanche 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	FLT20-1PH	*Single phase fault and sequence like previous*
21	FLT21-3PH	3 phase fault on the Spearville (531469) to Comanche (531487) 345kV line, 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.
22	FLT22-1PH	*Single phase fault and sequence like previous*
23	FLT23-3PH	3 phase fault on one of the GEN-2007-025 (532781) to Wichita (532796) 345kV lines, near GEN-2007-025. a. Apply fault at the GEN-2007-025 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.
24	FLT24-1PH	*Single phase fault and sequence like previous*
25	FLT25-3PH	3 phase fault on the GEN-2007-040 (210400) to Spearville (531469) 345kV line, near GEN-2007-004. a. Apply fault at the GEN-2007-040 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.
26	FLT26-1PH	*Single phase fault and sequence like previous*

Cont. No.	Cont. Name	Description
27	FLT27-3PH	3 phase fault on the Spearville 345kV (531469) to 230kV (539695) transformer, near the 345 kV bus. a. Apply fault at the Spearville 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
28	FLT28-1PH	*Single phase fault and sequence like previous*
29	FLT29-3PH	3 phase fault on the Wichita (532796) to Benton (532791) 345kV line, near Wichita. a. Apply fault at the Wichita 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
30	FLT30-1PH	*Single phase fault and sequence like previous*
31	FLT31-3PH	3 phase fault on Wichita 345kV (532796) to 138kV (533040) transformer 12X, near the 345 kV bus. a. Apply fault at the Wichita 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
32	FLT32-1PH	*Single phase fault and sequence like previous*
33	FLT33-3PH	3 phase fault on the Woodring (514715) to Cimarron (514901) 345kV line, near Woodring. a. Apply fault at the Woodring 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
34	FLT34-1PH	*Single phase fault and sequence like previous*
35	FLT35-3PH	3 phase fault on the Woodring (514715) to Sooner (514803) 345kV line, near Woodring. a. Apply fault at the Woodring 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
36	FLT36-1PH	*Single phase fault and sequence like previous*
37	FLT37-3PH	3 phase fault on the Cimarron (514901) to Draper (514934) 345kV line, near Cimarron. a. Apply fault at the Cimarron 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.
38	FLT38-1PH	*Single phase fault and sequence like previous*
39	FLT39-3PH	3 phase fault on the Northwest (514880) to Arcadia (514908) 345kV line, near Northwest. a. Apply fault at the Northwest 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.
40	FLT40-1PH	*Single phase fault and sequence like previous*
41	FLT41-3PH	3 phase fault on the Northwest (514880) to Spring Creek (514881) 345kV line, near Northwest. a. Apply fault at the Northwest 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.
42	FLT42-1PH	*Single phase fault and sequence like previous*

Cont. No.	Cont. Name	Description
43	FLT43-3PH	3 phase fault on the Northwest (514880) to Cimarron (514901) 345kV line, near Northwest. a. Apply fault at the Northwest 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.
44	FLT44-1PH	*Single phase fault and sequence like previous*
45	FLT45-3PH	3 phase fault on Northwest 345kV (514880) to 138kV (514879) transformer T2, near the 345 kV bus. a. Apply fault at the Northwest 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
46	FLT46-1PH	*Single phase fault and sequence like previous*
47	FLT47-3PH	3 phase fault on the Hitchland (523097) to GEN-2003-013 (560029) 345kV line, near Hitchland. a. Apply fault at the Hitchland 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
48	FLT48-1PH	*Single phase fault and sequence like previous*
49	FLT49-3PH	3 phase fault on the Hitchland (523097) to GEN-2005-017 (51700) 345kV line, near Hitchland. a. Apply fault at the Hitchland 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
50	FLT50-1PH	*Single phase fault and sequence like previous*
51	FLT51-3PH	3 phase fault on the GEN-2005-017 (51700) to Potter (523961) 345kV line, near GEN-2005-017. a. Apply fault at the GEN-2005-017 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.
52	FLT52-1PH	*Single phase fault and sequence like previous*
53	FLT53-3PH	3 phase fault on the Potter (523961) to Grapevine (523772) 345kV line, near Potter. a. Apply fault at the Potter 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	FLT54-1PH	*Single phase fault and sequence like previous*
55	FLT55-3PH	3 phase fault on the GEN-2003-013 (560029) to Finney (523853) 345kV line, near GEN-2003-013. a. Apply fault at the GEN-2003-013 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.
56	FLT56-1PH	*Single phase fault and sequence like previous*
57	FLT57-3PH	3 phase fault on the Woodward 138kV (515376) to 345kV (515375) transformer, near the 138kV bus. a. Apply fault at the Woodward 138kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
58	FLT58-1PH	*Single phase fault and sequence like previous*

Cont. No.	Cont. Name	Description
59	FLT59-3PH	3 phase fault on the Woodward EHV (515376) to Iodine (514796) 138kV line, near Woodward EHV. a. Apply fault at the Woodward EHV 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.
60	FLT60-1PH	*Single phase fault and sequence like previous*
61	FLT61-3PH	3 phase fault on the Woodward (514785) to GEN-2001-037 (515785) 138kV line, near Woodward. a. Apply fault at the Woodward 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.
62	FLT62-1PH	*Single phase fault and sequence like previous*
63	FLT63-3PH	3 phase fault on the GEN-2001-037 (515785) to Woodward (514785) 138kV line, near GEN-2001-037. a. Apply fault at the GEN-2001-037 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.
64	FLT64-1PH	*Single phase fault and sequence like previous*
65	FLT65-3PH	3 phase fault on the GEN-2001-037 (515785) to Mooreland (520999) 138kV line, near GEN-2001-037. a. Apply fault at the GEN-2001-037 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.
66	FLT66-1PH	*Single phase fault and sequence like previous*
67	FLT67-3PH	3 phase fault on the Mooreland (520999) to GEN-2001-037 (515785) 138kV line, near Mooreland. a. Apply fault at the Mooreland 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.
68	FLT68-1PH	*Single phase fault and sequence like previous*
69	FLT69-3PH	3 phase fault on the Mooreland (520999) to Iodine (520957) 138kV line, near Mooreland. a. Apply fault at the Mooreland 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.
70	FLT70-1PH	*Single phase fault and sequence like previous*
71	FLT71-3PH	3 phase fault on the Mooreland (520999) to Glass Mountain (514788) 138kV line, near Mooreland. a. Apply fault at the Mooreland 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.
72	FLT72-1PH	*Single phase fault and sequence like previous*

Cont. No.	Cont. Name	Description
73	FLT73-3PH	3 phase fault on the Mooreland (520999) to Cedardale (520848) 138kV line, near Mooreland. a. Apply fault at the Mooreland 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.
74	FLT74-1PH	*Single phase fault and sequence like previous*
75	FLT75-3PH	3 phase fault on the Mooreland (520999) to Morewood (521001) 138kV line, near Mooreland. a. Apply fault at the Mooreland 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.
76	FLT76-1PH	*Single phase fault and sequence like previous*
77	FLT77-3PH	3 phase fault on the Mooreland (520999) to Taloga (521065) 138kV line, near Mooreland. a. Apply fault at the Mooreland 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.
78	FLT78-1PH	*Single phase fault and sequence like previous*
79	FLT79-3PH	3 phase fault on the Taloga 138kV (521065) to 69kV (521064) transformer, near the 138kV bus. a. Apply fault at the Taloga 138kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
80	FLT80-1PH	*Single phase fault and sequence like previous*
81	FLT81-3PH	3 phase fault on the Taloga (521065) to Dewey (514787) 138kV line, near Taloga. a. Apply fault at the Taloga 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.
82	FLT82-1PH	*Single phase fault and sequence like previous*
83	FLT83-3PH	3 phase fault on the Dewey (514787) to Taloga (521065) 138kV line, near Dewey. a. Apply fault at the Dewey 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.
84	FLT84-1PH	*Single phase fault and sequence like previous*
85	FLT85-3PH	3 phase fault on the Dewey (514787) to Southard (514822) 138kV line, near Dewey. a. Apply fault at the Dewey 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.
86	FLT86-1PH	*Single phase fault and sequence like previous*
87	FLT107-3PH	*3 phase fault on the Hitchland (523097) to Beaver County (523098) 345kV line, near Hitchland.* *a. Apply fault at the Hitchland 345kV bus.* *b. Clear fault after 5 cycles by tripping the faulted line.* *c. Wait 20 cycles, and then re-close the line in (b) back into the fault.* *d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.*
88	FLT108-1PH	*Single phase fault and sequence like previous*

Cont. No.	Cont. Name	Description
89	FLT109-3PH	*3 phase fault on the GEN-2003-013 (*560029*) to GEN-2007-040 (210400) 345kV line, near GEN-2003-013.* *a. Apply fault at the GEN-2003-013 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.*
90	FLT110-1PH	*Single phase fault and sequence like previous*
91	FLT111-3PH	*3 phase fault on the GEN-2007-040 (210400) to Comanche (531487) 345kV line, near Comanche.* *a. Apply fault at the Comanche 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.*
92	FLT112-1PH	*Single phase fault and sequence like previous*
93	FLT113-3PH	*3 phase fault on the Woodward (515375) to Beaver County (523098) 345kV line, near Beaver County.* *a. Apply fault at the Beaver 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.*
94	FLT114-1PH	*Single phase fault and sequence like previous*

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 of 60% of nominal.

The control areas monitored:

- Oklahoma Gas and Electric (OKGE)
- Western Farmers Electric Cooperative (WFEC)
- AEP West (AEPW)
- Sunflower Electric Power Company (SUNC)
- Mid-Kansas Electric Company (MKEC)
- Southwestern Public Service (SPS)
- Westar Energy, Inc (WERE)

The prior queued projects monitored are listed in Table 6.2.

Table 6.2: Prior queued wind farm projects monitored

Request	**Size**	**Wind Turbine Model**	**Point of Interconnection**
GEN-2002-005	120	Acciona 1.5MW	Moorewood – Elk City 138kV
GEN-2001-037	102	GE 1.5MW	Woodward-Mooreland 138kV
GEN-2005-008	120	GE 1.5MW	Woodward 138kV
GEN-2006-046	130	Mitsubishi 2.4MW	Taloga 138kV
GEN-2001-014	94	Suzlon 2.1MW	Fort Supply 138kV
GEN-2007-006	160	Suzlon 2.1MW	Roman Nose 138kV

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 reasonable operating level. Frequencies should settle to the nominal 60 Hz power frequency.

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6.2 Modeling of Wind Turbine Generators

Transient stability simulations used an updated version of the GE 1.5 MW originally released under PSS/E Wind package issue 2.0.0 as a library model. S&C found that the existing GE 1.5 MW model would negatively interact with the Mitsubishi MWT-92/95 PSS/E model. PTI provided the updated model to S&C with the necessary corrections on August 1, 2008. The Mitsubishi library model has a file modified date of December 11, 2006 and the Siemens model has file modified date of May 14, 2007.

The voltage and frequency relay settings used with the GE 1.5 MW model for the Cluster Group 1 projects are listed in Table 6.3. The Mitsubishi and Siemens wind turbine generator relay settings are listed in Table 6.4 and 6.5 respectively.

Table 6.3: GE 1.5 MW relay settings of Cluster Group 1 projects

Relay type	Description	Trip setting and time delay	Units
Undervoltage (27-1)	Relay trips if |Vbus|<	0.85	Pu
	for t =	10.0	S
Undervoltage (27-2)	Relay trips if |Vbus|<	0.75	Pu
	for t =	1.0	S
Undervoltage (27-3)	Relay trips if |Vbus|<	0.70	Pu
	for t =	0.625	S
Undervoltage (27-4)	Relay trips if |Vbus|<	0.15	Pu
	for t =	0.625	S
Overvoltage (59-1)	Relay trips if |Vbus|>	1.1	Pu
	for t =	1.0	S
Overvoltage (59-2)	Relay trips if |Vbus|>	1.15	Pu
	for t =	0.1	S
Overvoltage (59-3)	Relay trips if |Vbus|>	1.3	Pu
	for t =	0.02	S
Underfrequency (81U-1)	Relay trips if Fbus <	57.5	Hz
	for t =	10.0	S
Underfrequency (81U-2)	Relay trips if Fbus <	56.5	Hz
	for t =	0.02	S
Overfrequency (81O-1)	Relay trips if Fbus >	61.5	Hz
	for t =	30.0	S
Overfrequency (81U-2)	Relay trips if Fbus >	62.5	Hz
	for t =	0.02	S

Table 6.4: Mitsubishi MWT-95 - 2.4 MW relay settings of GEN-2008-019

Relay type	Description	Trip setting and time delay	units
Undervoltage (27-1)	Relay trips if |Vbus|<	0.90	pu
	for t =	3.00	s
Undervoltage (27-2)	Relay trips if |Vbus|<	0.85	pu
	for t =	2.842	s
Undervoltage (27-3)	Relay trips if |Vbus|<	0.75	pu
	for t =	2.525	s
Undervoltage (27-4)	Relay trips if |Vbus|<	0.65	pu
	for t =	2.208	s
Undervoltage (27-5)	Relay trips if |Vbus|<	0.55	pu
	for t =	1.892	s
Undervoltage (27-6)	Relay trips if |Vbus|<	0.45	pu
	for t =	1.575	s
Undervoltage (27-7)	Relay trips if |Vbus|<	0.35	pu
	for t =	1.258	s
Undervoltage (27-8)	Relay trips if |Vbus|<	0.25	pu
	for t =	0.942	s
Undervoltage (27-9)	Relay trips if |Vbus|<	0.20	pu
	for t =	0.783	s
Undervoltage (27-10)	Relay trips if |Vbus|<	0.025	pu
	for t =	0.15	s
Overvoltage (59-1)	Relay trips if |Vbus|>	1.10	pu
	for t =	0.020	s
Overfrequency (81O)	Relay trips if Fbus >	61.00	Hz
	for t =	0.30	s
Underfrequency (81U)	Relay trips if Fbus <	59.00	Hz
	for t =	0.30	s

Table 6.5: Siemens SWT 2.3 MW (SWT-2.3-93 60 Hz) relay settings of GEN-2007-050 and GEN-2008-003

Relay type	Description	Trip setting and time delay	Units
Undervoltage (27-1)	Relay trips if |Vbus|<	0.90	Pu
	for t =	3	S
Undervoltage (27-2)	Relay trips if |Vbus|<	0.5	Pu
	for t =	1.735	S
Undervoltage (27-3)	Relay trips if |Vbus|<	0.85	Pu
	for t =	0.650	S
Undervoltage (27-4)	Relay trips if |Vbus|<	0.15	Pu
	for t =	0.075	S
Overvoltage (59-1)	Relay trips if |Vbus|>	1.10	Pu
	for t =	1	S
Overvoltage (59-2)	Relay trips if |Vbus|>	1.20	Pu
	for t =	0.2	S
Underfrequency (81U-1)	Relay trips if Fbus <	0.95	Pu
	for t =	10	S
Underfrequency (81U-2)	Relay trips if Fbus <	0.94	Pu
	for t =	0.1	S
Overfrequency (81O-1)	Relay trips if Fbus >	1.04	Pu
	for t =	0.1	S

6.3 Transient Stability Results: Summer Peak 2010

An undisturbed run of 10 seconds was performed on the Summer Peak 2010 power flow case that was modified with items listed in Table 5.4. Voltage, angle and frequency channels were constant and held steady values throughout the run. This indicated proper initialization of dynamic models.

The areas monitored will be stable for Table 6.1 fault contingencies #1 through #94. For fault #63 – 3 phase fault near GEN-2001-037, on the GEN-2001-037 to Woodward 138kV line with reclosing, the GEN-2001-037 GE 1.5 MW wind turbine generators will trip off on the V_N < 70 % under-voltage relay setting. Figure 6.1 shows the trip event involving GEN-2001-037 wind turbine generators. Table 6.6 lists voltage and frequency relay settings of GEN-2001-037 wind turbine generators.

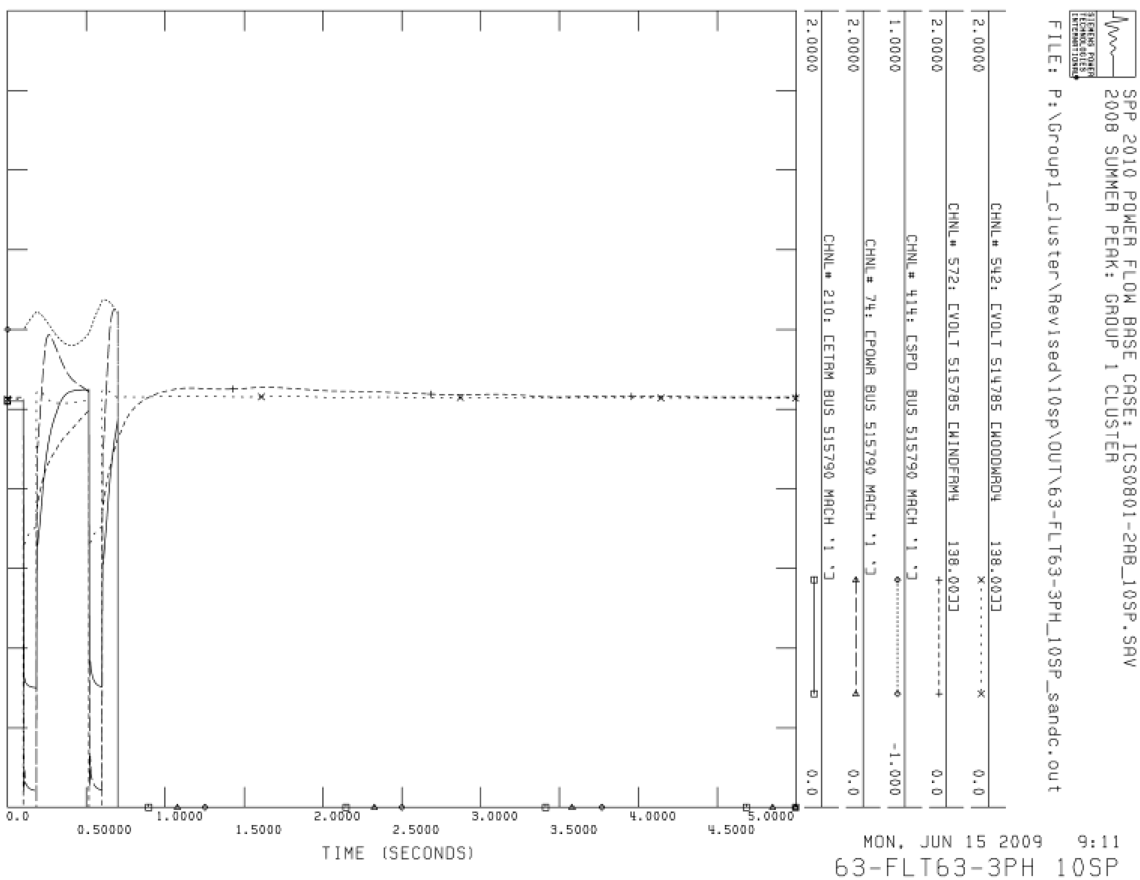
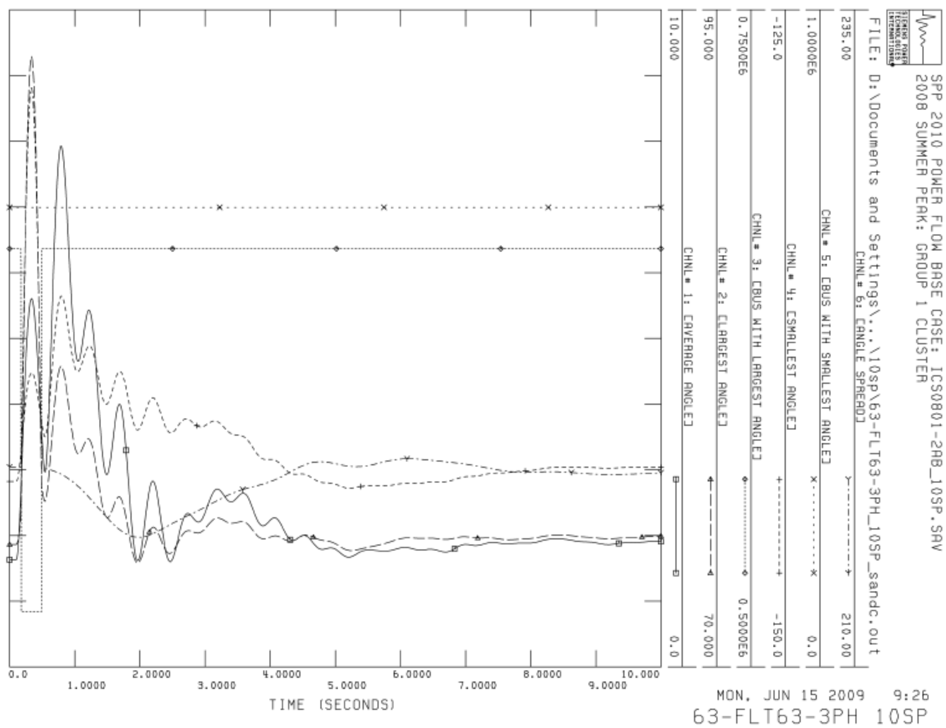


Figure 6.1: Trip event at GEN-2002-037 for fault contingency #63 – summer peak

Table 6.6: GE 1.5 MW relay settings of GEN-2001-037

Relay type	Description	Trip setting and time delay	Units
Undervoltage (27-1)	Relay trips if |Vbus|<	0.85	Pu
	for t =	10.0	S
Undervoltage (27-2)	Relay trips if |Vbus|<	0.75	Pu
	for t =	1.0	S
Undervoltage (27-3)	Relay trips if |Vbus|<	0.70	Pu
	for t =	0.10	S
Undervoltage (27-4)	Relay trips if |Vbus|<	0.3	Pu
	for t =	0.02	S
Overvoltage (59-1)	Relay trips if |Vbus|>	1.1	Pu
	for t =	1.0	S
Overvoltage (59-2)	Relay trips if |Vbus|>	1.15	Pu
	for t =	0.1	S
Overvoltage (59-3)	Relay trips if |Vbus|>	1.3	Pu
	for t =	0.02	S
Underfrequency (81U-1)	Relay trips if Fbus <	57.5	Hz
	for t =	10.0	S
Underfrequency (81U-2)	Relay trips if Fbus <	56.5	Hz
	for t =	0.02	S
Overfrequency (81O-1)	Relay trips if Fbus >	61.5	Hz
	for t =	30.0	S
Overfrequency (81U-2)	Relay trips if Fbus >	62.5	Hz
	for t =	0.02	S

Fault contingency #63 was re-studied with voltage protection disabled to prevent the wind turbine generators at GEN-2001-037 from tripping off. The results, which are shown in Figure 6.2, indicate that the system will be stable if GEN-2001-037 happens to survive this fault. Whether the wind farm stays connected or trips off, the system will be stable after the fault has been cleared.



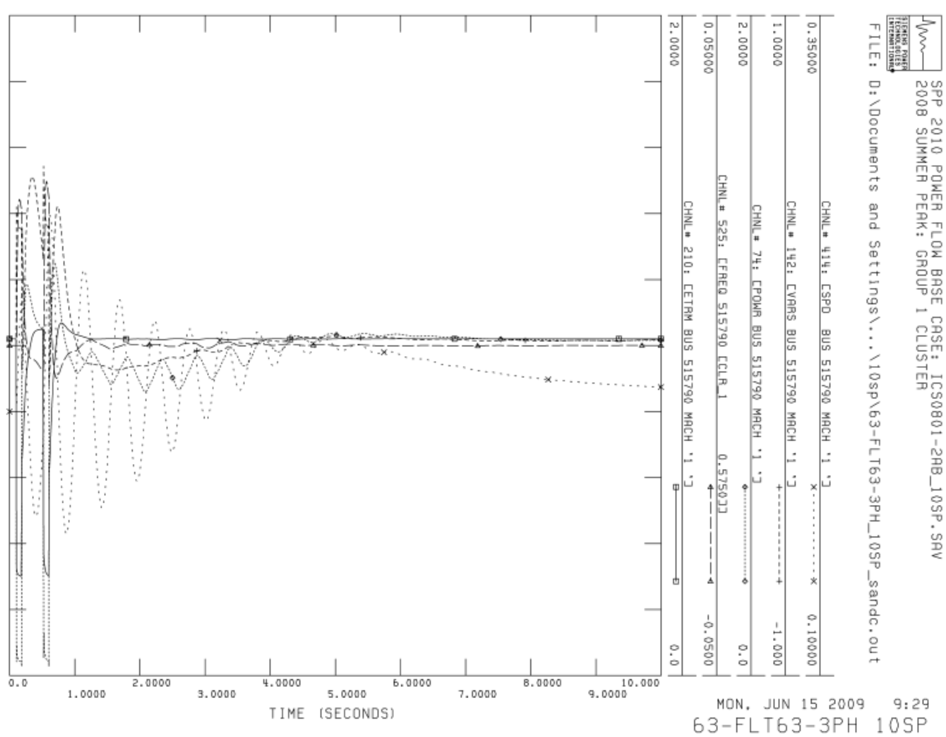


Figure 6.2: Trip event at GEN-2002-037 for fault contingency #63 – summer peak with wind turbine protection disabled.

6.4 Transient Stability Results: Winter Peak 2010

The areas monitored will be stable for Table 6.1 fault contingencies #1 through #94. Cluster Group 1 projects and prior queued projects will survive each fault contingency. Transient stability analysis results are summarized in Table 6.7.

7. CONCLUSIONS AND RECOMMENDATIONS

1 Cluster Group 1 wind farms are required to demonstrate that they can operate at the following power factors for the worst single transmission facility outage contingency in each case.

- 98.80% leading power factor at Tatonga 345 kV POI
- 99.86% leading power factor at Woodward 138 kV POI
- 98.50% lagging power factor at Mooreland 138 kV POI
- Unity power factor at Woodward 345 kV POI
- 98.23% leading power factor at Wichita – Woodring 345 kV POI

2 It is recommended that wind farm developers take advantage of the reactive output power capability of GE wind turbine generators to meet the voltage schedule at the POI. This will reduce capacitor bank requirements.

3 The system will remain stable for 3-phase and single-line-to-ground fault contingencies at locations specified by SPP. Cluster Group 1 and prior queued project will survive each fault contingency with the exception of GEN-2001-037 for fault contingency #63 for summer peak. No remedial action is required. The system will be stable regardless of whether GEN-2001-037 trips off or survives fault contingency #63.

K: Stability Study for Group 2

R100-09

Generator Interconnection Impact Study for Cluster # 1: ICS-2008-001 - Group 2

Prepared for

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Draft Report: June 29, 2009

Siemens PTI Project Number: P/21-113379-B-1

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Section

1

Introduction

1.1 Background

Pursuant to the tariff and at the request of the Southwest Power Pool (SPP), Siemens PTI performed the following Impact Study to satisfy the Impact Study Agreement executed by the requesting customers and SPP for SPP Generation Interconnection request. The requests for interconnection were placed with SPP in accordance to SPP's Open Access Transmission Tariff, which covers new generation interconnections on SPP's transmission system.

The purpose of this report is to present the results of the stability and power factor analysis performed to evaluate the impact of the proposed cluster of interconnections of the ICS-2008-001 with regard to Group 2 projects on the Southwest Power Pool system. The indicative solutions to the identified issues are proposed based on the impact of each generation interconnection on the Southwest Power Pool system.

The Group 2 of ICS-2008-001 comprises seven different projects interconnected at different voltage levels ranging from115 kV to 345 kV, described in detail on Section 2.

Transient stability analysis was performed using the package provide by SPP. It contains the latest stability database in PSS™E version 30.3.2. The stability package also includes the dynamic data for the previously queued projects.

1.2 Purpose

The steady state and stability study was carried out to:

(a) Determine the ability of the proposed generation facility to remain in synchronism and within applicable planning standards following system faults with unsuccessful reclosing.

(b) Determine the amount of capacitor banks required at the wind farm facilities on the customer side to meet the power factor requirement at the POI.

(c) Determine the ability of the wind farm to meet FERC Order 661A (low voltage ride through and wind farm recovery to pre-fault voltage) with and without additional reactive support.

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Section

2

Model Development

The study has considered the 2008 Summer Peak and Winter Peak load flow models with the required interconnection generation modeled and provided by SPP. The base cases contain all the significant previous queued generation interconnection projects in the interconnection queue.

2.1 Power Flow Data

Table 2-1 presents the size of the wind generation projects, the Wind Turbine Generator (WTG) manufacturers, the reactive capability of each generation project as well as the point of interconnection and the PSS®E bus numbers in the load flow model.

Table 2-1 – Details of the Interconnection Requests

Request	Size (MW)	Model	Reactive Capability of Wind Farm		Point of Interconnection	Bus Number
			Max (MVAR)	Min (MVAR)		
GEN-2007-005	200	Furhlander 1.5 MW	65.6	-65.6	PRINGLE 115kV	523266
GEN-2007-033	200	Furhlander 1.5 MW	65.6	-65.6	PRINGLE -HARRINGTON 230kV	210330
GEN-2007-041	600	Suzlon 2.1 MW	0.0	0.0	HITCHLAND 345 kV	523097
GEN-2007-042	360	GE 1.5 MW	151.3	-174.4		523097
GEN-2007-046	199.5	GE 1.5 MW	65.0	-65.0	HITCHLAND 115 kV	523093
GEN-2007-056	600	GE 1.5 MW	197.2	-197.2	HITCHLAND 345 kV	523095
GEN-2007-057	34.5	GE 1.5 MW	11.3	-11.3	MOORE CO EAST 115kV	523308

The analysis was carried out using the database package provided by SPP which also includes the modeling data for the previously queued projects, as shown in Table 2-2:

Table 2-2 – Details of the Prior Queued Interconnection Requests

Request	Size (MW)	Model	Point of Interconnection	Bus Number
GEN-2002-006	150	GE 1.5 MW	TEXAS CO 115kV	523090
GEN-2002-008	240	GE 1.5 MW	HITCHLAND 345 kV	523097
GEN-2002-009	80	Suzlon 2.1 MW	HANSFORD 345 kV	523195
GEN-2003-013	196	GE 1.5 MW	HITCHLAND-FINNEY 345 kV	560029
GEN-2003-020	160	GE 1.5 MW	CARSON CO 115 kV	523924
GEN-2005-002	80	Gamesa 2.0 MW	RIVERVIEW-PRINGLE 115 kV	99937
GEN-2005-017	340	GE 1.5 MW	HITCHLAND-POTTER 345 kV	51700
GEN-2006-020	19.5	GE 1.5 MW	HITCHLAND-SHERMAN TAP 115 kV	560200
GEN-2006-044	370	GE 1.5 MW	HITCHLAND 345 kV	523097
GEN-2006-049	400	GE 1.5 MW	HITCHLAND-FINNEY 345 kV	560029

2.2 Stability Database

In this study, the wind generation projects are modeled using equivalents representing groups of turbines and the collector system.

The trip levels of the low-voltage ride through protection for each one of the proposed projects were modeled in the stability simulations described in this report according to the provided developer's information. The thresholds and durations are the typical settings given in the technical documentation of the manufacturer. Note that the voltages monitored for the LVRT are the wind turbine generator terminal voltages.

Appendix A presents the dynamic models and parameters for each one of the proposed wind generation projects.

Section

3

Methodology and Assumptions

The study has considered the 2008 Summer Peak and Winter Peak load flow models with the required interconnection generation modeled and provided by SPP. The base cases contains all the significant previous queued generation interconnection projects in the interconnection queue.

The areas of interest for this study are shown in Table 3-1. These areas were monitored in the stability analysis

Table 3-1 – Areas of Interest

Area Number	Area Name
520	AEPW
524	OKGE
525	WFEC
526	SPS
531	MIDW
534	SUNC
536	WERE

3.1 Methodology

3.1.1 Stability Simulations

The dynamic simulations were performed using the PSS™E version 30.3.2 with the latest stability database provided by SPP. Three-phase faults and single-phase faults with normal clearing in the neighborhood of ICS-2008-001 (Group 2) cluster were simulated. Any adverse impact on the system stability was documented and further investigated with appropriate solutions to determine whether a static or dynamic VAR device is required or not.

3.1.2 Steady State Simulations

3.1.2.1 N-1 Contingency Analysis

An N-1 contingency analysis was performed to determine the voltage violations caused by disturbances (tripping of the faulted line). The voltages at each he POI were monitored for any deviations from the base case voltage and the percentage voltage deviations were documented.

3.1.2.2 Power Factor Analysis

A QV analysis was performed for all contingencies in PSS™E version 30.3.2 to determine the capacitor banks required to maintain the base case voltage at the POIs. QV curves are used to determine the reactive power support required at each POI in order to maintain the bus voltage to the required value. The curve is obtained through a series of AC load flow calculations. Starting with no reactive support at a bus, the voltage can be computed for a series of power flows as the reactive support is increased in steps, until the power flow experiences convergence difficulties as the system approaches the voltage collapse point.

3.2 Disturbances for Stability Analysis

The stability simulations included three-phase (3PH) faults and single line-to-ground (SLG) faults. The fault clearing line is assumed 5 cycles. For all contingencies, the fault clearing process includes an unsuccessful three-phase reclosing (reclosing under fault conditions) followed by trip of both ends of the transmission line under fault after 20 cycles. The disturbances evaluated are listed in Table 3-2, as follows:

Table 3-2: Disturbances for Stability Analysis

#	Fault Location	Fault Type	Clearing	Fault Clearing
1	At Hitchland end of 345 kV line to GEN-2003-013	3PH	Normal	5 cycles - trip Hitchland – GEN-2003-013 345 kV
2	At Hitchland end of 345 kV line to GEN-2003-013	SLG	Normal	5 cycles - trip Hitchland – GEN-2003-013 345 kV
3	At Hitchland end of 345 kV line to GEN-2005-017	3PH	Normal	5 cycles - trip Hitchland – GEN-2005-017 345 kV
4	At Hitchland end of 345 kV line to GEN-2005-017	SLG	Normal	5 cycles - trip Hitchland – GEN-2005-017 345 kV
5	At Hitchland end of 345 kV line to Woodward	3PH	Normal	5 cycles - trip Hitchland – Woodward 345 kV
6	At Hitchland end of 345 kV line to Woodward	SLG	Normal	5 cycles - trip Hitchland – Woodward 345 kV
7	At Hitchland 345 kV end of 230/345 kV transformer	3PH	Normal	5 cycles - trip Hitchland 230/345 kV transformer
8	At Hitchland 345 kV end of 230/345 kV transformer	SLG	Normal	5 cycles - trip Hitchland 230/345 kV transformer
9	At Hitchland 230 kV end of 230/345 kV transformer	3PH	Normal	5 cycles - trip Hitchland 230/345 kV transformer
10	At Hitchland 230 kV end of 230/345 kV transformer	SLG	Normal	5 cycles - trip Hitchland 230/345 kV transformer
11	At Hitchland end of 230 kV line to Pringle	3PH	Normal	5 cycles - trip Hitchland – Pringle 345 kV

#	Fault Location	Fault Type	Clearing	Fault Clearing
12	At Hitchland end of 230 kV line to Pringle	SLG	Normal	5 cycles - trip Hitchland – Pringle 345 kV
13	At Hitchland end of 230 kV line to Moore Co	3PH	Normal	5 cycles - trip Hitchland – Moore Co 345 kV
14	At Hitchland end of 230 kV line to Moore Co	SLG	Normal	5 cycles - trip Hitchland – Moore Co 345 kV
15	At GEN-2005-017 end of 345 kV line to Potter Co	3PH	Normal	5 cycles - trip GEN-2005-017 – Potter Co 345 kV
16	At GEN-2005-017 end of 345 kV line to Potter Co	SLG	Normal	5 cycles - trip GEN-2005-017 – Potter Co 345 kV
17	At Potter Co end of 345 kV line to Grapevine	3PH	Normal	5 cycles - trip Potter Co – Grapevine 345 kV
18	At Potter Co end of 345 kV line to Grapevine	SLG	Normal	5 cycles - trip Potter Co – Grapevine 345 kV
19	At Moore Co end of 230 kV line to Hitchland	3PH	Normal	5 cycles - trip Moore Co – Hitchland 230 kV
20	At Moore Co end of 230 kV line to Hitchland	SLG	Normal	5 cycles - trip Moore Co – Hitchland 230 kV
21	At Moore Co end of 230 kV line to Potter Co	3PH	Normal	5 cycles - trip Moore Co – Potter Co 230 kV
22	At Moore Co end of 230 kV line to Potter Co	SLG	Normal	5 cycles - trip Moore Co – Potter Co 230 kV
23	At Pringle end of 230 kV line to Hitchland	3PH	Normal	5 cycles - trip Pringle – Hitchland 230 kV
24	At Pringle end of 230 kV line to Hitchland	SLG	Normal	5 cycles - trip Pringle – Hitchland 230 kV
25	At Pringle end of 230 kV line to GEN-2007-033	3PH	Normal	5 cycles - trip Pringle – GEN-2007-033 230 kV
26	At Pringle end of 230 kV line to GEN-2007-033	SLG	Normal	5 cycles - trip Pringle – GEN-2007-033 230 kV
27	At GEN-2007-033 end of 230 kV line to Pringle	3PH	Normal	5 cycles - trip GEN-2007-033 – Pringle 230 kV
28	At GEN-2007-033 end of 230 kV line to Pringle	SLG	Normal	5 cycles - trip GEN-2007-033 – Pringle 230 kV
29	At GEN-2007-033 end of 230 kV line to Harrington	3PH	Normal	5 cycles - trip GEN-2007-033 – Harrington 230 kV
30	At GEN-2007-033 end of 230 kV line to Harrington	SLG	Normal	5 cycles - trip GEN-2007-033 – Harrington 230 kV

#	Fault Location	Fault Type	Clearing	Fault Clearing
31	At GEN-2007-013 end of 345 kV line to Finney	3PH	Normal	5 cycles - trip GEN-2007-033 – Finney 345 kV
32	At GEN-2007-013 end of 345 kV line to Finney	SLG	Normal	5 cycles - trip GEN-2007-033 – Finney 345 kV
33	At GEN-2007-019 end of 345 kV line to Lamar	3PH	Normal	5 cycles - trip GEN-2007-019 – Lamar 345 kV
34	At GEN-2007-019 end of 345 kV line to Lamar	SLG	Normal	5 cycles - trip GEN-2007-019 – Lamar 345 kV
35	At Holocomb end of 345 kV line to Setab	3PH	Normal	5 cycles - trip Holocomb – Setab 345 kV
36	At Holocomb end of 345 kV line to Setab	SLG	Normal	5 cycles - trip Holocomb – Setab 345 kV
37	At Holocomb end of 345 kV line to GEN-2007-040	3PH	Normal	5 cycles - trip Holocomb – GEN-2007-040 345 kV
38	At Holocomb end of 345 kV line to GEN-2007-040	SLG	Normal	5 cycles - trip Holocomb – GEN-2007-040 345 kV
39	At GEN-2007-040 end of 345 kV line to Spearville	3PH	Normal	5 cycles - trip GEN-2007-040 – Spearville 345 kV
40	At GEN-2007-040 end of 345 kV line to Spearville	SLG	Normal	5 cycles - trip GEN-2007-040 – Spearville 345 kV
41	At Spearville end of 345 kV line to Comanche	3PH	Normal	5 cycles - trip Spearville – Comanche 345 kV
42	At Spearville end of 345 kV line to Comanche	SLG	Normal	5 cycles - trip Spearville – Comanche 345 kV
43	At Comanche end of 345 kV line to GEN-2007-025	3PH	Normal	5 cycles - trip Comanche – GEN-2007-025 345 kV
44	At Comanche end of 345 kV line to GEN-2007-025	SLG	Normal	5 cycles - trip Comanche – GEN-2007-025 345 kV
45	At GEN-2007-025 end of 345 kV line to Wichita	3PH	Normal	5 cycles - trip GEN-2007-025 – Wichita 345 kV
46	At GEN-2007-025 end of 345 kV line to Wichita	SLG	Normal	5 cycles - trip GEN-2007-025 – Wichita 345 kV
47	At Woodward end of 345 kV line to Comanche	3PH	Normal	5 cycles - trip Woodward – Comanche 345 kV
48	At Woodward end of 345 kV line to Comanche	SLG	Normal	5 cycles - trip Woodward – Comanche 345 kV
49	At Woodward end of 345 kV line to Tatonga	3PH	Normal	5 cycles - trip Woodward – Tatonga 345 kV

#	Fault Location	Fault Type	Clearing	Fault Clearing
50	At Woodward end of 345 kV line to Tatonga	SLG	Normal	5 cycles - trip Woodward – Tatonga 345 kV
51	At Nichols end of 345 kV line to Grapevine	3PH	Normal	5 cycles - trip Nichols – Grapevine 345 kV
52	At Nichols end of 345 kV line to Grapevine	SLG	Normal	5 cycles - trip Nichols – Grapevine 345 kV
53	At Grapevine end of 345 kV line to State Line	3PH	Normal	5 cycles - trip Grapevine – State Line 345 kV
54	At Grapevine end of 345 kV line to State Line	SLG	Normal	5 cycles - trip Grapevine – State Line 345 kV
55	At Grapevine end of 345 kV line to Lawton Eastside	3PH	Normal	5 cycles - trip Grapevine – Lawton Eastside 345 kV
56	At Grapevine end of 345 kV line to Lawton Eastside	SLG	Normal	5 cycles - trip Grapevine – Lawton Eastside 345 kV
57	At Grapevine end of 345 kV line to Beckham Co	3PH	Normal	5 cycles - trip Grapevine – Beckham Co 345 kV
58	At Grapevine end of 345 kV line to Beckham Co	SLG	Normal	5 cycles - trip Grapevine – Beckham Co 345 kV
59	At Beckham Co end of 345 kV line to Grapevine	3PH	Normal	5 cycles - trip Beckham Co – Grapevine 345 kV
60	At Beckham Co end of 345 kV line to Grapevine	SLG	Normal	5 cycles - trip Beckham Co – Grapevine 345 kV
61	At Anadarko end of 345 kV line to GEN-2007-043	3PH	Normal	5 cycles - trip Anadarko – GEN-2007-043 345 kV
62	At Anadarko end of 345 kV line to GEN-2007-043	SLG	Normal	5 cycles - trip Anadarko – GEN-2007-043 345 kV
63	At Lawton Eastside end of 345 kV line to Sunnyside	3PH	Normal	5 cycles - trip Lawton Eastside – Sunnyside 345 kV
64	At Lawton Eastside end of 345 kV line to Sunnyside	SLG	Normal	5 cycles - trip Lawton Eastside – Sunnyside 345 kV
65	At Hitchland end of 115 kV line to Texas Co	3PH	Normal	5 cycles - trip Hitchland – Texas Co 115 kV
66	At Hitchland end of 115 kV line to Texas Co	SLG	Normal	5 cycles - trip Hitchland – Texas Co 115 kV
67	At Hitchland end of 115 kV line to Sherman	3PH	Normal	5 cycles - trip Hitchland - GEN-2006-020 - Sherman Tap-Moore Co East - Sherman 115 kV
68	At Hitchland end of 115 kV line to Sherman	SLG	Normal	5 cycles - trip Hitchland - GEN-2006-020 - Sherman Tap-Moore Co East - Sherman 115 kV

#	Fault Location	Fault Type	Clearing	Fault Clearing
69	At Hitchland end of 115 kV line to Hansford	3PH	Normal	5 cycles - trip Hitchland – Hansford 115 kV
70	At Hitchland end of 115 kV line to Hansford	SLG	Normal	5 cycles - trip Hitchland – Hansford 115 kV
71	At Hitchland 115 kV end of 115/230 kV transformer	3PH	Normal	5 cycles - trip Hitchland 115/230 kV transformer
72	At Hitchland 115 kV end of 115/230 kV transformer	SLG	Normal	5 cycles - trip Hitchland 115/230 kV transformer
73	At Pringle end of 115 kV line to Spearman	3PH	Normal	5 cycles - trip Pringle – Spearman 115 kV
74	At Pringle end of 115 kV line to Spearman	SLG	Normal	5 cycles - trip Pringle – Spearman 115 kV
75	At Pringle end of 115 kV line to Blackhawk	3PH	Normal	5 cycles - trip Pringle – Blackhawk 115 kV
76	At Pringle end of 115 kV line to Blackhawk	SLG	Normal	5 cycles - trip Pringle – Blackhawk 115 kV
77	At Pringle end of 115 kV line to GEN-2005-002	3PH	Normal	5 cycles - trip Pringle – GEN-2005-002 115 kV
78	At Pringle end of 115 kV line to GEN-2005-002	SLG	Normal	5 cycles - trip Pringle – GEN-2005-002 115 kV
79	At Pringle 115 kV end of 115/230 kV transformer	3PH	Normal	5 cycles - trip Pringle 115/230 kV transformer
80	At Pringle 115 kV end of 115/230 kV transformer	SLG	Normal	5 cycles - trip Pringle 115/230 kV transformer
81	At Moore Co East of 115 kV line to Sherman	3PH	Normal	5 cycles - trip Moore Co East - Sherman Tap GEN-2006-020 - Hitchland - Sherman 115 kV
82	At Moore Co East of 115 kV line to Sherman	SLG	Normal	5 cycles - trip Moore Co East - Sherman Tap GEN-2006-020 - Hitchland - Sherman 115 kV
83	At Moore Co East of 115 kV line to RB Hogu	3PH	Normal	5 cycles - trip Moore Co East – RB Hogu 115 kV
84	At Moore Co East of 115 kV line to RB Hogu	SLG	Normal	5 cycles - trip Moore Co East – RB Hogu 115 kV
85	At Moore Co West of 115 kV line to Dumas	3PH	Normal	5 cycles - trip Moore Co West – Dumas 115 kV
86	At Moore Co West of 115 kV line to Dumas	SLG	Normal	5 cycles - trip Moore Co West – Dumas 115 kV
87	At Moore Co West of 115 kV line to RB Sneed	3PH	Normal	5 cycles - trip Moore Co West – RB Sneed 115 kV

#	Fault Location	Fault Type	Clearing	Fault Clearing
88	At Moore Co West of 115 kV line to RB Sneed	SLG	Normal	5 cycles - trip Moore Co West – RB Sneed 115 kV
89	At Moore Co East 115 kV end of 115/230 kV transformer	3PH	Normal	5 cycles - trip Moore Co East 115/230 kV transformer
90	At Moore Co East 115 kV end of 115/230 kV transformer	SLG	Normal	5 cycles - trip Moore Co East 115/230 kV transformer
91	At Blackhawk North of 115 kV line to Pringle	3PH	Normal	5 cycles - trip Blackhawk North – Pringle 115 kV
92	At Blackhawk North of 115 kV line to Pringle	SLG	Normal	5 cycles - trip Blackhawk North – Pringle 115 kV
93	At Blackhawk South of 115 kV line to Hutchinson	3PH	Normal	5 cycles - trip Blackhawk South – Hutchinson 115 kV
94	At Blackhawk South of 115 kV line to Hutchinson	SLG	Normal	5 cycles - trip Blackhawk South – Hutchinson 115 kV
95	At Spearman of 115 kV line to Spearman Sub	3PH	Normal	5 cycles - trip Spearman – Spearman Sub 115 kV
96	At Spearman of 115 kV line to Spearman Sub	SLG	Normal	5 cycles - trip Spearman – Spearman Sub 115 kV
97	At Perryton 115 kV end of 115/230 kV transformer	3PH	Normal	5 cycles - trip Perryton 115/230 kV transformer
98	At Perryton 115 kV end of 115/230 kV transformer	SLG	Normal	5 cycles - trip Perryton 115/230 kV transformer
99	At Texas Co of 115 kV line to TC-MMRY3	3PH	Normal	5 cycles - trip Texas Co – TC-MMRY3 115 kV
100	At Texas Co of 115 kV line to TC-MMRY3	SLG	Normal	5 cycles - trip Texas Co – TC-MMRY3 115 kV
101	At Texas Co 115 kV end of 115 kV phase shift transformer	3PH	Normal	5 cycles - trip Texas Co 115 kV phase shift transformer
102	At Texas Co 115 kV end of 115 kV phase shift transformer	SLG	Normal	5 cycles - trip Texas Co 115 kV phase shift transformer
103	At Dalhart of 115 kV line to Sherman	3PH	Normal	5 cycles - trip Dalhart – Sherman 115 kV
104	At Dalhart of 115 kV line to Sherman	SLG	Normal	5 cycles - trip Dalhart – Sherman 115 kV
105	At Dalhart of 115 kV line to Channing	3PH	Normal	5 cycles - trip Dalhart – Channing 115 kV
106	At Dalhart of 115 kV line to Channing	SLG	Normal	5 cycles - trip Dalhart – Channing 115 kV

In order to simulate single line to ground faults, equivalent reactances were determined to be applied at the buses. Table 3-3 presents equivalent reactances used in the simulations:

Table 3-3: Equivalent Reactances – Line to Ground Faults

BUS	Equivalent Reactor (Mvar)
523097	-4800
523095	-3000
51700	-2800
523961	-3200
523309	-1700
523267	-1800
210330	-1700
560029	-4000
210190	-1800
531449	-4300
210400	-4300
531469	-3500
531487	-3900
532781	-2200
515375	-5200
524044	-5200
523771	-1200
523772	-2500
560019	-2000
521210	-3500
511468	-3600
523093	-1300
523266	-1500
523308	-1200
523304	-1200
523344	-1400
523346	-1400
523186	-1000
523158	-700
523090	-800
523246	-400

Section

4

Analysis Performed

4.1 Steady State Performance

Table 4-1 and Table 4-2 summarize the results obtained from the steady state analysis for Summer Peak and Winter Peak base cases, respectively. The table lists the voltage deviations at the points of interconnection of the proposed study projects of Group 2, as well as the prior queued projects. Note that only the contingencies that cause an impact of at least 1% in the POI's voltages are listed.

Table 4-1: Results Obtained – Steady State Analysis – Summer Peak Base Case

Points of Interconnection			Contingency Voltage	Base Voltage	Voltage Deviation
Bus #	Name	kV			
Base Case					
51700	G05-017	345	-	0.9873	-
99937	2005-02	115	-	1.0302	-
210330	GEN_2007_03	230	-	0.9852	-
523090	TEXAS_CNTY3	115	-	1.0308	-
523093	HITCHLAND 3	115	-	1.0315	-
523095	HITCHLAND 6	230	-	0.9779	-
523097	HITCHLAND 7	345	-	0.9836	-
523195	HANSFORD 3	115	-	1.0348	-
523266	PRINGLE3	115	-	1.0366	-
523308	MOORE_E 3	115	-	1.0120	-
523924	CARSON_SUB3	115	-	1.0184	-
560029	G03-13	345	-	1.0011	-
560200	GEN2006-020	115	-	1.0160	-
FLT33PH					
51700	G05-017	345	1.0065	0.9873	1.92%
99937	2005-02	115	1.0259	1.0302	-0.43%
210330	GEN_2007_03	230	0.9783	0.9852	-0.69%
523090	TEXAS_CNTY3	115	1.0259	1.0308	-0.49%
523093	HITCHLAND 3	115	1.0248	1.0315	-0.68%
523095	HITCHLAND 6	230	0.9638	0.9779	-1.41%
523097	HITCHLAND 7	345	0.9614	0.9836	-2.22%

Points of Interconnection			Contingency Voltage	Base Voltage	Voltage Deviation
Bus #	Name	kV			
523195	HANSFORD 3	115	1.0281	1.0348	-0.67%
523266	PRINGLE3	115	1.0317	1.0366	-0.49%
523308	MOORE_E 3	115	1.0120	1.0120	0.00%
523924	CARSON_SUB3	115	1.0167	1.0184	-0.17%
560029	G03-13	345	0.9876	1.0011	-1.35%
560200	GEN2006-020	115	1.0098	1.0160	-0.62%
FLT93PH					
51700	G05-017	345	0.9928	0.9873	0.55%
99937	2005-02	115	1.0279	1.0302	-0.23%
210330	GEN_2007_03	230	0.9816	0.9852	-0.36%
523090	TEXAS_CNTY3	115	1.0271	1.0308	-0.38%
523093	HITCHLAND 3	115	1.0263	1.0315	-0.52%
523095	HITCHLAND 6	230	0.9675	0.9779	-1.04%
523097	HITCHLAND 7	345	0.9917	0.9836	0.81%
523195	HANSFORD 3	115	1.0297	1.0348	-0.50%
523266	PRINGLE3	115	1.0334	1.0366	-0.32%
523308	MOORE_E 3	115	1.0120	1.0120	0.00%
523924	CARSON_SUB3	115	1.0179	1.0184	-0.06%
560029	G03-13	345	1.0050	1.0011	0.39%
560200	GEN2006-020	115	1.0121	1.0160	-0.39%
FLT313PH					
51700	G05-017	345	0.9664	0.9873	-2.09%
99937	2005-02	115	1.0264	1.0302	-0.38%
210330	GEN_2007_03	230	0.9791	0.9852	-0.61%
523090	TEXAS_CNTY3	115	1.0244	1.0308	-0.64%
523093	HITCHLAND 3	115	1.0230	1.0315	-0.85%
523095	HITCHLAND 6	230	0.9597	0.9779	-1.82%
523097	HITCHLAND 7	345	0.9554	0.9836	-2.82%
523195	HANSFORD 3	115	1.0265	1.0348	-0.82%
523266	PRINGLE3	115	1.0313	1.0366	-0.54%
523308	MOORE_E 3	115	1.0120	1.0120	0.00%
523924	CARSON_SUB3	115	1.0176	1.0184	-0.08%
560029	G03-13	345	0.9654	1.0011	-3.58%
560200	GEN2006-020	115	1.0100	1.0160	-0.60%
FLT353PH					
51700	G05-017	345	0.9756	0.9873	-1.17%
99937	2005-02	115	1.0282	1.0302	-0.21%
210330	GEN_2007_03	230	0.9821	0.9852	-0.32%
523090	TEXAS_CNTY3	115	1.0277	1.0308	-0.32%
523093	HITCHLAND 3	115	1.0275	1.0315	-0.41%
523095	HITCHLAND 6	230	0.9695	0.9779	-0.84%

Points of Interconnection			Contingency Voltage	Base Voltage	Voltage Deviation
Bus #	Name	kV			
523097	HITCHLAND 7	345	0.9706	0.9836	-1.30%
523195	HANSFORD 3	115	1.0308	1.0348	-0.39%
523266	PRINGLE3	115	1.0340	1.0366	-0.26%
523308	MOORE_E 3	115	1.0120	1.0120	0.00%
523924	CARSON_SUB3	115	1.0178	1.0184	-0.07%
560029	G03-13	345	0.9904	1.0011	-1.07%
560200	GEN2006-020	115	1.0128	1.0160	-0.31%
FLT533PH					
51700	G05-017	345	0.9783	0.9873	-0.90%
99937	2005-02	115	1.0291	1.0302	-0.12%
210330	GEN_2007_03	230	0.9838	0.9852	-0.15%
523090	TEXAS_CNTY3	115	1.0272	1.0308	-0.36%
523093	HITCHLAND 3	115	1.0266	1.0315	-0.49%
523095	HITCHLAND 6	230	0.9695	0.9779	-0.84%
523097	HITCHLAND 7	345	0.9720	0.9836	-1.16%
523195	HANSFORD 3	115	1.0301	1.0348	-0.46%
523266	PRINGLE3	115	1.0341	1.0366	-0.25%
523308	MOORE_E 3	115	1.0120	1.0120	0.00%
523924	CARSON_SUB3	115	1.0189	1.0184	0.05%
560029	G03-13	345	0.9923	1.0011	-0.88%
560200	GEN2006-020	115	1.0133	1.0160	-0.27%
FLT573PH					
51700	G05-017	345	0.9784	0.9873	-0.89%
99937	2005-02	115	1.0283	1.0302	-0.20%
210330	GEN_2007_03	230	0.9824	0.9852	-0.28%
523090	TEXAS_CNTY3	115	1.0264	1.0308	-0.44%
523093	HITCHLAND 3	115	1.0256	1.0315	-0.60%
523095	HITCHLAND 6	230	0.9667	0.9779	-1.12%
523097	HITCHLAND 7	345	0.9671	0.9836	-1.65%
523195	HANSFORD 3	115	1.0291	1.0348	-0.57%
523266	PRINGLE3	115	1.0333	1.0366	-0.33%
523308	MOORE_E 3	115	1.0120	1.0120	0.00%
523924	CARSON_SUB3	115	1.0184	1.0184	-0.01%
560029	G03-13	345	0.9868	1.0011	-1.43%
560200	GEN2006-020	115	1.0123	1.0160	-0.36%
FLT593PH					
51700	G05-017	345	0.9801	0.9873	-0.72%
99937	2005-02	115	1.0279	1.0302	-0.24%
210330	GEN_2007_03	230	0.9818	0.9852	-0.34%
523090	TEXAS_CNTY3	115	1.0255	1.0308	-0.54%
523093	HITCHLAND 3	115	1.0243	1.0315	-0.72%

Points of Interconnection			Contingency Voltage	Base Voltage	Voltage Deviation
Bus #	Name	kV			
523095	HITCHLAND 6	230	0.9644	0.9779	-1.35%
523097	HITCHLAND 7	345	0.9635	0.9836	-2.01%
523195	HANSFORD 3	115	1.0279	1.0348	-0.69%
523266	PRINGLE3	115	1.0326	1.0366	-0.40%
523308	MOORE_E 3	115	1.0120	1.0120	0.00%
523924	CARSON_SUB3	115	1.0184	1.0184	-0.01%
560029	G03-13	345	0.9827	1.0011	-1.84%
560200	GEN2006-020	115	1.0116	1.0160	-0.44%
FLT613PH					
51700	G05-017	345	0.9850	0.9873	-0.23%
99937	2005-02	115	1.0288	1.0302	-0.14%
210330	GEN_2007_03	230	0.9832	0.9852	-0.21%
523090	TEXAS_CNTY3	115	1.0267	1.0308	-0.42%
523093	HITCHLAND 3	115	1.0259	1.0315	-0.56%
523095	HITCHLAND 6	230	0.9678	0.9779	-1.01%
523097	HITCHLAND 7	345	0.9689	0.9836	-1.47%
523195	HANSFORD 3	115	1.0294	1.0348	-0.53%
523266	PRINGLE3	115	1.0337	1.0366	-0.30%
523308	MOORE_E 3	115	1.0120	1.0120	0.00%
523924	CARSON_SUB3	115	1.0189	1.0184	0.04%
560029	G03-13	345	0.9868	1.0011	-1.43%
560200	GEN2006-020	115	1.0129	1.0160	-0.31%
FLT693PH					
51700	G05-017	345	0.9874	0.9873	0.01%
99937	2005-02	115	1.0303	1.0302	0.01%
210330	GEN_2007_03	230	0.9853	0.9852	0.01%
523090	TEXAS_CNTY3	115	1.0303	1.0308	-0.06%
523093	HITCHLAND 3	115	1.0305	1.0315	-0.10%
523095	HITCHLAND 6	230	0.9779	0.9779	0.00%
523097	HITCHLAND 7	345	0.9837	0.9836	0.01%
523195	HANSFORD 3	115	1.0448	1.0348	1.01%
523266	PRINGLE3	115	1.0373	1.0366	0.06%
523308	MOORE_E 3	115	1.0120	1.0120	0.00%
523924	CARSON_SUB3	115	1.0182	1.0184	-0.02%
560029	G03-13	345	1.0012	1.0011	0.01%
560200	GEN2006-020	115	1.0157	1.0160	-0.02%
FLT713PH					
51700	G05-017	345	0.9933	0.9873	0.60%
99937	2005-02	115	1.0264	1.0302	-0.39%
210330	GEN_2007_03	230	0.9872	0.9852	0.20%
523090	TEXAS_CNTY3	115	1.0158	1.0308	-1.50%

Points of Interconnection			Contingency Voltage	Base Voltage	Voltage Deviation
Bus #	Name	kV			
523093	HITCHLAND 3	115	1.0093	1.0315	-2.23%
523095	HITCHLAND 6	230	0.9907	0.9779	1.28%
523097	HITCHLAND 7	345	0.9921	0.9836	0.85%
523195	HANSFORD 3	115	1.0141	1.0348	-2.06%
523266	PRINGLE3	115	1.0315	1.0366	-0.51%
523308	MOORE_E 3	115	1.0120	1.0120	0.00%
523924	CARSON_SUB3	115	1.0174	1.0184	-0.11%
560029	G03-13	345	1.0057	1.0011	0.46%
560200	GEN2006-020	115	0.9940	1.0160	-2.20%

Table 4-2: Results Obtained – Steady State Analysis – Winter Peak Base Case

Points of Interconnection			Contingency Voltage	Base Voltage	Voltage Deviation
Bus #	Name	kV			
Base Case					
51700	G05-017	345	-	0.9710	-
99937	2005-02	115	-	1.0368	-
210330	GEN_2007_03	230	-	1.0200	-
523090	TEXAS_CNTY3	115	-	1.0361	-
523093	HITCHLAND 3	115	-	1.0275	-
523095	HITCHLAND 6	230	-	0.9695	-
523097	HITCHLAND 7	345	-	0.9667	-
523195	HANSFORD 3	115	-	1.0331	-
523266	PRINGLE3	115	-	1.0418	-
523308	MOORE_E 3	115	-	1.0267	-
523924	CARSON_SUB3	115	-	1.0246	-
560029	G03-13	345	-	0.9812	-
560200	GEN2006-020	115	-	1.0192	-
FLT113PH					
51700	G05-017	345	0.9564	0.9710	-1.46%
99937	2005-02	115	1.0387	1.0368	0.20%
210330	GEN_2007_03	230	1.0200	1.0200	0.00%
523090	TEXAS_CNTY3	115	1.0238	1.0361	-1.23%
523093	HITCHLAND 3	115	1.0148	1.0275	-1.27%
523095	HITCHLAND 6	230	0.9482	0.9695	-2.13%
523097	HITCHLAND 7	345	0.9499	0.9667	-1.68%
523195	HANSFORD 3	115	1.0234	1.0331	-0.97%
523266	PRINGLE3	115	1.0469	1.0418	0.51%
523308	MOORE_E 3	115	1.0251	1.0267	-0.16%
523924	CARSON_SUB3	115	1.0216	1.0246	-0.30%
560029	G03-13	345	0.9743	0.9812	-0.70%
560200	GEN2006-020	115	1.0103	1.0192	-0.89%

Points of Interconnection			Contingency Voltage	Base Voltage	Voltage Deviation
Bus #	Name	kV			
			FLT693PH		
51700	G05-017	345	0.9708	0.9710	-0.02%
99937	2005-02	115	1.0373	1.0368	0.05%
210330	GEN_2007_03	230	1.0200	1.0200	0.00%
523090	TEXAS_CNTY3	115	1.0338	1.0361	-0.23%
523093	HITCHLAND 3	115	1.0245	1.0275	-0.30%
523095	HITCHLAND 6	230	0.9691	0.9695	-0.04%
523097	HITCHLAND 7	345	0.9664	0.9667	-0.03%
523195	HANSFORD 3	115	1.0523	1.0331	1.91%
523266	PRINGLE3	115	1.0433	1.0418	0.15%
523308	MOORE_E 3	115	1.0267	1.0267	0.00%
523924	CARSON_SUB3	115	1.0241	1.0246	-0.05%
560029	G03-13	345	0.9812	0.9812	-0.01%
560200	GEN2006-020	115	1.0178	1.0192	-0.14%
			FLT713PH		
51700	G05-017	345	0.9801	0.9710	0.91%
99937	2005-02	115	1.0323	1.0368	-0.44%
210330	GEN_2007_03	230	1.0200	1.0200	0.00%
523090	TEXAS_CNTY3	115	1.0224	1.0361	-1.37%
523093	HITCHLAND 3	115	1.0151	1.0275	-1.25%
523095	HITCHLAND 6	230	0.9793	0.9695	0.99%
523097	HITCHLAND 7	345	0.9763	0.9667	0.97%
523195	HANSFORD 3	115	1.0194	1.0331	-1.37%
523266	PRINGLE3	115	1.0358	1.0418	-0.60%
523308	MOORE_E 3	115	1.0262	1.0267	-0.05%
523924	CARSON_SUB3	115	1.0235	1.0246	-0.10%
560029	G03-13	345	0.9866	0.9812	0.54%
560200	GEN2006-020	115	1.0022	1.0192	-1.70%
			FLT793PH		
51700	G05-017	345	0.9705	0.9710	-0.04%
99937	2005-02	115	1.0402	1.0368	0.34%
210330	GEN_2007_03	230	1.0188	1.0200	-0.12%
523090	TEXAS_CNTY3	115	1.0336	1.0361	-0.25%
523093	HITCHLAND 3	115	1.0249	1.0275	-0.26%
523095	HITCHLAND 6	230	0.9678	0.9695	-0.17%
523097	HITCHLAND 7	345	0.9660	0.9667	-0.06%
523195	HANSFORD 3	115	1.0327	1.0331	-0.04%
523266	PRINGLE3	115	1.0523	1.0418	1.05%
523308	MOORE_E 3	115	1.0267	1.0267	0.00%
523924	CARSON_SUB3	115	1.0211	1.0246	-0.35%
560029	G03-13	345	0.9812	0.9812	0.00%
560200	GEN2006-020	115	1.0172	1.0192	-0.20%
			FLT893PH		
51700	G05-017	345	0.9739	0.9710	0.30%
99937	2005-02	115	1.0343	1.0368	-0.25%

Points of Interconnection			Contingency Voltage	Base Voltage	Voltage Deviation
Bus #	Name	kV			
210330	GEN_2007_03	230	1.0200	1.0200	0.00%
523090	TEXAS_CNTY3	115	1.0364	1.0361	0.03%
523093	HITCHLAND 3	115	1.0275	1.0275	0.00%
523095	HITCHLAND 6	230	0.9741	0.9695	0.46%
523097	HITCHLAND 7	345	0.9696	0.9667	0.30%
523195	HANSFORD 3	115	1.0333	1.0331	0.01%
523266	PRINGLE3	115	1.0419	1.0418	0.01%
523308	MOORE_E 3	115	0.9923	1.0267	-3.44%
523924	CARSON_SUB3	115	1.0233	1.0246	-0.13%
560029	G03-13	345	0.9823	0.9812	0.11%
560200	GEN2006-020	115	1.0092	1.0192	-1.01%

4.2 Power Factor Analysis

A QV analysis was performed to determine the amount of reactive support required to maintain the scheduled voltages at the points of interconnection of each one of the proposed wind facilities. The contingencies described in Table 3-2 were evaluated in steady state conditions for summer and winter peak base cases, with variable Mvar injection at the POIs.

Table 4-3 presents the Mvar requirements for each one of the proposed wind facilities in Group 2.

Table 4-3: Mvar Requirements at POI for the Proposed Projects Interconnection

Project	Point of Interconnection	V Scheduled (p.u)	Mvar Requirement at POI	Contingency	Power Factor at POI (lagging)
GEN-2007-005	Pringle 115 kV	1.045	50 Mvar	FLT 01 (WP)	0.970
GEN-2007-033	Pringle - Harrington 230 kV	1.005	55 Mvar	FLT 15 (WP)	0.964
GEN-2007-041	Hitchland 345 kV	1.020	340 Mvar	FLT 01 (WP)	0.977
GEN-2008-042					
GEN-2008-056					
GEN-2008-046	Hitchland 115 kV	1.035	60 Mvar	FLT 01 (WP)	0.958
GEN-2008-057	Moore Co. 115 kV	1.015	10 Mvar	FLT 13 (SP)	0.960

4.3 Dynamic Results

The stability analysis was carried out using both Summer Peak and Winter Peak load flow models.

In order to determine the impact of the project on the overall system dynamics as well as to determine the requirements to meet the FERC Order 661-A Guidelines, 106 contingencies listed by Table 3-2 were simulated. The results obtained are described in this sub-section.

Table 4-4 and Table 4-5 summarize the results obtained from the stability simulations for Summer Peak and Winter Peak base cases, respectively. The table lists the dynamic performance of the proposed study projects of Group 2, as well as the prior queued projects. Note that only the critical contingencies that lead to trips due to LVRT or loss of synchronism are listed.

Table 4-4: Results Obtained – Summer Peak Base Case

Name	Wind Projects Dynamic Performance
FLT01-3PH	G07-56-AG2 (523108) tripped for over frequency at 0.8375 s
	G07-56-AG1 (523107) tripped for over frequency at 0.8417 s
FLT03-3PH	G07-56-AG2 (523108) tripped for over frequency at 0.8167 s
	G07-56-AG1 (523107) tripped for over frequency at 0.8208 s
	G07-56-BG1 (523112) tripped for over frequency at 0.8250 s
	G07-56-BG2 (523116) tripped for over frequency at 0.8250 s
	WTG1 (3291) tripped for over voltage at 1.129 s
	WTG2 (3292) tripped for over voltage at 1.129 s
FLT05-3PH	G07-56-AG1 (523107) tripped for over frequency at 0.8958 s
	G07-56-AG2 (523108) tripped for over frequency at 0.8958 s
	WTG1 (3291) tripped for over voltage at 1.104 s
	WTG2 (3292) tripped for over voltage at 1.104 s
FLT07-3PH	G07-56-AG2 (523108) tripped for over frequency at 0.8083 s
	G07-56-AG1 (523107) tripped for over frequency at 0.8125 s
	G07-56-BG1 (523112) tripped for over frequency at 0.8125 s
	G07-56-BG2 (523116) tripped for over frequency at 0.8125 s
FLT011-3PH	G07-56-BG1 (523112) tripped for over frequency at 1.3250 s
	G07-56-BG2 (523116) tripped for over frequency at 1.3250 s
FLT013-3PH	G07-56-BG2 (523116) tripped for under frequency at 1.4000 s
	G07-56-BG1 (523112) tripped for over frequency at 1.4042 s
FLT31-3PH	GEN-2003-013 (90840) tripped for low voltage at 1.1 s
	G07-56-AG1 (523107) tripped for over frequency at 1.1792 s
	G07-56-AG2 (523108) tripped for over frequency at 1.1792 s
	G07-56-BG1 (523112) tripped for over frequency at 1.1792 s
	G07-56-BG2 (523116) tripped for over frequency at 1.1792 s

Name	Wind Projects Dynamic Performance
FLT041-3PH	GPEWIND1 (543116) tripped for low voltage at 0.6125 s
FLT067-3PH	GEN-2006-020 (90201) tripped for over frequency at 0.7250 s
FLT068-1PH	GEN-2006-020 (90201) tripped for over frequency at 0.7292 s
FLT082-1PH	GEN-2006-020 (90201) tripped for over frequency at 0.7250 s
FLT081-3PH	GEN-2006-020 (90201) tripped for over frequency at 0.7333 s

Table 4-5: Results Obtained – Winter Peak Base Case

Name	Wind Projects Dynamic Performance
FLT01-3PH	G07-56-AG2 (523108) tripped for over frequency at 0.7917 s
	G07-56-AG1 (523107) tripped for over frequency at 0.7917 s
	GEN-2005-020 (90870) tripped for over voltage at 1.3917 s
FLT02-1PH	G07-56-AG2 (523108) tripped for over frequency at 1.1542 s
	G07-56-AG1 (523107) tripped for over frequency at 1.1542 s
	G07-56-BG1 (523112) tripped for over frequency at 1.1583 s
	G07-56-BG2 (523116) tripped for over frequency at 1.1583 s
FLT03-3PH	G07-56-AG2 (523108) tripped for over frequency at 0.7667 s
	G07-56-AG1 (523107) tripped for over frequency at 0.7667 s
	G07-56-BG1 (523112) tripped for over frequency at 0.7750 s
	G07-56-BG2 (523116) tripped for over frequency at 0.7750 s
	GEN-2005-020 (90870) tripped for over voltage at 1.2625 s
FLT04-1PH	G07-56-AG2 (523108) tripped for over frequency at 1.2083 s
	G07-56-AG1 (523107) tripped for over frequency at 1.2083 s
	G07-56-BG1 (523112) tripped for over frequency at 1.2042 s
	G07-56-BG2 (523116) tripped for over frequency at 1.2000 s
	GEN-2005-020 (90870) tripped for over voltage at 1.265 s
FLT05-3PH	G07-56-AG2 (523108) tripped for over frequency at 0.8167 s
	G07-56-AG1 (523107) tripped for over frequency at 0.8208 s
	GEN-2005-020 (90870) tripped for over voltage at 1.3833 s
FLT06-1PH	G07-56-AG2 (523108) tripped for over frequency at 2.0875 s
	G07-56-AG1 (523107) tripped for over frequency at 2.1000 s
	G07-56-BG2 (523116) tripped for over frequency at 2.1500 s
FLT07-3PH	G07-56-AG2 (523108) tripped for over frequency at 0.7542 s
	G07-56-AG1 (523107) tripped for over frequency at 0.7542 s
	G07-56-BG1 (523112) tripped for over frequency at 0.7625 s
	G07-56-BG2 (523116) tripped for over frequency at 0.7583 s
FLT09-3PH	G07-56-AG2 (523108) tripped for over frequency at 1.3083 s

Name	Wind Projects Dynamic Performance
	G07-56-AG1 (523107) tripped for over frequency at 1.3083s
	G07-56-BG1 (523112) tripped for over frequency at 1.3375 s
	G07-56-BG2 (523116) tripped for over frequency at 1.3417 s
FLT011-3PH	G07-56-AG2 (523108) tripped for over frequency at 1.1250 s
	G07-56-AG1 (523107) tripped for over frequency at 1.1250s
	G07-56-BG1 (523112) tripped for over frequency at 1.1292 s
	G07-56-BG2 (523116) tripped for over frequency at 1.1292 s
	GEN-2005-020 (90870) tripped for over voltage at 1.265 s
FLT013-3PH	G07-56-AG2 (523108) tripped for over frequency at 1.1333 s
	G07-56-AG1 (523107) tripped for over frequency at 1.1333 s
	G07-56-BG1 (523112) tripped for over frequency at 1.1333 s
	G07-56-BG2 (523116) tripped for over frequency at 1.1292 s
	GEN-2005-020 (90870) tripped for over voltage at 1.2708 s
FLT015-3PH	G07-56-AG2 (523108) tripped for over frequency at 1.1125 s
	G07-56-AG1 (523107) tripped for over frequency at 1.1125 s
	G07-56-BG1 (523112) tripped for over frequency at 1.1208 s
	G07-56-BG2 (523116) tripped for over frequency at 1.1208 s
	GEN-2005-020 (90870) tripped for over voltage at 1.3042 s
FLT017-3PH	G07-56-AG2 (523108) tripped for over frequency at 1.6417 s
	G07-56-AG1 (523107) tripped for over frequency at 1.6417 s
FLT031-3PH	GEN-2003-013 (90840) tripped for low voltage at 0.6833 s
FLT037-3PH	G07-56-BG1 (523112) tripped for over frequency at 1.4333 s
	G07-56-BG2 (523116) tripped for over frequency at 1.4333 s
FLT041-3PH	GPEWIND1 (543116) tripped for low voltage at 0.6125 s
FLT047-3PH	G07-56-AG2 (523108) tripped for over frequency at 1.1875 s
	G07-56-AG1 (523107) tripped for over frequency at 1.1875 s
	G07-56-BG1 (523112) tripped for over frequency at 1.1875 s
	G07-56-BG2 (523116) tripped for over frequency at 1.1875 s
	GEN-2005-020 (90870) tripped for over voltage at 1.3500 s
FLT049-3PH	G07-56-AG2 (523108) tripped for over frequency at 1.2375 s
	G07-56-AG1 (523107) tripped for over frequency at 1.2375 s
	G07-56-BG1 (523112) tripped for over frequency at 1.2375 s
	G07-56-BG2 (523116) tripped for over frequency at 1.2375 s
	GEN-2005-020 (90870) tripped for over voltage at 1.3958 s
FLT067-3PH	GEN-2006-020 (90201) tripped for over frequency at 0.7250 s
FLT068-1PH	GEN-2006-020 (90201) tripped for over frequency at 0.7292 s
FLT081-3PH	GEN-2006-020 (90201) tripped for over frequency at 0.7292 s
FLT082-1PH	GEN-2006-020 (90201) tripped for over frequency at 0.7333 s

The results indicate that reactive support is required to address the trips due to LVRT. Additionally, a transmission upgrade is required to address the overfrequency trip of Gen-2007-056 project. Table 4-6 presents the proposed solutions for each proposed wind project.

Table 4-6: Proposed Solutions to Address Dynamic Issues

Project	Point of Interconnection	Requirements
GEN-2007-005	Pringle 115 kV	-
GEN-2007-033	Pringle – Harrington 230 kV	2 x 15 Mvar Capacitor Banks at 34.5 kV
GEN-2007-041	Hitchland 345 kV	3 x 30 Mvar Capacitor Banks at 34.5 kV
GEN-2007-042	Hitchland 345 kV	3 x 15 Mvar Capacitor Banks at 34.5 kV
GEN-2007-046	Hitchland 115 kV	2 x 20 Mvar Mvar at 115 kV
GEN-2007-056	Hitchland 345 kV	175 Mvar at 345 kV Transmission Upgrade – 2^{nd} 345 kV Line Gen07-056 – Hitchland 345 kV and Third 345/138 kV Transformer
GEN-2007-057	Moore Co. East 115 kV	-

It is important to note that the capacitor banks, as well as the transmission upgrade are merely indicative. For the reactive support requirement, Table 4-5 is the reference that must be achieved using the wind turbine generator (WTG) capabilities and/or adding capacitor banks to the system.

The contingency analysis was conducted again, after including the proposed solutions listed above. The results obtained show:

- The new proposed projects, did not trip during any of the contingencies tested. That is, no trips occurred due to LVRT.
- All other generators in the monitored areas were stable and remained in synchronism during all contingencies and the system conditions considered.
- Acceptable damping and voltage recovery was observed, within applicable standards.

Additional plots of selected system variables documenting the stability simulations are included in Appendix B.

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Section

5

Conclusion

The seven projects of ICS-2008-001 Group2 have been evaluated to determine the system requirements to meet the requirements associated with FERC Order 661-A Guidelines for Low Voltage Ride Through (LVRT) and therefore, for them to deliver their full power to the SPP transmission system.

Steady state and stability analysis were carried out to evaluate the system performance under contingencies

The power factor analysis determined the amount of reactive support required to maintain the scheduled voltages at each one of the points of interconnection. The amount of reactive power indicated by Table 4-5 must be achieved using the wind turbine generator (WTG) capabilities and/or adding capacitor banks to the system.

The stability results indicate that reactive support is also required to address the trips due to LVRT. Additionally, a transmission upgrade is required to allow full output of GEN-2007-056, as shown by Table 4-6.

Including the reactive support indicated for each proposed wind project, there are no trips occurred due to LVRT. Furthermore, the transmission upgrade tested for GEN2007-056 interconnection was sufficient to mitigate the overfrequency trip. None of the seven projects have an adverse impact on the stability of the SPP system, for the contingencies and system conditions tested.

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L: Stability Study for Group 3

Final Report

For

Southwest Power Pool

From

S&C Electric Company

CLUSTER GROUP 3 GENERATION INTERCONNECTION IMPACT STUDY

S&C Project No. 3743

June 29, 2009

S&C Electric Company

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Report Revision History:

Date of Report	Issue	Comments
June 27 2009	Rev. A	Draft for review and comments
June 29, 2009	Rev. 0	Final report issued

Report prepared by:

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EXECUTIVE SUMMARY

S&C Electric Company has performed a grouped impact study for eight (8) wind generation projects (Cluster Group 3 projects) in response to a request through the Southwest Power Pool (SPP) Tariff studies. The wind generation projects will interconnect into Southwestern Public Service (SPS), Sunflower Electric Power Company (SUNC), and Mid-Kansas Electric Company (MKEC) at 345 kV Lamar to Finney substation, 345 kV Holcomb substation, 345 kV Finney Switch Station, 230 kV Spearville Substation, 345 kV Spearville Substation, and 345 kV Spearville to Holcomb Substation and have an in-service year request of 2010. Studies were performed for summer and winter 2010 peak loading with Cluster Group 3 wind farms operating at rated output power. Cluster Group 3 wind generation projects consist of GEN-2007-019, GEN-2008-011, GEN-2008-018, GEN-2006-006, GEN-2007-036, GEN-2007-037, GEN-2007-038, and GEN-2007-040 interconnection impact requests. The wind turbine generators represented are GE 1.5 MW, Clipper 2.5 MW, and Siemens 2.3 MW.

Cluster Group 3 wind projects can successfully interconnect into the transmission system at their desired locations provided that the wind farms can supply the reactive power needed to meet a voltage schedule equal to the base case voltage or nominal voltage, whichever is higher at the Point of Interconnection (POI) for single transmission facility outage contingencies specified by SPP. It is recommended that GE wind turbine generators use the dynamic VAR capabilities through GE WindCONTROL to provide steady-state leading and lagging reactive power in meeting the voltage schedule at the POI. Additional capacitor banks will be required for few wind projects. These capacitor banks should be sized to satisfy unity and leading power factor requirements at the POI. Provided the GE turbines are setup to provide lagging power factor to the POI and capacitor banks can be switched off, lagging power factor supplies will be sufficient. Cluster Group 3 unity and leading power factor requirements for worst single transmission facility outage contingencies consist of the following:

- Unity power factor at 345 kV Holcomb substation POI for summer and winter outage of the Holcomb to GEN-2007-040 345kV line.
- Unity power factor at the 345 kV Finney Switch Station POI for winter outage of the Holcomb to GEN-2007-040 345kV line.
- 99.83% leading power factor at 230 kV Spearville Substation POI for summer outage of the Spearville 345kV to 230kV transformer

- 92.50% leading power factor at 345 kV Spearville Substation POI for summer outage of the Spearville to Comanche 345kV line
- 97.89% leading power factor at 345 kV Spearville to Holcomb Substation POI for summer Outage of the GEN-2003-013 to GEN-2007-040 345kV line

Transient stability analysis performed for 3-phase and single-line-to-ground fault contingencies at locations specified by SPP indicate that areas closely monitored, which consists of Oklahoma Gas and Electric (OKGE), Western Farmers Electric Cooperative (WFEC), AEP West (AEPW), Sunflower Electric Power Company (SUNC), Mid-Kansas Electric Company (MKEC), and Westar Energy, Inc (WERE) will recover and become stable for summer and winter peak cases. However, certain Nebraska Public Power District (NPPD) generating unit may become unstable for 3-phase faults near Mingo on the Ming to Knoll 345kV line in both summer and winter peak cases. The NPPD units may become unstable for 3-phase faults near Holcomb on the Holcomb to Setab 345kV line for summer peak. The NPPD instability issues will be addressed later as part of the facility study. Cluster Group 3 wind farms and prior queued wind farms will survive the SPP fault contingencies, but GEN-2007-019 will inevitably trip off on when it is islanded after the GEN-2007-019 to Finney 345kV line or the Finney to GEN-2007-019 345kV line is opened. No further action is to be taken to address the unintentional islanding of GEN-2007-019.

1. INTRODUCTION

S&C Electric Company has performed an interconnection impact study for eight (8) wind generation projects in response to a request through the Southwest Power Pool (SPP) Tariff studies. The wind generation projects will interconnect into Southwestern Public Service (SPS), Sunflower Electric Power Company (SUNC), and Mid-Kansas Electric Company (MKEC) and have an in-service year request of 2010. Studies were performed for summer and winter 2010 peak loading with wind farms at 100% output power. Seasonal power flow models including aggregate models of the projects studied were provided by SPP. Wind turbine generators represented by the projects are General Electric GE 1.5 MW, Siemens SWT 2.3 MW (SWT-2.3-93 60 Hz), and Clipper C93 2.5 MW.

Cluster Group 3 consists of the following wind generation projects:

GEN-2007-019 – GE 1.5 MW – 375 MW total rated capacity

GEN-2008-011 – GE 1.5 MW – 600 MW total rated capacity

GEN-2008-018 – GE 1.5 MW – 405 MW total rated capacity

GEN-2006-006 – GE 1.5 MW – 205.5 MW total rated capacity

GEN-2007-036 – Clipper C93 2.5 MW – 200 MW total rated capacity

GEN-2007-037 – Clipper C93 2.5 MW – 200 MW total rated capacity

GEN-2007-038 – Clipper C93 2.5 MW – 200 MW total rated capacity

GEN-2007-040 – Siemens 2.3 MW – 500 MW total rated capacity

2. TRANSMISSION SYSTEM AND STUDY AREA

The study area involves transmission facilities at 345, 230 and 115 kV. The wind generation projects will interconnect at the following locations:

345 kV Lamar to Finney substation (SPS): GEN-2007-019.

345 kV Holcomb substation (SUNC): GEN-2008-011

345 kV Finney Switch Station (SUNC): GEN-2008-018

230 kV Spearville Substation (MKEC): GEN-2006-006

345 kV Spearville Substation (SUNC): GEN-2007-036, GEN-2007-037, GEN-2007-038

345 kV Spearville to Holcomb Substation (SUNC): GEN-2007-040

Single outage and fault contingencies were considered for transmission facilities nearby the point of interconnection (POI) of these wind projects. Areas monitored consisted of:

- Oklahoma Gas and Electric (OKGE)
- Western Farmers Electric Cooperative (WFEC)
- AEP West (AEPW)
- Sunflower Electric Power Company (SUNC)
- Mid-Kansas Electric Company (MKEC)
- Westar Energy, Inc (WERE)

3. POWER FLOW BASE CASES

S&C received PSS/E power flow base cases for steady-state and transient stability analysis from SPP on April 2, 2009. The submittal consisted of the following base cases:

ICS08-01_G3_10SP.sav – Summer peak 2010, which includes aggregate representation of wind turbine generators for Cluster Group 3 wind farms and prior queued projects at 100% output power. Other cluster projects were also included with wind farms at 20% output power.

ICS08-01_G3_10WP.sav – Winter peak 2010, which includes aggregate representation of wind turbine generators for Cluster Group 3 wind farms and prior queued projects at 100% output power. Other cluster projects were also included with wind farms at 20% output power.

The original base cases were subsequently revised, renamed, and used for the studies by S&C with input from SPP:

ICS08-01_G3_10SP_sandc.sav – Summer peak 2010, which adds a 345 kV line from Spearville to Wichita and switches off the 150 MVAR SVC at Comanche.

ICS08-01_G3_10WP_sandc.sav – Winter peak 2010, which adds a 345 kV line from Spearville to Wichita and switches off the 150 MVAR SVC at Comanche.

4. Wind Farm Representation in Load Flow

An equivalent aggregate representation of wind turbine generators and equivalent collector system impedance was developed for each substation transformer to simplify analysis and representation in PSS/E. The equivalent collector system impedance was calculated (by others) from detailed collector cable impedance information provided by wind farm developer. The aggregate models were part of the base case supplied by SPP.

4.1 General Electric GE – 1.5 MW/60 Hz Wind Turbine Generator

The GE 1.5 MW wind turbine generator is a widely used variable-speed doubly-fed induction generator with power converter and electrical pitch control. The standard GE turbine can operate continuously between 95% leading (capacitive) to 95% lagging (inductive). With an optional upgrade, the turbines can continuously operate between 90% leading to 90% lagging. For wind farms that are required to meet a voltage schedule at the POI, the GE WindCONTROL system is available to dynamically control the power factor of each wind turbine generator as well as the switching operation of any capacitor/reactor bank. The GE controls feature local and remote voltage and power factor control.

4.2 Siemens SWT – 2.3 MW (SWT-2.3-93 60 Hz) 60 Hz Wind Turbine Generator

The SWT 2.3 MW wind turbine generator is an induction generator (squirrel cage type) with PWM control for variable reactive power output control, which can be configured to control the 0.69 kV terminal voltage or configured to deliver fixed reactive output power. The continuous reactive output capability of the machine is dependent on the terminal voltage and the real output power of the wind turbine generator. The power curve indicates that at rated 2.3 MW output power and 1.0 p.u. voltage, the wind turbine generator is capable of operating continuously between 86% leading to 86% lagging. Leading power factor range significantly decreases at any voltage other than 1.0 p.u. Also, an increase in terminal voltage would result in higher lagging power factor capability and a decrease in terminal voltage would result in lower lagging power factor capability. For steady-state operation, the wind turbine generator features local voltage and power factor control modes of operation.

4.3 Clipper C93 – 2.5 MW/60 Hz Wind Turbine Generator

The Clipper C93 - 2.5 MW wind turbine generator is a permanent magnet synchronous generator with rectifier and inverter stage. It features blade pitch control. Because of its topology, the Clipper C93 can operate at variable speed. Inverters are configured by default to operate at unity power factor. However, the fixed power factor set point can be changed. The Cliiper C93 can be operated anywhere from 95% leading to 95% lagging power factor.

5. POWER FLOW ANALYSIS

SPP has specific voltage and power factor requirements for interconnecting wind farm projects in relation to emergency conditions. Wind generation 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 transmission facility outage contingencies specified by SPP. It may not be possible in all cases to meet the voltage requirements specified by SPP since actual requirements on the wind farm(s) may exceed a power factor of +/-95%. FERC 661A requires for LGIA that the wind farm project maintain a power factor within +/-95% measured at the POI.

Voltage in the SPP base case of the various point of interconnections locations is listed in Table 5.1

Table 5.1: Base Case Voltage of Point of Interconnection Locations

Point of Interconnection	Summer Peak 2010 (pu)	Winter Peak 2010 (pu)
345 kV Lamar to Finney substation	1.0200	1.0037
345 kV Holcomb substation	1.0156	1.0164
345 kV Finney Switch Station	1.0157	1.0164
230 kV Spearville Substation	1.0052	1.0096
345 kV Spearville Substation	1.0113	1.0148
345 kV Spearville to Holcomb Substation	1.0270	1.0284

5.1 Facility Outage Contingencies

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

Table 5.2: List of N-1 Outage Contingencies

Cont.	Description
N-1_1	Outage of the GEN-2007-019 (210190) to Lamar (599950) 345kV line
N-1_2	Outage of the GEN-2007-019 (210190) to Finney (523853) 345kV line
N-1_3	Outage of the Finney (523853) to GEN-2003-013 (560029) 345kV line
N-1_4	Outage of one of the Finney (523853) to Holcomb (531449) 345kV lines
N-1_5	Outage of the Holcomb (531449) to Setab (531465) 345kV line
N-1_6	Outage of the Holcomb (531449) to GEN-2007-040 (210400) 345kV line
N-1_7	Outage of the Holcomb 345kV (531449) to 115kV (531448) transformer
N-1_8	Outage of the GEN-2007-040 (210400) to Spearville (531469) 345kV line
N-1_9	Outage of the Spearville (531469) to Comanche (531487) 345kV line
N-1_10	Outage of the Spearville 345kV (531469) to 230kV (539695) transformer
N-1_11	Outage of the Spearville 230kV (539695) to 115kV (539694) transformer #2
N-1_12	Outage of the Spearville (539695) to Mullergren (539679) 230kV line
N-1_13	Outage of the Mullergren (539679) to South Hays (530582) 230kV line
N-1_14	Outage of the Mullergren (539679) to Circle (532871) 230kV line
N-1_15	Outage of the GEN-2007-025 (532781) to Wichita (532796) 345kV line
N-1_16	Outage of the GEN-2007-025 (532781) to Comanche (531487) 345kV line
N-1_17	Outage of the Wichita (532796) to Benton (532791) 345kV line
N-1_18	Outage of the Comanche (531487) to Woodward (515375) 345kV line
N-1_19	Outage of the Judson Large (539671) to S Star (103) 115kV line
N-1_20	Outage of the Judson Large (539671) to Cudahy (539659) 115kV line
N-1_21	Outage of the GEN-2003-013 (560029) to Hitchland (523097) 345kV line
N-1_22	Outage of the Hitchland (523097) to Woodward (515375) 345kV line
N-1_23	Outage of the Hitchland (523097) to GEN-2005-017 (51700) 345kV line
N-1_24	Outage of the GEN-2005-017 (51700) to Potter Co. (523961) 345kV line
N-1_25	Outage of the Potter Co. (523961) to Grapevine (523772) 345kV line
N-1_26	Outage of the Potter Co. 345kV (523961) to 230kV (523959) transformer
N-1_27	Outage of the Woodward (515375) to Tatonga (515378) 345kV line
N-1_28	Outage of the Mingo (531451) to Knoll (530700) 345kV line
N-1_29	Outage of the Knoll (530558) to Smoky Hills (530592) 230kV line
N-1_30	Outage of the Hitchland (523097) to Beaver County (523098) 345kV line
N-1_31	Outage of the GEN-2003-013 (560029) to GEN-2007-040 (210400) 345kV line
N-1_32	Outage of the GEN-2007-040 (210400) to Comanche (531487) 345kV line
N-1_33	Outage of the Woodward (515375) to Beaver County (523098) 345kV line

5.2 Power Factor Requirements at the Point of Interconnection

The power factor requirement of each interconnecting project will depend largely on the collective ability of the wind farms to deliver leading or lagging reactive power required to maintain a voltage schedule at the POI consistent with the voltage in the SPP base case or nominal voltage, whichever is higher. Leading power factor requirements are summarized in Table 5.3. Provided the GE turbines are setup to provide lagging power factor to the POI and capacitor banks can be switched off, lagging power factor supplies will be sufficient. Wind farm owners need to make necessary provisions in the form of wind turbine voltage control or addition of switched capacitor banks to satisfy the requirements.

Table 5.3: Power factor requirements to maintain the base case voltage schedule at the POI

Point of Interconnection	**Total Rated MW Capacity**	**Worst Case Contingency (from Table 5.2)**	**Power Factor Requirement**	
345 kV Lamar to Finney substation	375	N-1_9 Summer Peak	98.22%	lagging
345 kV Holcomb substation	600	N-1_6 Winter Peak N-1_6 Summer Peak	100.00%	unity
345 kV Finney Switch Station	405	N-1_6 Winter Peak	100.00%	unity
230 kV Spearville Substation	205.5	N-1_10 Summer Peak	99.83%	leading
345 kV Spearville Substation	600	N-1_9 Winter Peak	92.50%	leading
345 kV Spearville to Holcomb Substation	500	N-1_31 Summer Peak	97.89%	leading

6. TRANSIENT STABILITY ANALYSIS

Transient stability analysis was performed for fault contingencies in Table 6.1.

Table 6.1: SPP fault contingencies

Cont. No.	Cont. Name	Description
1	FLT01-3PH	3 phase fault on the GEN-2007-019 (210190) to Lamar (599950) 345kV line, near GEN-2007-019. a. Apply fault at the GEN-2007-019 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 GEN-2007-019 (210190) to Finney (523853) 345kV line, near GEN-2007-019. a. Apply fault at the GEN-2007-019 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 Finney (523853) to GEN-2007-019 (210190) 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.
6	FLT06-1PH	*Single phase fault and sequence like previous*
7	FLT07-3PH	3 phase fault on the Finney (523853) to GEN-2003-013 (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.
8	FLT08-1PH	*Single phase fault and sequence like previous*
9	FLT09-3PH	3 phase fault on one of the Finney (523853) to Holcomb (531449) 345kV lines, 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 one of the Holcomb (531449) to Finney (523853) 345kV lines, 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.
12	FLT12-1PH	*Single phase fault and sequence like previous*
13	FLT13-3PH	3 phase fault on the Holcomb (531449) to Setab (531465) 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.
14	FLT14-1PH	*Single phase fault and sequence like previous*

Cont. No.	Cont. Name	Description
15	FLT15-3PH	3 phase fault on the Holcomb (531449) to GEN-2007-040 (210400) 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.
16	FLT16-1PH	*Single phase fault and sequence like previous*
17	FLT17-3PH	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. b. Clear fault after 5 cycles by tripping the faulted transformer.
18	FLT18-1PH	*Single phase fault and sequence like previous*
19	FLT19-3PH	3 phase fault on the GEN-2007-040 (210400) to Holcomb (531449) 345kV line, near GEN-2007-040. a. Apply fault at the GEN-2007-040 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	FLT20-1PH	*Single phase fault and sequence like previous*
21	FLT21-3PH	3 phase fault on the GEN-2007-040 (210400) to Spearville (531469) 345kV line, near GEN-2007-040. a. Apply fault at the GEN-2007-040 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.
22	FLT22-1PH	*Single phase fault and sequence like previous*
23	FLT23-3PH	3 phase fault on the Spearville (531469) to GEN-2007-040 (210400) 345kV line, 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.
24	FLT24-1PH	*Single phase fault and sequence like previous*
25	FLT25-3PH	3 phase fault on the Spearville (531469) to Comanche (531487) 345kV line, 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.
26	FLT26-1PH	*Single phase fault and sequence like previous*
27	FLT27-3PH	3 phase fault on the Spearville 345kV (531469) to 230kV (539695) transformer, near the 345 kV bus. a. Apply fault at the Spearville 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
28	FLT28-1PH	*Single phase fault and sequence like previous*
29	FLT29-3PH	3 phase fault on the Spearville 230kV (539695) to 345kV (531469) transformer, near the 230 kV bus. a. Apply fault at the Spearville 230kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
30	FLT30-1PH	*Single phase fault and sequence like previous*
31	FLT31-3PH	3 phase fault on the Spearville 230kV (539695) to 115kV (539694) transformer #2, near the 230 kV bus. a. Apply fault at the Spearville 230kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
32	FLT32-1PH	*Single phase fault and sequence like previous*

Cont. No.	Cont. Name	Description
33	FLT33-3PH	3 phase fault on the Spearville (539695) to Mullergren (539679) 230kV line, near Spearville. a. Apply fault at the Spearville 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	FLT34-1PH	*Single phase fault and sequence like previous*
35	FLT35-3PH	3 phase fault on the Mullergren (539679) to South Hays (530582) 230kV line, near Mullergren. a. Apply fault at the Mullergren 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	FLT36-1PH	*Single phase fault and sequence like previous*
37	FLT37-3PH	3 phase fault on the Mullergren (539679) to Circle (532871) 230kV line, near Mullergren. a. Apply fault at the Mullergren 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	FLT38-1PH	*Single phase fault and sequence like previous*
39	FLT39-3PH	3 phase fault on the GEN-2007-025 (532781) to Wichita (532796) 345kV line, near GEN-2007-025. a. Apply fault at the GEN-2007-025 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.
40	FLT40-1PH	*Single phase fault and sequence like previous*
41	FLT41-3PH	3 phase fault on the GEN-2007-025 (532781) to Comanche (531487) 345kV line, near GEN-2007-025. a. Apply fault at the GEN-2007-025 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.
42	FLT42-1PH	*Single phase fault and sequence like previous*
43	FLT43-3PH	3 phase fault on the Wichita (532796) to Benton (532791) 345kV line, near Wichita. a. Apply fault at the Wichita 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
44	FLT44-1PH	*Single phase fault and sequence like previous*
45	FLT45-3PH	3 phase fault on the Comanche (531487) to Woodward (515375) 345kV line, near Comanche. a. Apply fault at the Comanche 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.
46	FLT46-1PH	*Single phase fault and sequence like previous*
47	FLT47-3PH	3 phase fault on the Judson Large (539671) to S Star (103) 115kV line, near Judson Large. a. Apply fault at the Judson Large 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	FLT48-1PH	*Single phase fault and sequence like previous*

Cont. No.	Cont. Name	Description
49	FLT49-3PH	3 phase fault on the Judson Large (539671) to Cudahy (539659) 115kV line, near Judson Large. a. Apply fault at the Judson Large 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	FLT50-1PH	*Single phase fault and sequence like previous*
51	FLT51-3PH	3 phase fault on the GEN-2003-013 (560029) to Hitchland (523097) 345kV line, near GEN-2003-013. a. Apply fault at the GEN-2003-013 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.
52	FLT52-1PH	*Single phase fault and sequence like previous*
53	FLT53-3PH	3 phase fault on the Hitchland (523097) to Woodward (515375) 345kV line, near Hitchland. a. Apply fault at the Hitchland 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
54	FLT54-1PH	*Single phase fault and sequence like previous*
55	FLT55-3PH	3 phase fault on the Hitchland (523097) to GEN-2005-017 (51700) 345kV line, near Hitchland. a. Apply fault at the Hitchland 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
56	FLT56-1PH	*Single phase fault and sequence like previous*
57	FLT57-3PH	3 phase fault on the GEN-2005-017 (51700) to Potter Co. (523961) 345kV line, near GEN-2005-017. a. Apply fault at the GEN-2005-017 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	FLT58-1PH	*Single phase fault and sequence like previous*
59	FLT59-3PH	3 phase fault on the Potter Co. (523961) to Grapevine (523772) 345kV line, near Potter Co. a. Apply fault at the Potter Co. 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.
60	FLT60-1PH	*Single phase fault and sequence like previous*
61	FLT61-3PH	3 phase fault on the Potter Co. 345kV (523961) to 230kV (523959) transformer, near the 345 kV bus. a. Apply fault at the Potter Co. 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
62	FLT62-1PH	*Single phase fault and sequence like previous*
63	FLT63-3PH	3 phase fault on the Woodward (515375) to Tatonga (515378) 345kV line, near Woodward. a. Apply fault at the Woodward 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.
64	FLT64-1PH	*Single phase fault and sequence like previous*

Cont. No.	Cont. Name	Description
65	FLT65-3PH	3 phase fault on the Mingo (531451) to Knoll (530700) 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.
66	FLT66-1PH	*Single phase fault and sequence like previous*
67	FLT67-3PH	3 phase fault on the Knoll (530558) to Smoky Hills (530592) 230kV line, near Knoll. a. Apply fault at the Knoll 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
68	FLT68-1PH	*Single phase fault and sequence like previous*
69	FLT107-3PH	3 phase fault on the Hitchland (523097) to Beaver County (523098) 345kV line, near Beaver County. a. Apply fault at the Beaver 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.
70	FLT70-1PH	*Single phase fault and sequence like previous*
71	FLT71-3PH	3 phase fault on the GEN-2003-013 (560019) to GEN-2007-040 (210400) 345kV line, near GEN-2003-013. a. Apply fault at the GEN-2003-013 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.
72	FLT72-1PH	*Single phase fault and sequence like previous*
73	FLT73-3PH	3 phase fault on the GEN-2007-040 (210400) to Comanche (531487) 345kV line, near GEN-2007-040. a. Apply fault at the GEN-2007-040 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.
74	FLT74-1PH	*Single phase fault and sequence like previous*
75	FLT75-3PH	3 phase fault on the Woodward (515375) to Beaver County (523098) 345kV line, near Beaver County. a. Apply fault at the Beaver 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.
76	FLT76-1PH	*Single phase fault and sequence like previous*

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 of 60% of nominal.

The control areas monitored:

- Oklahoma Gas and Electric (OKGE)
- Western Farmers Electric Cooperative (WFEC)
- AEP West (AEPW)
- Sunflower Electric Power Company (SUNC)
- Mid-Kansas Electric Company (MKEC)
- Southwestern Public Service (SPS)
- Westar Energy, Inc (WERE)

The prior queued projects monitored are listed in Table 6.2.

Table 6.2: Prior queued wind farm projects monitored

Request	Size	Wind Turbine Model	Point of Interconnection
GEN-2001-039A	105	Clipper 2.5MW	Judson Large – Greensburg 115kV
GEN-2002-025A	150	GE 1.5 MW	Spearville 230kV
GEN-2004-014	154.5	GE 1.5 MW	Spearville 230kV
GEN-2005-012	250	Vestas V90 3.0MW	Spearville 345kV

6.1 Modeling of Power Factor Requirements

GE wind turbine generators were setup in the load flow model to satisfy a minimum voltage schedule at the POI as listed in Table 5.1. Siemens turbines were setup to operate at a fixed 99% leading power factor. Clipper C93 turbines were setup to operate at a fixed 98% leading power factor. Capacitor banks were added to wind farms at 34.5 kV to provide the additional reactive power support required to meet the power factor requirements listed in Table 5.3. Table 6.3 summarizes the control scheme for each project, location and size of cap banks as well as transformer no-load tap settings. Figures 6.1 to 6.6 show the power flow diagrams corresponding to each point of interconnection and wind farm projects for the worst contingencies, which are listed in Table 5.3.

Table 6.3: Summary of wind farm control, wind turbine specifications, capacitor bank requirements and transformer tap settings of Cluster Group 3 projects.

Project Name	Point of Interconnection	Wind Turbine Generator			Mechanically Switched Cap Bank Requirement		XFMR no-load tap setting (% of high side winding)		
		Model	Power Factor Range	Control Scheme and Settings	Size (MVAR)	Location	345/138 kV	138/34.5 kV, 230/34.5 kV or 345/34.5 kV	Wind Turbine Generator Step Up
GEN-2007-019	345 kV Lamar to Finney substation	GE 1.5 MW	+/- 95%	Meet voltage schedule at POI using dynamic var control through GE WindCONTROL 1.02 pu for summer 1.0037 pu for winter	none	none	none	100.0	100.0
GEN-2008-011	345 kV Holcomb substation	GE 1.5 MW	+/- 95%[1]	Meet voltage schedule at POI using dynamic var control through GE WindCONTROL 1.0156 pu for summer 1.0164 pu for winter	none	none	none	100.0	100.0
GEN-2008-018	345 kV Finney Switch Station	GE 1.5MW	+/- 95%[1]	Meet voltage schedule at POI using dynamic var control through GE WindCONTROL 1.0157 pu for summer 1.0164 pu for winter	none	none	none	100.0	100.0
GEN-2006-006	230 kV Spearville Substation	GE 1.5MW	+/- 95%[1]	Meet voltage schedule at POI using dynamic var control through GE WindCONTROL 1.03 pu for summer and winter	57 MVAR	At 230 kV POI	none	105.0	100.0
GEN-2007-036	345 kV Spearville Substation	Clipper 2.5 MW	+/- 95%	Fixed 98% leading power factor	Two (2) 5.40 MVAR	One on each 34.5 kV collector bus	none	105.0	100.0
GEN-2007-037	345 kV Spearville Substation	Clipper 2.5 MW	+/- 95%	Fixed 98% leading power factor	Two (2) 5.40 MVAR	One on each 34.5 kV collector bus	none	105.0	100.0
GEN-2007-038	345 kV Spearville Substation	Clipper 2.5 MW	+/- 95%	Fixed 98% leading power factor.	Two (2) 5.40 MVAR	One on each 34.5 kV collector bus	none	105.0	100.0
GEN-2007-040	Holcomb – Spearville 345 kV line	Siemens 2.3 MW	Dependent on voltage versus reactive power curve	Fixed 99% leading power factor.	Three (3) 25.20 MVAR	One on each 34.5 kV collector bus	none	105.0	100.0

Notes:

- Assume standard reactive output capability. Wind farm developer to confirm this information.

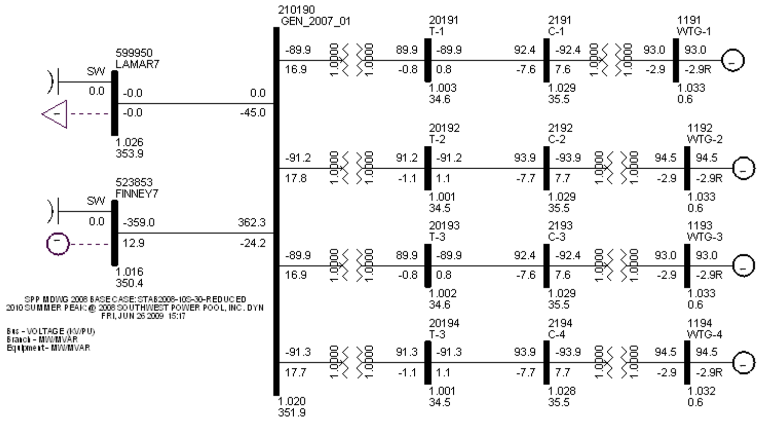

Figure 6.1: Power flow diagram of GEN-2007-019 for N-1_9 summer peak outage contingency

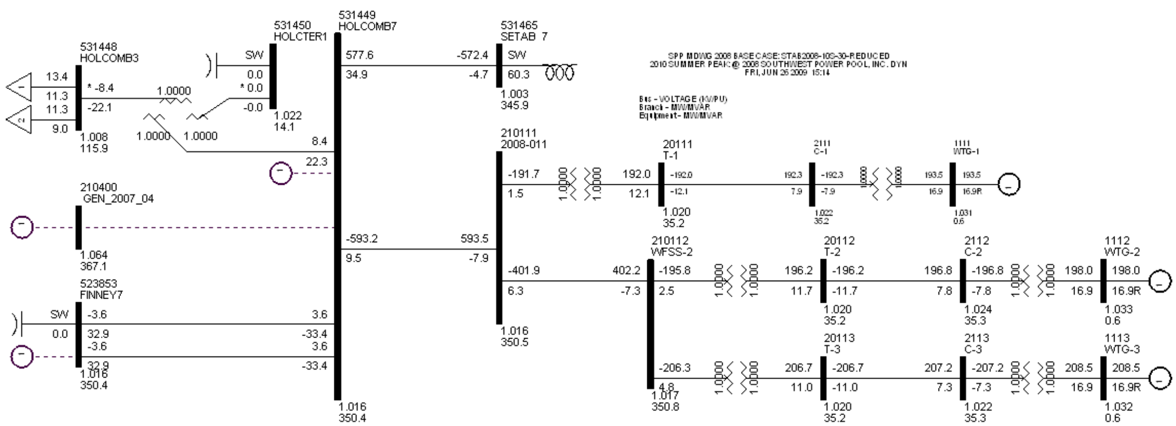

Figure 6.2: Power flow diagram of GEN-2008-011 for N-1_6 summer peak outage contingency

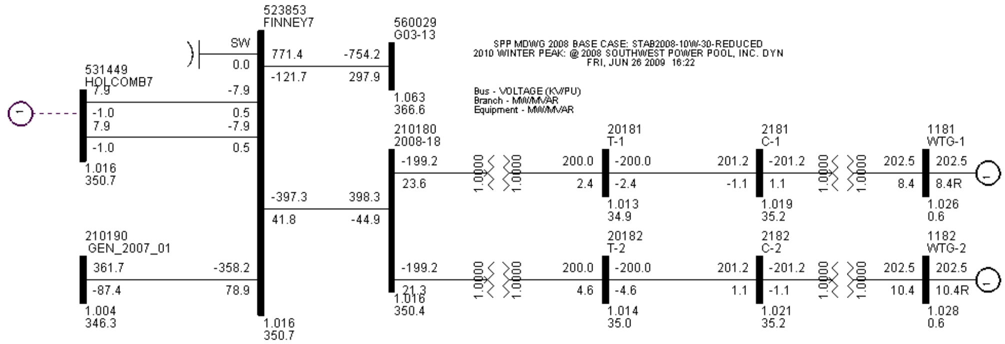

Figure 6.3: Power flow diagram of GEN-2008-018 for N-1_6 winter peak outage contingency

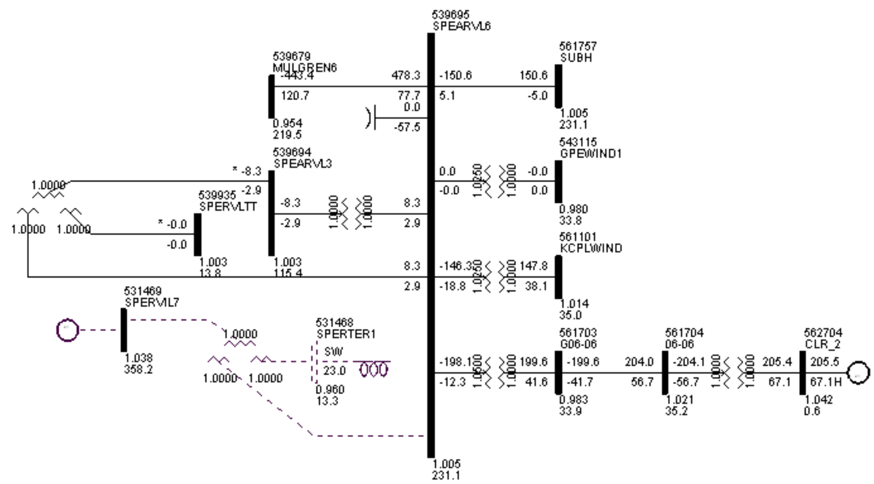

Figure 6.4: Power flow diagram of GEN-2006-006 for N-1_10 summer peak outage contingency

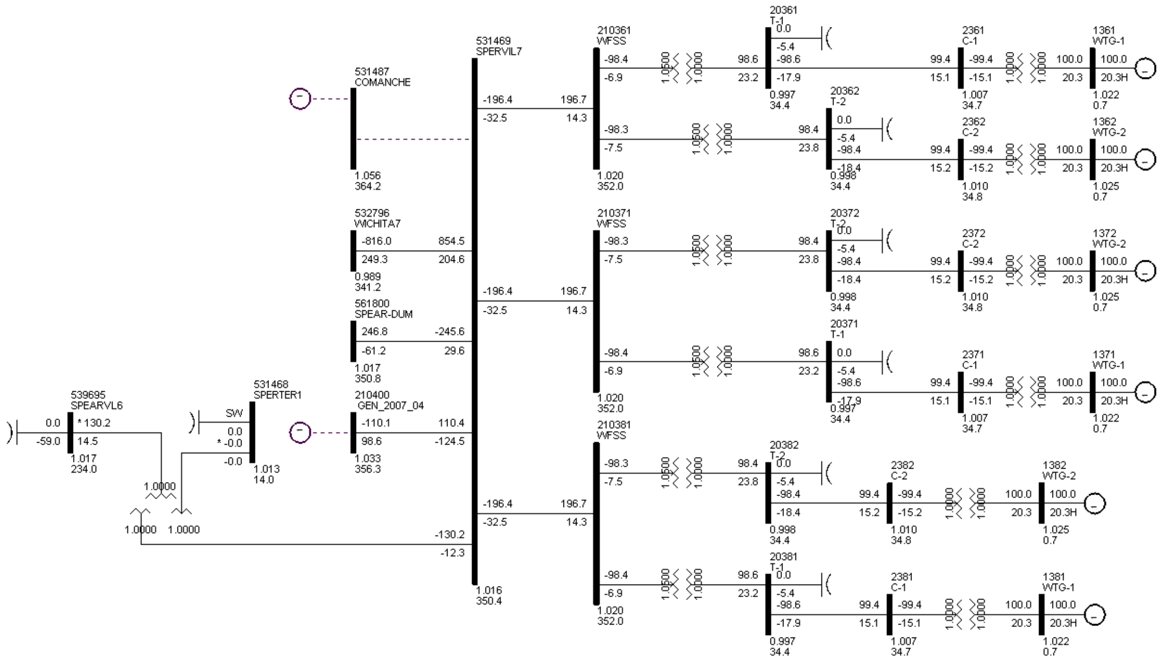

Figure 6.5: Power flow diagram of GEN-2007-036, GEN-2007-037, and GEN-2007-038 for N-1_9 winter peak outage contingency

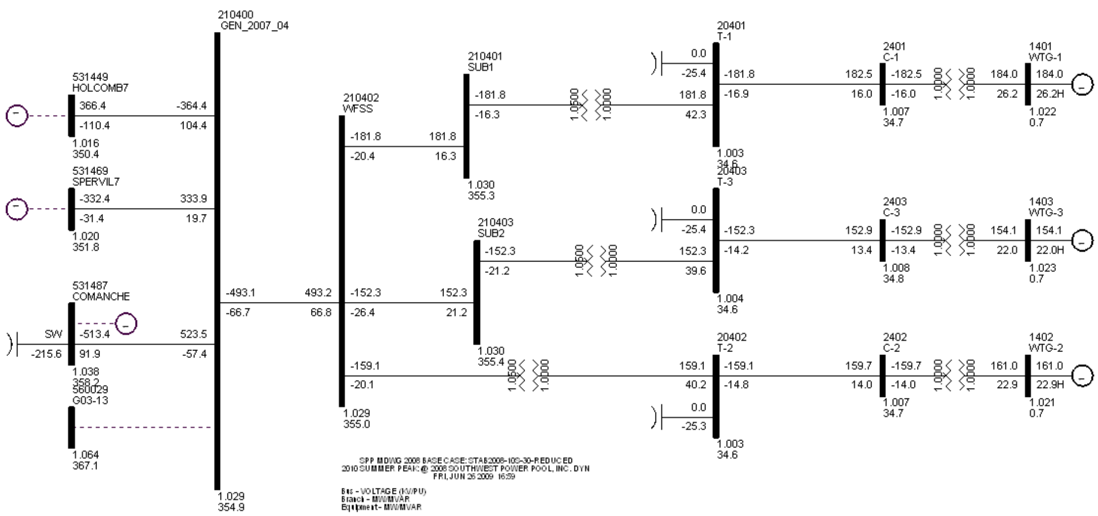

Figure 6.6: Power flow diagram of GEN-2007-040 for N-1_31 summer peak outage contingency

6.2 Stability Criteria

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

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

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

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

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

.Modeling of Wind Turbine Generators

Transient stability simulations used an updated version of the GE 1.5 MW originally released under PSS/E Wind package issue 2.0.0 as a library model. S&C found that the existing GE 1.5 MW model would negatively interact with another vendor's wind turbine PSS/E model. PTI provided the updated model to S&C with the necessary corrections on August 1, 2008.

The voltage and frequency relay settings used with the GE 1.5 MW model for the Cluster Group 3 projects are listed in Table 6.4. The Clipper and Siemens wind turbine generator relay settings are listed in Table 6.5 and 6.6 respectively.

Table 6.4: GE 1.5 MW voltage and frequency settings

Relay type	Description	Trip setting and time delay	Units
Undervoltage (27-1)	Relay trips if |Vbus|<	0.85	Pu
	for t =	10.0	S
Undervoltage (27-2)	Relay trips if |Vbus|<	0.75	Pu
	for t =	1.0	S
Undervoltage (27-3)	Relay trips if |Vbus|<	0.70	Pu
	for t =	0.625	S
Undervoltage (27-4)	Relay trips if |Vbus|<	0.15	Pu
	for t =	0.625	S
Overvoltage (59-1)	Relay trips if |Vbus|>	1.1	Pu
	for t =	1.0	S
Overvoltage (59-2)	Relay trips if |Vbus|>	1.15	Pu
	for t =	0.1	S
Overvoltage (59-3)	Relay trips if |Vbus|>	1.3	Pu
	for t =	0.02	S
Underfrequency (81U-1)	Relay trips if Fbus <	57.5	Hz
	for t =	10.0	S
Underfrequency (81U-2)	Relay trips if Fbus <	56.5	Hz
	for t =	0.02	S
Overfrequency (81O-1)	Relay trips if Fbus >	61.5	Hz
	for t =	30.0	S
Overfrequency (81U-2)	Relay trips if Fbus >	62.5	Hz
	for t =	0.02	S

Table 6.4: Clipper C93 - 2.5 MW voltage and frequency settings

Relay type	Description	Trip setting and time delay	units
Undervoltage (27-1)	Relay trips if |Vbus|<	0.90	pu
	for t =	3.00	s
Undervoltage (27-2)	Relay trips if |Vbus|<	0.1	pu
	for t =	instantaneous	s
Overvoltage (59-1)	Relay trips if |Vbus|>	1.1	pu
	for t =	5	s
Overvoltage (59-2)	Relay trips if |Vbus|>	1.2	pu
	for t =	0.5	s
Overvoltage (59-3)	Relay trips if |Vbus|>	1.3	pu
	for t =	instantaneous	s
Overfrequency (81O)	Relay trips if Fbus >	63.00	Hz
	for t =	instantaneous	s
Underfrequency (81U)	Relay trips if Fbus <	57.00	Hz
	for t =	instantaneous	s

Table 6.5: Siemens SWT 2.3 MW (SWT-2.3-93 60 Hz) voltage and frequency settings

Relay type	Description	Trip setting and time delay	Units
Undervoltage (27-1)	Relay trips if |Vbus|<	0.90	Pu
	for t =	3	S
Undervoltage (27-2)	Relay trips if |Vbus|<	0.5	Pu
	for t =	1.735	S
Undervoltage (27-3)	Relay trips if |Vbus|<	0.85	Pu
	for t =	0.650	S
Undervoltage (27-4)	Relay trips if |Vbus|<	0.15	Pu
	for t =	0.075	S
Overvoltage (59-1)	Relay trips if |Vbus|>	1.10	Pu
	for t =	1	S
Overvoltage (59-2)	Relay trips if |Vbus|>	1.20	Pu
	for t =	0.2	S
Underfrequency (81U-1)	Relay trips if Fbus <	0.95	Pu
	for t =	10	S
Underfrequency (81U-2)	Relay trips if Fbus <	0.94	Pu
	for t =	0.1	S
Overfrequency (81O-1)	Relay trips if Fbus >	1.04	Pu
	for t =	0.1	S

6.3 Transient Stability Results: Summer Peak 2010

An undisturbed run of 10 seconds was performed on the Summer Peak 2010 power flow case that was modified with items listed in Table 6.3. Voltage, angle and frequency channels were constant and held steady values throughout the run. This indicated proper initialization of dynamic models.

Fault contingencies #1 through #76 from Table 6.1 were simulated. During initial studies, 110 MW of Vestas V47 660kW wind generation located in Sunflower/MKEC area would become unstable as wind turbine speed oscillations would not gradually decrease to zero, but remain constant or gradually increase. The Vestas V47 model, under suspicion that it is not performing correctly under PSS/E version 30.3.2, was replaced with a classic generator with inertia constant of 10 and damping constant of 10. Fault contingencies #1 through #76 re-studied. The final simulation results show the following:

- GEN-2007-019 will trip off after it is unintentionally islanded for contingency #3 #4, #5, and #6.
- Areas OKGE, WFEC, AEPW, SUNC, MKEC, SPS, and WERE are stable for all contingencies
- The SPP base case, which extends beyond the areas closely monitored shows that the Brocken Bow - 8.3 MW generation in the Nebraska Public Power District (NPPD) will become unstable for fault contingency #13 and #65 (Figure 6.7 and 6.8). These contingencies were restudied without line reclosing and reduced number of Cluster Group 3 projects online, but the results were practically the same with NPPD becoming unstable. The NPPD instability issues will be addressed later as part of the facility study.

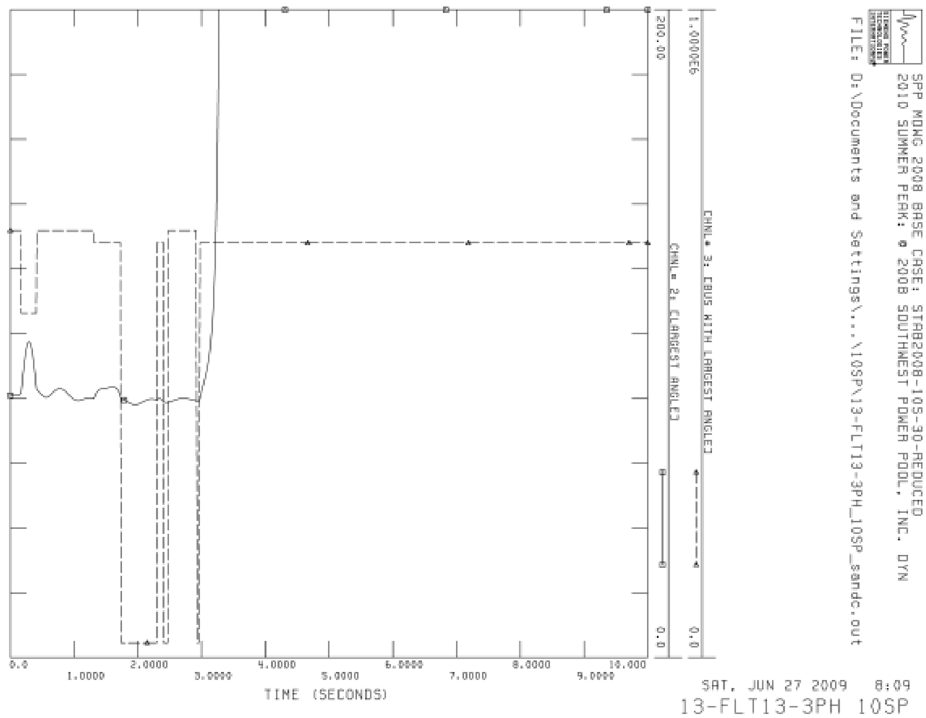

Figure 6.7: Angle from Brocken Bow generation for fault #13 (summer)

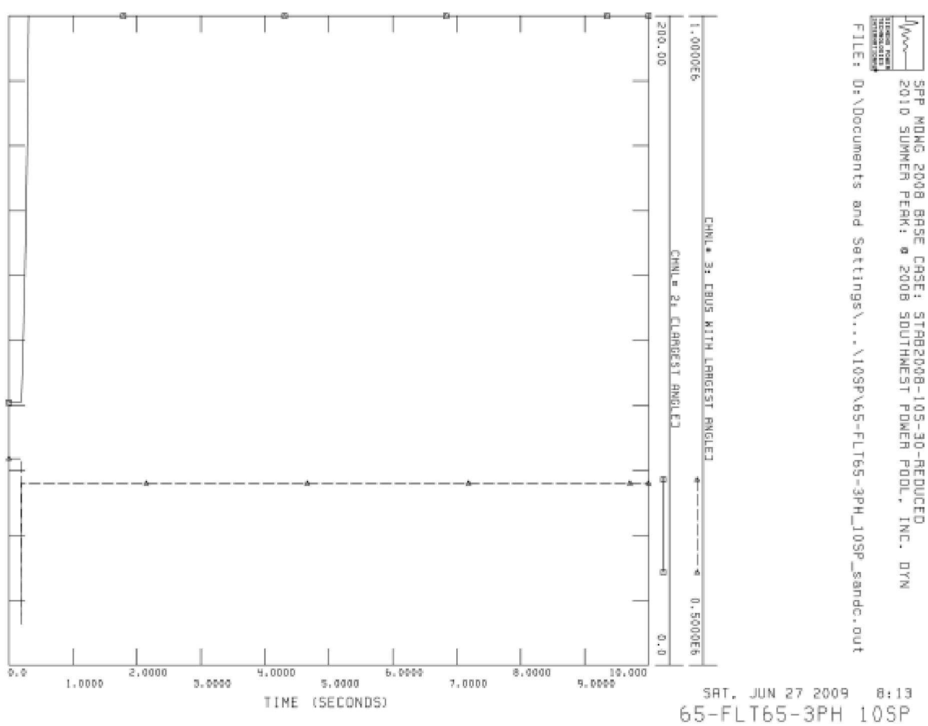

Figure 6.8: Angle from Brocken Bow generation for fault #65 (summer)

6.4 Transient Stability Results: Winter Peak 2010

Much of the same issues covered in the summer peak 2010 transient stability discussion applies for the winter peak case. Results are summarized in Table 6.6. The final simulation results show the following:

- GEN-2007-019 will trip off after it is unintentionally islanded for contingency #3 #4, #5, and #6.
- Areas OKGE, WFEC, AEPW, SUNC, MKEC, SPS, and WERE are stable for all contingencies
- Brocken Bow - 8.3 MW generation in NPPD will become unstable for fault contingency #65 (Figure 6.9). These contingencies were restudied without line reclosing and reduced number of Cluster Group 3 projects online, but the results were practically the same with NPPD becoming unstable. The NPPD instability issues will be addressed later as part of the facility study.

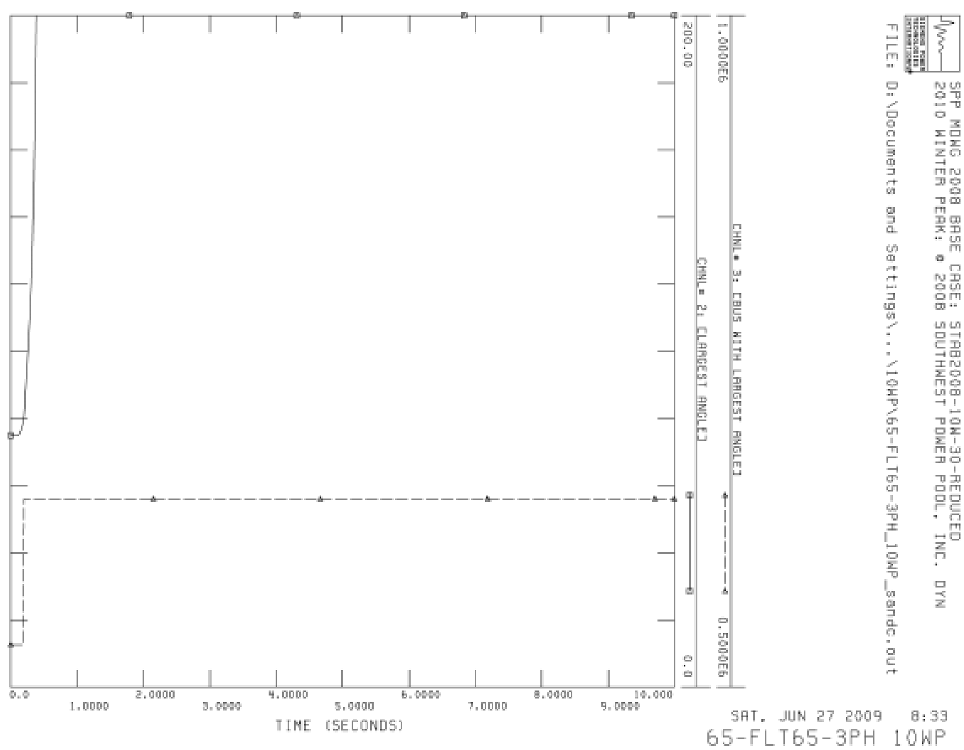

Figure 6.9 Angle from Brocken Bow generation for fault #65 (winter)

Table 6.6: Transient Stability Results for Cluster Group 3 Interconnection Impact Requests

Cont. No.	Name	Summer 2010	Winter 2010
1	FLT01-3PH	STABLE	STABLE
2	FLT02-1PH	STABLE	STABLE
3	FLT03-3PH	STABLE GEN-2007-019 trips off	STABLE GEN-2007-019 trips off
4	FLT04-1PH	STABLE GEN-2007-019 trips off	STABLE GEN-2007-019 trips off
5	FLT05-3PH	STABLE GEN-2007-019 trips off	STABLE GEN-2007-019 trips off
6	FLT06-1PH	STABLE GEN-2007-019 trips off	STABLE GEN-2007-019 trips off
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	UNSTABLE	STABLE
14	FLT14-1PH	STABLE	STABLE
15	FLT15-3PH	STABLE	STABLE
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	FLT21-3PH	STABLE	STABLE
22	FLT22-1PH	STABLE	STABLE
23	FLT23-3PH	STABLE	STABLE
24	FLT24-1PH	STABLE	STABLE
25	FLT25-3PH	STABLE	STABLE
26	FLT26-1PH	STABLE	STABLE
27	FLT27-3PH	STABLE	STABLE
28	FLT28-1PH	STABLE	STABLE
29	FLT29-3PH	STABLE	STABLE
30	FLT30-1PH	STABLE	STABLE
31	FLT31-3PH	STABLE	STABLE
32	FLT32-1PH	STABLE	STABLE
33	FLT33-3PH	STABLE	STABLE
34	FLT34-1PH	STABLE	STABLE
35	FLT35-3PH	STABLE	STABLE
36	FLT36-1PH	STABLE	STABLE
37	FLT37-3PH	STABLE	STABLE
38	FLT38-1PH	STABLE	STABLE
39	FLT39-3PH	STABLE	STABLE
40	FLT40-1PH	STABLE	STABLE
41	FLT41-3PH	STABLE	STABLE

Cont. No.	Name	Summer 2010	Winter 2010
42	FLT42-1PH	STABLE	STABLE
43	FLT43-3PH	STABLE	STABLE
44	FLT44-1PH	STABLE	STABLE
45	FLT45-3PH	STABLE	STABLE
46	FLT46-1PH	STABLE	STABLE
47	FLT47-3PH	STABLE	STABLE
48	FLT48-1PH	STABLE	STABLE
49	FLT49-3PH	STABLE	STABLE
50	FLT50-1PH	STABLE	STABLE
51	FLT51-3PH	STABLE	STABLE
52	FLT52-1PH	STABLE	STABLE
53	FLT53-3PH	STABLE	STABLE
54	FLT54-1PH	STABLE	STABLE
55	FLT55-3PH	STABLE	STABLE
56	FLT56-1PH	STABLE	STABLE
57	FLT57-3PH	STABLE	STABLE
58	FLT58-1PH	STABLE	STABLE
59	FLT59-3PH	STABLE	STABLE
60	FLT60-1PH	STABLE	STABLE
61	FLT61-3PH	STABLE	STABLE
62	FLT62-1PH	STABLE	STABLE
63	FLT63-3PH	STABLE	STABLE
64	FLT64-1PH	STABLE	STABLE
65	FLT65-3PH	UNSTABLE	UNSTABLE
66	FLT66-1PH	STABLE	STABLE
67	FLT67-3PH	STABLE	STABLE
68	FLT68-1PH	STABLE	STABLE
69	FLT107-3PH	STABLE	STABLE
70	FLT70-1PH	STABLE	STABLE
71	FLT71-3PH	STABLE	STABLE
72	FLT72-1PH	STABLE	STABLE
73	FLT73-3PH	STABLE	STABLE
74	FLT74-1PH	STABLE	STABLE
75	FLT75-3PH	STABLE	STABLE
76	FLT76-1PH	STABLE	STABLE

7. CONCLUSIONS AND RECOMMENDATIONS

1 Cluster Group 3 wind farms are required to demonstrate that they can operate at the following power factors for the worst single transmission facility outage contingency in each case. Provided the GE turbines are setup to provide lagging power factor to the POI and capacitor banks can be switched off, lagging power factor supplies will be sufficient.

- Unity power factor at 345 kV Holcomb substation POI for summer and winter outage of the Holcomb to GEN-2007-040 345kV line.
- Unity power factor at the 345 kV Finney Switch Station POI for winter outage of the Holcomb to GEN-2007-040 345kV line.
- 99.83% leading power factor at 230 kV Spearville Substation POI for summer outage of the Spearville 345kV to 230kV transformer
- 92.50% leading power factor at 345 kV Spearville Substation POI for summer outage of the Spearville to Comanche 345kV line
- 97.89% leading power factor at 345 kV Spearville to Holcomb Substation POI for summer Outage of the GEN-2003-013 to GEN-2007-040 345kV line

2 It is recommended that wind farm developers take advantage of the reactive output power capability of GE wind turbine generators to meet the voltage schedule at the POI. This will reduce capacitor bank requirements.

3 Few if not all fault contingencies should be re-studied with a stable version of the Vestas V47 wind turbine generator.

4 Revisit fault #13 and 65# and address the NPPD instability issues as part of the facility study.

M: Stability Study for Group 4

POWER SYSTEMS DIVISION
GRID SYSTEMS CONSULTING

System Impact Study for SPP Group 4

FINAL REPORT

REPORT NO.: 2009-E2952-R0
Issued On: June 1, 2009
Revised on: June 19, 2009
Revised on: June 29, 2009

Prepared for:
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Southwest Power Pool, Inc.	No. 2009-E2952-R0	
System Impact Study for SPP Group 4	Date: 06/01/09	# Pages 57

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Executive Summary

Southwest Power Pool, Inc. (SPP) has commissioned ABB Inc. to perform a system impact study for approximately 1004 MW of wind-based generation (collectively known as Group 4 Projects) on the SPP system. The proposed windfarms are located in Northwest Kansas. Below are the details of the Group 4 wind farm projects:

Request	Size	Wind Turbine Technology	Point of Interconnection	County
GEN-2007-012	300	Acciona 1.5 MW	Mingo - Red Willow 345Kv (#531436)	Rawlins, Kansas
GEN-2007-047	204	Acciona 1.5 MW	Mingo 115kV (#531429)	Thomas, Kansas
GEN-2008-001	200	Gamesa 2.0 MW	Knoll 230kV (#530558)	Ellis, Kansas
GEN-2008-017	300	GE 1.5 MW	Setab 345kV (#531465)	Scott, Kansas

The main objectives of this study were

1) To determine the need of reactive power compensation, if any, for the proposed wind farms
2) To determine the impact of proposed Group 4 (1004 MW) generation on system stability and the nearby transmission system and generating stations.
3) To validate the compliance with FERC LVRT requirement for wind farms.

To achieve these objectives the following analyses were performed on the 2010 Summer Peak and 2010 Winter Peak system conditions with Group 4 projects in-service

- Power factor analysis for the selected contingencies.
- Transient stability analysis under various local and regional contingencies.
- LVRT performance under selected contingencies near POI.

Following is the summary of study findings:

<u>Power factor analysis</u>
The power factor analysis was performed to determine the need of additional reactive power compensation, if any, for the Group4 wind farm projects. The results of power factor analysis indicated that all the Group 4 projects, ***<u>except</u>*** GEN-2008-001 wind farm project, have the adequate reactive power capability to meet the power factor requirement at the POI.

For GEN-2008-001 (200 MW) wind farm project, total of 50 Mvar shunt compensation (25 Mvar at each 34.5 kV collector bus) is required to meet SPP's power factor and voltage requirement at the POI.

It should be noted that the Gamesa wind turbine generators are doubly fed induction generators (DFIG) with a reactive power capability of +/- 0.95 p.f. In power factor control mode the Gamesa wind turbine generators operate at a constant power factor. Hence, during this study the wind turbine generators were assumed to be operated at fixed unity p.f. at machine terminal. The reactive power required to maintain the acceptable voltage and p.f. at the POI was provided by using shunt capacitors at the 34.5 kV collector bus. The WTGs reactive power capability would influence the sizing of the shunt capacitors. Optimization between the WTG reactive power capacity and the shunt capacitors was not performed in this study.

Stability Analysis

The stability analysis was performed to determine the impact, if any, of the proposed Group 4 projects on the stability of the SPP system. The significant results of stability analysis are as follows:

- The system was found to be UNSTABLE following 3-phase and single-phase faults at Gentleman 345 kV substation. SPP indicated that the instability following faults at Gentleman 345 kV substation is a known modeling problem and has been observed WITHOUT Group 4 projects. Hence, the impact of the Group 4 projects following the fault at Gentleman 345 kV substation can not be quantified. SPP indicated that the effect of interconnection of proposed Group 4 projects on the stability of NPPD system will be addressed during the facility study.
- The system was found to be UNSTABLE following faults involving loss of Mingo 345/115 kV substation (FLT13-3PH and FLT14-1PH). The GEN-2007-047 (204 MW) of the Group 4 projects is connected at Mingo 115 kV substation. Following the loss of Mingo 345/115 kV transformer, total of 312 MW (204 MW of GEN-2007-012 + 108 MW of GEN-2006-040) is pushed onto the underlying 115 kV system.
- Undamped oscillations in the speed of GEN-2008-001 (200 MW comprised of Gamesa 2.0 MW WTGs) were observed following all the simulated faults. Further investigation indicated that the undamped oscillations are due to the user-written model used for representing the Gamesa wind turbine generators. Additional analysis with a better model will be necessary to confirm the impact, if any, on the system performance.
- The system was found to be STABLE following all the simulated faults (except for the fault discussed above) with the Group 4 projects.

FERC Order 661A Compliance

Selected faults were simulated at the Point of Interconnection (POI) of the proposed Group 4 wind farms to determine the compliance with FERC 661 – A post-transition period LVRT standard. The results indicated that all the proposed projects meet the FERC LVRT requirement for windfarms.

Sensitivity Analysis

A sensitivity analysis was performed by considering the proposed change in the interconnection scheme of the GEN-2007-047 wind farm project. According to the proposed change in the interconnection scheme for GEN-2007-047 project the wind farm would interconnect at Mingo 345 kV bus instead of Mingo 115 kV bus.

The power factor analysis and transient stability analysis were repeated. Following is the summary of the results:

Power factor analysis

The results of power factor analysis indicated that all the Group 4 projects, ***except*** GEN-2008-001 wind farm project, have the adequate reactive power capability to meet the power factor requirement at the POI.

For GEN-2008-001 (200 MW) wind farm project, total of 40 Mvar shunt compensation (25 Mvar at each 34.5 kV collector bus) is required to meet SPP's power factor and voltage requirement at the POI.

It should be noted that the Gamesa wind turbine generators are doubly fed induction generators (DFIG) with a reactive power capability of +/- 0.95 p.f. In power factor control mode the Gamesa wind turbine generators operate at a constant power factor. Hence, during this study the wind turbine generators were assumed to be operated at fixed unity p.f. at machine terminal. The reactive power required to maintain the acceptable voltage and p.f. at the POI was provided by using shunt capacitors at the 34.5 kV collector bus. The WTGs reactive power capability would influence the sizing of the shunt capacitors. Optimization between the WTG reactive power capacity and the shunt capacitors was not performed in this study.

Transient Stability analysis

The results of transient stability analysis indicated that the system would be STABLE following all the simulated faults ***except*** the faults at Gentleman 345 kV substation. As indicated previously the instability following faults at Gentleman 345 kV substation is a known problem and has been observed WITHOUT Group 4 projects. Hence, the impact of the Group 4 projects following the fault at Gentleman 345 kV substation can not be quantified.

As indicated previously, the undamped oscillations in the speed of GEN-2008-001 (200 MW comprised of Gamesa 2.0 MW WTGs) were observed following all the simulated faults.

The results of transient stability analysis indicated that the proposed Group 4 windfarm projects would not have any adverse impact on the stability of the SPP transmission system following simulated faults.

FERC 661A compliance

Selected faults were simulated at the Point of Interconnection (POI) of the proposed Group 4 wind farms to determine the compliance with FERC 661 – A post-transition period LVRT standard. The results indicated that all the proposed projects meet the FERC LVRT requirement for windfarms.

<u>Final Conclusions</u>:

1. The reactive power capability of all the Group 4 wind farm projects, ***<u>except</u>*** GEN-2008-001, is adequate to meet the interconnection requirement.
2. The proposed Group 4 wind farm projects do not adversely impact the stability of the SPP transmission system ***<u>except</u>*** for the faults involving loss of Mingo 345/115 kV transformer
3. The UNSTABLE system condition following loss of Mingo 345/115 kV transformer was not observed with the new proposed interconnection scheme for GEN-2007-047 (interconnecting at Mingo 345 kV instead of Mingo 115 kV)
4. All the proposed Group 4 wind farm projects meet the FERC 661A LVRT criteria for windfarm interconnection.

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

Rev No.	Revision Description	Date	Authored by	Reviewed by	Approved by
0	Draft Report	06/01/09	Trinadh	A. Kekare	W. Wong
1	Sensitivity Analysis added	06/18/09	Trinadh	A. Kekare	W. Wong
2	FINAL REPORT	06/29/09	Trinadh	A. Kekare	W. Wong
DISTRIBUTION: Charles Hendrix – Southwest Power Pool, Inc. Ray Offenbacker – Southwest Power Pool, Inc.					

TABLE OF CONTENTS

1 INTRODUCTION

Southwest Power Pool, Inc. (SPP) has commissioned ABB Inc. to perform a system impact study for approximately 1004 MW of wind-based generation (collectively known as Group 4 Projects) on the SPP system. There are total four (4) generation projects (see Table 1-1). The proposed windfarms are located in Northwest Kansas. Figure 1-1 shows the locations of Group 4 projects with proposed 1004 MW generation.

The study evaluated the "collective impact" of the Group 4 generation projects on the stability of the SPP system. The scope of this study was limited to the transient stability analysis.

The main objectives of this study were

1) To determine the need of reactive power compensation, if any, for the proposed wind farms
2) To determine the impact of proposed Group 4 (1000 MW) generation on system stability and the nearby transmission system and generating stations.
3) To validate the compliance with FERC LVRT requirement for wind farms.

To achieve these objectives the following analyses were performed on the 2010 Summer Peak and 2010 Winter Peak system conditions with Group 4 projects in-service

- o Power factor analysis for the selected contingencies.
- o Transient stability analysis under various local and regional contingencies.
- o LVRT performance under selected contingencies near POI.

The study was performed on 2010 Summer Peak and winter peak cases, provided by SPP. This report documents the methods, analysis and results of the system impact study.

Table 1-1: List of Group 4 Projects

Request	Size	Wind Turbine Model	Point of Interconnection	County
GEN-2007-012	300	Acciona 1.5 MW	Mingo - Red Willow 345Kv (#531436)	Rawlins, Kansas
GEN-2007-047	204	Acciona 1.5 MW	Mingo 115kV (#531429)	Thomas, Kansas
GEN-2008-001	200	Gamesa 2.0 MW	Knoll 230kV (#530558)	Ellis, Kansas
GEN-2008-017	300	GE 1.5 MW	Setab 345kV (#531465)	Scott, Kansas

1.1 REPORT ORGANIZATION

This report is organized as follows:

Section 2: Description of proposed Group 4 Projects
Section 3: Study methodology
Section 4: Model Development
Section 5: Power Factor Analysis Results
Section 6: Stability Analysis Results
Section 7: Conclusions

The detailed study results are compiled in separate Appendices.

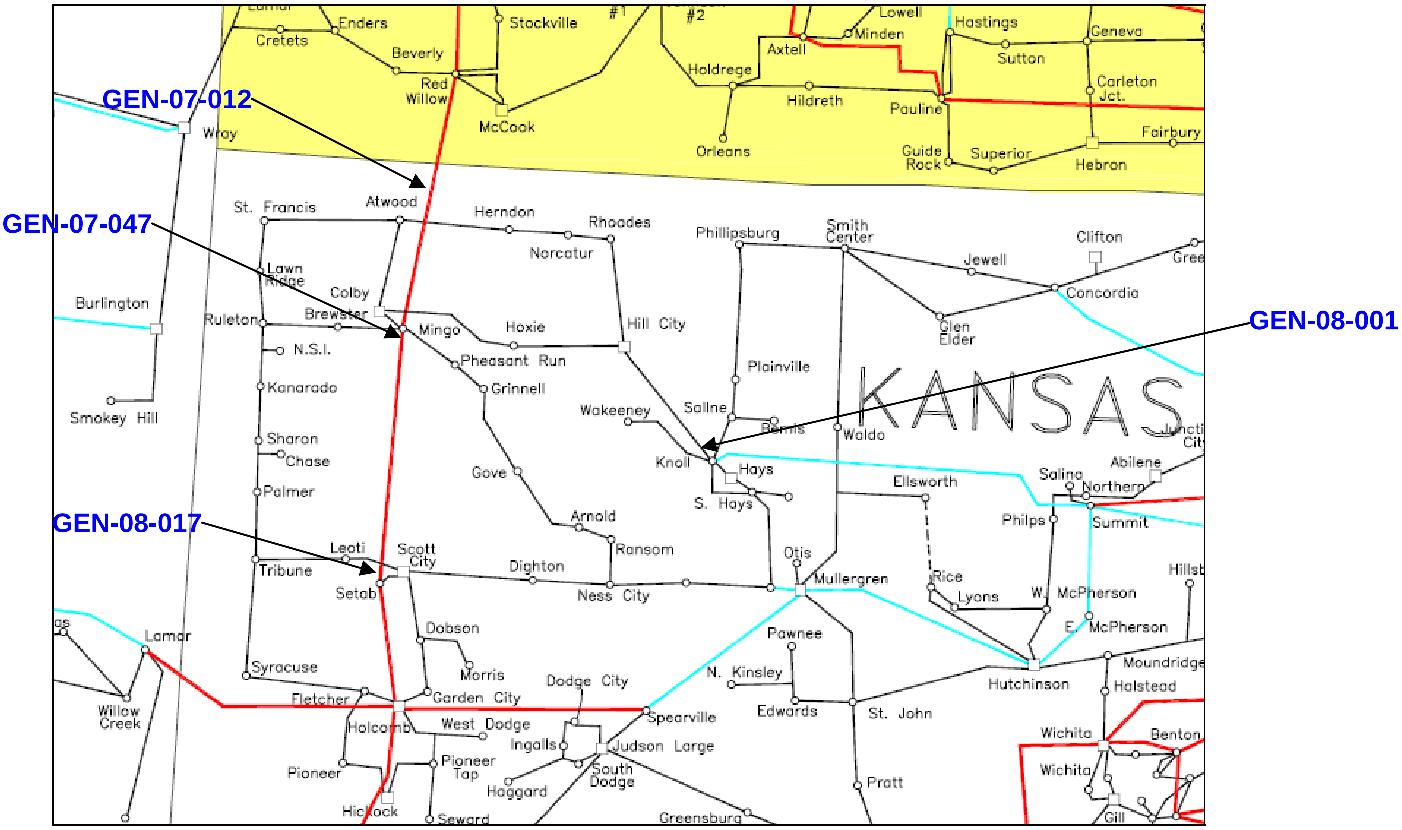

Figure 1-1 Group 4 Project locations

2 DESCRIPTION OF GROUP 4 PROJECTS

The details of load flow and dynamic data for the Group 4 wind farm projects are included in the Appendix A.

2.1 GEN-2007-012

- Wind farm rating: 300 MW
- Interconnection:

  Voltage: 345 kV

  Location: Nebraska Public Power District (NPPD) Mingo – Red Willow 345 kV line; within Sunflower Electric Corporation (SUNC). The windfarm will be connected to the proposed POI via 17.6 miles 345 kV line.

  Transformer: Two (2) step-up transformers connecting to the 345 kV

  MVA: 120/160/200 MVA

  Voltage: 345/34.5/6.9 kV

  Z: 9.99 % on 120 MVA
- Wind Turbines:

  Number: Two hundred (200)

  Manufacturer: Acciona

  Type: Doubly-fed induction generator (DFIG)

  Machine Terminal voltage: 12 kV

  Rated Power: 1.5 MW

  Frequency: 60 Hz

  Generator Step-up Transformer

  MVA: 1.7
  High voltage: 34.5 kV,
  Low voltage: 12.0 kV
  Z: 6.0% on 1.7 MVA
- Reactive Power Capability: 0.95 lagging/ 0.95 leading
- Fault Ride-through: Manufacturer's default ride-through capability was modeled
- Frequency tolerance: 57.0 – 63.0 Hz, a continuous operation
- Project protection: Overvoltage

  Undervoltage

  Overfrequency

  Underfrequency
- PSSE Model Used AW1500_60HZ_rev30-2

No additional reactive power compensation (e.g. shunt capacitor bank) was modeled for the proposed GEN-2007-012 Windfarm.

Figure 2-1 shows the one-line diagram of the GEN-2007-012 windfarm.

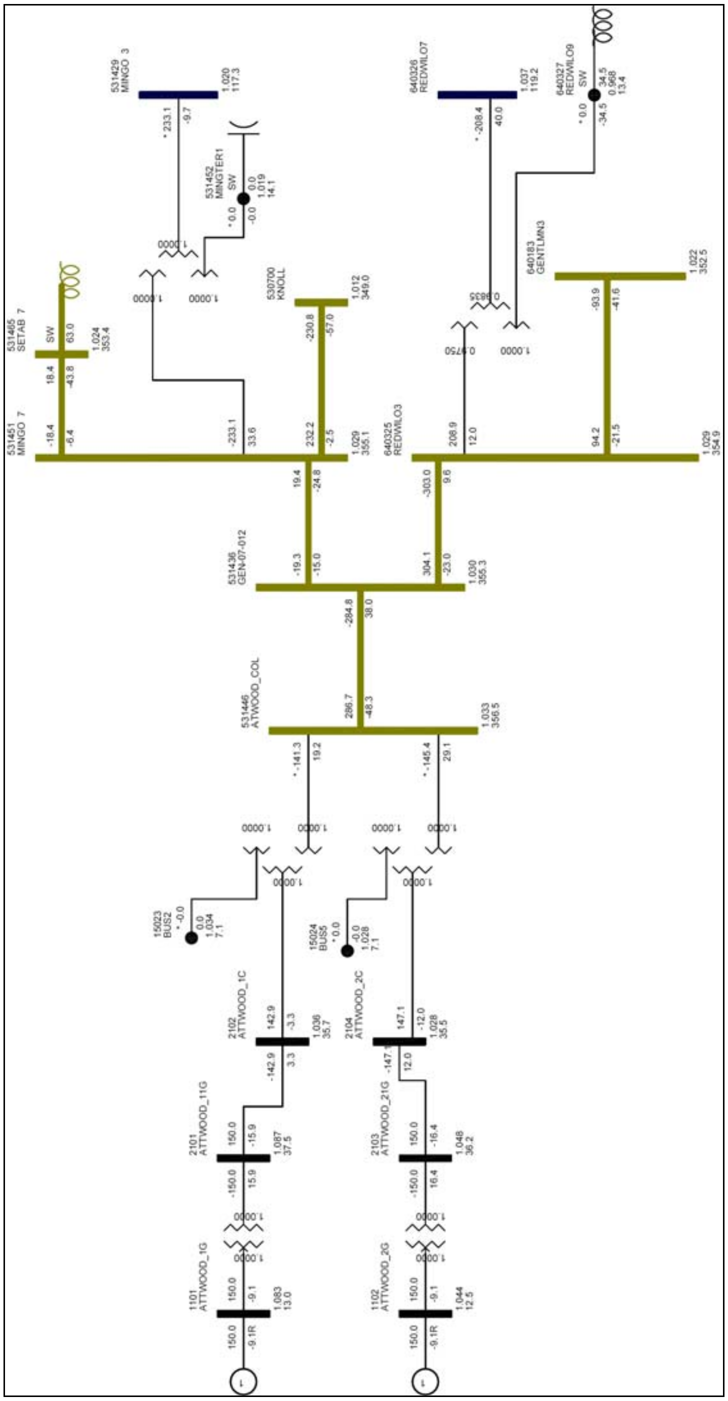

Figure 2-1 One-line diagram for GEN-2007-012 Project

2.2 GEN-2007-047

- Wind farm rating: 204 MW
- Interconnection:

  Voltage: 115 kV

  Location: Existing Mingo 115 kV substation; owned by Sunflower Electric Corporation (SUNC). The windfarm was assumed to be connected to Mingo 115 kV substation via 5 miles of 115 kV line.

  Transformer: Two (2) step-up transformers connecting to the 115 kV

  MVA: 75/100 MVA

  Voltage: 115/34.5 kV

  Z: 8.00 % on 75 MVA

- Wind Turbines:

  Number: One hundred and thirty six (136)

  Manufacturer: Acciona

  Type: Doubly-fed induction generator (DFIG)

  Machine Terminal voltage: 12 kV

  Rated Power: 1.5 MW

  Frequency: 60 Hz

  Generator Step-up Transformer

  MVA: 1.7
  High voltage: 34.5 kV,
  Low voltage: 12.0 kV
  Z: 6.0% on 1.7 MVA

- Reactive Power Capability: 0.95 lagging/ 0.95 leading
- Fault Ride-through: Manufacturer's default ride-through capability was modeled
- Frequency tolerance: 57.0 – 63.0 Hz, a continuous operation
- Project protection: Overvoltage

  Undervoltage

  Overfrequency

  Underfrequency

- PSSE Model Used AW1500_60HZ_rev30-2

No additional reactive power compensation (e.g. shunt capacitor bank) was modeled for the proposed GEN-2007-047 windfarm.

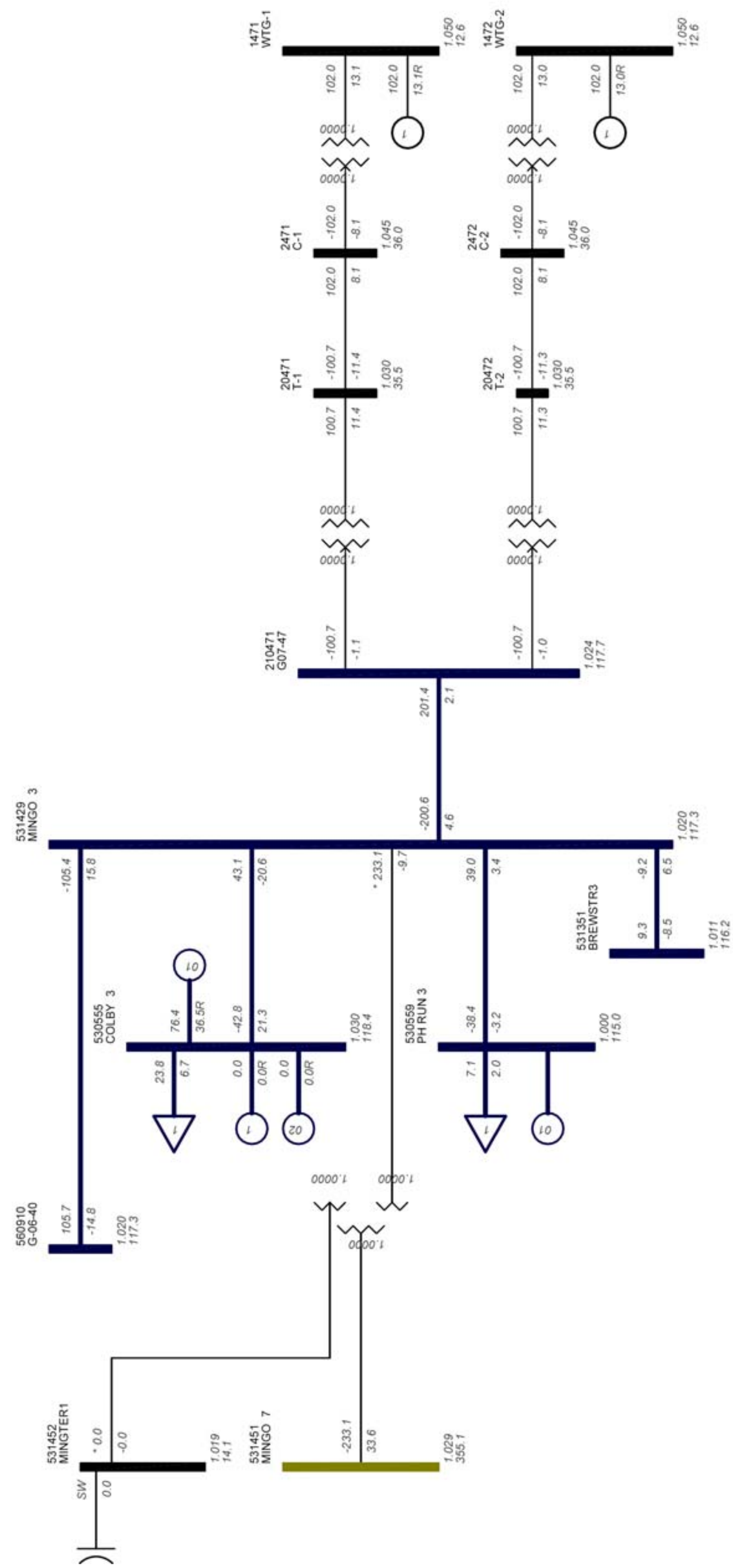

Figure 2-2: one-line diagram for GEN-2007-047 Project

2.3 GEN-2008-001

- Wind farm rating: 200 MW
- Interconnection:

  Voltage: 230 kV

  Location: Existing Knoll 230 kV substation; owned by Midwest Energy. The windfarm was assumed to be interconnected via 18 miles of 230 kV line.

  Transformer: Two (2) step-up transformers connecting to the 230 kV

  MVA: 60/80/100 MVA

  Voltage: 230/34.5

  Z: 9.00 % on 60 MVA

- Wind Turbines:

  Number: One hundred (100)

  Manufacturer: Gamesa G87

  Type: Doubly-fed induction generator (DFIG)

Machine Terminal voltage: 690 V

  Rated Power: 2.0 MW

  Frequency: 60 Hz

  Generator Step-up Transformer

  MVA: 2.5
  High voltage: 34.5 kV,
  Low voltage: 0.690 kV
  Z: 6.0% on 2.5 MVA

- Reactive Power Capability++[1]:Fixed p.f. (+/- 0.95 p.f); Modeled at fixed unity p.f.
- Fault Ride-through: Manufacturer's default ride-through capability was modeled
- Frequency tolerance: 57.0 – 63.0 Hz, a continuous operation
- Project protection: Overvoltage

  Undervoltage

  Overfrequency

  Underfrequency

- PSSE Model Used GXX001V303

1 ++ The Gamesa G87 2.0 MW wind turbine generators are doubly fed induction generators with +/- 0.95 p.f reactive power capability. In the power factor control mode, the wind turbine generators are operated at constant power factor. For the purpose of this study the wind turbine generators were assumed to be operated at fixed unity p.f. The additional reactive power compensation, if any, was determined by the power factor analysis.

Total of 50 Mvar (25 Mvar on each 34.5 kV collector system) was modeled for the GEN-2008-001 windfarm (see section 5.3 for details).

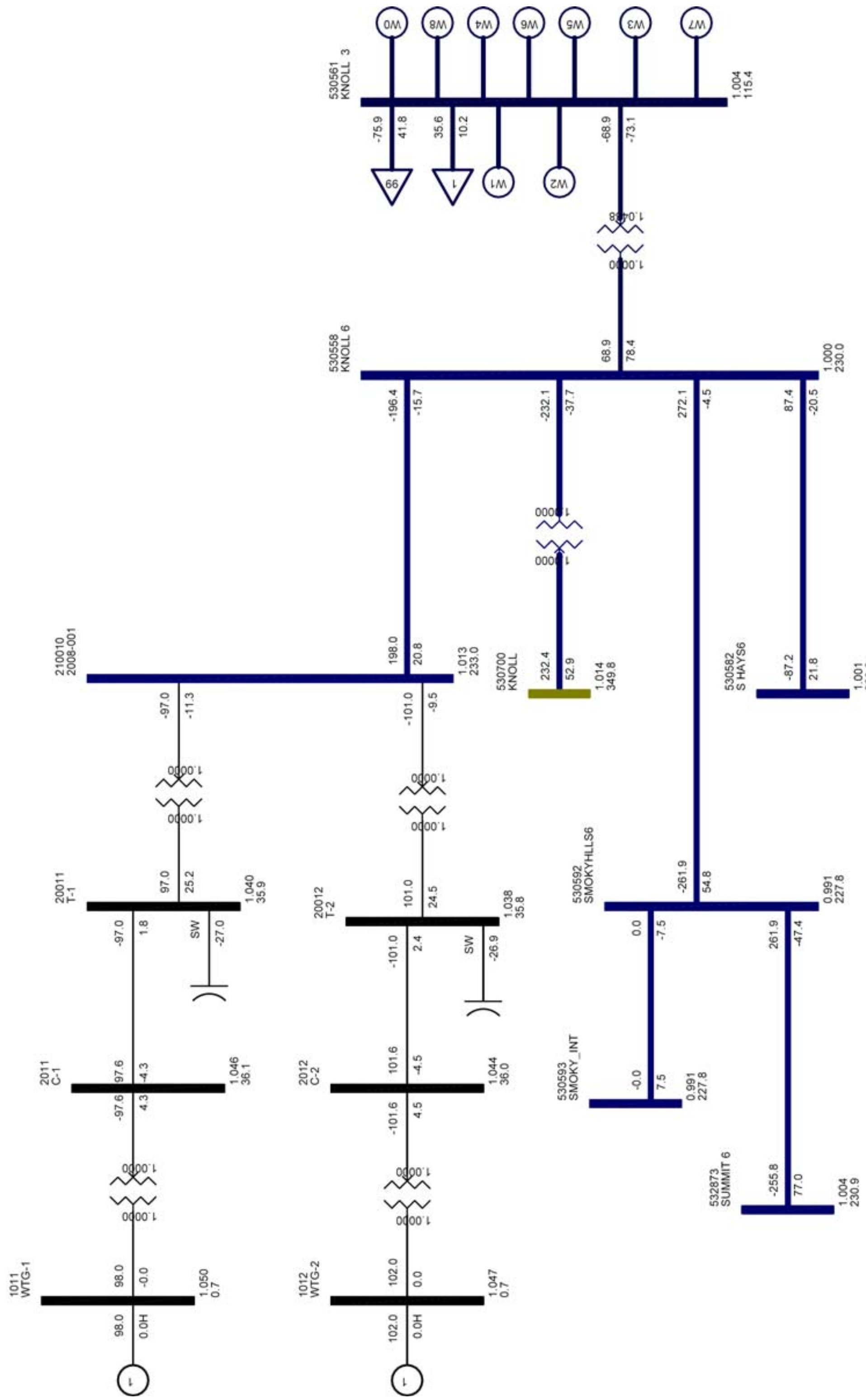

Figure 2-3: One-line diagram for GEN-2008-001 Project

2.4 GEN-2008-017

- Wind farm rating: 300 MW
- Interconnection:

  Voltage: 345 kV

  Location: Existing Setab 345 kV substation; owned by Sunflower Electric Corporation (SUNC). The windfarm was assumed to be connected to Setab 345 kV substation via 15 miles of 345 kV line.

  Transformer: Three (3) step-up transformers connecting to the 345 kV

  MVA: 100/133/167 MVA

  Voltage: 345/34.5

  Z: 7.5 % on 100 MVA

- Wind Turbines:

  Number: Two hundred (200)

  Manufacturer: GE

  Type: Doubly-fed induction generator (DFIG)

  Machine Terminal voltage: 575 V

  Rated Power: 1.5 MW

  Frequency: 60 Hz

  Generator Step-up Transformer

  MVA: 1.75
  High voltage: 34.5 kV,
  Low voltage: 0.575 kV
  Z: 5.75% on 1.7 MVA

- Fault Ride-through: Zero voltage rid through (ZVRT) capability was assumed.
- Frequency tolerance: 57.0 – 63.0 Hz, a continuous operation
- Project protection: Overvoltage

  Undervoltage

  Overfrequency

  Underfrequency

- PSSE Model Used psse_gewt_w5

No additional reactive power compensation (e.g. shunt capacitor bank) was modeled for the proposed GEN-2008-017 Windfarm.

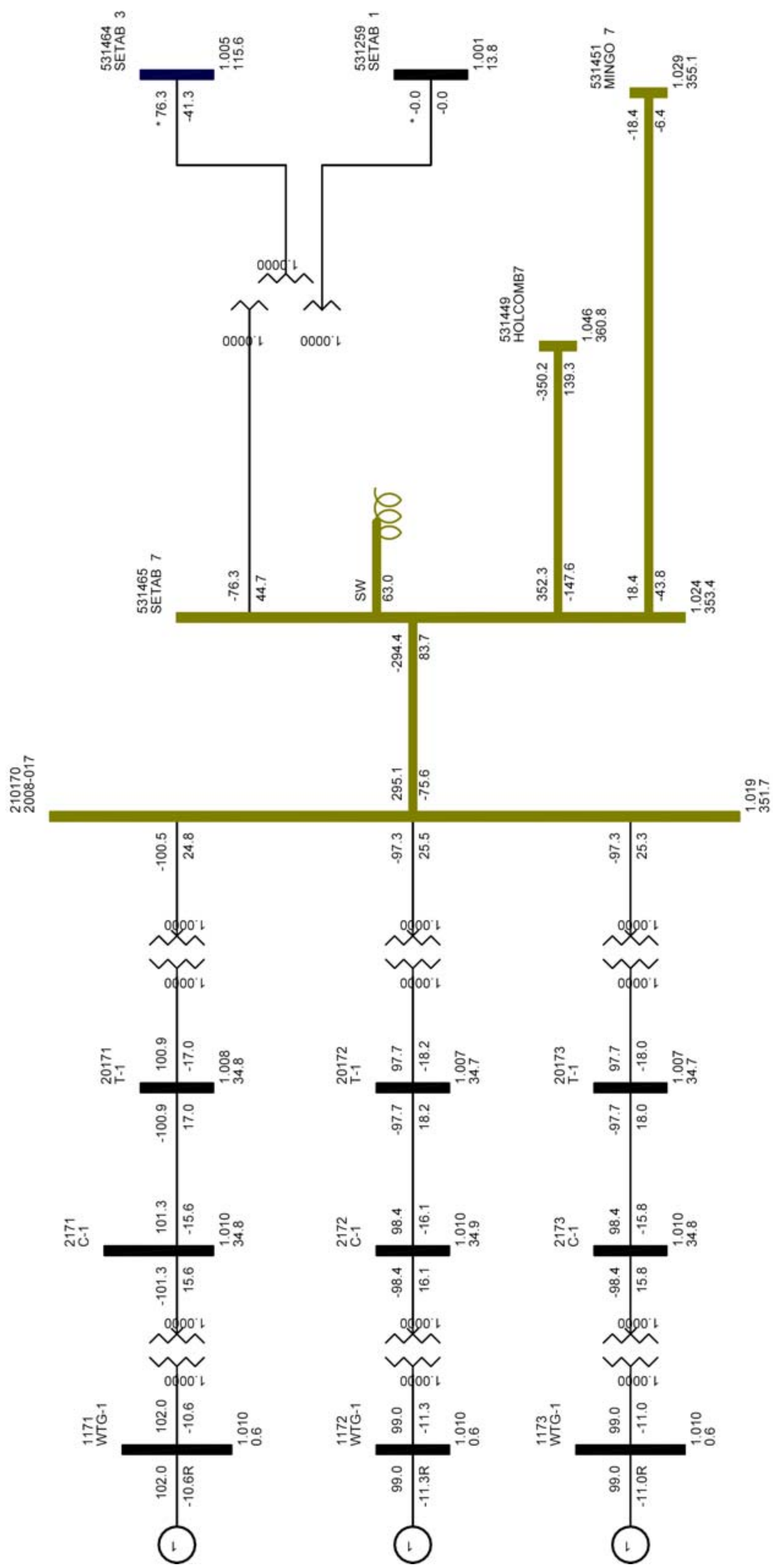

Figure 2-4: one-line diagram for GEN-2008-017 Project

3 STUDY METHODOLOGY

3.1 POWER FACTOR ANALYSIS

SPP transmission planning criteria[2] requires the generation interconnection projects

a. To maintain the power factor at the Point of Interconnection (POI) to near-unity for system intact conditions and within lag/lead 0.95 p.f. range for post-contingency conditions ,and

If the reactive power capability of the proposed project is not adequate to meet the above-mentioned requirements then additional reactive power compensation (e.g. shunt capacitors) need to be added.

The purpose of the power factor analysis was to determine whether the proposed wind farm projects will meet the power factor requirement at the Point of Interconnection (POI) in system intact and contingency conditions.

This analysis was performed for each wind farm project at a time, considering the other wind farms to be on-line at maximum output and without additional reactive power compensation. Following steps were taken to perform the power factor analysis:

- A VAR generator with large capacity (+/- 9999 Mvar) was modeled at the POI of the subject wind farm. The VAR generator was set to hold the POI voltage consistent with the voltage schedule in the provided base case or 1.00 p.u. (whichever was higher). The reactive power capability of the wind farm was set to zero.
- A list of selected contingencies in the vicinity of the subject windfarm project was simulated. The results were used to identify the most-limiting contingency from steady state voltage and power factor perspective.
- If the required reactive power support, to maintain an acceptable power factor at the POI, was found to be beyond the capability of proposed windfarm then the additional reactive power compensation (e.g. shunt capacitor banks) was considered.

It is important to note that the reactive power compensation identified in this analysis was primarily to meet steady state criteria. The need for dynamic reactive power support, if any, will be determined during transient stability analysis.

3.2 TRANSIENT STABILITY ANALYSIS

The purpose of the transient stability analysis was to determine the “collective impact”, if any, of the Group 4 wind farm projects on the system stability and the nearby transmission system and generating stations.

Using Planning Standards approved by NERC, the following stability definition was applied in the Transient Stability Analysis:

[2] The SPP transmission planning criteria was provided for the purpose of this study.

"Power system stability is defined as that condition in which the differences of the angular positions of synchronous machine rotors become constant following an aperiodic system disturbance."

Stability analysis was performed using Siemens-PTI's PSS/E™ dynamics program V30.3.2. Three-phase and single-line-to-ground (SLG) faults were simulated for the specified duration and synchronous machine rotor angles and wind turbine generator speeds were monitored to check whether synchronism is maintained following fault removal.

For three-phase faults, a fault admittance of –j2E9 was used (essentially infinite admittance or zero impedance). The PSS/E dynamics program only simulates the positive sequence network. Unbalanced faults (like single-phase line faults) involve the positive, negative, and zero sequence networks. For unbalanced faults, the equivalent fault admittance was inserted in the PSS/E positive sequence model between the faulted bus and ground to simulate the effect of the negative and zero sequence networks. For a single-line-to-ground (SLG) fault, the fault admittance equals the inverse of the sum of the positive, negative and zero sequence Thevenin impedances at the faulted bus. Since PSS/E inherently models the positive sequence fault impedance, the sum of the negative and zero sequence Thevenin impedances needs to be added and entered as the fault impedance at the faulted bus. The fault impedance was estimated to give a positive sequence voltage at the fault location of approximately 60% of pre-fault voltage, which is a typical value.

Another important aspect of the stability analysis was to determine the ability of the wind generators to stay connected to the grid during disturbances. This is primarily determined by their low-voltage ride-through capabilities – or lack thereof – as represented in the models by low-voltage trip settings. The Federal Energy Regulatory Commission (FERC) Post-transition period LVRT standard for Interconnection of Wind generating plants includes a Low Voltage Ride Through (LVRT) requirement. The key features of LVRT requirements are:

- A wind generating plant must remain in-service during three-phase faults with normal clearing (maximum 9 cycles) and single-line-to-ground faults with delayed clearing, and have subsequent post-fault recovery to pre-fault voltage unless the clearing of the fault effectively disconnects the generator from the system.
- The maximum clearing time the wind generating plant shall be required to withstand a three-phase fault shall be 9 cycles after which, if the fault remains following the location-specific normal clearing time for three-phase faults, the wind generating plant may disconnect from the transmission system. A wind generating plant shall remain interconnected during such a fault on transmission system for a voltage level as low as zero volts, as measured at the high voltage side of the GSU connected at POI.

These criteria were used to evaluate the LVRT capabilities of the Group 4 Projects.

4 MODEL DEVELOPMENT

Two power flow cases – "ICS08-01_G4_10SP.sav" and "ICS08-01_G4_10WP.sav" – representing the 2010 Summer Peak and Winter Peak conditions were provided by SPP. The base cases included all the Group 4 projects ***except*** GEN-2007-012 (300 MW) wind farm project.

4.1 MODEL DEVELOPMENT FOR GEN-2007-012

The details of the GEN-2007-012 wind farm project are provided in section 2.1. The proposed GEN-2007-012 wind farm (300 MW) will be comprised of two hundred (200) Acciona 1.5 MW doubly fed induction generators (DFIG).

The proposed wind farm was modeled by using two single equivalent wind turbine-generators, each representing hundred (100) Acciona 1.5 MW wind turbine generators. The wind turbine generators were modeled in voltage control mode to maintain 1.03 p.u. voltage at POI (consistent with voltage WITHOUT GEN-2007-012 project). A lumped equivalent of generator step-up transformer (GSU) was modeled connecting the single equivalent generators to the equivalent collector system at 34.5 kV. The equivalent collector system impedance was calculated based on the information provided by SPP. The collector system was connected to 345 kV through two (2) 34.5/345/6.9 kV transmission step-up transformers. The proposed windfarm was connected to the 345 kV POI through 17.6 miles 345 kV line. Figure 2-1 shows the one-line diagram for the GEN-2007-012 wind farm project.

The GEN-2007-012 (300 MW) project was dispatched against the generation subsystem provided by SPP. The list of generation buses is included in **Error! Reference source not found.** for reference.

Thus two power flow cases including the GEN-2007-012 were established and named as 'ICS08-01_G4_10SP+GEN-07-012.sav' (2010 summer peak) and 'ICS08-01_G4_10WP+GEN-07-012.sav' (2010 winter peak).

Figure 4-1 and Figure 4-2 show the one-line diagram in the local area of Group 4 projects for 2010 summer peak and 2010 winter peak system conditions respectively.

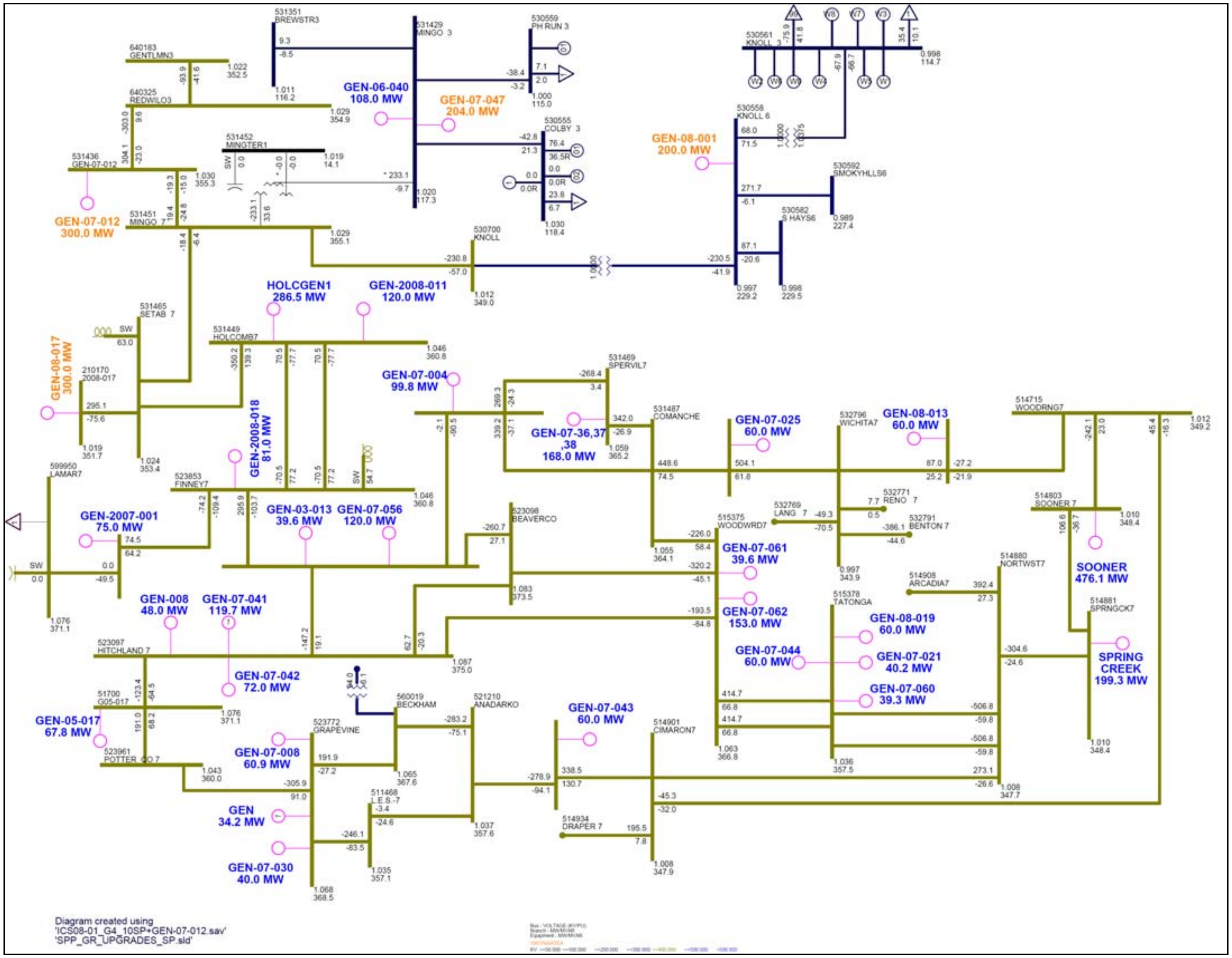

Figure 4-1 One-line Diagram of the local area with Group 4 Projects (2010 Summer Peak)

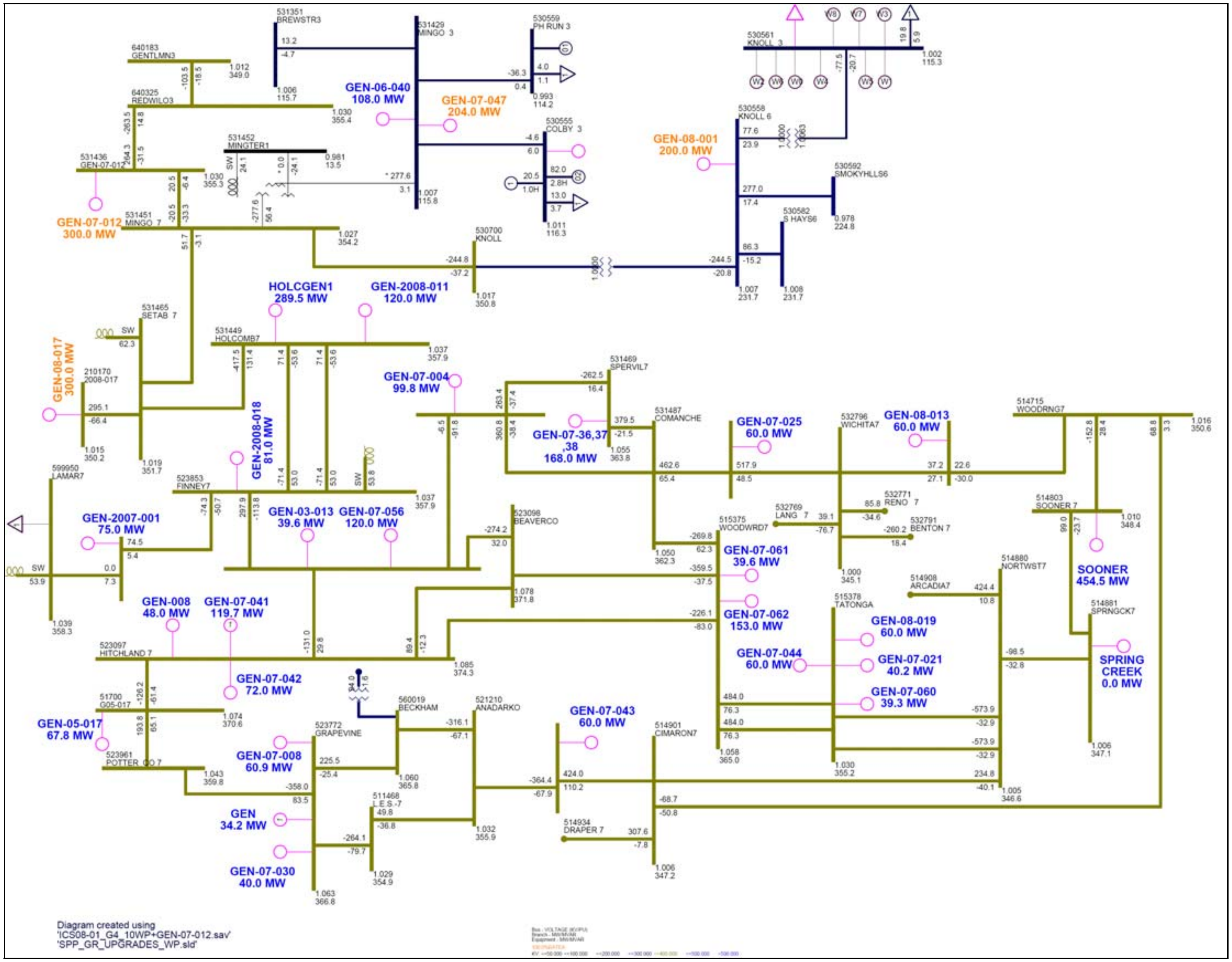

Figure 4-2 One-line Diagram of the local area with Group 4 Projects (2010 Winter Peak)

5 POWER FACTOR ANALYSIS RESULTS

Table 5-1 lists the contingencies simulated for Power Factor analysis.

Table 5-1: List of contingencies simulated for Power Factor Analysis

Contingency Name	Contingency Description
CONT_01	Setab (531465) to Holcomb (531449) 345kV line
CONT_02	Setab (531465) to Mingo (531451) 345kV line
CONT_03	Setab 345kV (531465) to 115kV (531464) transformer
CONT_04	Mingo (531451) to Setab (531465) 345kV line
CONT_05	Mingo (531451) to GEN-2007-012 (????) 345kV line
CONT_06	Mingo (531451) to Knoll (530700) 345kV line
CONT_07	Mingo 345kV (531451) to 115kV (531429) transformer
CONT_08	GEN-2007-012 (531436) to Mingo (531451) 345kV line
CONT_09	GEN-2007-012 (531436) to Red Willow (640325) 345kV line
CONT_10	Gentleman (640183) to Keystone (640252) 345kV line
CONT_11	Gentleman (640183) to Sweetwater (640374) 345kV line
CONT_12	Colby (530555) to Hoxie (530556) 115kV line
CONT_13	Colby (530555) to Atwood (530554) 115kV line
CONT_14	Holcomb (531449) to GEN-2007-040 (210400) 345kV line
CONT_15	Holcomb 345kV (531449) to 115kV (531448) transformer
CONT_16	Finney (523853) to GEN-2007-019 (210190) 345kV line
CONT_17	Finney (523853) to GEN-2003-013 (560029) 345kV line
CONT_18	Knoll (530558) to Smoky Hill (530592) 230kV line
CONT_19	Knoll (530558) to South Hays (530582) 230kV line
CONT_20	Knoll 230kV (530558) to 345kV (530700) transformer
CONT_21	Knoll 230kV (530558) to 115kV (530561) transformer
CONT_22	Knoll (530561) to Saline (530551) 115kV line
CONT_23	Knoll (530561) to Redline (530605) 115kV line
CONT_24	South Hays (530582) to Mullergren (539679) 230kV line
CONT_25	Mullergren (539679) to Circle (532871) 230kV line
CONT_26	Summit (532873) to Morris (532863) 230kV line
CONT_27	Summit (532873) to E. McPherson (532872) 230kV line
CONT_28	Summit 230kV (532873) to 345kV (532773) transformer

Power factor analysis was performed for each of the windfarm project in Group 4.

5.1 Power Factor Analysis results for GEN-2007-012

The proposed GEN-2007-012 windfarm (300 MW) will be comprised of Acciona 2.0 MW wind turbine generators. These wind turbine generators are doubly fed induction generators (DFIG) with a reactive power capability of +/- 0.95 p.f. The wind turbine generators were modeled in voltage control mode.

Next, as described in section 3.1, the VAR generator was modeled at POI. The VAR generator was set to hold the 345 kV POI voltage consistent with the pre-contingency voltage schedule in the provided base cases. The reactive power capability of the wind farm was set to zero.

The contingencies from Table 5-1 were simulated on 2010 summer peak and 2010 winter peak system conditions. Table 5-2 lists the VARs provided by the VAR generator at POI following the simulated contingencies.

Table 5-2 VAR generator output at the GEN-07-012 POI

Contingency	2010 summer peak	2010 winter peak
SYSTEM INTACT (ALL LINES IN-SERVICE)	15.3**	15.9**
CONT_01	**94**	**107.9**
CONT_02	11	6
CONT_03	24.9	23.2
CONT_05	6.4	10.8
CONT_06	7.6	7.1
CONT_07	7.8	0*
CONT_09	43.8	54.6
CONT_10	10.8	16.8
CONT_11	9.7	11.5
CONT_12	3.8	3.6
CONT_13	11.3	14.8
CONT_14	23.1	24.3
CONT_15	21.4	21.3
CONT_16	8.4	14.8
CONT_17	4.0	4
CONT_18	1.5	13.3
CONT_19	11.0	13.1
CONT_20	57.1	44.4
CONT_21	23.5	17.4
CONT_22	13.4	13.4
CONT_23	18.5	15.1
CONT_24	7.3	1.4
CONT_25	8.7	11.4
CONT_26	14.3	14.6
CONT_27	15.0	15.5
CONT_28	9.1	11.2

**The reactive power capability of the wind farm was set to unity p.f at machine terminal (i.e Qmax=Qmin=Qgen= 0 Mvar).

The results indicated that the *CONT_01*: loss of Setab – Holocomb 345 kV line will yield the maximum reactive power output for GEN-2007-012.

In addition to the above analysis, the list of contingencies was repeated without the VAR generator at the POI. The voltage at the POI was monitored. The results of the contingency analysis are included in **Error! Reference source not found.**. The *CONT_01*: loss of Setab – Holocomb 345 kV line resulted in lowest voltage at POI in post-contingency conditions in both summer peak and winter peak system conditions.

Next, the '*CONT_01*' was repeated without the VAR generator. The Table 5-3 summarizes the results of the post-contingency voltage and p.f. at the POI. The results indicated that the GEN-2007-012 wind farm has adequate reactive power capability to maintain required p.f. and the voltage at the POI in system intact and in post-contingency conditions for simulated contingencies. Hence, GEN-2007-012 wind farm does not require any additional reactive power support (e.g. shunt capacitor banks etc.).

Table 5-3: Voltage & p.f. at POI without VAR generator:GEN-2007-012

System condition		Voltage (in p.u.)	P.F.	Additional Mvars from the system at 345 kV POI	Acceptable POI voltage?	Acceptable POI p.f.?
2010 summer peak	System Intact	1.03	0.9931	33.7	YES	YES
	Post-cotingency (1)	1.03	0.9600	-82.0	YES	YES
2010 winter peak	System Intact	1.03	0.9928	34.3	YES	YES
	Post-cotingency (1)	1.03	0.9565	-86.7	YES	YES

(1)'*CONT_01*': Loss of Setab – Holocomb 345 kV line

5.2 POWER FACTOR ANALYSIS RESULTS FOR GEN-2007-047

The proposed GEN-2007-047 windfarm (204 MW) will be comprised of Acciona 2.0 MW wind turbine generators. These wind turbine generators are doubly fed induction generators (DFIG) with a reactive power capability of +/- 0.95 p.f. The wind turbine generators were modeled in voltage control mode.

Next, as described in section 3.1, a VAR generator was modeled at the POI (Mingo 115 kV). The VAR generator was set to hold the POI voltage consistent with the pre-contingency voltage schedule in the provided base cases. The reactive power capability of the wind farm was set to zero.

The contingencies from Table 5-1 were simulated on 2010 summer peak and 2010 winter peak system conditions. Table 5-4 lists the VARs provided by the VAR generator at POI following the simulated contingencies.

Table 5-4 VAR generator output at the GEN-07-047 POI

Contingency	2010 summer peak	2010 winter peak
SYSTEM INTACT (ALL LINES IN-SERVICE)	28.1**	41.2**
CONT_01	**63.4**	**85.5**
CONT_02	31.6	42.2
CONT_03	30.9	45.9
CONT_05	42.6	56.8
CONT_06	21.2	47.8
CONT_07	50.2	**167.8**‡
CONT_09	49.4	67.3
CONT_10	28.1	41.0
CONT_11	31.4	47.4
CONT_12	46.3	61.6
CONT_13	35.6	41.3
CONT_14	42.1	58.3
CONT_15	30.9	43.5
CONT_16	32.1	42.2
CONT_17	35.3	49.5
CONT_18	30.2	38.4
CONT_19	29.1	41.7
CONT_20	0	26.3
CONT_21	23.5	43.7
CONT_22	27.4	45.9
CONT_23	26.2	49.4
CONT_24	37.7	49.9
CONT_25	27.8	39.9
CONT_26	28.4	41.6
CONT_27	28.3	41.5
CONT_28	31.1	43.6

**The reactive power capability of the wind farm was set to unity p.f at machine terminal (i.e Qmax=Qmin=Qgen= 0 Mvar).

‡ The contingency failed to provide solution.

The results indicated that the *CONT_01*: loss of Setab – Holocomb 345 kV line will yield the maximum reactive power output for GEN-2007-047.

In addition to the above analysis, the list of contingencies was repeated without the VAR generator at the POI. The voltage at the POI was monitored. The results of the contingency analysis are included in **Error! Reference source not found.**. The *CONT_01*: loss of Setab – Holocomb 345 kV resulted in lowest voltage at POI in post-contingency conditions for both summer peak and winter peak system conditions.

Next, the '*CONT_01*' was repeated without the VAR generator. The Table 5-5 summarizes the results of the post-contingency voltage and p.f. at the POI. The results indicated that the GEN-2007-047 wind farm has adequate reactive power capability to maintain the required p.f. and the voltage at the POI in system intact and in post-contingency conditions for simulated contingencies. Hence, GEN-2007-047 wind farm does not require any additional reactive power support (e.g. shunt capacitor banks etc.).

Table 5-5 Voltage & p.f. at POI without VAR generator: GEN-2007-047

System condition		Voltage (in p.u.)	P.F.	Additional Mvars from the system at 115 kV POI	Acceptable POI voltage?	Acceptable POI p.f.?
2010 summer peak	System Intact	1.0192	0.9997	4.3	YES	YES
	Post-cotingency (1)	1.0109	0.9998	-3.3	YES	YES
2010 winter peak	System Intact	1.0063	0.9993	-7.5	YES	YES
	Post-cotingency (1)	0.9948	0.9961	-17.7	YES	YES

(1)'*CONT_01*': Loss of Setab – Holocomb 345 kV line

5.3 POWER FACTOR ANALYSIS RESULTS FOR GEN-2008-001

The proposed GEN-2008-001 windfarm (200 MW) will be comprised of Gamesa G87 2.0 MW wind turbine generators. These wind turbine generators are doubly fed induction generators (DFIG) with a reactive power capability of +/- 0.95 p.f. In power factor control mode the Gamesa wind turbine generators operate at a constant power factor. In the base cases provided by SPP the wind turbine generators were assumed to be operated at unity p.f. at the machine terminal (i.e. Qmax= Qmin= 0 Mvar).

A total of 30 Mvar of shunt compensation (15 Mvar capacitor banks at each 34.5 kV collector system) was included in the base cases provided by SPP. The power factor at the POI in system intact condition was 0.9987 lagging for 2010 summer peak and 0.9993 leading for 2010 winter peak.

Next, as described in section 3.1 a VAR generator was modeled at the POI (Knoll 230 kV). The VAR generator was set to hold the 230 kV POI voltage consistent with the pre-contingency voltage schedule in the provided base cases.

The contingencies from Table 5-1 were repeated on 2010 summer peak and 2010 winter peak system conditions. Table 5-6 lists the VAR generator output following the simulated contingencies.

Table 5-6 VAR generator output at the GEN-08-001 POI

Contingency	2010 summer peak	2010 winter peak
SYSTEM INTACT (ALL LINES IN-SERVICE)	0	0
CONT_01	67.1	**82.8**
CONT_02	0	9.6
CONT_03	1.3	0
CONT_05	13	9
CONT_06	44.3	20.3
CONT_07	53	0
CONT_09	**74**	66.4
CONT_10	0	0
CONT_11	15.5	19.9
CONT_12	5.2	1.5
CONT_13	5.5	1.5
CONT_14	26.8	28.4
CONT_15	1.2	1.4
CONT_16	0	2.3
CONT_17	13.8	14.9
CONT_18	13.1	15.1
CONT_19	15.4	11.6
CONT_20	43.6	19.1
CONT_21	23.5	4.8
CONT_22	8.8	5.7
CONT_23	8.1	9.5
CONT_24	38	25
CONT_25	6.5	0

Contingency	2010 summer peak	2010 winter peak
CONT_26	2.7	3
CONT_27	1.1	1.2
CONT_28	19.1	15.5

The results indicated that the *CONT_01*: loss of Setab – Holocomb 345 kV line and *CONT_09:* loss of Red willow – GEN-2007-012 line will yield maximum reactive power output in winter peak and summer peak system conditions respectively.

In addition to the above analysis, the list of contingencies was repeated without the VAR generator at the POI. The voltage at the POI was monitored. The results of the contingency analysis are included in **Error! Reference source not found.**. '*CONT_06*' – Loss of Ming – Knoll 345 kV resulted in the lowest voltage at the POI in summer peak condition.

Hence, the three contingencies ('*CONT_01*' '*CONT_06*' and '*CONT_09*' were repeated without the VAR generator at the POI. The Table 5-7 summarizes the results of the post-contingency voltage and p.f. at the POI.

Table 5-7 Voltage & p.f. at POI without VAR generator: GEN-2008-001

System condition		Voltage (in p.u.)	P.F.	Additional Mvars from the system at 230 kV POI	Acceptable POI voltage?	Acceptable POI p.f.?
2010 summer peak	System Intact	0.9908	0.9987	9.9	YES	YES
	Post-cotingency (2)	0.9468	0.9953	19	NO	YES
	Post-cotingency (3)	0.9369	0.9942	21.1	NO	YES
2010 winter peak	System Intact	1.0031	0.9993	7.5	YES	YES
	Post-cotingency (1)	0.9640	0.9969	15.3	YES	YES

(1)'CONT_01': Loss of Setab – Holocomb 345 kV line,
(2)'CONT_09': Loss of Redwillow-GEN-07-012 345 kv line
(3)'CONT_06': Loss of Mingo – Knoll 345 kV

It can be seen from Table 5-7 that the POI voltage will be less than 0.95 p.u. for summer peak system conditions following CONT_09. Hence, in addition to the 30 Mvar shunt compensation, required for system intact conditions, 20 Mvar (10 Mvar at each 34.5 kV collector system) shunt capacitors were added to bring the voltage at POI above 0.95 p.u in post-contingency conditions. The three contingencies were repeated. The results are summarized in Table 5-8.

Table 5-8 Results for power factor analysis without VAR generator: GEN-2008-001 with additional 20 Mvar (total 50 Mvar) compensation

System condition		Voltage (in p.u.)	P.F.	Additional Mvars from the system at230 kV POI	Acceptable POI voltage?	Acceptable POI p.f.?
2010 summer peak	System Intact	1.0001	0.9968	-15.7	YES	YES
	Post-cotingency (2)	0.9578	0.9996	-5.5	YES	YES
	Post-cotingency (3)	0.9584	0.9995	-5.7	YES	YES
2010 winter peak	System Intact	1.0117	0.9956	-18.4	YES	YES
	Post-cotingency (1)	0.9696	0.9991	-8.4	YES	YES

(1)'CONT_01': Loss of Setab – Holocomb 345 kV line,
(2)'CONT_09': Loss of Redwillow-GEN-07-012 345 kv line

(3)'CONT_06' Loss of Mingo – Knoll 345 kV line

The results of power factor analysis indicated that total of 50 Mvar (25 Mvar at each 34.5 kV collector system) shunt compensation will be required to meet the required p.f. and the voltage at the POI in system intact and in post-contingency conditions for simulated contingencies.

It should be noted that the Gamesa wind turbine generators are doubly fed induction generators (DFIG) with a reactive power capability of +/- 0.95 p.f. In power factor control mode the Gamesa wind turbine generators operate at a constant power factor. Hence, during this study the wind turbine generators were assumed to be operated at fixed unity p.f. at machine terminal. The reactive power required to maintain the acceptable voltage and p.f. at the POI was provided by using shunt capacitors at the 34.5 kV collector bus. The WTGs reactive power capability would influence the sizing of the shunt capacitors. Optimization between the WTG reactive power capacity and the shunt capacitors was not performed in this study.

5.4 POWER FACTOR ANALYSIS RESULTS FOR GEN-2008-017

The proposed GEN-2008-017 windfarm (300 MW) will be comprised of GE 1.5 MW wind turbine generators. These wind turbine generators are doubly fed induction generators (DFIG) with a reactive power capability of +/- 0.95 p.f. The wind turbine generators were modeled in voltage control mode.

Next, as described in section 3.1 a VAR generator was modeled at the POI (Setab 345 kV). The VAR generator was set to hold the 345 kV POI voltage consistent with the pre-contingency voltage schedule in the provided base cases. The reactive power capability of the wind farm was set to zero.

The contingencies from Table 5-1 were repeated on 2010 summer peak and 2010 winter peak system conditions. Table 5-9 lists the VARs provided by the VAR generator at POI following the simulated contingencies.

Table 5-9 VAR generator output at the GEN-08-017 POI

Contingency	2010 summer peak	2010 winter peak
SYSTEM INTACT (ALL LINES IN-SERVICE)	34.5**	24.9**
CONT_01	**117.7**	**117**
CONT_02	8.7	16.8
CONT_03	76.9	62
CONT_05	10.8	2.9
CONT_06	13.5	10.5
CONT_07	0	0
CONT_09	49.6	57.2
CONT_10	34.6	25.9
CONT_11	19.4	3.1
CONT_12	24	13.7
CONT_13	31.6	24.5
CONT_14	37	48.4
CONT_15	65.5	53.4
CONT_16	10.5	5.5
CONT_17	10.6	22.2
CONT_18	14.8	10
CONT_19	31	21.6
CONT_20	46.4	23.6
CONT_21	39.7	25.5
CONT_22	32.5	22.6
CONT_23	36.9	24.2
CONT_24	6.4	2
CONT_25	28.5	19.1
CONT_26	33.6	23.7
CONT_27	33.8	24.1
CONT_28	30	21.2

**The reactive power capability of the wind farm was set to unity p.f at machine terminal (i.e Qmax=Qmin=Qgen= 0 Mvar).

The results indicated that the *CONT_01*: loss of Setab – Holocomb 345 kV line will yield the maximum reactive power output for GEN-2008-017 in summer peak and winter peak conditions.

In addition to the above analysis, the list of contingencies was repeated without the VAR generator at the POI. The voltage at the POI was monitored. The results of the contingency analysis are included in **Error! Reference source not found.**. The *CONT_01*: loss of Setab – Holocomb 345 kV line resulted in lowest voltage at POI in post-contingency conditions in both summer peak and winter peak system conditions.

Hence, the '*CONT_01*' was repeated without the VAR generator. The Table 5-10 summarizes the results of the post-contingency voltage and p.f. at the POI. The results indicated that the GEN-2008-017 wind farm has adequate reactive power capability to maintain the acceptable p.f. at the POI in system intact and in post-contingency conditions for simulated contingencies. Hence, GEN-2008-017 wind farm does not require any additional reactive power support (e.g. shunt capacitor banks etc.).

Table 5-10 Voltage & p.f. at POI without VAR generator: GEN-2008-017

System condition		Voltage (in p.u.)	P.F.	Additional Mvars from the system at 345 kV POI	Acceptable POI voltage?	Acceptable POI p.f.?
2010 summer peak	System Intact	1.0240	0.9625	82.9	YES	YES
	Post-cotingency (1)	0.9901	0.9970	22.8	YES	YES
2010 winter peak	System Intact	1.0189	0.9700	73.8	YES	YES
	Post-cotingency (1)	0.9879	0.9978	19.2	YES	YES

(1)'*CONT_01*': Loss of Setab – Holocomb 345 kV line

6 STABILITY ANALYSIS RESULTS

Stability simulations were performed to examine the transient behavior of the Group 4 projects and impact of the proposed addition of generation on the SPP system. A number of three-phase and single phase faults with re-closing were simulated. The fault clearing times and re-closing times used for the simulations are given in Table 6-1.

Table 6-1: Fault Clearing Times

Faulted bus kV level	Normal Clearing	Time before reclosing
345	5 cycles	20 cycles
230	5 cycles	20 cycles
115	5 cycles	20 cycles

Table 6-2 lists all the faults simulated for transient stability analysis.

Twenty six (26) three phase and twenty six (26) single-line-to-ground faults with re-closing were simulated. For all cases analyzed, the initial disturbance was applied at t = 0.1 seconds. The breaker clearing was applied at the appropriate time following this fault inception.

Table 6-2 List of Simulated Faults for Group 4 SIS

Cont. No.	Cont. Name	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 FLT01-3PH*
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 FLT03-3PH*
5	FLT05-3PH	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. b. Clear fault after 5 cycles by tripping the faulted transformer.
6	FLT06-1PH	*single phase fault and sequence like FLT05-3PH*
7	FLT07-3PH	3 phase fault on the Mingo (531451) to Setab (531465) 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.
8	FLT08-1PH	*single phase fault and sequence like FLT07-3PH*
9	FLT09-3PH	3 phase fault on the Mingo (531451) to GEN-2007-012 (????) 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.
10	FLT10-1PH	*single phase fault and sequence like FLT09-3PH*
11	FLT11-3PH	3 phase fault on the Mingo (531451) to Knoll (530700) 345kV line, near Mingo. a. Apply fault at the Mingo 345kV bus.

Cont. No.	Cont. Name	Description
		b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close 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 FLT11-3PH*
13	FLT13-3PH	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. b. Clear fault after 5 cycles by tripping the faulted transformer.
13a	FLT13-3PH_NT	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. b. Clear fault after 5 cycles by tripping the faulted transformer.
14	FLT14-1PH	*single phase fault and sequence like FLT13-3PH*
14a	FLT14-1PH_NT	*single phase fault and sequence like FLT13-3PH*
15	FLT15-3PH	3 phase fault on the GEN-2007-012 (????) to Mingo (531451) 345kV line, near GEN-2007-012. a. Apply fault at the GEN-2007-012 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 FLT15-3PH*
17	FLT17-3PH	3 phase fault on the GEN-2007-012 (????) to Red Willow (640325) 345kV line, near GEN-2007-012. a. Apply fault at the GEN-2007-012 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	FLT18-1PH	*single phase fault and sequence like FLT17-3PH*
19	FLT19-3PH	3 phase fault on the Gentleman (640183) to Keystone (640252) 345kV line, near Gentleman. a. Apply fault at the Gentleman 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
20	FLT20-1PH	*single phase fault and sequence like FLT19-3PH*
21	FLT21-3PH	3 phase fault on the Gentleman (640183) to Sweetwater (640374) 345kV line, near Gentleman. a. Apply fault at the Gentleman 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
22	FLT22-1PH	*single phase fault and sequence like FLT21-3PH*
23	FLT23-3PH	3 phase fault on the Colby (530555) to Hoxie (530556) 115kV line, near Colby. a. Apply fault at the Colby 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
24	FLT24-1PH	*single phase fault and sequence like FLT23-3PH*
25	FLT25-3PH	3 phase fault on the Colby (530555) to Atwood (530554) 115kV line, near Colby. a. Apply fault at the Colby 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
26	FLT26-1PH	*single phase fault and sequence like FLT25-3PH*
27	FLT27-3PH	3 phase fault on the Holcomb (531449) to GEN-2007-040 (210400) 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.
28	FLT28-1PH	*single phase fault and sequence like FLT27-3PH*

Cont. No.	Cont. Name	Description
29	FLT29-3PH	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. b. Clear fault after 5 cycles by tripping the faulted transformer.
30	FLT30-1PH	*single phase fault and sequence like FLT29-3PH*
31	FLT31-3PH**	3 phase fault on the Finney (523853) to GEN-2007-019 (210190) 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.
32	FLT32-1PH**	*single phase fault and sequence like FLT31-3PH*
33	FLT33-3PH	3 phase fault on the Finney (523853) to GEN-2003-013 (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.
34	FLT34-1PH	*single phase fault and sequence like FLT33-3PH*
35	FLT35-3PH	3 phase fault on the Knoll (530558) to Smoky Hill (530592) 230kV line, near Knoll. a. Apply fault at the Knoll 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
36	FLT36-1PH	*single phase fault and sequence like FLT35-3PH*
37	FLT37-3PH	3 phase fault on the Knoll (530558) to South Hays (530582) 230kV line, near Knoll. a. Apply fault at the Knoll 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
38	FLT38-1PH	*single phase fault and sequence like FLT37-3PH*
39	FLT39-3PH	3 phase fault on the Knoll 230kV (530558) to 345kV (530700) transformer, near the 230kV bus. a. Apply fault at the Knoll 230kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
40	FLT40-1PH	*single phase fault and sequence like FLT39-3PH*
41	FLT41-3PH	3 phase fault on the Knoll 230kV (530558) to 115kV (530561) transformer, near the 230kV bus. a. Apply fault at the Knoll 230kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
42	FLT42-1PH	*single phase fault and sequence like FLT41-3PH*
43	FLT43-3PH	3 phase fault on the Knoll (530561) to Saline (530551) 115kV line, near Knoll. a. Apply fault at the Knoll 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
44	FLT44-1PH	*single phase fault and sequence like FLT43-3PH*
45	FLT45-3PH	3 phase fault on the Knoll (530561) to Redline (530605) 115kV line, near Knoll. a. Apply fault at the Knoll 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
46	FLT46-1PH	*single phase fault and sequence like FLT45-3PH*
47	FLT47-3PH	3 phase fault on the South Hays (530582) to Mullergren (539679) 230kV line, near South Hays. a. Apply fault at the South Hays 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
48	FLT48-1PH	*single phase fault and sequence like FLT47-3PH*
49	FLT49-3PH	3 phase fault on the Mullergren (539679) to Circle (532871) 230kV line, near Mullergren. a. Apply fault at the Mullergren 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line.

Cont. No.	Cont. Name	Description
		c. Wait 20 cycles, and then re-close 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	FLT50-1PH	*single phase fault and sequence like FLT49-3PH*
51	FLT51-3PH	3 phase fault on the Summit (532873) to Morris (532863) 230kV line, near Summit. a. Apply fault at the Summit 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.
52	FLT52-1PH	*single phase fault and sequence like FLT51-3PH*
53	FLT53-3PH	3 phase fault on the Summit (532873) to E. McPherson (532872) 230kV line, near Summit. a. Apply fault at the Summit 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.
54	FLT54-1PH	*single phase fault and sequence like FLT53-3PH*
55	FLT55-3PH	3 phase fault on the Summit 230kV (532873) to 345kV (532773) transformer, near the 230kV bus. a. Apply fault at the Summit 230kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
56	FLT56-1PH	*single phase fault and sequence like FLT55-3PH*

** Following loss of Finney – GEN-2007-019 345 kV line the GEN-2007-019 windfarm will be islanded. Hence, GEN-2007-019 wind farm was tripped following the fault.

Table 6-3 and Table 6-4 summarize the stability analysis results for 2010 summer peak and 2010 winter peak system conditions.

The system was stable following all simulated 3-Phase and single-phase faults ***except*** for the eight (8) faults. Also, no undervoltage tripping of any other windfarms in the system was observed following the simulated faults ***except*** following the UNSTABLE faults. The stability plots for the transient stability analysis are included in **Error! Reference source not found.** for reference.

Faults at Gentleman 345 kV substation:

SPP indicated that the instability following faults at Gentleman 345 kV substation (FLT19-3PH, FLT20-1PH, FLT21-3PH, FLT22-1PH) is a known modeling problem and it has been observed without Group 4 Projects. Hence, the impact of the Group 4 projects following the fault at Gentleman can not be quantified. SPP indicated that the effect of interconnection of proposed Group 4 projects on the stability of NPPD system will be addressed during the facility study.

Faults at Mingo 345 kV with loss of Mingo 345/115 kV transformer:

The system was found to be UNSTABLE following faults involving loss of Mingo 345/115 kV transformer (FLT13-3PH and FLT14-1PH). Figure 6-1 shows the voltage recovery at Mingo substation following the FLT13-3PH fault. The GEN-2007-047 (204 MW) of the Group 4 is connected at Mingo 345 kV substation. Figure 6-2 shows the one-line diagram of the local 115 kV system in the vicinity of the Mingo 115 kV substation. Following the loss of Mingo 345/115 kV transformer, total of 312 MW (204 MW of GEN-2007-012 + 108 MW of GEN-2006-040) is pushed onto the underlying 115 kV system.

Following FLT31-3PH and FLT32-1PH Finney – GEN-2007-019 345 kV line was tripped resulting in islanding of GEN-2007-019 windfarm. As the wind turbine generator is a induction generator and can not operate in the islanding situation, the GEN-2007-019 wind farm was tripped following FLT31-3PH and FLT32-1PH.

Undamped oscillations in speed of GEN-2008-001 (Gamesa WTGs)

Following all the faults undamped oscillations in the speed of the GEN-2008-001 (200 MW comprised of Gamesa 2.0 MW WTGs) were observed. Figure 6-3 shows the undamped speed oscillations following FLT35_3PH fault. The voltage at Knoll 230 kV (POI of GEN-2008-001) recovers promptly after the fault clearing. Further investigation indicated that the oscillations in the speed of the machine are due to the user-written model used for Gamesa wind turbine generators. Additional analysis with a better model will be necessary to confirm the impact, if any, on the system performance.

Table 6-3 Results of stability analysis – summer peak 2010

FAULT	2008 Summer Peak	
	Without Group 4 Projects	With Group 4 Projects
FLT_1_3PH	---	STABLE
FLT_2_1PH	---	STABLE
FLT_3_3PH	---	STABLE
FLT_4_1PH	---	STABLE
FLT_5_3PH	---	STABLE
FLT_6_1PH	---	STABLE

FAULT	2008 Summer Peak	
	Without Group 4 Projects	With Group 4 Projects
FLT_7_3PH	---	STABLE
FLT_8_1PH	---	STABLE
FLT_9_3PH	---	STABLE
FLT_10_1PH	---	STABLE
FLT_11_3PH	---	STABLE
FLT_12_1PH	---	STABLE
FLT_13_3PH	---	UNSTABLE
FLT_14_1PH	---	UNSTABLE
FLT_15_3PH	---	STABLE
FLT_16_1PH	---	STABLE
FLT_17_3PH	---	STABLE
FLT_18_1PH	---	STABLE
FLT_19_3PH	---	UNSTABLE*
FLT_20_1PH	---	UNSTABLE*
FLT_21_3PH	---	UNSTABLE*
FLT_22_1PH	---	UNSTABLE*
FLT_23_3PH	---	STABLE
FLT_24_1PH	---	STABLE
FLT_25_3PH	---	STABLE
FLT_26_1PH	---	STABLE
FLT_27_3PH	---	STABLE
FLT_28_1PH	---	STABLE
FLT_29_3PH	---	STABLE
FLT_30_1PH	---	STABLE
FLT_31_3PH	---	STABLE
FLT_32_1PH	---	STABLE
FLT_33_3PH	---	STABLE
FLT_34_1PH	---	STABLE
FLT_35_3PH	---	STABLE
FLT_36_1PH	---	STABLE
FLT_37_3PH	---	STABLE
FLT_38_1PH	---	STABLE
FLT_39_3PH	---	STABLE
FLT_40_1PH	---	STABLE
FLT_41_3PH	---	STABLE
FLT_42_1PH	---	STABLE
FLT_43_3PH	---	STABLE
FLT_44_1PH	---	STABLE
FLT_45_3PH	---	STABLE
FLT_46_1PH	---	STABLE
FLT_47_3PH	---	STABLE

FAULT	2008 Summer Peak	
	Without Group 4 Projects	With Group 4 Projects
FLT_48_1PH	---	STABLE
FLT_49_3PH	---	STABLE
FLT_50_1PH	---	STABLE
FLT_51_3PH	---	STABLE
FLT_52_1PH	---	STABLE
FLT_53_3PH	---	STABLE
FLT_54_1PH	---	STABLE
FLT_55_3PH	---	STABLE
FLT_56_1PH	---	STABLE

* SPP indicated instability observed in WITHOUT Group 4 projects.

Table 6-4 Results of stability analysis – winter peak 2010

FAULT	2008 Winter Peak	
	Without Group 4 Projects	With Group 4 Projects
FLT_1_3PH	---	STABLE
FLT_2_1PH	---	STABLE
FLT_3_3PH	---	STABLE
FLT_4_1PH	---	STABLE
FLT_5_3PH	---	STABLE
FLT_6_1PH	---	STABLE
FLT_7_3PH	---	STABLE
FLT_8_1PH	---	STABLE
FLT_9_3PH	---	STABLE
FLT_10_1PH	---	STABLE
FLT_11_3PH	---	STABLE
FLT_12_1PH	---	STABLE
FLT_13_3PH	---	UNSTABLE
FLT_14_1PH	---	UNSTABLE
FLT_15_3PH	---	STABLE
FLT_16_1PH	---	STABLE
FLT_17_3PH	---	STABLE
FLT_18_1PH	---	STABLE
FLT_19_3PH	---	UNSTABLE*
FLT_20_1PH	---	UNSTABLE*
FLT_21_3PH	---	UNSTABLE*
FLT_22_1PH	---	UNSTABLE*
FLT_23_3PH	---	STABLE
FLT_24_1PH	---	STABLE
FLT_25_3PH	---	STABLE
FLT_26_1PH	---	STABLE
FLT_27_3PH	---	STABLE
FLT_28_1PH	---	STABLE
FLT_29_3PH	---	STABLE
FLT_30_1PH	---	STABLE

FAULT	2008 Winter Peak	
	Without Group 4 Projects	With Group 4 Projects
FLT_31_3PH	---	STABLE
FLT_32_1PH	---	STABLE
FLT_33_3PH	---	STABLE
FLT_34_1PH	---	STABLE
FLT_35_3PH	---	STABLE
FLT_36_1PH	---	STABLE
FLT_37_3PH	---	STABLE
FLT_38_1PH	---	STABLE
FLT_39_3PH	---	STABLE
FLT_40_1PH	---	STABLE
FLT_41_3PH	---	STABLE
FLT_42_1PH	---	STABLE
FLT_43_3PH	---	STABLE
FLT_44_1PH	---	STABLE
FLT_45_3PH	---	STABLE
FLT_46_1PH	---	STABLE
FLT_47_3PH	---	STABLE
FLT_48_1PH	---	STABLE
FLT_49_3PH	---	STABLE
FLT_50_1PH	---	STABLE
FLT_51_3PH	---	STABLE
FLT_52_1PH	---	STABLE
FLT_53_3PH	---	STABLE
FLT_54_1PH	---	STABLE
FLT_55_3PH	---	STABLE
FLT_56_1PH	---	STABLE

* SPP indicated instability observed in WITHOUT Group 4 projects

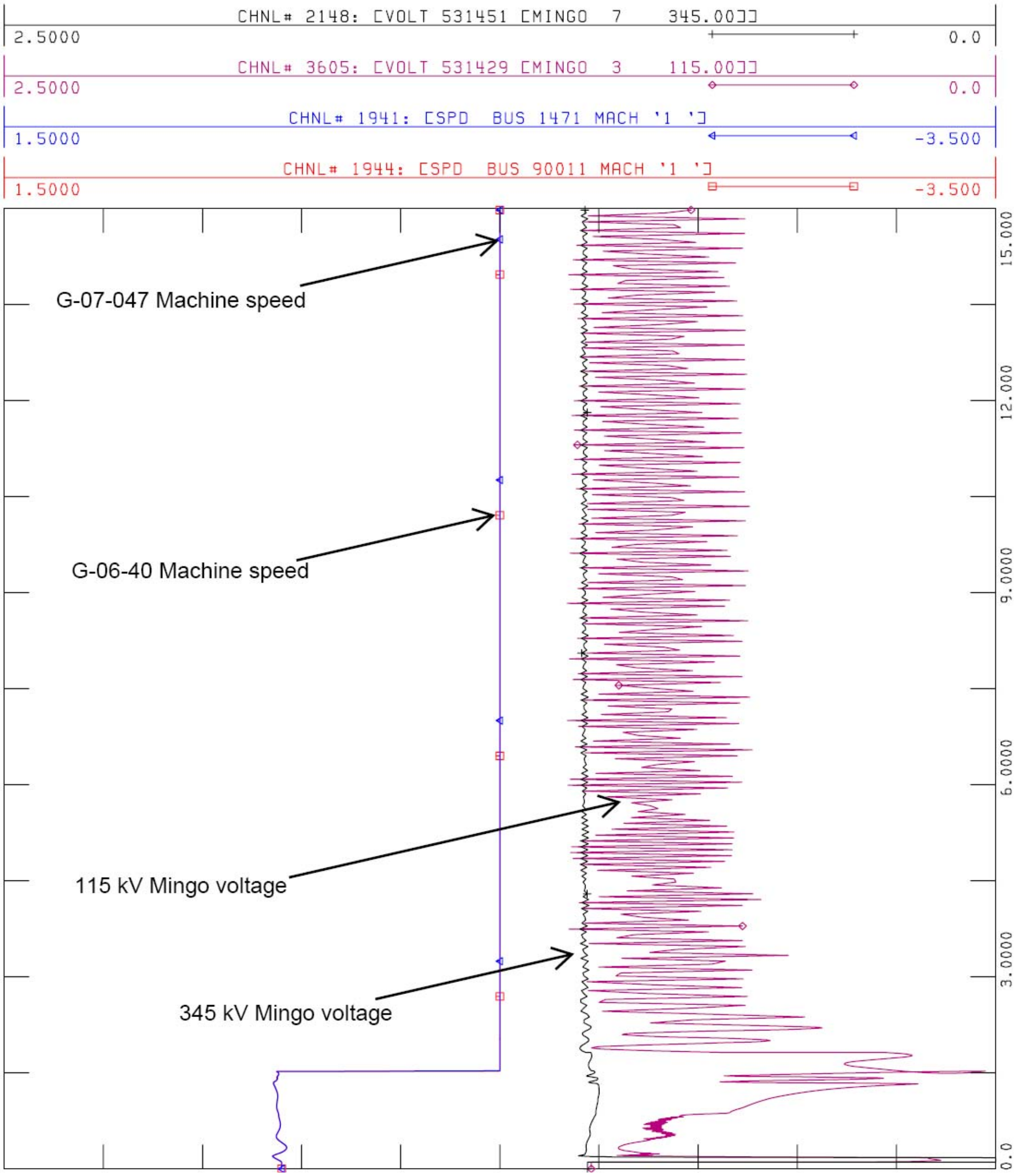

Figure 6-1: Voltage recovery after FLT13-3PH (summer peak)

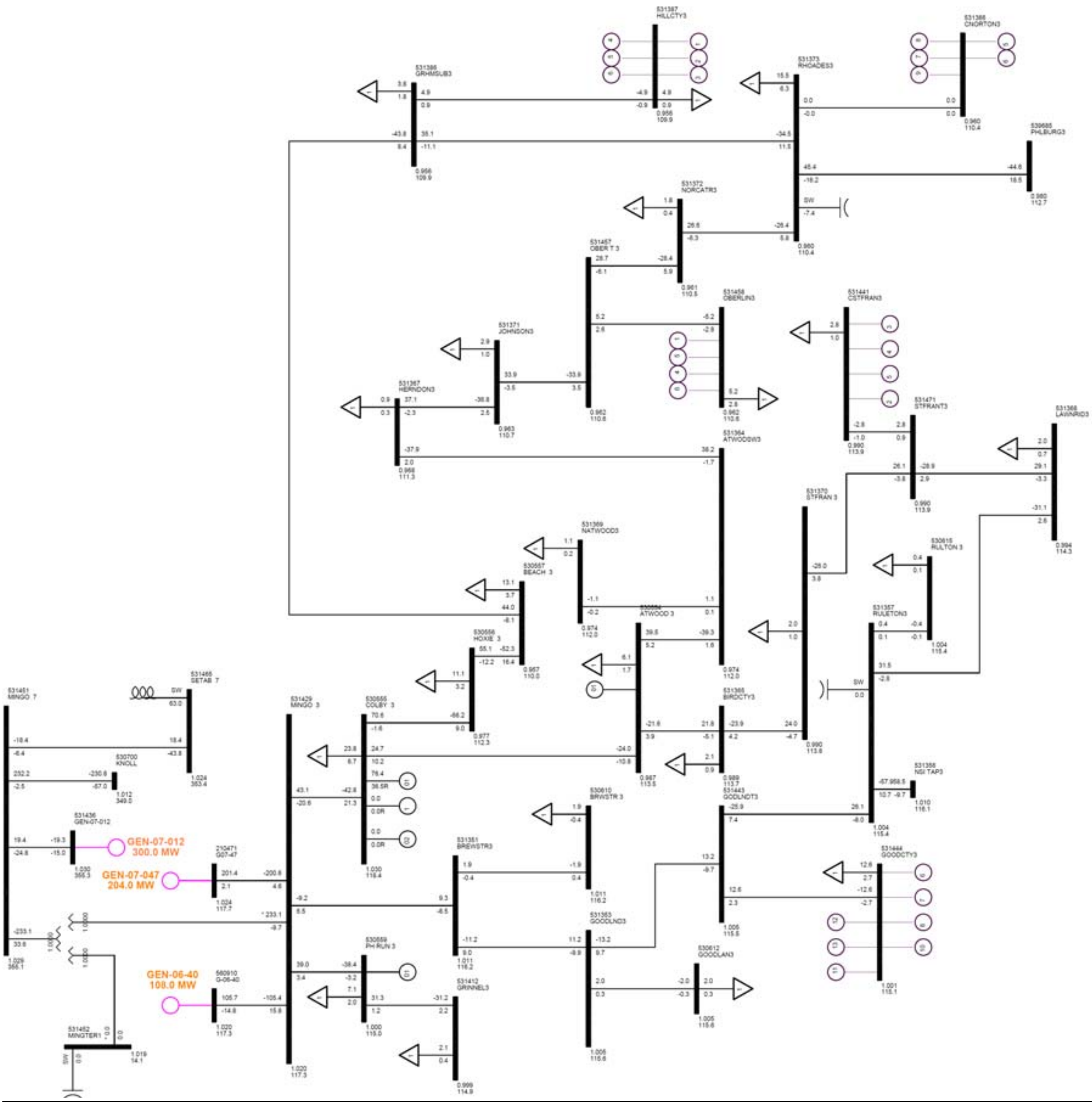

Figure 6-2: One-line diagram of the local area of GEN-07-047

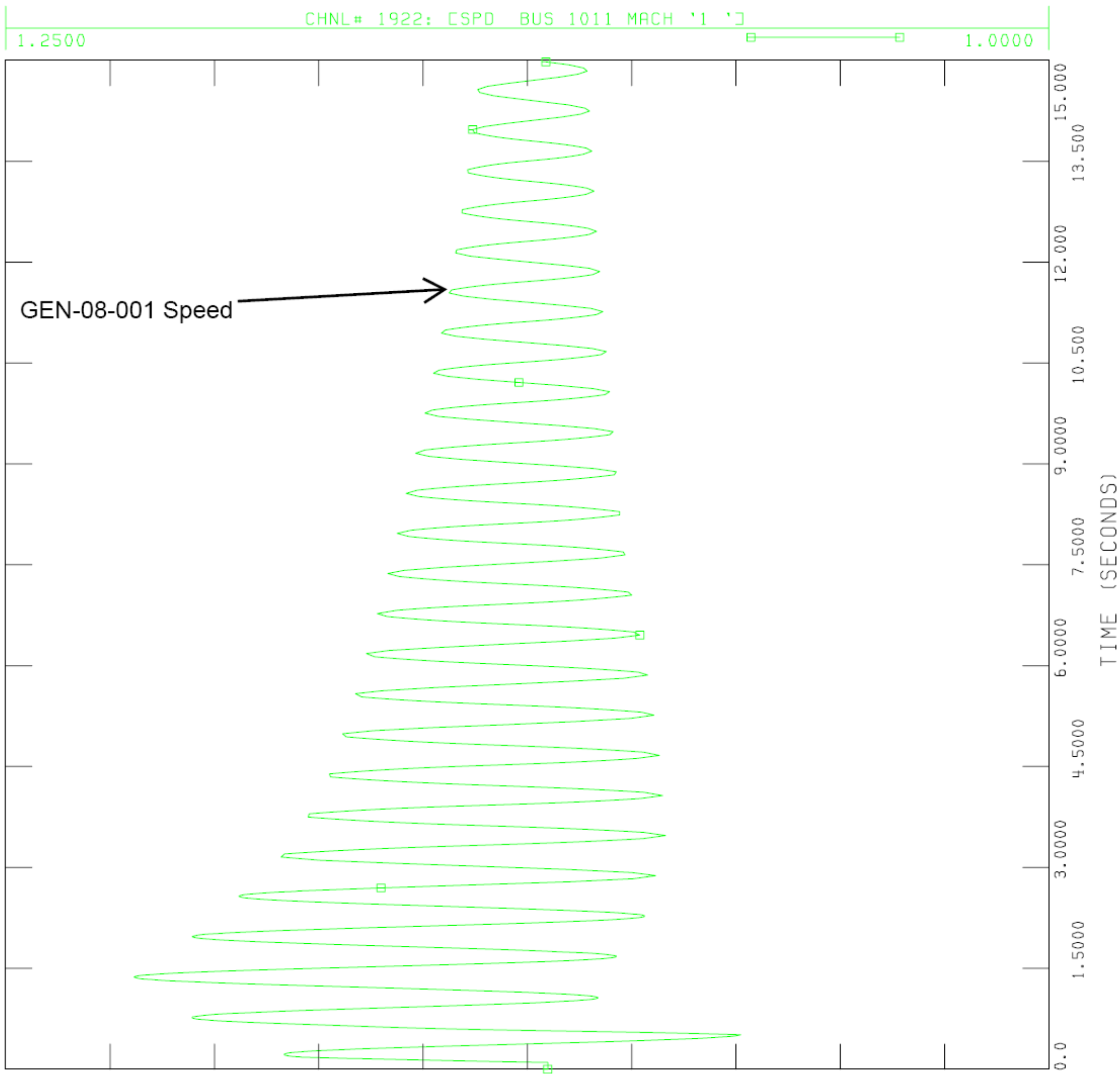

Figure 6-3: Undamped oscillations in GEN-2008-001 FLT35-3PH (summer peak)

6.1 FERC LVRT COMPLIANCE

As explained in section 2, the proposed Group 4 windfarm projects were modeled with the low voltage ride through capacity. To determine the compliance of the Group 4 wind farm projects total of fourteen (14) faults were simulated. Faults were simulated at the POI of each Group 4 wind farm project and normally cleared by tripping one transmission element at a time. Table 6-5 lists the faults simulated for LVRT analysis.

Table 6-5: List of faults for FERC LVRT compliance

Fault Name	Description
FLT01-3PH_LVRT	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.
FLT03-3PH_LVRT	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.
FLT05-3PH_LVRT	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. b. Clear fault after 5 cycles by tripping the faulted transformer.
GEN-07-047_3PH_AutoTxmr_LVRT	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. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT15-3PH_LVRT	3 phase fault on the GEN-2007-012 (531436) to Mingo (531451) 345kV line, near GEN-2007-012. a. Apply fault at the GEN-2007-012 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT17-3PH_LVRT	3 phase fault on the GEN-2007-012 (531436) to Red Willow (640325) 345kV line, near GEN-2007-012. a. Apply fault at the GEN-2007-012 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT35-3PH_LVRT	3 phase fault on the Knoll (530558) to Smoky Hill (530592) 230kV line, near Knoll. a. Apply fault at the Knoll 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT37-3PH_LVRT	3 phase fault on the Knoll (530558) to South Hays (530582) 230kV line, near Knoll. a. Apply fault at the Knoll 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT39-3PH_LVRT	3 phase fault on the Knoll 230kV (530558) to 345kV (530700) transformer, near the 230kV bus. a. Apply fault at the Knoll 230kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT41-3PH_LVRT	3 phase fault on the Knoll 230kV (530558) to 115kV (530561) transformer, near the 230kV bus. a. Apply fault at the Knoll 230kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
GEN-07-047_3PH_BREWSTR3_LVRT	3 phase fault on the MINGO3 (531429) to BREWSTR3 (531351) 115 kv line, near the Mingo3. a. Apply fault at the Mingo 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
GEN-07-047_3PH_COLBY3_LVRT	3 phase fault on the MINGO3 (531429) to COLBY3 (530555) 115 kv line, near the Mingo3. a. Apply fault at the Mingo 115kV bus.

Fault Name	Description
	b. Clear fault after 5 cycles by tripping the faulted line.
GEN-07-047_3PH_PHRUN3_LVRT	3 phase fault on the MINGO3 (531429) to PHRUN3 (530559) 115 kv line, near the Mingo3. a. Apply fault at the Mingo 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
GEN-07-047_3PH_G-06-40_LVRT	3 phase fault on the MINGO3 (531429) to G-06-40 (560910) 115 kv line, near the Mingo3. a. Apply fault at the Mingo 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line.

The results of the simulations indicated that all the four (4) wind farm projects in the Group 4 meet the FERC LVRT criteria for the interconnection of the windfarm generation (FERC Order 661 – A).

The results of the FERC LVRT compliance are included in **Error! Reference source not found.** for reference.

7 SENSITIVITY ANALYSIS

A sensitivity analysis was performed by considering the proposed change in the interconnection scheme of the GEN-2007-047 wind farm project. The GEN-2007-047 (204 MW) wind farm project was supposed to interconnect at Mingo 115 kV substation. According to the proposed change in the interconnection scheme for GEN-2007-047 project the wind farm would interconnect at Mingo 345 kV bus instead of Mingo 115 kV bus.

A sensitivity analysis including the power factor analysis and transient stability analysis was performed to determine the impact of the proposed change in the interconnection scheme of the GEN-2007-047 project.

7.1 MODEL DEVELOPMENT

To model the proposed change in the GEN-2007-047 interconnection scheme, the two power flow cases - 'ICS08-01_G4_10SP+GEN-07-012.sav' and 'ICS08-01_G4_10SP+GEN-07-012_Sens_1.sav' - described in Section 4.1 were updated. The GEN-2007-047 was connected to the Mingo 345 kV substation through 5 mile 345 kV line. The 34.5/345 kV transformer impedance was assumed to be 8% on 75 MVA transformer base.

Two power flow cases were created for the sensitivity analysis were named as 'ICS08-01_G4_10SP+GEN-07-012_Sens_1.sav' and 'ICS08-01_G4_10WP+GEN-07-012_Sens_1.sav' for summer peak and winter peak system conditions.

7.2 POWER FACTOR ANALYSIS

Power factor analysis for the Group 4 projects was repeated on the sensitivity cases developed. The procedure for the power factor analysis is described in Section 3.1.

To that end the contingencies from Table 5-1 were repeated. **Error! Reference source not found.** lists the VARs provided by the VAR generator at POI following the simulated contingencies for the Group 4 projects

In addition to the above analysis, the list of contingencies was repeated without the VAR generator at the POI for the Group 4 projects. The voltages at the POI were monitored. The results of the contingency analysis are included in **Error! Reference source not found.**.

The contingency resulting in the highest VAR generator output and the contingency resulting in the lowest POI voltage with out the VAR generator were considered as most-limiting contingencies. The limiting contingencies from the analysis for summer and winter peak conditions are given in Table 7-1 and Table 7-2 respectively. These contingencies were repeated for the Group 4 projects to check whether the voltage and power factor are within the acceptable range. Table 7-3 through Table 7-6 show the voltage and power factor following the most limiting contingencies for the respective project.

The results indicated that the reactive power capability of all the proposed wind farms, ***except* GEN-2008-001**, would be adequate to meet the voltage and power factor criteria.

The results indicated that the POI voltage (Knoll 230 kV) will be less than 0.95 p.u. for summer peak system conditions following CONT_06. Hence, in addition to the 30 Mvar shunt compensation, required for system intact conditions, 10 Mvar (5 Mvar at each 34.5 kV collector system) shunt capacitors were added to bring the voltage at POI above 0.95 p.u in post-contingency conditions. The three contingencies were repeated. The results are summarized in Table 7-7.

Table 7-1 List of severe contingencies-Summer Peak

Project	Contingency	
	With highest MVAR from VAR generator	With lowest POI voltage with out VAR generator
GEN-07-012	CONT_01	CONT_01
GEN-07-047	CONT_01	CONT_01
GEN-08-001	CONT_09	CONT_06
GEN-08-017	CONT_01	CONT_01

Table 7-2 List of severe contingencies-Winter Peak

Project	Severe Contingency	
	With highest MVAR from VAR generator	With lowest POI voltage with out VAR generator
GEN-07-012	CONT_01	CONT_01
GEN-07-047	CONT_01	CONT_01
GEN-08-001	CONT_01	CONT_01
GEN-08-017	CONT_01	CONT_01

Table 7-3 Voltage & p.f. at POI without VAR generator:GEN-2007-012

System condition		Voltage (in p.u.)	P.F.	Additional Mvars from the system at 345 kV POI	Acceptable POI voltage?	Acceptable POI p.f.?
2010 summer peak	System Intact	1.03	0.9907	39.1	YES	YES
	Post-cotingency (1)	1.03	0.9719	-69.0	YES	YES
2010 winter peak	System Intact	1.03	0.9874	45.5	YES	YES
	Post-cotingency (1)	1.03	0.9711	-69.9	YES	YES

(1)'*CONT_01*': Loss of Setab – Holocomb 345 kV line

Table 7-4 Voltage & p.f. at POI without VAR generator:GEN-2007-047

System condition		Voltage (in p.u.)	P.F.	Additional Mvars from the system at 345 kV POI	Acceptable POI voltage?	Acceptable POI p.f.?
2010 summer peak	System Intact	1.029	0.9999	0.3	YES	YES
	Post-cotingency (1)	1.0102	0.9950	-20.1	YES	YES
2010 winter peak	System Intact	1.0285	1.0000	-0.2	YES	YES
	Post-cotingency (1)	1.0102	0.995	-20.1	YES	YES

(1)'*CONT_01*': Loss of Setab – Holocomb 345 kV line

Table 7-5 Voltage & p.f. at POI without VAR generator:GEN-2008-001

System condition	Voltage (in p.u.)	P.F.	Additional Mvars from the system at 230 kV POI	Acceptable POI voltage?	Acceptable POI p.f.?

2010 summer peak	System Intact	0.9951	0.9989	9.0	YES	YES
	Post-cotingency (2)	0.9536	0.9956	17.5	YES	YES
	Post-cotingency (3)	**0.9463**	0.9952	19.1	**NO**	YES
2010 winter peak	System Intact	1.0051	0.9993	7.1	YES	YES
	Post-cotingency (1)	0.9654	0.9970	15	YES	YES

(1)'CONT_01': Loss of Setab – Holocomb 345 kV line,
(2)'CONT_09': Loss of Redwillow-GEN-07-012 345 kv line
(3)'CONT_06': Loss of Mingo – Knoll 345 kV

Table 7-6 Voltage & p.f. at POI without VAR generator:GEN-2008-017

System condition		Voltage (in p.u.)	P.F.	Additional Mvars from the system at 345 kV POI	Acceptable POI voltage?	Acceptable POI p.f.?
2010 summer peak	System Intact	1.0251	0.9608	85.1	YES	YES
	Post-cotingency (1)	0.9916	0.9963	25.4	YES	YES
2010 winter peak	System Intact	1.0202	0.9682	76.0	YES	YES
	Post-cotingency (1)	0.9907	0.9967	23.9	YES	YES

(1)'*CONT_01*': Loss of Setab – Holocomb 345 kV line

Table 7-7 Voltage & p.f. at POI without VAR generator:GEN-2008-001 with additional 10 Mvar (total 40 Mvar) compensation

System condition		Voltage (in p.u.)	P.F.	Additional Mvars from the system at 230 kV POI	Acceptable POI voltage?	Acceptable POI p.f.?
2010 summer peak	System Intact	1.0000	0.9998	-3.7	YES	YES
	Post-cotingency (2)	0.9591	0.9996	5.4	YES	YES
	Post-cotingency (3)	0.9562	0.9995	6.0	YES	YES
2010 winter peak	System Intact	1.0090	0.9995	-5.7	YES	YES
	Post-cotingency (1)	0.9723	0.9999	2.4	YES	YES

The results of power factor analysis indicated that total of 40 Mvar (20 Mvar at each 34.5 kV collector system) shunt compensation will be required to meet the required p.f. and the voltage at the POI in system intact and in post-contingency conditions for simulated contingencies.

It should be noted that the Gamesa wind turbine generators are doubly fed induction generators (DFIG) with a reactive power capability of +/- 0.95 p.f. In power factor control mode the Gamesa wind turbine generators operate at a constant power factor. Hence, during this study the wind turbine generators were assumed to be operated at fixed unity p.f. at machine terminal. The reactive power required to maintain the acceptable voltage and p.f. at the POI was provided by using shunt capacitors at the 34.5 kV collector bus. The WTGs reactive power capability would influence the sizing of the shunt capacitors. Optimization between the WTG reactive power capacity and the shunt capacitors was not performed in this study.

7.3 STABILITY ANALYSIS

Stability simulations were performed to examine the transient behavior of the Group 4 projects and impact of the proposed addition of generation on the SPP system with the new interconnection scheme for GEN-2007-047 project.

The faults listed in Table 6-2 were repeated for both summer and winter peak conditions.

Table 7-8 and Table 7-9 summarize the stability analysis results for 2010 summer peak and 2010 winter peak system conditions.

The system was stable following all simulated 3-Phase and 1-phase faults ***except*** for the faults at Gentlemen substation (see section 6 for further details). No undervoltage tripping of any other windfarms in the system was observed following the simulated faults ***except*** following the UNSTABLE faults. The plots for transient stability analysis are included in **Error! Reference source not found.** for reference.

Table 7-8 Results of stability analysis – summer peak 2010(Sensitivity)

FAULT	2008 Summer Peak	
	Without Group 4 Projects	With Group 4 Projects
FLT_1_3PH	---	STABLE
FLT_2_1PH	---	STABLE
FLT_3_3PH	---	STABLE
FLT_4_1PH	---	STABLE
FLT_5_3PH	---	STABLE
FLT_6_1PH	---	STABLE
FLT_7_3PH	---	STABLE
FLT_8_1PH	---	STABLE
FLT_9_3PH	---	STABLE
FLT_10_1PH	---	STABLE
FLT_11_3PH	---	STABLE
FLT_12_1PH	---	STABLE
FLT_13_3PH	---	STABLE
FLT_14_1PH	---	STABLE
FLT_15_3PH	---	STABLE
FLT_16_1PH	---	STABLE
FLT_17_3PH	---	STABLE
FLT_18_1PH	---	STABLE
FLT_19_3PH	---	UNSTABLE*
FLT_20_1PH	---	UNSTABLE*
FLT_21_3PH	---	UNSTABLE*
FLT_22_1PH	---	UNSTABLE*
FLT_23_3PH	---	STABLE
FLT_24_1PH	---	STABLE
FLT_25_3PH	---	STABLE

FAULT	2008 Summer Peak	
	Without Group 4 Projects	With Group 4 Projects
FLT_26_1PH	---	STABLE
FLT_27_3PH	---	STABLE
FLT_28_1PH	---	STABLE
FLT_29_3PH	---	STABLE
FLT_30_1PH	---	STABLE
FLT_31_3PH	---	STABLE
FLT_32_1PH	---	STABLE
FLT_33_3PH	---	STABLE
FLT_34_1PH	---	STABLE
FLT_35_3PH	---	STABLE
FLT_36_1PH	---	STABLE
FLT_37_3PH	---	STABLE
FLT_38_1PH	---	STABLE
FLT_39_3PH	---	STABLE
FLT_40_1PH	---	STABLE
FLT_41_3PH	---	STABLE
FLT_42_1PH	---	STABLE
FLT_43_3PH	---	STABLE
FLT_44_1PH	---	STABLE
FLT_45_3PH	---	STABLE
FLT_46_1PH	---	STABLE
FLT_47_3PH	---	STABLE
FLT_48_1PH	---	STABLE
FLT_49_3PH	---	STABLE
FLT_50_1PH	---	STABLE
FLT_51_3PH	---	STABLE
FLT_52_1PH	---	STABLE
FLT_53_3PH	---	STABLE
FLT_54_1PH	---	STABLE
FLT_55_3PH	---	STABLE
FLT_56_1PH	---	STABLE

* SPP indicated instability was a known problem

Table 7-9 Results of stability analysis – Winter peak 2010(Sensitivity)

FAULT	2008 Winter Peak	
	Without Group 4 Projects	With Group 4 Projects
FLT_1_3PH	---	STABLE
FLT_2_1PH	---	STABLE
FLT_3_3PH	---	STABLE
FLT_4_1PH	---	STABLE
FLT_5_3PH	---	STABLE

FAULT	2008 Winter Peak	
	Without Group 4 Projects	With Group 4 Projects
FLT_6_1PH	---	STABLE
FLT_7_3PH	---	STABLE
FLT_8_1PH	---	STABLE
FLT_9_3PH	---	STABLE
FLT_10_1PH	---	STABLE
FLT_11_3PH	---	STABLE
FLT_12_1PH	---	STABLE
FLT_13_3PH	---	STABLE
FLT_14_1PH	---	STABLE
FLT_15_3PH	---	STABLE
FLT_16_1PH	---	STABLE
FLT_17_3PH	---	STABLE
FLT_18_1PH	---	STABLE
FLT_19_3PH	---	UNSTABLE*
FLT_20_1PH	---	UNSTABLE*
FLT_21_3PH	---	UNSTABLE*
FLT_22_1PH	---	UNSTABLE*
FLT_23_3PH	---	STABLE
FLT_24_1PH	---	STABLE
FLT_25_3PH	---	STABLE
FLT_26_1PH	---	STABLE
FLT_27_3PH	---	STABLE
FLT_28_1PH	---	STABLE
FLT_29_3PH	---	STABLE
FLT_30_1PH	---	STABLE
FLT_31_3PH	---	STABLE
FLT_32_1PH	---	STABLE
FLT_33_3PH	---	STABLE
FLT_34_1PH	---	STABLE
FLT_35_3PH	---	STABLE
FLT_36_1PH	---	STABLE
FLT_37_3PH	---	STABLE
FLT_38_1PH	---	STABLE
FLT_39_3PH	---	STABLE
FLT_40_1PH	---	STABLE
FLT_41_3PH	---	STABLE
FLT_42_1PH	---	STABLE
FLT_43_3PH	---	STABLE
FLT_44_1PH	---	STABLE
FLT_45_3PH	---	STABLE
FLT_46_1PH	---	STABLE

FAULT	2008 Winter Peak	
	Without Group 4 Projects	With Group 4 Projects
FLT_47_3PH	---	STABLE
FLT_48_1PH	---	STABLE
FLT_49_3PH	---	STABLE
FLT_50_1PH	---	STABLE
FLT_51_3PH	---	STABLE
FLT_52_1PH	---	STABLE
FLT_53_3PH	---	STABLE
FLT_54_1PH	---	STABLE
FLT_55_3PH	---	STABLE
FLT_56_1PH	---	STABLE

* SPP indicated instability was a known problem

7.4 FERC LVRT COMPLIANCE

As explained in section 2, the proposed Group 4 windfarm projects were modeled with the low voltage ride through capacity. To determine the compliance of the Group 4 wind farm projects total of thirteen (13) faults were simulated. Faults were simulated at the POI of each Group 4 wind farm project and normally cleared by tripping one transmission element at a time. Table 7-10 lists the faults simulated for LVRT analysis.

Table 7-10 List of faults for FERC LVRT compliance

Fault Name	Description
FLT01-3PH_LVRT_SENS_1	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.
FLT03-3PH_LVRT_SENS_1	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.
FLT05-3PH_LVRT_SENS_1	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.
	b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT15-3PH_LVRT_SENS_1	3 phase fault on the GEN-2007-012 (531436) to Mingo (531451) 345kV line, near GEN-2007-012.
	a. Apply fault at the GEN-2007-012 345kV bus.
	b. Clear fault after 5 cycles by tripping the faulted line.
FLT17-3PH_LVRT_SENS_1	3 phase fault on the GEN-2007-012 (531436) to Red Willow (640325) 345kV line, near GEN-2007-012.
	a. Apply fault at the GEN-2007-012 345kV bus.
	b. Clear fault after 5 cycles by tripping the faulted line.
FLT35-3PH_LVRT_SENS_1	3 phase fault on the Knoll (530558) to Smoky Hill (530592) 230kV line, near Knoll.
	a. Apply fault at the Knoll 230kV bus.
	b. Clear fault after 5 cycles by tripping the faulted line.
FLT37-3PH_LVRT_SENS_1	3 phase fault on the Knoll (530558) to South Hays (530582) 230kV line, near Knoll.
	a. Apply fault at the Knoll 230kV bus.
	b. Clear fault after 5 cycles by tripping the faulted line.
FLT39-3PH_LVRT_SENS_1	3 phase fault on the Knoll 230kV (530558) to 345kV (530700) transformer, near the 230kV bus.
	a. Apply fault at the Knoll 230kV bus.
	b. Clear fault after 5 cycles by tripping the faulted transformer.

Fault Name	Description
FLT41-3PH_LVRT_SENS_1	3 phase fault on the Knoll 230kV (530558) to 115kV (530561) transformer, near the 230kV bus.
	a. Apply fault at the Knoll 230kV bus.
	b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT07-3PH_LVRT_SENS_1	3 phase fault on the Mingo (531451) to Setab (531465) 345kV line, near Mingo.
	a. Apply fault at the Mingo 345kV bus.
	b. Clear fault after 5 cycles by tripping the faulted line.
FLT09-3PH_LVRT_SENS_1	3 phase fault on the Mingo (531451) to GEN-2007-012 (531436) 345kV line, near Mingo.
	a. Apply fault at the Mingo 345kV bus.
	b. Clear fault after 5 cycles by tripping the faulted line.
FLT11-3PH_LVRT_SENS_1	3 phase fault on the Mingo (531451) to Knoll (530700) 345kV line, near Mingo.
	a. Apply fault at the Mingo 345kV bus.
	b. Clear fault after 5 cycles by tripping the faulted line.
FLT13-3PH_LVRT_SENS_1	3 phase fault on the Mingo 345kV/115/13.8 kV transformer, near the 345 kV bus.
	a. Apply fault at the Mingo 345kV bus.
	b. Clear fault after 5 cycles by tripping the faulted transformer.

The results of the simulations indicated that all the four (4) wind farm projects in the Group 4 meet the FERC LVRT criteria for the interconnection of the windfarm generation (FERC Order 661 – A).

The stability plots for the simulations for FERC LVRT compliance are included in **Error! Reference source not found.** for reference.

8 CONCLUSIONS

The main objectives of this study were

1) To determine the need of reactive power compensation, if any, for the proposed wind farms
2) To determine the impact of proposed Group 4 (1000 MW) generation on system stability and the nearby transmission system and generating stations.
3) To validate the compliance with FERC LVRT requirement.

The study was performed on 2010 Summer Peak and winter peak cases, provided by SPP.

To achieve these objective the following analyses were performed on the 2010 Summer Peak and 2010 winter peak system conditions with Group 4 projects in-service

- Power factor Analysis for the selected contingencies.
- Transient Stability analysis under various local and regional contingencies.
- LVRT performance under selected contingencies near POI.

Following is the summary of study findings:

<u>Power factor analysis</u>

The power factor analysis was performed to determine the need of additional reactive power compensation, if any, for the Group4 wind farm projects. The results of power factor analysis indicated that all the Group 4 projects, ***<u>except</u>*** GEN-2008-001 wind farm project, have the adequate reactive power capability to meet the power factor requirement at the POI.

For GEN-2008-001 (200 MW) wind farm project, total of 50 Mvar shunt compensation (25 Mvar at each 34.5 kV collector bus) is required to meet SPP's power factor and voltage requirement at the POI.

It should be noted that the Gamesa wind turbine generators are doubly fed induction generators (DFIG) with a reactive power capability of +/- 0.95 p.f. In power factor control mode the Gamesa wind turbine generators operate at a constant power factor. Hence, during this study the wind turbine generators were assumed to be operated at fixed unity p.f. at machine terminal. The reactive power required to maintain the acceptable voltage and p.f. at the POI was provided by using shunt capacitors at the 34.5 kV collector bus. The WTGs reactive power capability would influence the sizing of the shunt capacitors. Optimization between the WTG reactive power capacity and the shunt capacitors was not performed in this study.

<u>Stability Analysis</u>

The stability analysis was performed to determine the impact, if any, of the proposed Group 4 projects on the stability of the SPP system. The significant results of stability analysis are as follows:

- The system was found to be UNSTABLE following 3-phase and single-phase faults at Gentleman 345 kV substation. SPP indicated that the instability following faults at Gentleman 345 kV substation is a known modeling problem and has been observed WITHOUT Group 4 projects. Hence, the impact of the Group 4 projects following the fault at

Gentleman 345 kV substation can not be quantified. SPP indicated that the effect of interconnection of proposed Group 4 projects on the stability of NPPD system will be addressed during the facility study.

- The system was found to be UNSTABLE following faults involving loss of Mingo 345/115 kV substation (FLT13-3PH and FLT14-1PH). The GEN-2007-047 (204 MW) of the Group 4 projects is connected at Mingo 115 kV substation. Following the loss of Mingo 345/115 kV transformer, total of 312 MW (204 MW of GEN-2007-012 + 108 MW of GEN-2006-040) is pushed onto the underlying 115 kV system.
- Undamped oscillations in the speed of GEN-2008-001 (200 MW comprised of Gamesa 2.0 MW WTGs) were observed following all the simulated faults. Further investigation indicated that the undamped oscillations are due to the user-written model used for representing the Gamesa wind turbine generators. Additional analysis with a better model will be necessary to confirm the impact, if any, on the system performance.
- The system was found to be STABLE following all the simulated faults (except for the fault discussed above) with the Group 4 projects.

<u>FERC Order 661A Compliance</u>
Selected faults were simulated at the Point of Interconnection (POI) of the proposed Group 4 wind farms to determine the compliance with FERC 661 – A post-transition period LVRT standard. The results indicated that all the proposed projects meet the FERC LVRT requirement for windfarms.

<u>Sensitivity Analysis</u>
A sensitivity analysis was performed by considering the proposed change in the interconnection scheme of the GEN-2007-047 wind farm project. According to the proposed change in the interconnection scheme for GEN-2007-047 project the wind farm would interconnect at Mingo 345 kV bus instead of Mingo 115 kV bus.

The power factor analysis and transient stability analysis were repeated. Following is the summary of the results:

<u>Power factor analysis</u>
The results of power factor analysis indicated that all the Group 4 projects, ***<u>except</u>*** GEN-2008-001 wind farm project, have the adequate reactive power capability to meet the power factor requirement at the POI.

For GEN-2008-001 (200 MW) wind farm project, total of 40 Mvar shunt compensation (25 Mvar at each 34.5 kV collector bus) is required to meet SPP's power factor and voltage requirement at the POI.

It should be noted that the Gamesa wind turbine generators are doubly fed induction generators (DFIG) with a reactive power capability of +/- 0.95 p.f. In power factor control mode the Gamesa wind turbine generators operate at a constant power factor. Hence, during this study the wind turbine generators were assumed to be operated at fixed unity p.f. at machine terminal. The reactive power required to maintain the acceptable voltage and p.f. at the POI was provided by using shunt capacitors at the 34.5 kV collector bus.

The WTGs reactive power capability would influence the sizing of the shunt capacitors. Optimization between the WTG reactive power capacity and the shunt capacitors was not performed in this study.

Transient Stability analysis
The results of transient stability analysis indicated that the system would be STABLE following all the simulated faults ***except*** the faults at Gentleman 345 kV substation. As indicated previously the instability following faults at Gentleman 345 kV substation is a known problem and has been observed WITHOUT Group 4 projects. Hence, the impact of the Group 4 projects following the fault at Gentleman 345 kV substation can not be quantified.

As indicated previously, the undamped oscillations in the speed of GEN-2008-001 (200 MW comprised of Gamesa 2.0 MW WTGs) were observed following all the simulated faults.

The results of transient stability analysis indicated that the proposed Group 4 windfarm projects would not have any adverse impact on the stability of the SPP transmission system following simulated faults.

FERC 661A compliance
Selected faults were simulated at the Point of Interconnection (POI) of the proposed Group 4 wind farms to determine the compliance with FERC 661 – A post-transition period LVRT standard. The results indicated that all the proposed projects meet the FERC LVRT requirement for windfarms.

Final Conclusions:

1. The reactive power capability of all the Group 4 wind farm projects, ***except*** GEN-2008-001, is adequate to meet the interconnection requirement.
2. The proposed Group 4 wind farm projects do not adversely impact the stability of the SPP transmission system ***except*** for the faults involving loss of Mingo 345/115 kV transformer
3. The UNSTABLE system condition following loss of Mingo 345/115 kV transformer was not observed with the new proposed interconnection scheme for GEN-2007-047 (interconnecting at Mingo 345 kV instead of Mingo 115 kV)
4. All the proposed Group 4 wind farm projects meet the FERC 661A LVRT criteria for windfarm interconnection.

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

N: Stability Study for Group 5

SPP Cluster #1 Group #5 Impact Study

Report for

Southwest Power Pool

Prepared by:

Excel Engineering, Inc.

June 10, 2009

Principal Contributors:

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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 Minnesota.

William Quaintance
Registration Number 47402
June 3, 2009

1. Background and Scope

The Cluster #1 Group #5 Impact Study is a generation interconnection study performed by Excel Engineering, Inc. for its non-affiliated client, Southwest Power Pool (SPP). Its purpose was to study the impacts of interconnecting each of the six projects shown in Table 1-1. The in-service date assumed for the generation addition was 2010.

Table 1-1. Interconnection Requests to be Evaluated

Request	Size	Wind Turbine Model	Point of Interconnection
GEN-2007-008	300	Suzlon 2.1MW	Grapevine 345kV (#523772)
GEN-2007-010	200	GE 1.5MW	Potter – Plant X 230kV line (#560109)
GEN-2007-026	126	Suzlon 2.1MW	Bushland – Deaf Smith 230kV line (#560109)
GEN-2007-030	200	Fuhrlaender	Grapevine 345kV (#523772)
GEN-2007-045	171	Suzlon 2.1MW	Grapevine 345kV (#523772)
GEN-2007-048	400	Fuhrlaender	Amarillo South – Swisher 230kV line (#525228)

The previously-queued requests shown in Table 1-2 were included in this study.

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

Request	Size	Wind Turbine Model	Point of Interconnection
GEN-2002-022	240	Siemens 2.3MW	Bushland 230kV
GEN-2004-003	240	GE 1.5MW	Conway 115kV
GEN-2005-021	85.5	GE 1.5MW	Kirby 115kV
GEN-2006-039	400	Clipper 2.5MW	Potter – Plant X 230kV line
GEN-2006-045	240	Suzlon 2.1MW	Potter – Plant X 230kV line
GEN-2006-047	240	Suzlon 2.1MW	Bushland – Deaf Smith 230kV line
GEN-2007-002	160	Steam Turbine	Grapevine 115kV

Figure 1-1 shows the location of each of these projects on the transmission system. The green ellipses indicate the study projects points of interconnection (POI), and the yellow ellipses indicate the prior-queued project POIs. The red X's indicate the fault locations examined in this study. Orange transmission lines are nominally 345 kV, blue lines are 230 kV, and black lines are lower voltage.

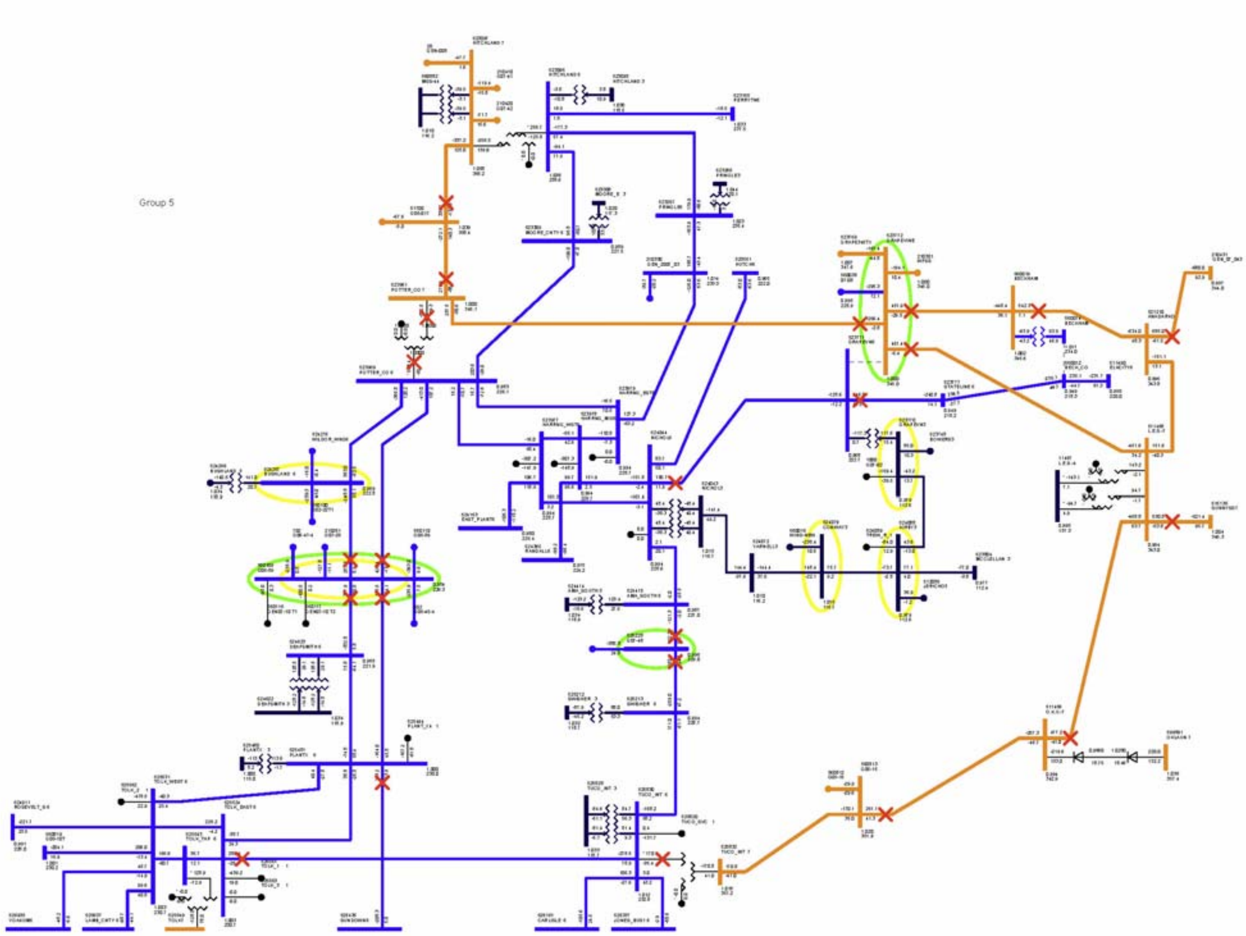

Figure 1-1. SPP Transmission System with Group 5 Projects

The study included a stability analysis for each proposed interconnection request. Contingencies that resulted in a prior-queued project tripping off-line were re-run with the prior-queued project's voltage and frequency tripping disabled. Since all of the interconnection requests in this group were wind projects, a power factor analysis also was done for each project.

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 this 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 other generation additions and transmission improvements being contemplated by other entities. Changes in the assumptions of the timing of other generation additions or transmission improvements will affect this study's conclusions.

2. Executive Summary

The Cluster #1 Group #5 Impact Study evaluated the impacts of interconnecting each of the six projects shown below.

Table 2-1. Interconnection Requests to be Evaluated

Request	Size	Wind Turbine Model	Point of Interconnection
GEN-2007-008	300	Suzlon 2.1MW	Grapevine 345kV (#523772)
GEN-2007-010	200	GE 1.5MW	Potter – Plant X 230kV line (#560109)
GEN-2007-026	126	Suzlon 2.1MW	Bushland – Deaf Smith 230kV line (#560109)
GEN-2007-030	200	Fuhrlaender	Grapevine 345kV (#523772)
GEN-2007-045	171	Suzlon 2.1MW	Grapevine 345kV (#523772)
GEN-2007-048	400	Fuhrlaender	Amarillo South – Swisher 230kV line (#525228)

No stability problems were found during summer or winter peak conditions with the addition of these generators.

Power factor requirements were determined, and all six study plants must install sufficient reactive power resources to meet the requirements listed in Table 4-2. Because no stability problems were found, the reactive power resources need not be high speed or continuously controlled. However, any change in wind turbine model or controls could change the stability results, possibly resulting in a need for a high-speed reactive power supply.

Some minor generator tripping problems occurred during Fault 39 (3-phase fault on the Tolk-Tuco 230 kV line). In this instance, the two GEN-2005-010 Gamesa generators tripped due to undervoltage in both summer and winter peak conditions. As specified by SPP standards, this fault was retested with tripping turned off to check for instability. With tripping disabled, no stability problems were found in either summer or winter peak conditions.

All Suzlon wind turbines have rather oscillatory machine speeds, with low but positive damping. The oscillations die out within 30 seconds. These speed oscillations have minimal impact on the electric system. The turbine manufacturer should review the PSS/E dynamic model.

The Fuhrlaender models are slow to recover to steady state. The Fuhrlaender model documentation indicates that this is normal for these wind turbines.

3. Study Development and Assumptions

3.1 Study Procedure

The Siemens Power Technologies, Inc. "PSS/E" digital computer power flow simulation program Version 30.3.2 was used in this study.

3.2 Models Used

SPP provided its latest stability database cases for both summer and winter peak seasons. Both models had been screened and run prior to their use in this study, and no additional screening was done. Each generator's PSS/E equivalent model had been previously developed prior to this study and included in the power flow case and the dynamics database. As a result, no additional generator modeling was required. Power flow one-line diagrams of the study projects are shown in Figure 3-1, Figure 3-2, and Figure 3-3. As the figures show, each plant model includes explicit representation of the radial transmission line, if any; the substation transformer(s) from transmission voltage to 34.5 kV; and the substation reactive power device(s), if any. The remainder of each wind farm is represented by one or more lumped equivalents including a generator, a step-up transformer, and a 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.

3.3 Monitored Facilities

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

3.4 Performance Criteria

The wind generators must comply with the FERC Order 661A on low voltage ride through for wind farms. Therefore, the wind generator should not trip off line for faults for under voltage relay actuation. If the wind generator trips off line, an appropriate sized SVC or STATCOM device may need to be specified to keep the wind generator on-line for the fault. SPP should be 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 were re-run with the prior-queued project's voltage and frequency tripping disabled to check for stability issues.

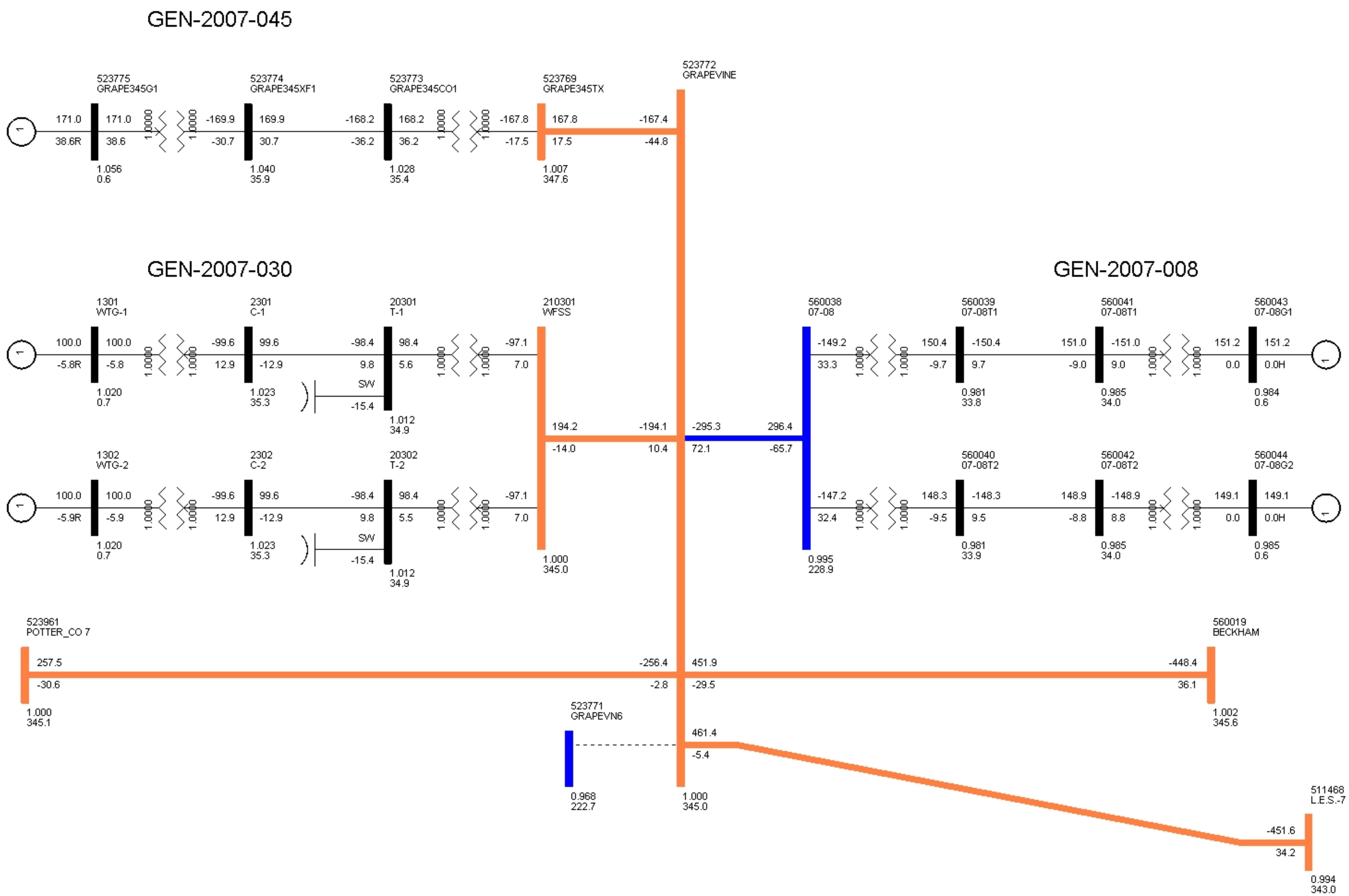

Figure 3-1. Power Flow One-line for GEN-2007-008, GEN-2007-030, and GEN-2007-045

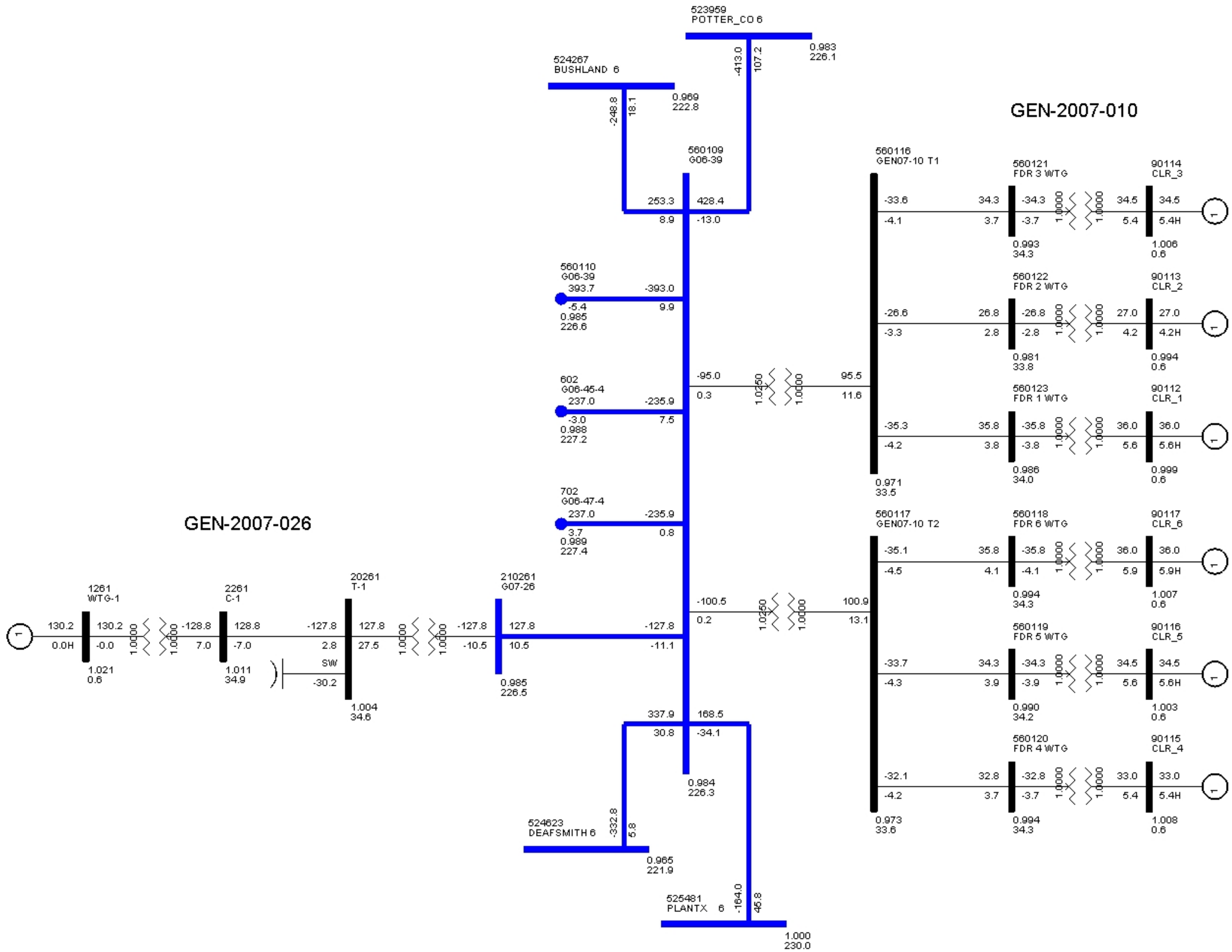

Figure 3-2. Power Flow One-line for GEN-2007-010 and GEN-2007-026

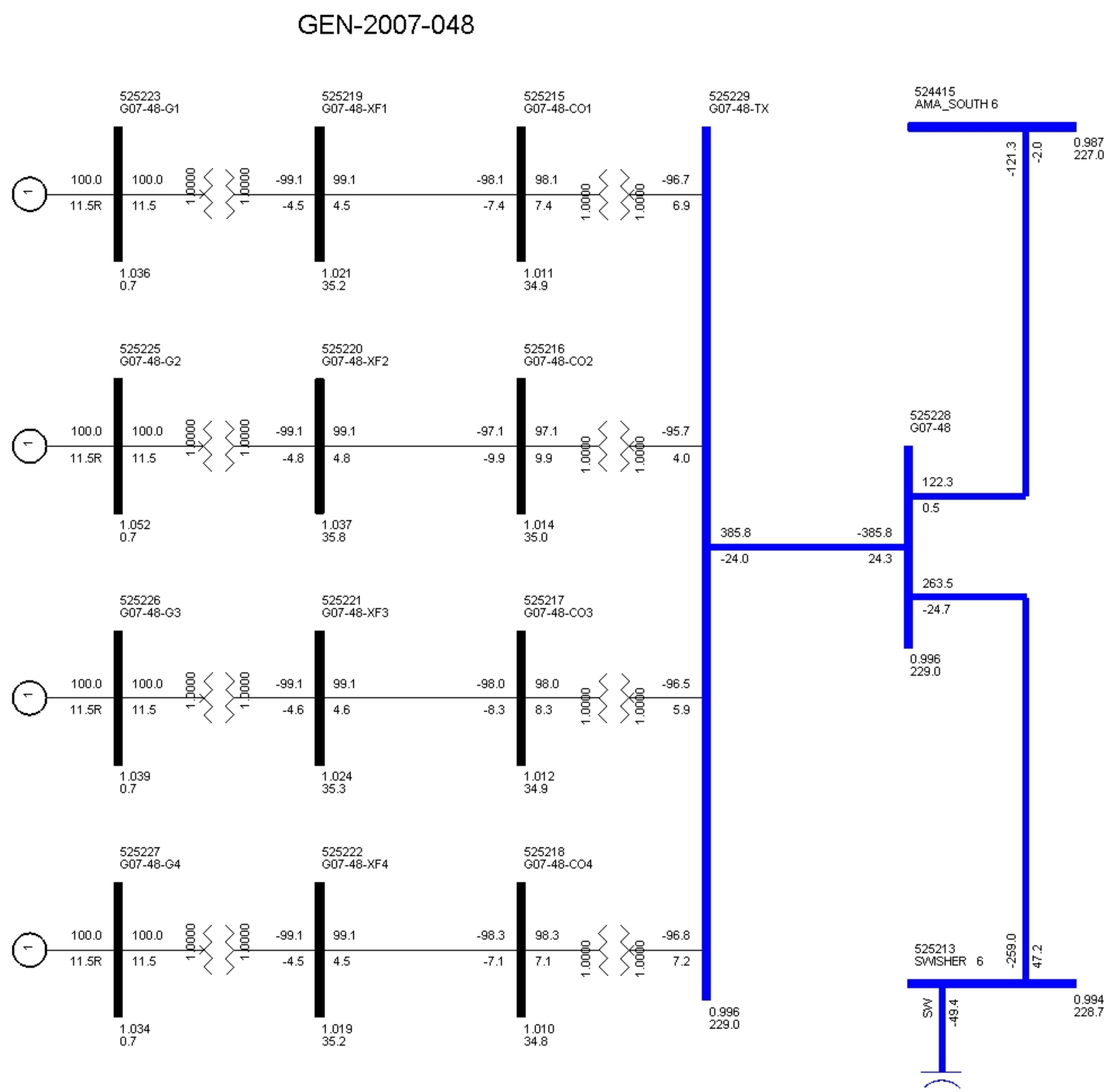

Figure 3-3. Power Flow One-line for GEN-2007-048

3.5 Performance Evaluation Methods

Stability analyses were done for each proposed interconnection request. Since each of the interconnection requests was also a wind project, a power factor analysis was also done. The power factor analysis consisted of modeling a var generator at the wind farm's substation high voltage bus. The var generator was set to hold a voltage schedule at the POI consistent with the higher of the voltage schedule in the base case provided by SPP or 1.0 per unit (p.u.) voltage.

If the required power factor at the POI is beyond the capability at the POI of the studied wind turbines, then capacitor banks would be considered. Factors to sizing capacitor banks would include the ability of the wind generator to meet FERC Order 661A (low voltage ride through) with and without capacitor banks; the ability of the wind farm to meet FERC Order 661A (wind farm recovery to pre-fault voltage). If 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.

The following faults (three phase and single phase as noted) were run for each case.

Table 3-1. Fault Definitions for Group 5

Cont. No.	Cont. Name	Description
1	FLT01-3PH	3 phase fault on the Grapevine (523772) to Potter Co. (523961) 345kV line, near Grapevine. a. Apply fault at the Grapevine 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 Grapevine (523772) to Beckham Co. (560019) 345kV line, near Grapevine. a. Apply fault at the Grapevine 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 Grapevine (523772) to Lawton Eastside (511468) 345kV line, near Grapevine. a. Apply fault at the Grapevine 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*

Cont. No.	Cont. Name	Description
7	FLT07-3PH	3 phase fault on the Potter Co. (523961) to GEN-2005-017 (51700) 345kV line, near Potter Co. a. Apply fault at the Potter Co. 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 GEN-2005-017 (51700) to Hitchland (523097) 345kV line, near GEN-2005-017. a. Apply fault at the GEN-2005-017 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 Potter Co. 345kV (523961) to 230kV (523959) transformer, near the 345kV kV bus. a. Apply fault at the Potter Co. 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
12	FLT12-1PH	*Single phase fault and sequence like previous*
13	FLT13-3PH	3 phase fault on the Potter Co. 230kV (523959) to 345kV (523961) transformer, near the 230kV bus. a. Apply fault at the Potter Co. 230kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
14	FLT14-1PH	*Single phase fault and sequence like previous*
15	FLT15-3PH	3 phase fault on the Beckham Co. (560019) to Anadarko (521210) 345kV line, near Beckham Co. a. Apply fault at the Beckham Co. 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	FLT17-3PH	3 phase fault on the Anadarko (521210) to GEN-2007-043 (210431) 345kV line, near Anadarko. a. Apply fault at the Anadarko 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	FLT18-1PH	*Single phase fault and sequence like previous*
19	FLT19-3PH	3 phase fault on the Lawton Eastside (511468) to Sunnyside (515136) 345kV line, near Lawton Eastside. a. Apply fault at the Lawton Eastside 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	FLT20-1PH	*Single phase fault and sequence like previous*

Cont. No.	Cont. Name	Description
21	FLT21-3PH	3 phase fault on the GEN-2007-048 (525228) to Amarillo South (524415) 230kV line, near GEN-2007-048. a. Apply fault at the GEN-2007-048 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	FLT22-1PH	*Single phase fault and sequence like previous*
23	FLT23-3PH	3 phase fault on the GEN-2007-048 (525228) to Swisher (525213) 230kV line, near GEN-2007-048. a. Apply fault at the GEN-2007-048 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	FLT24-1PH	*Single phase fault and sequence like previous*
25	FLT25-3PH	3 phase fault on the Nichols (524044) to Grapevine (523771) 230kV line, near Nichols. a. Apply fault at the Nichols 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	FLT26-1PH	*Single phase fault and sequence like previous*
27	FLT27-3PH	3 phase fault on the Grapevine (523771) to Stateline (523777) 230kV line, near Grapevine. a. Apply fault at the Grapevine 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.
28	FLT28-1PH	*Single phase fault and sequence like previous*
29	FLT29-3PH	3 phase fault on the GEN-2006-039 (560109) to Bushland (524267) 230kV line, near GEN-2006-039. a. Apply fault at the GEN-2006-039 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	FLT30-1PH	*Single phase fault and sequence like previous*
31	FLT31-3PH	3 phase fault on the GEN-2006-039 (560109) to Potter Co. (523959) 230kV line, near GEN-2006-039. a. Apply fault at the GEN-2006-039 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	FLT32-1PH	*Single phase fault and sequence like previous*
33	FLT33-3PH	3 phase fault on the GEN-2006-039 (560109) to Deaf Smith (524623) 230kV line, near GEN-2006-039. a. Apply fault at the GEN-2006-039 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	FLT34-1PH	*Single phase fault and sequence like previous*

Cont. No.	Cont. Name	Description
35	FLT35-3PH	3 phase fault on the GEN-2006-039 (560109) to Plant X (525481) 230kV line, near GEN-2006-039. a. Apply fault at the GEN-2006-039 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	FLT36-1PH	*Single phase fault and sequence like previous*
37	FLT37-3PH	3 phase fault on the Plant X (525481) to Sundown (526435) 230kV line, near Plant X. a. Apply fault at the Plant X 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	FLT38-1PH	*Single phase fault and sequence like previous*
39	FLT39-3PH	3 phase fault on the Tolk (525524) to Tuco (525830) 230kV line, near Tolk. a. Apply fault at the Tolk 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	FLT40-1PH	*Single phase fault and sequence like previous*
41	FLT41-3PH	3 phase fault on the Tuco 230kV (525830) to 345kV (525832) transformer, near the 230kV bus. a. Apply fault at the Tuco 230kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
42	FLT42-1PH	*Single phase fault and sequence like previous*
43	FLT43-3PH	3 phase fault on the GEN-2005-015 (560813) to Oklaunion (511456) 345kV line, near GEN-2005-015. a. Apply fault at the GEN-2005-015 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.
44	FLT44-1PH	*Single phase fault and sequence like previous*
45	FLT45-3PH	3 phase fault on the Oklaunion (511456) to Lawton Eastside (511468) 345kV line, near Oklaunion. a. Apply fault at the Oklaunion 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.
46	FLT46-1PH	*Single phase fault and sequence like previous*
47	FLT47-3PH	3 phase fault on the Hitchland (523097) to Beaver County (523098) 345kV line, near Hitchland. a. Apply fault at the Hitchland 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
48	FLT488-1PH	*Single phase fault and sequence like previous*

Cont. No.	Cont. Name	Description
49	FLT49-3PH	3 phase fault on the GEN-2007-040 (210400) to Comanche (531487) 345kV line, near Comanche. a. Apply fault at the Comanche 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.
50	FLT50-1PH	*Single phase fault and sequence like previous*

4. Results and Observations

4.1 Stability Analysis Results

The fifty faults provided by SPP were run for both summer and winter peak conditions. If a previously-queued generator tripped for any of these faults, the voltage and frequency tripping was disabled, and the fault was re-run to check for system stability.

Table 4-1 summarizes the overall results for all faults run.

Table 4-1. Summary of Results

Cont. No.	Contingency Name	Contingency Description	Summer Peak Results	Winter Peak Results
1	FLT01-3PH	3 phase fault on the Grapevine (523772) to Potter Co. (523961) 345kV line, near Grapevine	OK	OK
2	FLT02-1PH	*Single phase fault and sequence like previous*	OK	OK
3	FLT03-3PH	3 phase fault on the Grapevine (523772) to Beckham Co. (560019) 345kV line, near Grapevine.	OK	OK
4	FLT04-1PH	*Single phase fault and sequence like previous*	OK	OK
5	FLT05-3PH	3 phase fault on the Grapevine (523772) to Lawton Eastside (511468) 345kV line, near Grapevine.	OK	OK
6	FLT06-1PH	*Single phase fault and sequence like previous*	OK	OK
7	FLT07-3PH	3 phase fault on the Potter Co. (523961) to GEN-2005-017 (51700) 345kV line, near Potter Co.	OK	OK
8	FLT08-1PH	*Single phase fault and sequence like previous*	OK	OK
9	FLT09-3PH	3 phase fault on the GEN-2005-017 (51700) to Hitchland (523097) 345kV line, near GEN-2005-017.	OK	OK
10	FLT10-1PH	*Single phase fault and sequence like previous*	OK	OK
11	FLT11-3PH	3 phase fault on the Potter Co. 345kV (523961) to 230kV (523959) transformer, near the 345kV kV bus.	OK	OK
12	FLT12-1PH	*Single phase fault and sequence like previous*	OK	OK
13	FLT13-3PH	3 phase fault on the Potter Co. 230kV (523959) to 345kV (523961) transformer, near the 230kV bus.	OK	OK
14	FLT14-1PH	*Single phase fault and sequence like previous*	OK	OK
15	FLT15-3PH	3 phase fault on the Beckham Co. (560019) to Anadarko (521210) 345kV line, near Beckham Co.	OK	OK
16	FLT16-1PH	*Single phase fault and sequence like previous*	OK	OK
17	FLT17-3PH	3 phase fault on the Anadarko (521210) to GEN-2007-043 (210431) 345kV line, near Anadarko.	OK	OK
18	FLT18-1PH	*Single phase fault and sequence like previous*	OK	OK
19	FLT19-3PH	3 phase fault on the Lawton Eastside (511468) to Sunnyside (515136) 345kV line, near Lawton Eastside.	OK	OK
20	FLT20-1PH	*Single phase fault and sequence like previous*	OK	OK

Cont. No.	Contingency Name	Contingency Description	Summer Peak Results	Winter Peak Results
21	FLT21-3PH	3 phase fault on the GEN-2007-048 (525228) to Amarillo South (524415) 230kV line, near GEN-2007-048.	OK	OK
22	FLT22-1PH	*Single phase fault and sequence like previous*	OK	OK
23	FLT23-3PH	3 phase fault on the GEN-2007-048 (525228) to Swisher (525213) 230kV line, near GEN-2007-048.	OK	OK
24	FLT24-1PH	*Single phase fault and sequence like previous*	OK	OK
25	FLT25-3PH	3 phase fault on the Nichols (524044) to Grapevine (523771) 230kV line, near Nichols.	OK	OK
26	FLT26-1PH	*Single phase fault and sequence like previous*	OK	OK
27	FLT27-3PH	3 phase fault on the Grapevine (523771) to Stateline (523777) 230kV line, near Grapevine.	OK	OK
28	FLT28-1PH	*Single phase fault and sequence like previous*	OK	OK
29	FLT29-3PH	3 phase fault on the GEN-2006-039 (560109) to Bushland (524267) 230kV line, near GEN-2006-039.	OK	OK
30	FLT30-1PH	*Single phase fault and sequence like previous*	OK	OK
31	FLT31-3PH	3 phase fault on the GEN-2006-039 (560109) to Potter Co. (523959) 230kV line, near GEN-2006-039.	OK	OK
32	FLT32-1PH	*Single phase fault and sequence like previous*	OK	OK
33	FLT33-3PH	3 phase fault on the GEN-2006-039 (560109) to Deaf Smith (524623) 230kV line, near GEN-2006-039.	OK	OK
34	FLT34-1PH	*Single phase fault and sequence like previous*	OK	OK
35	FLT35-3PH	3 phase fault on the GEN-2006-039 (560109) to Plant X (525481) 230kV line, near GEN-2006-039.	OK	OK
36	FLT36-1PH	*Single phase fault and sequence like previous*	OK	OK
37	FLT37-3PH	3 phase fault on the Plant X (525481) to Sundown (526435) 230kV line, near Plant X.	OK	OK
38	FLT38-1PH	*Single phase fault and sequence like previous*	OK	OK
39	FLT39-3PH	3 phase fault on the Tolk (525524) to Tuco (525830) 230kV line, near Tolk.	OK Generators at Buses 560817 and 560818 tripped at 1.1 sec.	OK
39-NT no trip	FLT39-3PH	3 phase fault on the Tolk (525524) to Tuco (525830) 230kV line, near Tolk. – Change breaker time from 3 cycles to 999 cycles at buses 560817 and 560818 (tripping disabled)	OK	OK
40	FLT40-1PH	*Single phase fault and sequence like previous*	OK	OK
41	FLT41-3PH	3 phase fault on the Tuco 230kV (525830) to 345kV (525832) transformer, near the 230kV bus.	OK	OK
42	FLT42-1PH	*Single phase fault and sequence like previous*	OK	OK
43	FLT43-3PH	3 phase fault on the GEN-2005-015 (560813) to Oklaunion (511456) 345kV line, near GEN-2005-015.	OK	OK
44	FLT44-1PH	*Single phase fault and sequence like previous*	OK	OK
45	FLT45-3PH	3 phase fault on the Oklaunion (511456) to Lawton Eastside (511468) 345kV line, near Oklaunion.	OK	OK

Cont. No.	Contingency Name	Contingency Description	Summer Peak Results	Winter Peak Results
46	FLT46-1PH	*Single phase fault and sequence like previous*	OK	OK
47	FLT47-3PH	3 phase fault on the Hitchland (523097) to Beaver County (523098) 345kV line, near Hitchland.	OK	OK
48	FLT48-1PH	*Single phase fault and sequence like previous*	OK	OK
49	FLT49-3PH	3 phase fault on the GEN-2007-040 (210400) to Comanche (531487) 345kV line, near Comanche.	OK	OK
50	FLT50-1PH	*Single phase fault and sequence like previous*	OK	OK

Figure 4-1 through Figure 4-9 show representative summer peak season plots for faults at the POIs for each of the six study projects. Complete sets of plots for both summer and winter peak seasons for each fault and each wind project are included in Appendices A and B.

The system remains stable for all simulated faults.

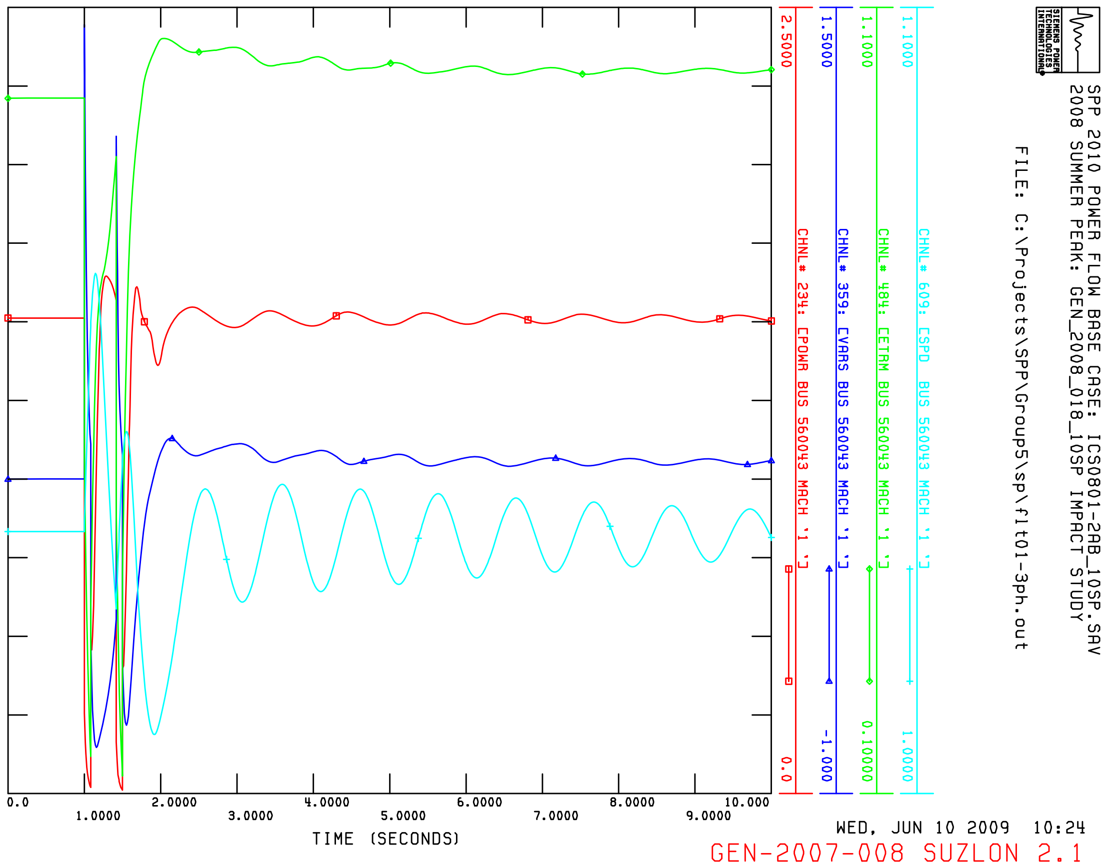

Figure 4-1. Fault 1 – 3-Phase Fault on the Grapevine to Potter Co. 345 kV line, near Grapevine – GEN-2007-008

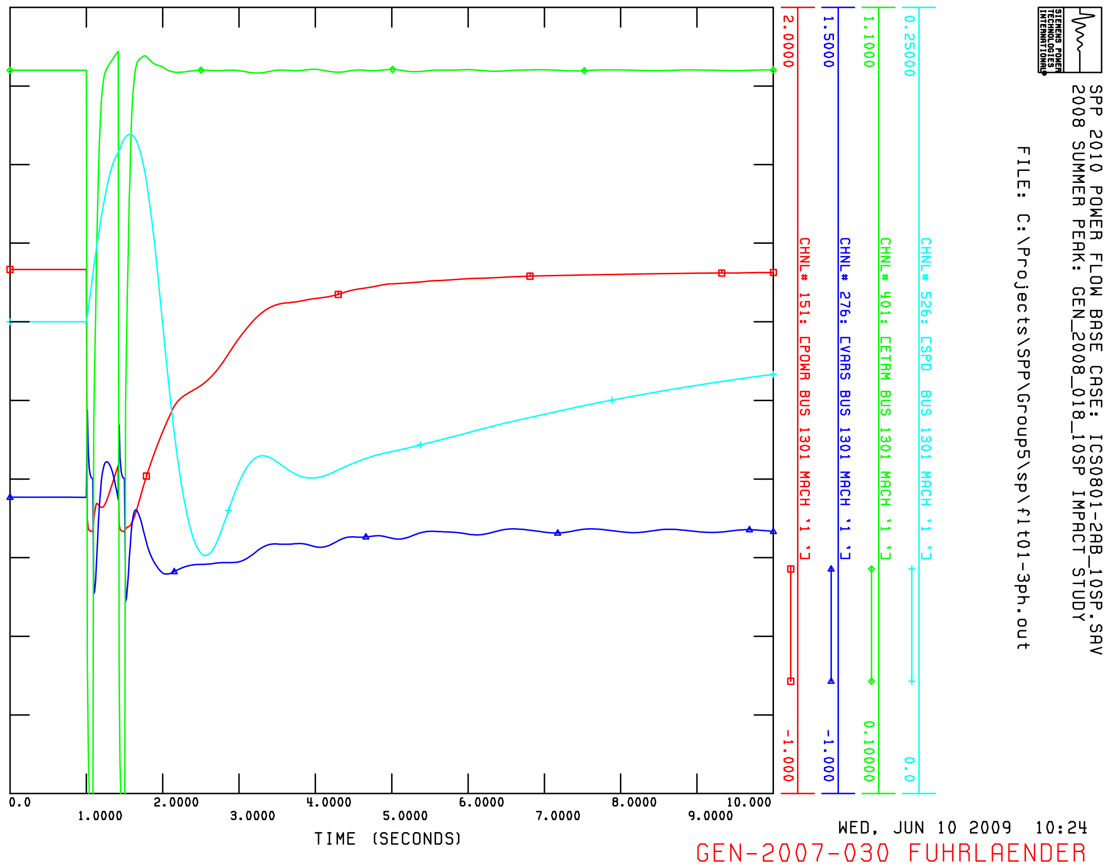

Figure 4-2. Fault 1 – 3-Phase Fault on the Grapevine to Potter Co. 345 kV line, near Grapevine – GEN-2007-030

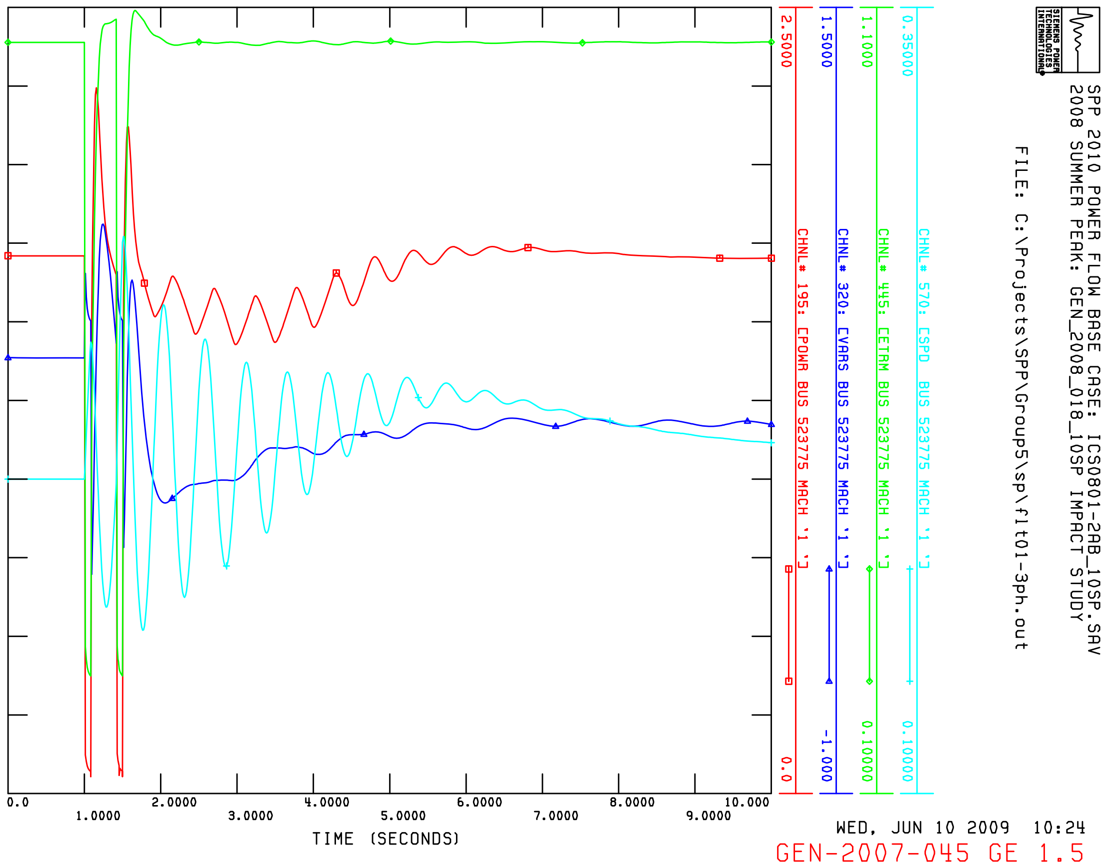

Figure 4-3. Fault 1 – 3-Phase Fault on the Grapevine to Potter Co. 345 kV line, near Grapevine – GEN-2007-045

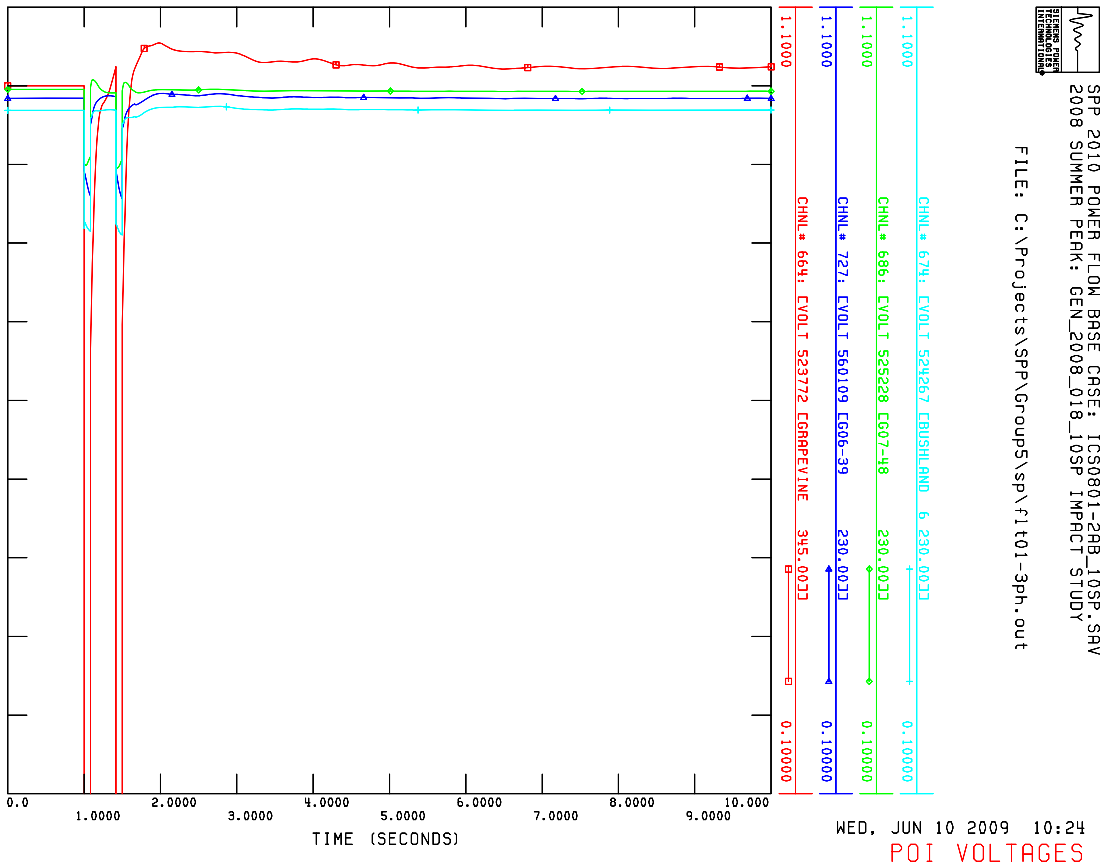

Figure 4-4. Fault 1 – 3-Phase Fault on the Grapevine to Potter Co. 345 kV line, near Grapevine – POI Voltages

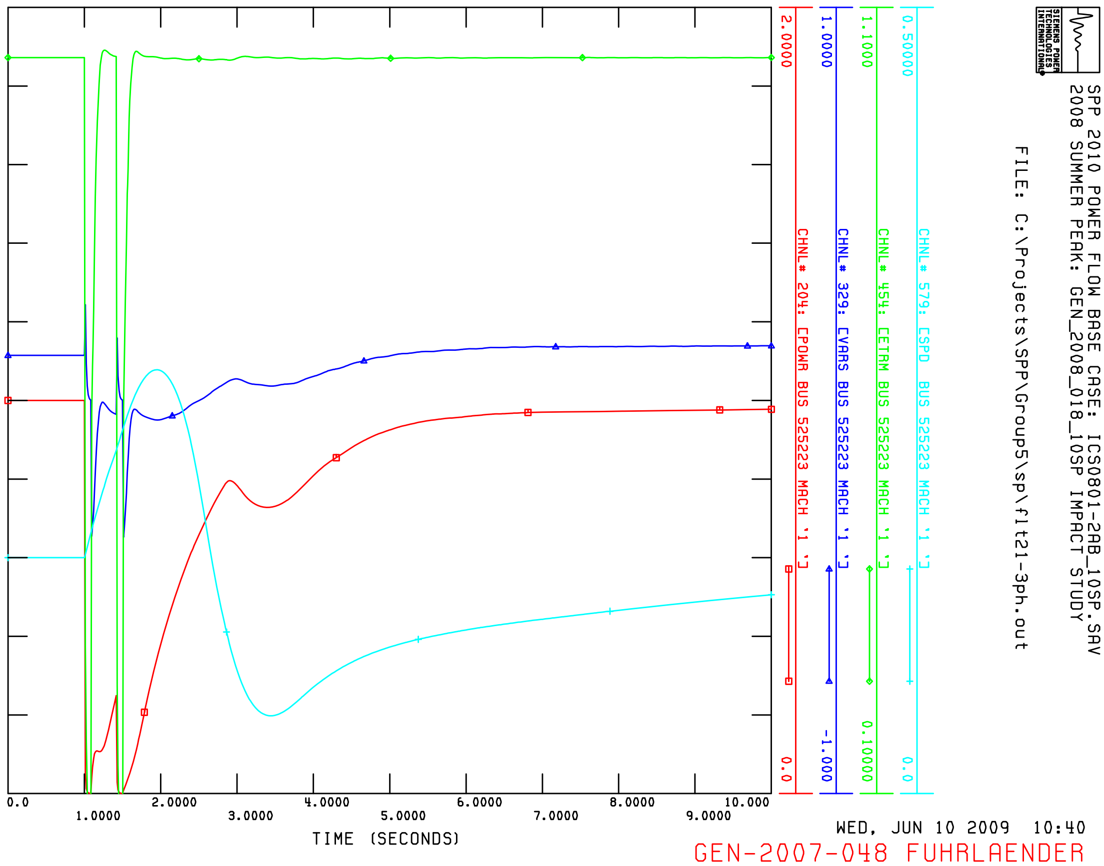

Figure 4-5. Fault 21 – 3-Phase Fault on the GEN-2007-048 to Amarillo South 230 kV line, near GEN-2007-048 – GEN-2007-048

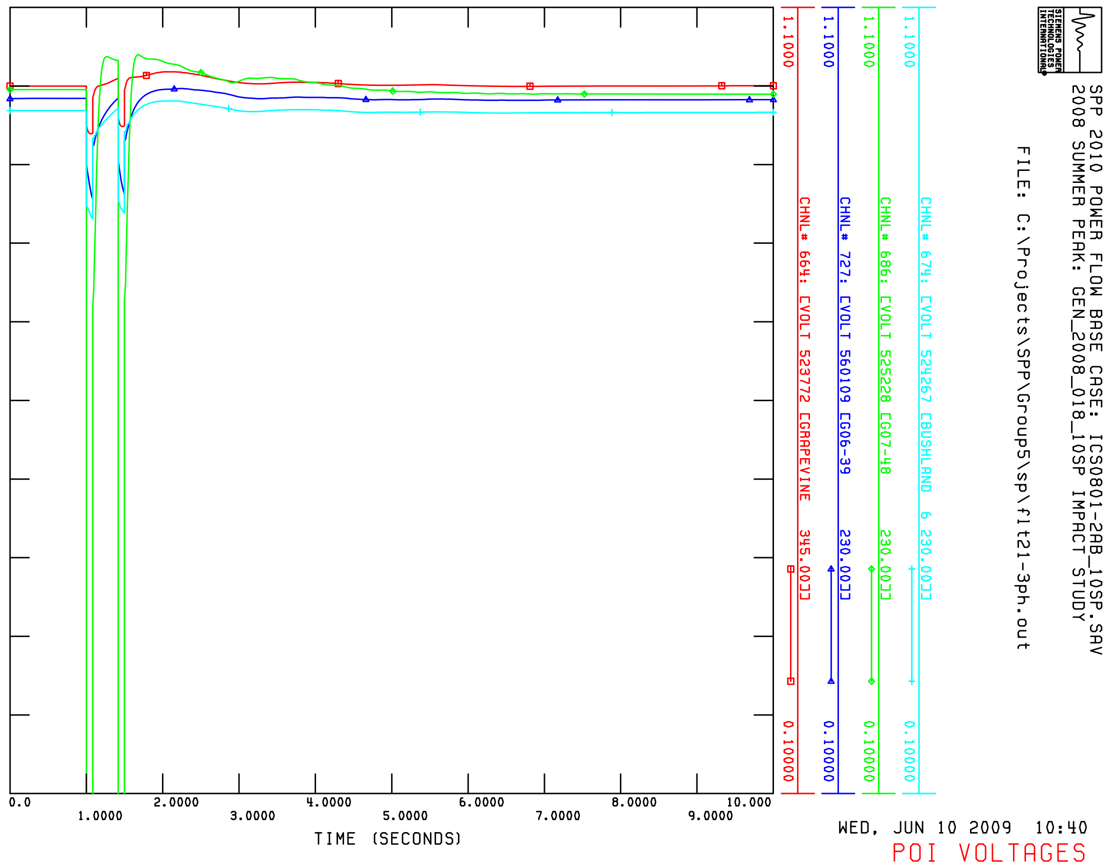

Figure 4-6. Fault 21 – 3-Phase Fault on the GEN-2007-048 to Amarillo South 230 kV line, near GEN-2007-048 – POI Voltages

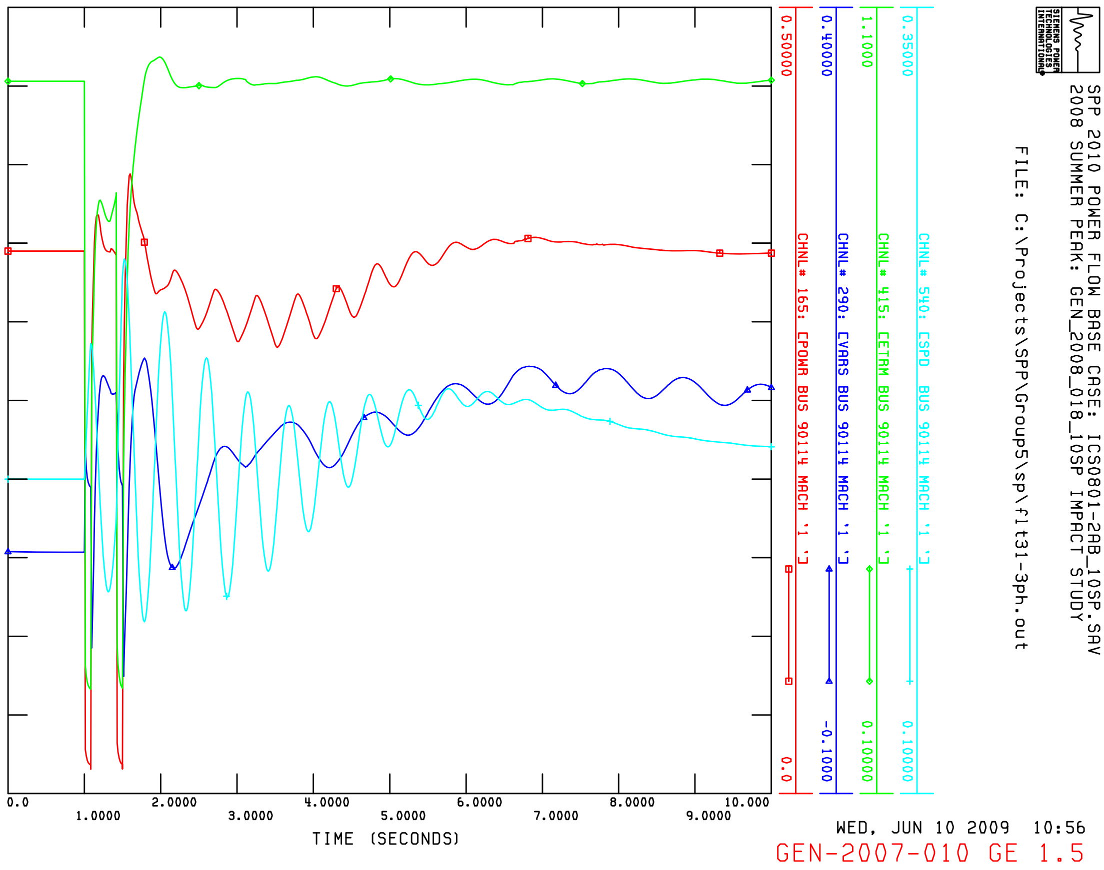

Figure 4-7. Fault 31 – 3-Phase Fault on the GEN-2006-039 to Bushland 230 kV line, near GEN-2006-039 – GEN-2007-010

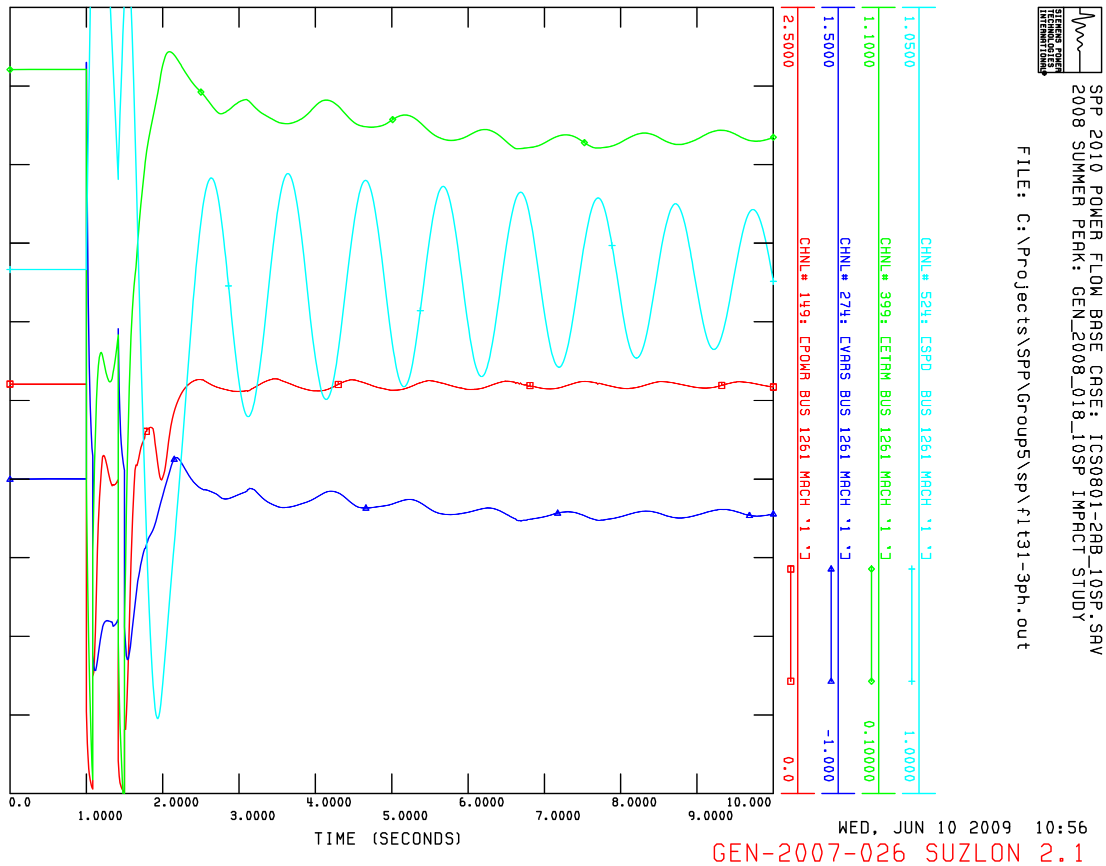

Figure 4-8. Fault 31 – 3-Phase Fault on the GEN-2006-039 to Bushland 230 kV line, near GEN-2006-039 – GEN-2007-026

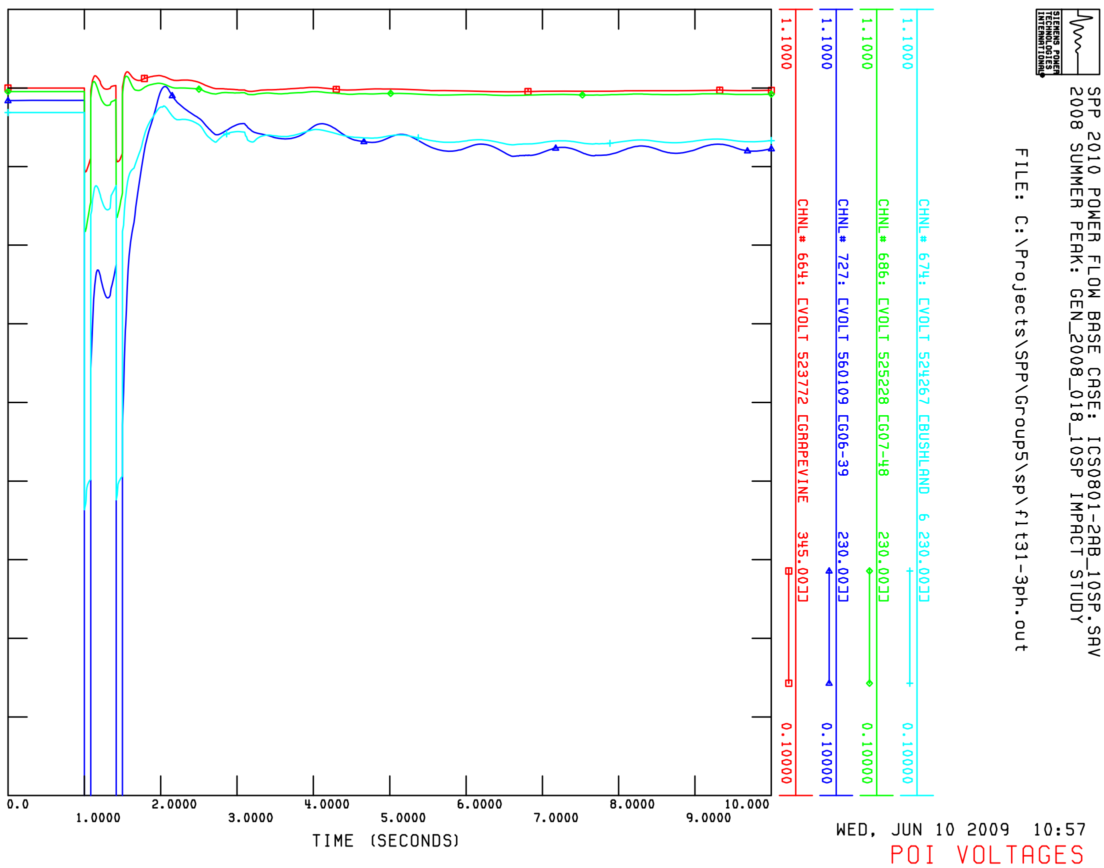

Figure 4-9. Fault 31 – 3-Phase Fault on the GEN-2006-039 to Bushland 230 kV line, near GEN-2006-039 – POI Voltages

4.2 Wind Turbine Performance

All Suzlon wind turbines have rather oscillatory generator speeds, with low but positive damping. The oscillations die out within 30 seconds as shown in Figure 4-10. These speed oscillations have minimal impact on the electric system. The Suzlon dynamic model should be reviewed by the turbine manufacturer.

The Fuhrlaender models are slow to recover to steady state (for example Figure 4-2 above). The Fuhrlaender model documentation indicates that this is normal for these wind turbines.

The two GEN-2005-010 Gamesa generators tripped due to undervoltage in both summer and winter peak conditions for Fault 39 (3-phase fault on the Tolk-Tuco 230 kV line). See Figure 4-11 below. The generators are set to trip if the voltage drops below 15% for more than 0.04 second; during this fault, the voltage dropped below 15% for 0.0875 second. As specified by SPP standards, this fault was retested with tripping turned off to check for instability. With tripping disabled (Figure 4-12), no stability problems were found in either summer or winter peak conditions. However, the POI voltages recover slowly after this particular fault, especially in the summer peak case (Figure 4-13). No stability criteria are violated.

The initial fault run for Fault 49 (3-phase fault on the GEN-2007-040 to Comanche 345 kV line) in winter peak resulted in PSS/E crashing (Figure 4-14). It was determined that the crash was caused by the Vestas V90 3.0 MW wind turbine models used at projects GEN-2001-039M and GEN-2005-012. These two projects are far from the Group 5 study projects and should have little or no affect on stability of the Group 5 projects. The V90 models were replaced with GE 1.5 MW wind turbine models for Fault 49 in winter peak only. The Fault 49 simulation then ran to completion with no problems (Figure 4-15). The Vestas V90 3.0 MW dynamic model should be reviewed by the manufacturer.

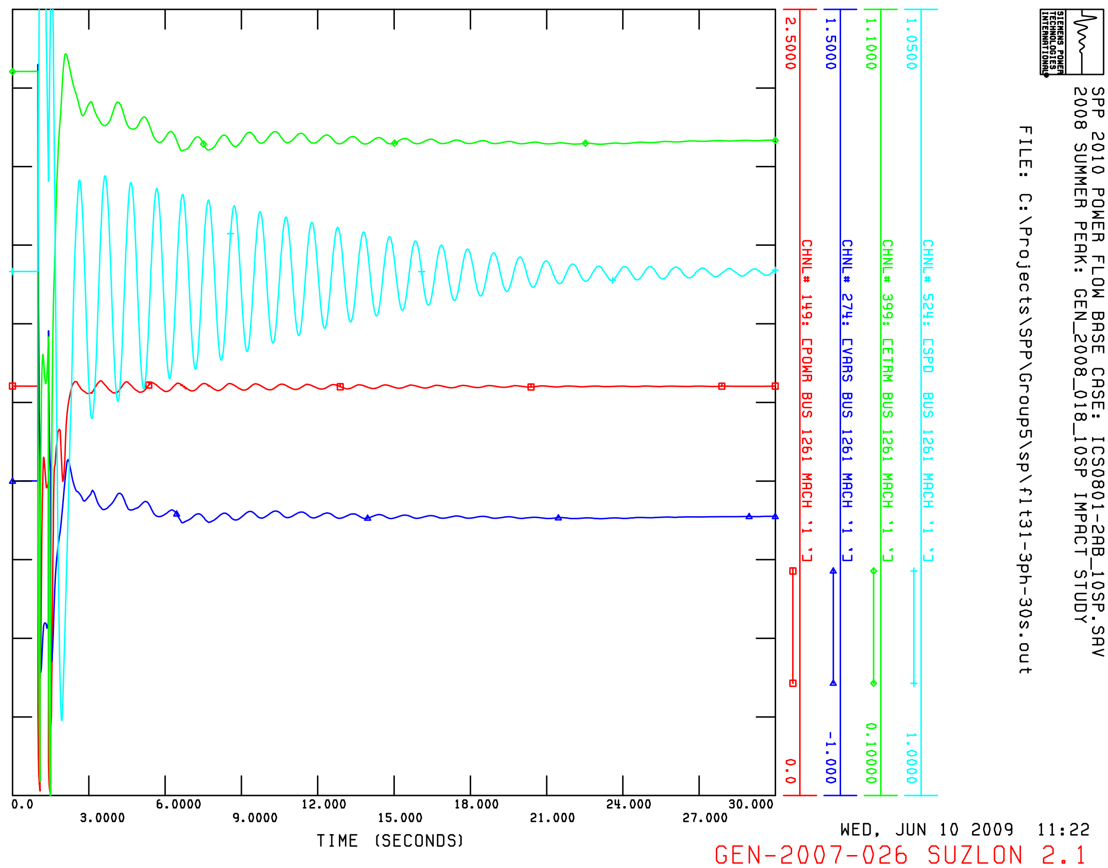

Figure 4-10. Fault 31 – 3-Phase Fault on the GEN-2006-039 to Bushland 230 kV line, near GEN-2006-039 – GEN-2007-026 – extended to 30 seconds

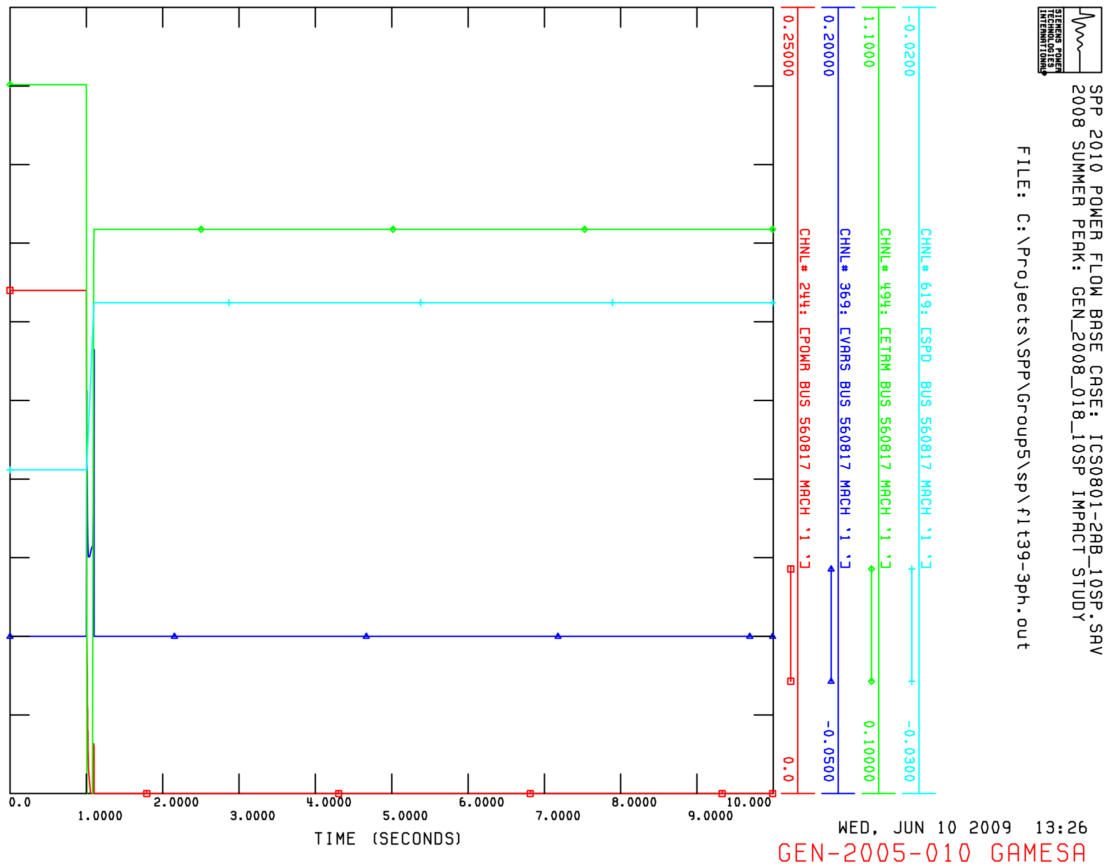

Figure 4-11. Fault 39 – 3-Phase Fault on the Tolk to Tuco 230kV line, near Tolk – GEN-2005-010 Trips

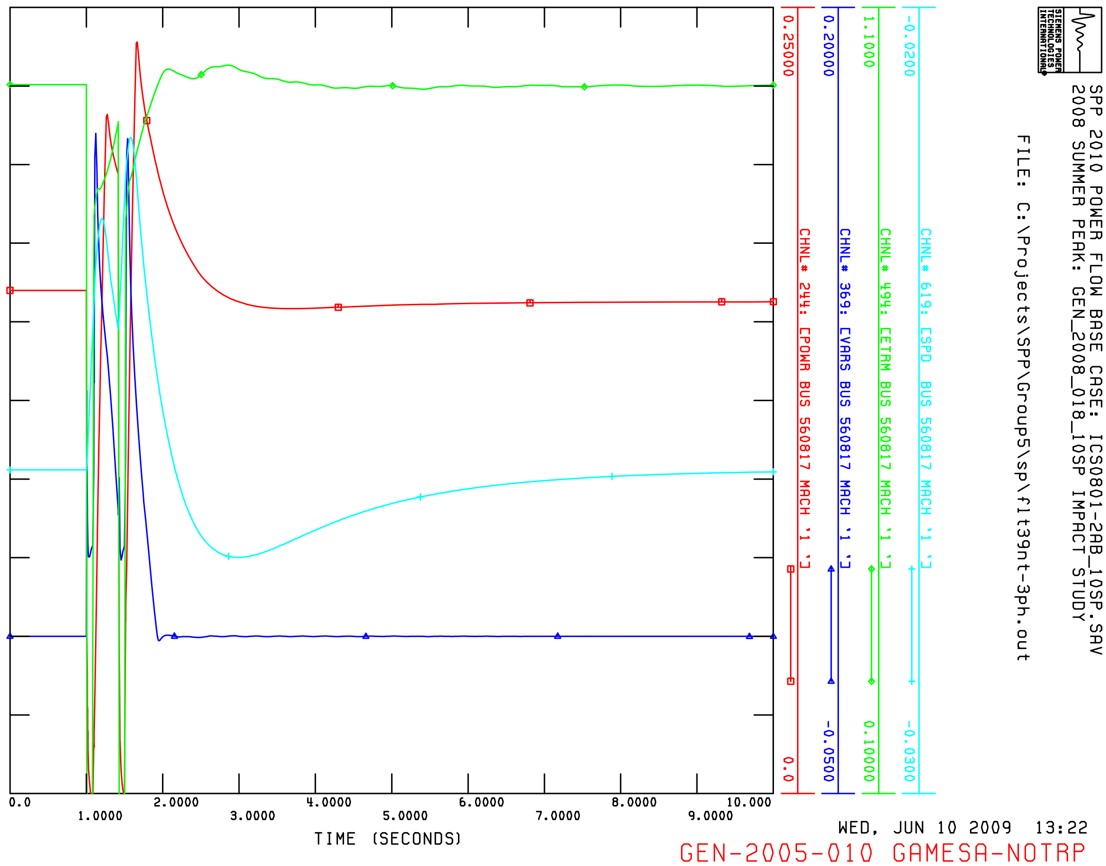

Figure 4-12. Fault 39 – 3-Phase Fault on the Tolk to Tuco 230kV line, near Tolk – GEN-2005-010 Tripping Blocked

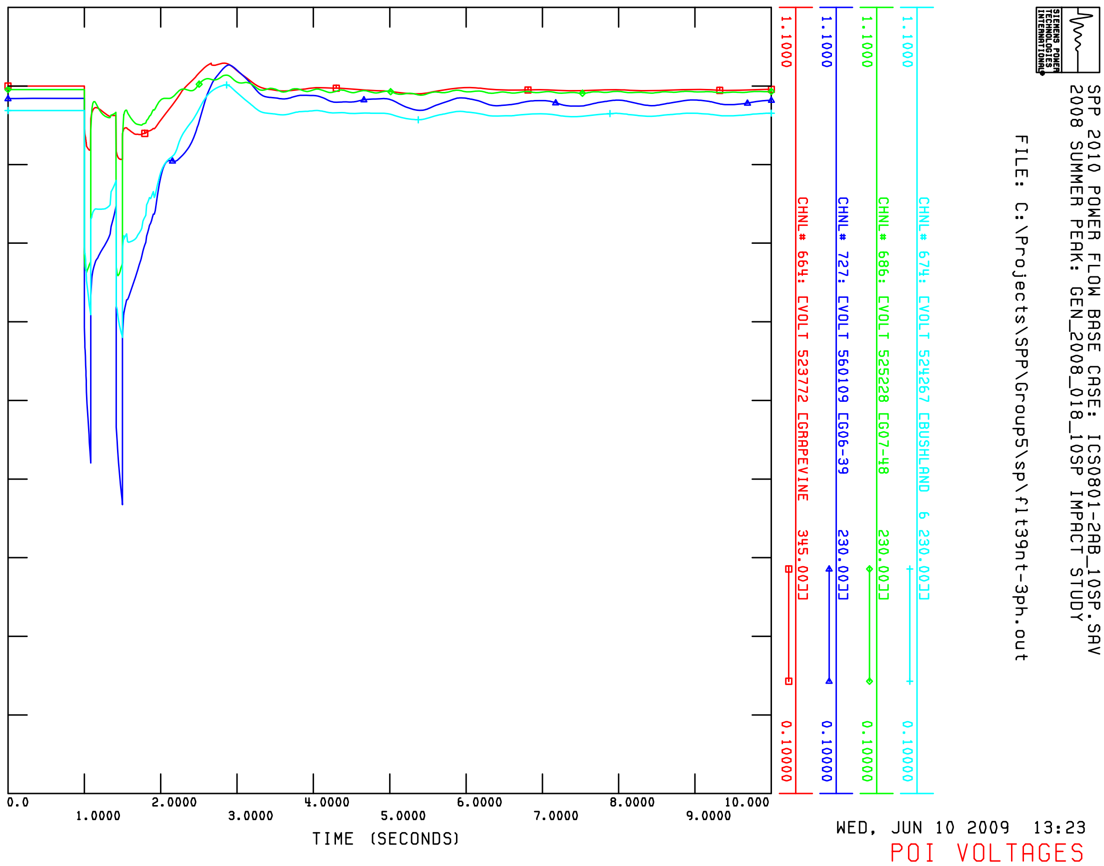

Figure 4-13. Fault 39 – 3-Phase Fault on the Tolk to Tuco 230 kV line, near Tolk – POI Voltages

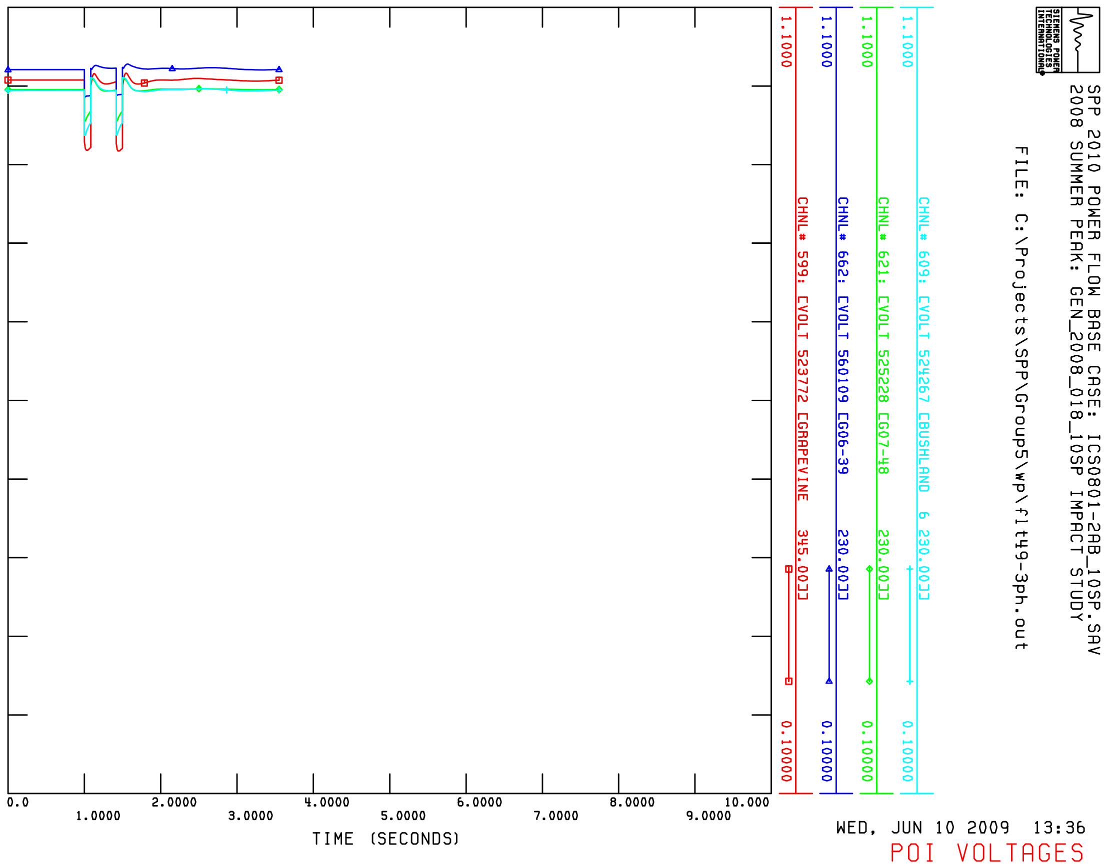

Figure 4-14. Fault 49 – 3-Phase Fault on the GEN-2007-040 to Comanche 345kV line, near Comanche, PSS/E Crashes

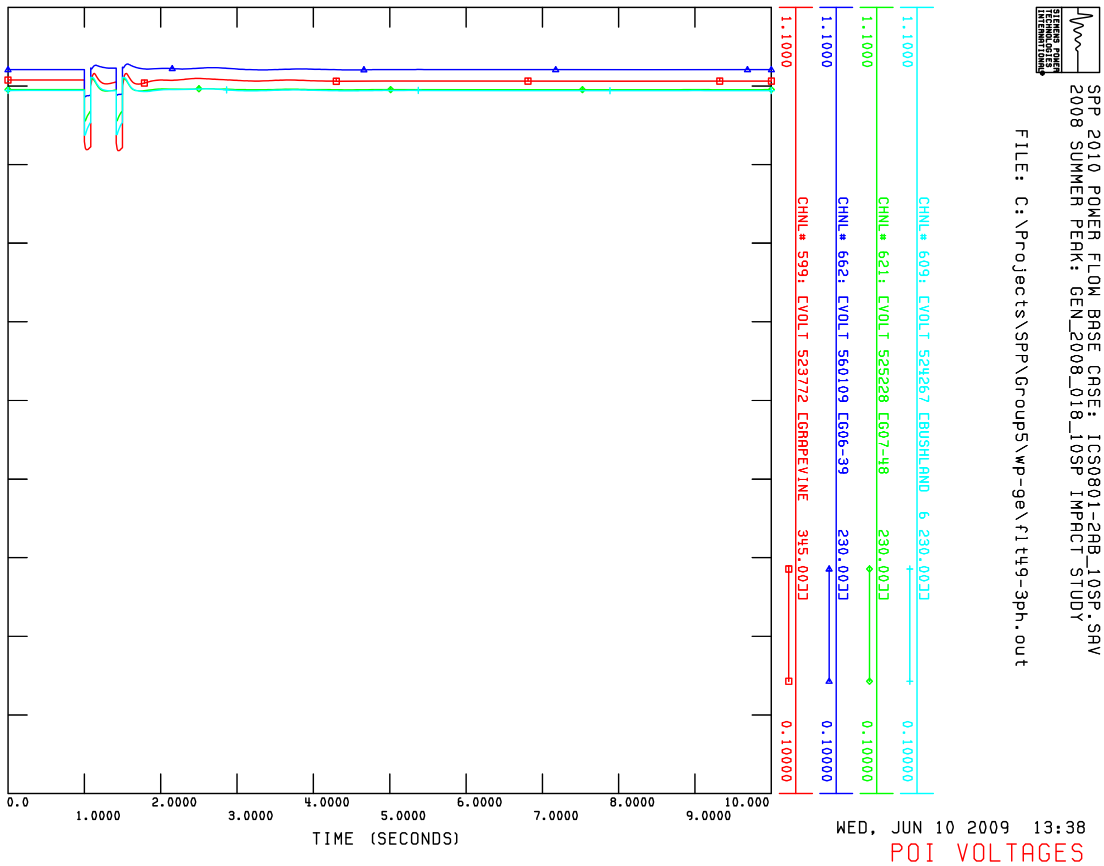

Figure 4-15. Fault 49 – 3-Phase Fault on the GEN-2007-040 to Comanche 345kV line, near Comanche, GE Model, No Crash

4.3 Power Factor Requirements

All of the stability faults were tested as power flow contingencies to determine the power factor requirements for the study projects to maintain scheduled voltage at their respective points of interconnection (POI). The voltage schedule was set to 1.0 per unit at each POI. Reactive power sources were added to the study projects as needed 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. The most leading and most lagging power factors determine the minimum power factor range capability that the study projects must install.

For multiple study projects sharing 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. Prior-queued projects at the same POI were not grouped with the study projects because their interconnection requirements have already been previously determined.

Per FERC and SPP Tariff requirements, if the power factor needed to maintain scheduled voltage was less than 0.95 lagging, then the requirement is set to 0.95 lagging. This is the case for all study projects except GEN-2007-048. The leading power factor requirement would also have been limited to no less 0.95, but this situation did not occur for these study projects.

The final power factor requirements are shown in Table 4-2 below. Projects with the same color shading have the same POI and thus the same power factor requirements. Projects GEN-2007-010 and GEN-2007-026 have different POIs shown in the table, but these two transmission lines are going to be tied together in a single new substation for connecting these and some prior-queued projects. The power factor requirements shown in Table 4-2 are only the minimum power factor ranges. A project developer may install more capability than this if desired.

The contingency causing the most lagging power factor from the wind farms is the outage of the Oklaunion – Lawton Eastside 345 kV line. This outage severs the primary 345 kV path from the southern Texas Panhandle into Oklahoma. Any power being imported from ERCOT at Oklaunion must flow west joining the Group 5 study projects. All this power then must flow north to Amarillo before finding additional paths to the east.

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

Table 4-2. Power Factor Requirements [1]

Project	MW	Turbine	POI	Final PF Requirement	
				Lagging [2]	Leading [3]
GEN-2007-008	300	Suzlon 2.1MW	Grapevine 345kV	0.95	0.9854
GEN-2007-030	200	Fuhrlaender	Grapevine 345kV	0.95	0.9854
GEN-2007-045	171	G.E. 1.5MW	Grapevine 345kV	0.95	0.9854
GEN-2007-010	200	GE 1.5MW	Potter – Plant X 230kV line	0.95	0.9822
GEN-2007-026	126	Suzlon 2.1MW	Bushland – Deaf Smith 230kV line	0.95	0.9822
GEN-2007-048	400	Fuhrlaender	Amarillo S. – Swisher 230kV line	0.9972	0.9979

Notes:

1. 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 wind farm. The power factor capability at the POI includes the net effect of the wind turbine generators, transformer and collector line impedances, and any reactive compensation devices installed on the plant side of the meter. Installing more capability than the minimum requirement is acceptable.
2. 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.
3. 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.

5. Conclusions

The Cluster #1 Group #5 Impact Study evaluated the impacts of interconnecting each of the six projects shown below.

Table 5-1. Interconnection Requests to be Evaluated

Request	Size	Wind Turbine Model	Point of Interconnection
GEN-2007-008	300	Suzlon 2.1 MW	Grapevine 345kV
GEN-2007-010	200	GE 1.5MW	Potter – Plant X 230kV line (#560109)
GEN-2007-026	126	Suzlon 2.1 MW	Bushland – Deaf Smith 230kV line (#560109)
GEN-2007-030	200	Fuhrlaender	Grapevine 345kV (#523772)
GEN-2007-045	171	Suzlon 2.1 MW	Grapevine 345kV (#523772)
GEN-2007-048	400	Fuhrlaender	Amarillo South – Swisher 230kV line

No stability problems were found during summer or winter peak conditions with the addition of these generators.

Power factor requirements were determined, and all six study plants must install sufficient reactive power resources to meet these requirements listed in Table 4-2. Because no stability problems were found, the reactive power resources need not be high speed or continuously controlled. However, any change in wind turbine model or controls could change the stability results, possibly resulting in a need for a high-speed reactive power supply.

Some minor generator tripping problems occurred during Fault 39 (3-phase fault on the Tolk-Tuco 230 kV line). In this instance, the two GEN-2005-010 Gamesa generators tripped due to undervoltage in both summer and winter peak conditions. As specified by SPP standards, this fault was retested with tripping turned off to check for instability. With tripping disabled, no stability problems were found in either summer or winter peak conditions.

All Suzlon wind turbines have rather oscillatory machine speeds, with low but positive damping. The oscillations die out within 30 seconds. These speed oscillations have minimal impact on the electric system. The turbine manufacturer should review the PSS/E dynamic model.

The Fuhrlaender models are slow to recover to steady state. The Fuhrlaender model documentation indicates that this is normal for these wind turbines.

Appendix A – Summer Peak Fault Plots

Appendix B – Winter Peak Fault Plots

Appendix C – Power Factor Details

Appendix D – Dynamic Model Data

O: Stability Study for Group 6

R101-09

Generator Interconnection Impact Study for Cluster # 1: ICS-2008-001 - Group 6

Prepared for

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Draft Report: June 28, 2009

Siemens PTI Project Number: P/21-113379-B-4

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Section

1

Introduction

1.1 Background

Pursuant to the tariff and at the request of the Southwest Power Pool (SPP), Siemens PTI performed the following Impact Study to satisfy the Impact Study Agreement executed by the requesting customers and SPP for SPP Generation Interconnection request. The requests for interconnection were placed with SPP in accordance to SPP's Open Access Transmission Tariff, which covers new generation interconnections on SPP's transmission system.

The purpose of this report is to present the results of the stability and power factor analysis performed to evaluate the impact of the proposed cluster of interconnections of the ICS-2008-001 with regard to Group 6 projects on the Southwest Power Pool system. The indicative solutions to the identified issues are proposed based on the impact of each generation interconnection on the Southwest Power Pool system.

Nine projects in this cluster are connected to seven different points of interconnection at different voltage levels ranging, from 69 kV to 345 kV. Section 2 describes all proposed wind farms projects in detail.

Transient stability analysis was performed using the package provide by SPP. It contains the latest stability database in PSS™E version 30.3.2. The stability package also includes the dynamic data for the previously queued projects.

1.2 Purpose

The steady state and stability study was carried out to:

(a) Determine the ability of the proposed generation facility to remain in synchronism and within applicable planning standards following system faults with unsuccessful reclosing.

(b) Determine the amount of capacitor banks required at the wind farm facilities on the customer side to meet the power factor requirement at the POI.

(c) Determine the ability of the wind farm to meet FERC Order 661A (low voltage ride through and wind farm recovery to pre-fault voltage) with and without additional reactive support.

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Section

2

Model Development

The study has considered the 2008 Summer Peak and Winter Peak load flow models with the required interconnection generation modeled and provided by SPP. The base cases contain all the significant previous queued generation interconnection projects in the interconnection queue.

2.1 Power Flow Data

The Group 6 of ICS-2008-001 contains the nine proposed wind generation projects. Table 2-1 presents the size of the wind generation projects, the Wind Turbine Generator (WTGs) manufacturers, the reactive capability of the wind farm as well as the point of interconnection and the PSS®E bus numbers in the load flow model.

Table 2-1 – Details of the Interconnection Requests

Request	Size (MW)	Model	Reactive Capability of Wind Farm		Point of Interconnection	Bus Number
			Max (MVAR)	Min (MVAR)		
GEN-2008-007	102	Vestas V90	0.0	0.0	GRASSLAND-JONES 230kV	210070
GEN-2007-027	60	Suzlon 2.1 MW	0.0	0.0	CURRY-TUCUMCARI 115kV	210270
GEN-2007-034	150	GE 1.5 MW	49.3	-49.3	TOLK-EDDY COUNTY 345kV	210340
GEN-2007-055	250	Siemens 2.3 MW	121.4	-121.4		210340
GEN-2008-009	60	GE 1.5 MW	19.7	-19.7	SAN JUAN MESA 230kV	524885
GEN-2008-016	248	Vestas V90	0.0	0.0	GRASSLAND 230kV	526677
GEN-2008-008	60	GE 1.5 MW	19.7	-19.7	GRAHAM 69kV	526693
GEN-2008-014	150	Vestas V90	0.0	0.0	TUCO-OKLAUNION 345 kV	560813
GEN-2008-015	150	Vestas V90	0.0	0.0		560813

The analysis was carried out using the database package provided by SPP which also includes the modeling data for the previously queued projects, as shown in Table 2-2:

Table 2-2 – Details of the Prior Queued Interconnection Requests

Request	Size (MW)	Model	Point of Interconnection	Bus Number
GEN-2001-033	180	Mitsubishi 1000	SAN JUAN MESA 230kV	524885
GEN-2001-036	80	CIMTR	CURRY-TUCUMCARI 115kV	210270
GEN-2005-010	160	Gamesa	TOLK-ROOSEVELT 230kV	560104
GEN-2005-015	150	Gamesa	TUCO-OKLAUNION 345 KV	560813
GEN-2006-048	150	Acciona	SEVEN RIVERS 230kV	528094
GEN-2007-004	150	Gamesa	YOAKUM 230kV	526935

2.2 Stability Database

The stability simulations considered both single line to ground and three and phase faults. All single line (SLG) faults have considered delayed clearing as a result of breaker failure. Seventy six contingencies provided by SPP were simulated in this study.

Section

3

Methodology and Assumptions

The study has considered the 2008 power flow cases with the required interconnection generation modeled and provided by SPP. The base case contains all the significant previous queued generation interconnection projects in the interconnection queue:

The areas of interest for this study are shown in Table 3-1. These areas were monitored in the stability analysis

Table 3-1 – Areas of Interest

Area Number	Area Name
520	AEPW
524	OKGE
525	WFEC
526	SPS
531	MIDW
534	SUNC
536	WERE

3.1 Methodology

3.1.1 Stability Simulations

The dynamic simulations were performed using the PSS™E version 30.3.2 with the latest stability database provided by SPP. Three-phase faults and single-phase faults with normal clearing in the neighborhood of ICS-2008-001 (Group 6) cluster were simulated. Any adverse impact on the system stability was documented and further investigated with appropriate solutions to determine whether a static or dynamic VAR device is required or not.

3.1.2 Steady State Simulations

3.1.2.1 N-1 Contingency Analysis

An N-1 contingency analysis was performed to determine the voltage violations caused by disturbances (tripping of the faulted line). The voltages at each he POI were monitored for any deviations from the base case voltage and the percentage voltage deviations were documented.

3.1.2.2 Power Factor Analysis

A QV analysis was performed for all the faults in PSS™E version 30.3.2 to determine the capacitor banks required to maintain the base case voltage at the POI. QV curves are used to determine the reactive power support required at each POI in order to maintain the bus voltage to the required value. The curve is obtained through a series of AC load flow calculations. Starting with no reactive support at a bus, the voltage can be computed for a series of power flows as the reactive support is increased in steps, until the power flow experiences convergence difficulties as the system approaches the voltage collapse point.

3.2 Disturbances for Stability Analysis

The stability simulations included three-phase (3PH) faults and single line-to-ground (SLG) faults. The fault clearing line is assumed 5 cycles. For all contingencies, the fault clearing process includes an unsuccessful three-phase reclosing (reclosing under fault conditions) followed by trip of both ends of the transmission line under fault after 20 cycles. The disturbances evaluated are listed in Table 3-2, as follows:

Table 3-2: Disturbances for Stability Analysis

#	Fault Location	Fault Type	Clearing	Fault Clearing
1	At GEN-2007-027 end of 115 kV line to Norton	3PH	Unsuccessful Reclosing	5 cycles - trip GEN-2007-027 – Norton 115 kV
2	At GEN-2007-027 end of 115 kV line to Norton	SLG	Unsuccessful Reclosing	5 cycles - trip GEN-2007-027 – Norton 115 kV
3	At GEN-2007-027 end of 115 kV line to Curry	3PH	Unsuccessful Reclosing	5 cycles - trip GEN-2007-027 – Curry 115 kV
4	At GEN-2007-027 end of 115 kV line to Curry	SLG	Unsuccessful Reclosing	5 cycles - trip GEN-2007-027 – Curry 115 kV
5	At Norton end of 115 kV line to Tucumcari	3PH	Unsuccessful Reclosing	5 cycles - trip Norton – Tucumcari 115 kV
6	At Norton end of 115 kV line to Tucumcari	SLG	Unsuccessful Reclosing	5 cycles - trip Norton – Tucumcari 115 kV
7	At Curry end of 115 kV line to DS#20	3PH	Unsuccessful Reclosing	5 cycles - trip Curry – DS#20 115 kV
8	At Curry end of 115 kV line to DS#20	SLG	Unsuccessful Reclosing	5 cycles - trip Curry – DS#20 115 kV
9	At Curry end of 115 kV line to Roosevelt	3PH	Unsuccessful Reclosing	5 cycles - trip Curry – Roosevelt 115 kV
10	At Curry end of 115 kV line to Roosevelt	SLG	Unsuccessful Reclosing	5 cycles - trip Curry – Roosevelt 115 kV
11	At Curry end of 115 kV line to Clovis	3PH	Unsuccessful Reclosing	5 cycles - trip Curry – Clovis 115 kV

#	Fault Location	Fault Type	Clearing	Fault Clearing
12	At Curry end of 115 kV line to Clovis	SLG	Unsuccessful Reclosing	5 cycles - trip Curry – Clovis 115 kV
13	At Curry end of 115 kV line to Norris	3PH	Unsuccessful Reclosing	5 cycles - trip Curry – Norris 115 kV
14	At Curry end of 115 kV line to Norris	SLG	Unsuccessful Reclosing	5 cycles - trip Curry – Norris 115 kV
15	At Roosevelt end of 115/230 kV transformer	3PH	Unsuccessful Reclosing	5 cycles - trip Roosevelt 115/230 kV transformer
16	At Roosevelt end of 115/230 kV transformer	SLG	Unsuccessful Reclosing	5 cycles - trip Roosevelt 115/230 kV transformer
17	At Roosevelt S end of 230 kV line to PNM DC	3PH	Unsuccessful Reclosing	5 cycles - trip Roosevelt S – PNM DC 230 kV
18	At Roosevelt S end of 230 kV line to PNM DC	SLG	Unsuccessful Reclosing	5 cycles - trip Roosevelt S – PNM DC 230 kV
19	At San Juan end of 230 kV line to Oasis	3PH	Unsuccessful Reclosing	5 cycles - trip San Juan – Oasis 230 kV
20	At San Juan end of 230 kV line to Oasis	SLG	Unsuccessful Reclosing	5 cycles - trip San Juan – Oasis 230 kV
21	At San Juan end of 230 kV line to Chaves Co	3PH	Unsuccessful Reclosing	5 cycles - trip San Juan – Chaves Co 230 kV
22	At San Juan end of 230 kV line to Chaves Co	SLG	Unsuccessful Reclosing	5 cycles - trip San Juan – Chaves Co 230 kV
23	At Eddy Co end of 230 kV line to EPTNP	3PH	Unsuccessful Reclosing	5 cycles - trip Eddy Co – EPTNP 230 kV
24	At Eddy Co end of 230 kV line to EPTNP	SLG	Unsuccessful Reclosing	5 cycles - trip Eddy Co – EPTNP 230 kV
25	At Eddy Co end of 230/345 kV transformer	3PH	Unsuccessful Reclosing	5 cycles - trip Eddy Co 230/345 kV transformer
26	At Eddy Co end of 230/345 kV transformer	SLG	Unsuccessful Reclosing	5 cycles - trip Eddy Co 230/345 kV transformer
27	At GEN-2007-055 end of 345 kV line to Eddy Co	3PH	Unsuccessful Reclosing	5 cycles - trip GEN-2007-055 – Eddy Co 345 kV
28	At GEN-2007-055 end of 345 kV line to Eddy Co	SLG	Unsuccessful Reclosing	5 cycles - trip GEN-2007-055 – Eddy Co 345 kV
29	At GEN-2007-055 end of 345 kV line to GEN-2007-034	3PH	Unsuccessful Reclosing	5 cycles - trip GEN-2007-055–GEN-07-034 345 kV
30	At GEN-2007-055 end of 345 kV line to GEN-2007-034	SLG	Unsuccessful Reclosing	5 cycles - trip GEN-2007-055 – GEN-07-034 345 kV

#	Fault Location	Fault Type	Clearing	Fault Clearing
31	At GEN-2007-034 end of 345 kV line to GEN-2007-055	3PH	Unsuccessful Reclosing	5 cycles - trip GEN-2007-034 – GEN-07-055 345 kV
32	At GEN-2007-034 end of 345 kV line to GEN-2007-055	SLG	Unsuccessful Reclosing	5 cycles - trip GEN-2007-034 – GEN-07-055 345 kV
33	At GEN-2007-034 end of 345 kV line to Tolk	3PH	Unsuccessful Reclosing	5 cycles - trip GEN-2007-034 – Tolk 345 kV
34	At GEN-2007-034 end of 345 kV line to Tolk	SLG	Unsuccessful Reclosing	5 cycles - trip GEN-2007-034 – Tolk 345 kV
35	At Tolk end of 230/345 kV transformer	3PH	Unsuccessful Reclosing	5 cycles - trip Tolk 230/345 kV transformer
36	At Tolk end of 230/345 kV transformer	SLG	Unsuccessful Reclosing	5 cycles - trip Tolk 230/345 kV transformer
37	At Tolk E end of 230 kV line to Tuco	3PH	Unsuccessful Reclosing	5 cycles - trip Tolk E – Tocu 345 kV
38	At Tolk E end of 230 kV line to Tuco	SLG	Unsuccessful Reclosing	5 cycles - trip Tolk E – Tocu 345 kV
39	At Plant X end of 230 kV line to Sundown	3PH	Unsuccessful Reclosing	5 cycles - trip Plant X – Sundown 230 kV
40	At Plant X end of 230 kV line to Sundown	SLG	Unsuccessful Reclosing	5 cycles - trip Plant X – Sundown 230 kV
41	At Graham end of 230 kV line to Garza	3PH	Unsuccessful Reclosing	5 cycles - trip Graham – Garza 230 kV
42	At Graham end of 230 kV line to Garza	SLG	Unsuccessful Reclosing	5 cycles - trip Graham – Garza 230 kV
43	At Graham end of 69/115 kV transformer	3PH	Unsuccessful Reclosing	5 cycles - trip Graham 69/115 kV transformer
44	At Graham end of 69/115 kV transformer	SLG	Unsuccessful Reclosing	5 cycles - trip Graham 69/115 kV transformer
45	At Grassland end of 115 kV line to Lynn Co	3PH	Unsuccessful Reclosing	5 cycles - trip Grassland – Lynn Co 115 kV
46	At Grassland end of 115 kV line to Lynn Co	SLG	Unsuccessful Reclosing	5 cycles - trip Grassland – Lynn Co 115 kV
47	At Grassland end of 115/230 kV transformer	3PH	Unsuccessful Reclosing	5 cycles - trip Grassland 115/230 kV transformer
48	At Grassland end of 115/230 kV transformer	SLG	Unsuccessful Reclosing	5 cycles - trip Grassland 115/230 kV transformer
49	At Grassland end of 230/115 kV transformer	3PH	Unsuccessful Reclosing	5 cycles - trip Grassland 230/115 kV transformer

#	Fault Location	Fault Type	Clearing	Fault Clearing
50	At Grassland end of 230/115 kV transformer	SLG	Unsuccessful Reclosing	5 cycles - trip Grassland 230/115 kV transformer
51	At Grassland end of 230 kV line to Borden	3PH	Unsuccessful Reclosing	5 cycles - trip Grassland – Borden 230 kV
52	At Grassland end of 230 kV line to Borden	SLG	Unsuccessful Reclosing	5 cycles - trip Grassland – Borden 230 kV
53	At Grassland end of 230 kV line to GEN-2008-007	3PH	Unsuccessful Reclosing	5 cycles - trip Grassland – GEN-2008-007 230 kV
54	At Grassland end of 230 kV line to GEN-2008-007	SLG	Unsuccessful Reclosing	5 cycles - trip Grassland – GEN-2008-007 230 kV
55	At GEN-2008-007 end of 230 kV line to Grassland	3PH	Unsuccessful Reclosing	5 cycles - trip GEN-2008-007 – Grassland 230 kV
56	At GEN-2008-007 end of 230 kV line to Grassland	SLG	Unsuccessful Reclosing	5 cycles - trip GEN-2008-007 – Grassland 230 kV
57	At GEN-2008-007 end of 230 kV line to Jones Bus2	3PH	Unsuccessful Reclosing	5 cycles - trip GEN-2008-007 – Jones Bus2 230 kV
58	At GEN-2008-007 end of 230 kV line to Jones Bus2	SLG	Unsuccessful Reclosing	5 cycles - trip GEN-2008-007 – Jones Bus2 230 kV
59	At Jones Bus2 end of 230 kV line to Lubbock E	3PH	Unsuccessful Reclosing	5 cycles - trip Jones Bus2 – Lubbock E 230 kV
60	At Jones Bus2 end of 230 kV line to Lubbock E	SLG	Unsuccessful Reclosing	5 cycles - trip Jones Bus2 – Lubbock E 230 kV
61	At Jones Bus1 end of 230 kV line to Tuco	3PH	Unsuccessful Reclosing	5 cycles - trip Jones Bus1 – Tuco 230 kV
62	At Jones Bus1 end of 230 kV line to Tuco	SLG	Unsuccessful Reclosing	5 cycles - trip Jones Bus1 – Tuco 230 kV
63	At Tuco end of 230 kV line to Swisher	3PH	Unsuccessful Reclosing	5 cycles - trip Tuco – Swisher 230 kV
64	At Tuco end of 230 kV line to Swisher	SLG	Unsuccessful Reclosing	5 cycles - trip Tuco – Swisher 230 kV
65	At Tuco end of 230/345 kV transformer	3PH	Unsuccessful Reclosing	5 cycles - trip Tuco 230/345 kV transformer
66	At Tuco end of 230/345 kV transformer	SLG	Unsuccessful Reclosing	5 cycles - trip Tuco 230/345 kV transformer
67	At GEN-2005-015 end of 345 kV line to Tuco	3PH	Unsuccessful Reclosing	5 cycles - trip GEN-2005-015 – Tuco 345 kV
68	At GEN-2005-015 end of 345 kV line to Tuco	SLG	Unsuccessful Reclosing	5 cycles - trip GEN-2005-015 – Tuco 345 kV

#	Fault Location	Fault Type	Clearing	Fault Clearing
69	At GEN-2005-015 end of 345 kV line to Oklaunion	3PH	Unsuccessful Reclosing	5 cycles - trip GEN-2005-015 – Oklaunioin 345 kV
70	At GEN-2005-015 end of 345 kV line to Oklaunion	SLG	Unsuccessful Reclosing	5 cycles - trip GEN-2005-015 – Oklaunioin 345 kV
71	At Oklaunion end of 345 kV line to Lawton Eastside	3PH	Unsuccessful Reclosing	5 cycles - trip Oklaunioin – Lawton Eastside 345 kV
72	At Oklaunion end of 345 kV line to Lawton Eastside	SLG	Unsuccessful Reclosing	5 cycles - trip Oklaunioin – Lawton Eastside 345 kV
73	At Potter Co end of 230/345 kV transformer	3PH	Unsuccessful Reclosing	5 cycles - trip Potter Co 230/345 kV transformer
74	At Potter Co end of 230/345 kV transformer	SLG	Unsuccessful Reclosing	5 cycles - trip Potter Co 230/345 kV transformer
75	At Nichols end of 230 kV line to Grapevine	3PH	Unsuccessful Reclosing	5 cycles - trip Nichols – Grapevine 230 kV
76	At Nichols end of 230 kV line to Grapevine	SLG	Unsuccessful Reclosing	5 cycles - trip Nichols – Grapevine 230 kV

In order to simulate single line to ground faults, equivalent reactances were determined to be applied at the buses. Table 3-3 presents equivalent reactances used in the simulations:

Table 3-3: Equivalent Reactances – Line to Ground Faults

BUS	Equivalent Reactance (Mvar)
210270	-400
524502	-290
524822	-850
524911	-1700
524885	-1000
527800	-1600
526257	-1300
210340	-1600
525543	-4400
525481	-4400
526693	-150
526676	-600
210070	-1700
526338	-2700
526337	-2700
525830	-2500
560813	-1600
511456	-1500
523959	-4500
524044	-5300

Section

4

Analysis Performed

4.1 Steady State Performance

Table 4-1 and Table 4-2 summarize the results obtained from the steady state analysis for Summer Peak and Winter Peak base cases, respectively. The table lists the voltage deviations at the points of interconnection of the proposed study projects of Group 2, as well as the prior queued projects. Note that only the contingencies that cause an impact of at least 1% in the POI's voltages are listed.

Table 4-1: Results Obtained – Steady State Analysis – Summer Peak Base Case

Points of Interconnection			Contingency Voltage	Base Voltage	Voltage Deviation
Bus #	Name	kV			
210070	2008-007	230	-	0.9963	-
210270	GEN_2007_02	115	-	1.0129	-
210340	POI	345	-	1.0308	-
524885	SN_JUAN_TAP6	230	-	0.9678	-
525524	TOLK_EAST 6	230	-	1.0030	-
526677	GRASSLAND 6	230	-	0.9983	-
526693	GRAHAM2	69	-	1.0135	-
526935	YOAKUM6	230	-	0.9960	-
528094	7-RIVERS 3	115	-	1.0172	-
560813	G05-15	345	-	0.9832	-
FLT53PH					
210070	2008-007	230	0.9963	0.9963	0.00%
210270	GEN_2007_02	115	1.0027	1.0129	-1.02%
210340	POI	345	1.0307	1.0308	0.00%
524885	SN_JUAN_TAP6	230	0.9664	0.9678	-0.15%
525524	TOLK_EAST 6	230	1.0030	1.0030	0.00%
526677	GRASSLAND 6	230	0.9983	0.9983	0.00%
526693	GRAHAM2	69	1.0134	1.0135	0.00%
526935	YOAKUM6	230	0.9960	0.9960	0.00%
528094	7-RIVERS 3	115	1.0171	1.0172	0.00%
560813	G05-15	345	0.9818	0.9832	-0.14%
FLT93PH					

Points of Interconnection			Contingency Voltage	Base Voltage	Voltage Deviation
Bus #	Name	kV			
210070	2008-007	230	0.9963	0.9963	0.00%
210270	GEN_2007_02	115	0.9999	1.0129	-1.30%
210340	POI	345	1.0308	1.0308	0.00%
524885	SN_JUAN_TAP6	230	0.9679	0.9678	0.01%
525524	TOLK_EAST 6	230	1.0030	1.0030	0.00%
526677	GRASSLAND 6	230	0.9983	0.9983	0.00%
526693	GRAHAM2	69	1.0135	1.0135	0.00%
526935	YOAKUM6	230	0.9960	0.9960	0.00%
528094	7-RIVERS 3	115	1.0172	1.0172	0.00%
560813	G05-15	345	0.9828	0.9832	-0.03%
FLT153PH					
210070	2008-007	230	0.9963	0.9963	0.00%
210270	GEN_2007_02	115	0.9956	1.0129	-1.72%
210340	POI	345	1.0308	1.0308	0.00%
524885	SN_JUAN_TAP6	230	0.9656	0.9678	-0.23%
525524	TOLK_EAST 6	230	1.0030	1.0030	0.00%
526677	GRASSLAND 6	230	0.9983	0.9983	0.00%
526693	GRAHAM2	69	1.0135	1.0135	0.00%
526935	YOAKUM6	230	0.9960	0.9960	0.00%
528094	7-RIVERS 3	115	1.0171	1.0172	-0.01%
560813	G05-15	345	0.9825	0.9832	-0.07%
FLT173PH					
210070	2008-007	230	0.9961	0.9963	-0.02%
210270	GEN_2007_02	115	1.0082	1.0129	-0.47%
210340	POI	345	1.0307	1.0308	0.00%
524885	SN_JUAN_TAP6	230	0.9623	0.9678	-0.55%
525524	TOLK_EAST 6	230	1.0030	1.0030	0.00%
526677	GRASSLAND 6	230	0.9981	0.9983	-0.02%
526693	GRAHAM2	69	1.0131	1.0135	-0.03%
526935	YOAKUM6	230	0.9957	0.9960	-0.03%
528094	7-RIVERS 3	115	1.0171	1.0172	-0.01%
560813	G05-15	345	0.9651	0.9832	-1.81%
FLT213PH					
210070	2008-007	230	0.9963	0.9963	0.01%
210270	GEN_2007_02	115	1.0018	1.0129	-1.10%
210340	POI	345	1.0313	1.0308	0.05%
524885	SN_JUAN_TAP6	230	0.9025	0.9678	-6.54%
525524	TOLK_EAST 6	230	1.0030	1.0030	0.00%
526677	GRASSLAND 6	230	0.9983	0.9983	0.00%
526693	GRAHAM2	69	1.0135	1.0135	0.00%
526935	YOAKUM6	230	0.9964	0.9960	0.04%

Points of Interconnection			Contingency Voltage	Base Voltage	Voltage Deviation
Bus #	Name	kV			
528094	7-RIVERS 3	115	1.0173	1.0172	0.02%
560813	G05-15	345	0.9823	0.9832	-0.08%
FLT233PH					
210070	2008-007	230	0.9960	0.9963	-0.03%
210270	GEN_2007_02	115	1.0118	1.0129	-0.10%
210340	POI	345	1.0293	1.0308	-0.15%
524885	SN_JUAN_TAP6	230	0.9657	0.9678	-0.22%
525524	TOLK_EAST 6	230	1.0030	1.0030	0.00%
526677	GRASSLAND 6	230	0.9980	0.9983	-0.03%
526693	GRAHAM2	69	1.0131	1.0135	-0.04%
526935	YOAKUM6	230	0.9950	0.9960	-0.11%
528094	7-RIVERS 3	115	1.0185	1.0172	0.13%
560813	G05-15	345	0.9651	0.9832	-1.81%
FLT353PH					
210070	2008-007	230	0.9960	0.9963	-0.03%
210270	GEN_2007_02	115	1.0112	1.0129	-0.16%
210340	POI	345	1.0436	1.0308	1.29%
524885	SN_JUAN_TAP6	230	0.9623	0.9678	-0.55%
525524	TOLK_EAST 6	230	1.0030	1.0030	0.00%
526677	GRASSLAND 6	230	0.9980	0.9983	-0.03%
526693	GRAHAM2	69	1.0134	1.0135	-0.01%
526935	YOAKUM6	230	0.9943	0.9960	-0.17%
528094	7-RIVERS 3	115	1.0191	1.0172	0.19%
560813	G05-15	345	0.9830	0.9832	-0.02%
FLT473PH					
210070	2008-007	230	0.9974	0.9963	0.11%
210270	GEN_2007_02	115	1.0129	1.0129	0.00%
210340	POI	345	1.0307	1.0308	0.00%
524885	SN_JUAN_TAP6	230	0.9678	0.9678	0.00%
525524	TOLK_EAST 6	230	1.0030	1.0030	0.00%
526677	GRASSLAND 6	230	1.0002	0.9983	0.19%
526693	GRAHAM2	69	1.0032	1.0135	-1.03%
526935	YOAKUM6	230	0.9960	0.9960	0.00%
528094	7-RIVERS 3	115	1.0172	1.0172	0.00%
560813	G05-15	345	0.9829	0.9832	-0.02%
FLT533PH					
210070	2008-007	230	0.9937	0.9963	-0.26%
210270	GEN_2007_02	115	1.0128	1.0129	-0.01%
210340	POI	345	1.0306	1.0308	-0.02%
524885	SN_JUAN_TAP6	230	0.9676	0.9678	-0.02%
525524	TOLK_EAST 6	230	1.0030	1.0030	0.00%

Points of Interconnection			Contingency Voltage	Base Voltage	Voltage Deviation
Bus #	Name	kV			
526677	GRASSLAND 6	230	0.9162	0.9983	-8.21%
526693	GRAHAM2	69	0.9843	1.0135	-2.92%
526935	YOAKUM6	230	0.9953	0.9960	-0.07%
528094	7-RIVERS 3	115	1.0169	1.0172	-0.02%
560813	G05-15	345	0.9820	0.9832	-0.12%
FLT693PH					
210070	2008-007	230	0.9965	0.9963	0.02%
210270	GEN_2007_02	115	1.0114	1.0129	-0.15%
210340	POI	345	1.0306	1.0308	-0.02%
524885	SN_JUAN_TAP6	230	0.9667	0.9678	-0.11%
525524	TOLK_EAST 6	230	1.0030	1.0030	0.00%
526677	GRASSLAND 6	230	0.9984	0.9983	0.02%
526693	GRAHAM2	69	1.0137	1.0135	0.02%
526935	YOAKUM6	230	0.9963	0.9960	0.03%
528094	7-RIVERS 3	115	1.0168	1.0172	-0.03%
560813	G05-15	345	1.0001	0.9832	1.70%
FLT713PH					
210070	2008-007	230	0.9966	0.9963	0.03%
210270	GEN_2007_02	115	1.0114	1.0129	-0.14%
210340	POI	345	1.0306	1.0308	-0.01%
524885	SN_JUAN_TAP6	230	0.9667	0.9678	-0.11%
525524	TOLK_EAST 6	230	1.0030	1.0030	0.00%
526677	GRASSLAND 6	230	0.9986	0.9983	0.03%
526693	GRAHAM2	69	1.0143	1.0135	0.08%
526935	YOAKUM6	230	0.9964	0.9960	0.04%
528094	7-RIVERS 3	115	1.0169	1.0172	-0.03%
560813	G05-15	345	1.0676	0.9832	8.44%
FLT733PH					
210070	2008-007	230	0.9962	0.9963	-0.01%
210270	GEN_2007_02	115	1.0130	1.0129	0.01%
210340	POI	345	1.0308	1.0308	0.00%
524885	SN_JUAN_TAP6	230	0.9680	0.9678	0.01%
525524	TOLK_EAST 6	230	1.0030	1.0030	0.00%
526677	GRASSLAND 6	230	0.9981	0.9983	-0.01%
526693	GRAHAM2	69	1.0131	1.0135	-0.04%
526935	YOAKUM6	230	0.9959	0.9960	-0.01%
528094	7-RIVERS 3	115	1.0172	1.0172	0.01%
560813	G05-15	345	0.9595	0.9832	-2.36%

Table 4-2: Results Obtained – Steady State Analysis – Winter Peak Base Case

Points of Interconnection			Contingency Voltage	Base Voltage	Voltage Deviation
Bus #	Name	kV			
210070	2008-007	230	-	0.9981	-
210270	GEN_2007_02	115	-	0.9991	-
210340	POI	345	-	1.0332	-
524885	SN_JUAN_TAP6	230	-	0.9697	-
526677	GRASSLAND 6	230	-	1.0009	-
526693	GRAHAM2	69	-	1.0095	-
526935	YOAKUM6	230	-	1.0059	-
528094	7-RIVERS 3	115	-	1.0116	-
560104	G05-10T	230	-	1.0192	-
560813	G05-15	345	-	0.9731	-
FLT13PH					
210070	2008-007	230	0.9981	0.9981	0.00%
210270	GEN_2007_02	115	1.0582	0.9991	5.91%
210340	POI	345	1.0333	1.0332	0.00%
524885	SN_JUAN_TAP6	230	0.9761	0.9697	0.64%
526677	GRASSLAND 6	230	1.0009	1.0009	0.00%
526693	GRAHAM2	69	1.0096	1.0095	0.00%
526935	YOAKUM6	230	1.0060	1.0059	0.01%
528094	7-RIVERS 3	115	1.0118	1.0116	0.02%
560104	G05-10T	230	1.0211	1.0192	0.19%
560813	G05-15	345	0.9766	0.9731	0.35%
FLT73PH					
210070	2008-007	230	0.9981	0.9981	0.00%
210270	GEN_2007_02	115	0.9817	0.9991	-1.75%
210340	POI	345	1.0332	1.0332	0.00%
524885	SN_JUAN_TAP6	230	0.9663	0.9697	-0.34%
526677	GRASSLAND 6	230	1.0009	1.0009	0.00%
526693	GRAHAM2	69	1.0095	1.0095	0.00%
526935	YOAKUM6	230	1.0059	1.0059	0.00%
528094	7-RIVERS 3	115	1.0115	1.0116	-0.01%
560104	G05-10T	230	1.0182	1.0192	-0.10%
560813	G05-15	345	0.9725	0.9731	-0.06%
FLT93PH					
210070	2008-007	230	0.9981	0.9981	0.00%
210270	GEN_2007_02	115	0.9658	0.9991	-3.33%
210340	POI	345	1.0332	1.0332	0.00%
524885	SN_JUAN_TAP6	230	0.9681	0.9697	-0.17%
526677	GRASSLAND 6	230	1.0009	1.0009	0.00%
526693	GRAHAM2	69	1.0095	1.0095	0.00%

Points of Interconnection			Contingency Voltage	Base Voltage	Voltage Deviation
Bus #	Name	kV			
526935	YOAKUM6	230	1.0059	1.0059	0.00%
528094	7-RIVERS 3	115	1.0115	1.0116	-0.01%
560104	G05-10T	230	1.0191	1.0192	-0.01%
560813	G05-15	345	0.9730	0.9731	-0.01%
FLT153PH					
210070	2008-007	230	0.9981	0.9981	0.00%
210270	GEN_2007_02	115	0.9436	0.9991	-5.55%
210340	POI	345	1.0332	1.0332	0.00%
524885	SN_JUAN_TAP6	230	0.9653	0.9697	-0.44%
526677	GRASSLAND 6	230	1.0009	1.0009	0.00%
526693	GRAHAM2	69	1.0095	1.0095	0.00%
526935	YOAKUM6	230	1.0059	1.0059	0.00%
528094	7-RIVERS 3	115	1.0114	1.0116	-0.01%
560104	G05-10T	230	1.0191	1.0192	-0.01%
560813	G05-15	345	0.9729	0.9731	-0.03%
FLT173PH					
210070	2008-007	230	0.9980	0.9981	-0.01%
210270	GEN_2007_02	115	0.9856	0.9991	-1.36%
210340	POI	345	1.0332	1.0332	0.00%
524885	SN_JUAN_TAP6	230	0.9635	0.9697	-0.62%
526677	GRASSLAND 6	230	1.0009	1.0009	-0.01%
526693	GRAHAM2	69	1.0095	1.0095	0.00%
526935	YOAKUM6	230	1.0057	1.0059	-0.02%
528094	7-RIVERS 3	115	1.0114	1.0116	-0.02%
560104	G05-10T	230	1.0167	1.0192	-0.24%
560813	G05-15	345	0.9600	0.9731	-1.31%
FLT213PH					
210070	2008-007	230	0.9981	0.9981	0.00%
210270	GEN_2007_02	115	0.9709	0.9991	-2.82%
210340	POI	345	1.0338	1.0332	0.05%
524885	SN_JUAN_TAP6	230	0.9222	0.9697	-4.75%
526677	GRASSLAND 6	230	1.0009	1.0009	0.00%
526693	GRAHAM2	69	1.0096	1.0095	0.00%
526935	YOAKUM6	230	1.0062	1.0059	0.03%
528094	7-RIVERS 3	115	1.0118	1.0116	0.02%
560104	G05-10T	230	1.0154	1.0192	-0.38%
560813	G05-15	345	0.9736	0.9731	0.05%
FLT233PH					
210070	2008-007	230	0.9979	0.9981	-0.02%
210270	GEN_2007_02	115	0.9961	0.9991	-0.30%

Points of Interconnection			Contingency Voltage	Base Voltage	Voltage Deviation
Bus #	Name	kV			
210340	POI	345	1.0318	1.0332	-0.14%
524885	SN_JUAN_TAP6	230	0.9674	0.9697	-0.23%
526677	GRASSLAND 6	230	1.0008	1.0009	-0.02%
526693	GRAHAM2	69	1.0095	1.0095	-0.01%
526935	YOAKUM6	230	1.0052	1.0059	-0.07%
528094	7-RIVERS 3	115	1.0127	1.0116	0.11%
560104	G05-10T	230	1.0188	1.0192	-0.04%
560813	G05-15	345	0.9598	0.9731	-1.33%
FLT253PH					
210070	2008-007	230	0.9982	0.9981	0.01%
210270	GEN_2007_02	115	0.9936	0.9991	-0.55%
210340	POI	345	1.0330	1.0332	-0.03%
524885	SN_JUAN_TAP6	230	0.9550	0.9697	-1.47%
526677	GRASSLAND 6	230	1.0010	1.0009	0.00%
526693	GRAHAM2	69	1.0095	1.0095	0.00%
526935	YOAKUM6	230	1.0066	1.0059	0.07%
528094	7-RIVERS 3	115	0.9846	1.0116	-2.70%
560104	G05-10T	230	1.0184	1.0192	-0.08%
560813	G05-15	345	0.9736	0.9731	0.05%
FLT413PH					
210070	2008-007	230	0.9977	0.9981	-0.04%
210270	GEN_2007_02	115	0.9991	0.9991	0.00%
210340	POI	345	1.0332	1.0332	0.00%
524885	SN_JUAN_TAP6	230	0.9697	0.9697	0.00%
526677	GRASSLAND 6	230	1.0005	1.0009	-0.04%
526693	GRAHAM2	69	0.9982	1.0095	-1.14%
526935	YOAKUM6	230	1.0059	1.0059	0.00%
528094	7-RIVERS 3	115	1.0116	1.0116	0.00%
560104	G05-10T	230	1.0192	1.0192	0.00%
560813	G05-15	345	0.9724	0.9731	-0.07%
FLT533PH					
210070	2008-007	230	0.9937	0.9981	-0.44%
210270	GEN_2007_02	115	0.9988	0.9991	-0.03%
210340	POI	345	1.0331	1.0332	-0.02%
524885	SN_JUAN_TAP6	230	0.9694	0.9697	-0.03%
526677	GRASSLAND 6	230	0.9623	1.0009	-3.86%
526693	GRAHAM2	69	0.9940	1.0095	-1.55%
526935	YOAKUM6	230	1.0053	1.0059	-0.06%
528094	7-RIVERS 3	115	1.0114	1.0116	-0.02%
560104	G05-10T	230	1.0192	1.0192	0.00%
560813	G05-15	345	0.9746	0.9731	0.15%

Points of Interconnection			Contingency Voltage	Base Voltage	Voltage Deviation
Bus #	Name	kV			
FLT653PH					
210070	2008-007	230	0.9981	0.9981	0.00%
210270	GEN_2007_02	115	0.9989	0.9991	-0.02%
210340	POI	345	1.0332	1.0332	0.00%
524885	SN_JUAN_TAP6	230	0.9696	0.9697	-0.01%
526677	GRASSLAND 6	230	1.0009	1.0009	0.00%
526693	GRAHAM2	69	1.0096	1.0095	0.00%
526935	YOAKUM6	230	1.0059	1.0059	0.00%
528094	7-RIVERS 3	115	1.0116	1.0116	0.00%
560104	G05-10T	230	1.0192	1.0192	0.00%
560813	G05-15	345	0.9226	0.9731	-5.05%
FLT673PH: Voltage Collapse					
FLT693PH					
210070	2008-007	230	0.9982	0.9981	0.01%
210270	GEN_2007_02	115	0.9947	0.9991	-0.44%
210340	POI	345	1.0331	1.0332	-0.02%
524885	SN_JUAN_TAP6	230	0.9684	0.9697	-0.13%
526677	GRASSLAND 6	230	1.0010	1.0009	0.01%
526693	GRAHAM2	69	1.0097	1.0095	0.01%
526935	YOAKUM6	230	1.0060	1.0059	0.01%
528094	7-RIVERS 3	115	1.0113	1.0116	-0.02%
560104	G05-10T	230	1.0189	1.0192	-0.03%
560813	G05-15	345	0.9990	0.9731	2.58%
FLT713PH					
210070	2008-007	230	0.9982	0.9981	0.02%
210270	GEN_2007_02	115	0.9947	0.9991	-0.44%
210340	POI	345	1.0331	1.0332	-0.02%
524885	SN_JUAN_TAP6	230	0.9685	0.9697	-0.12%
526677	GRASSLAND 6	230	1.0011	1.0009	0.01%
526693	GRAHAM2	69	1.0099	1.0095	0.03%
526935	YOAKUM6	230	1.0061	1.0059	0.02%
528094	7-RIVERS 3	115	1.0113	1.0116	-0.02%
560104	G05-10T	230	1.0189	1.0192	-0.03%
560813	G05-15	345	1.0550	0.9731	8.19%
FLT733PH					
210070	2008-007	230	0.9980	0.9981	0.00%
210270	GEN_2007_02	115	0.9991	0.9991	0.00%
210340	POI	345	1.0333	1.0332	0.00%
524885	SN_JUAN_TAP6	230	0.9698	0.9697	0.01%
526677	GRASSLAND 6	230	1.0009	1.0009	0.00%

Points of Interconnection			Contingency Voltage	Base Voltage	Voltage Deviation
Bus #	Name	kV			
526693	GRAHAM2	69	1.0095	1.0095	-0.01%
526935	YOAKUM6	230	1.0058	1.0059	-0.01%
528094	7-RIVERS 3	115	1.0116	1.0116	0.00%
560104	G05-10T	230	1.0192	1.0192	0.00%
560813	G05-15	345	0.9517	0.9731	-2.14%

4.2 Power Factor Analysis

A QV analysis was performed to determine the amount of reactive support required to maintain the scheduled voltages at the points of interconnection of each one of the proposed wind facilities. The contingencies described in Table 3-2 were evaluated in steady state conditions for summer and winter peak base cases, with variable Mvar injection at the POIs.

Table 4-3 presents the Mvar requirements for each one of the proposed wind facilities in Group 6.

Table 4-3: Mvar Requirements at POI for the Proposed Projects Interconnection

Project	Point of Interconnection	V Scheduled (p.u)	Mvar Requirements at POI	Contingency	Power Factor at POI (lagging)
GEN-2007-027	Curry – Tucumcari 115 kV	1.040	10 Mvar	FLT 15 (SP)	0.985
GEN-2007-034	Tolk – Eddy County 345 kV	1.040	34 Mvar	FLT 27 (SP)	0.975
GEN-2007-055	Tolk – Eddy County 345 kV	1.040	61 Mvar	FLT 29 (WP)	0.970
GEN-2008-007	Grassland – Jones 230 kV	1.000	41 Mvar	FLT 53 (SP/WP)	0.930
GEN-2008-008	Graham 69 kV	1.015	11 Mvar	FLT 53 (SP/WP)	0.985
GEN-2008-009	San Juan Mesa 230 kV	1.015	35 Mvar	FLT 21 (SP/WP)	0.864
GEN-2008-014	Tuco – Oklaunion 345 kV	1.000	148 Mvar	FLT 17 (WP)	0.897
GEN-2008-015	Tuco – Oklaunion 345 kV				0.897
GEN-2008-016	Grassland 230 kV	1.000	57 Mvar	FLT 57 (SP/WP)	0.987

4.3 Dynamic Results

The stability analysis was carried out using both Summer Peak and Winter Peak load flow models.

In order to determine the impact of the project on the overall system dynamics as well as to determine the requirements to meet the FERC Order 661-A Guidelines, 76 contingencies listed by Table 3-2 were simulated. The results obtained are described in this sub-section.

Table 4-4 and Table 4-5 summarize the results obtained from the stability simulations for Summer Peak and Winter Peak base cases, respectively. Note that only the critical contingencies that lead to trips due to LVRT or loss of synchronism are listed.

Table 4-4: Results Obtained – Summer Peak Base Case

Name	Wind Projects Dynamic Performance
FLT03-3PH	GEN-2007-027 (1271) tripped for low voltage at 1.63 s
FLT04-1PH	GEN-2007-027 (1271) tripped for low voltage at 1.74 s
FLT05-3PH	GEN-2007-027 (1271) tripped for low voltage at 3.3 s
FLT07-3PH	GEN-2001-033 (560961) tripped for low voltage at 1.921 s
	GEN-2001-033 (560963) tripped for low voltage at 1.908 s
	GEN-2001-033 (560965) tripped for low voltage at 1.925 s
	GEN-2001-033 (560967) tripped for low voltage at 1.913 s
	GEN-2001-033 (560969) tripped for low voltage at 1.921 s
	GEN-2001-033 (560971) tripped for low voltage at 1.921 s
	GEN-2001-033 (560973) tripped for low voltage at 1.917 s
	GEN-2007-027 (1271) tripped for low voltage at 3.3 s
FLT09-3PH	GEN-2001-033 (560963) tripped for low voltage at 1.921 s
	GEN-2001-033 (560967) tripped for low voltage at 1.925 s
	GEN-2007-027 (1271) tripped for low voltage at 2.51 s
FLT11-3PH	GEN-2001-033 (560961) tripped for low voltage at 1.933 s
	GEN-2001-033 (560963) tripped for low voltage at 1.925 s
	GEN-2001-033 (560967) tripped for low voltage at 1.925 s
	GEN-2001-033 (560969) tripped for low voltage at 1.933 s
	GEN-2001-033 (560971) tripped for low voltage at 1.933 s
	GEN-2001-033 (560973) tripped for low voltage at 1.929 s
	GEN-2007-027 (1271) tripped for low voltage at 3.3 s
FLT13-3PH	GEN-2007-027 (1271) tripped for low voltage at 3.3 s
FLT15-3PH	GEN-2007-027 (1271) tripped for low voltage at 3.3 s
FLT16-1PH	GEN-2007-027 (1271) tripped for low voltage at 8.1 s

Name	Wind Projects Dynamic Performance
FLT17-3PH	GEN-2001-033 (560961) tripped for low voltage at 1.521 s
	GEN-2001-033 (560963) tripped for low voltage at 1.521 s
	GEN-2001-033 (560965) tripped for low voltage at 1.521 s
	GEN-2001-033 (560967) tripped for low voltage at 1.521 s
	GEN-2001-033 (560969) tripped for low voltage at 1.521 s
	GEN-2001-033 (560971) tripped for low voltage at 1.521 s
	GEN-2001-033 (560973) tripped for low voltage at 1.521 s
	GEN-2001-033 (560975) tripped for low voltage at 1.521 s
	GEN-2007-027 (1271) tripped for low voltage at 3.3 s
FLT19-3PH	GEN-2001-033 (560961) tripped for low voltage at 0.754 s
	GEN-2001-033 (560963) tripped for low voltage at 0.754 s
	GEN-2001-033 (560965) tripped for low voltage at 0.754 s
	GEN-2001-033 (560967) tripped for low voltage at 0.754 s
	GEN-2001-033 (560969) tripped for low voltage at 0.754 s
	GEN-2001-033 (560971) tripped for low voltage at 0.754 s
	GEN-2001-033 (560973) tripped for low voltage at 0.754 s
	GEN-2001-033 (560975) tripped for low voltage at 0.754 s
FLT20-1PH	GEN-2001-033 (560961) tripped for low voltage at 1.271 s
	GEN-2001-033 (560963) tripped for low voltage at 1.271 s
	GEN-2001-033 (560965) tripped for low voltage at 1.275 s
	GEN-2001-033 (560967) tripped for low voltage at 1.271 s
	GEN-2001-033 (560969) tripped for low voltage at 1.275 s
	GEN-2001-033 (560971) tripped for low voltage at 1.271 s
	GEN-2001-033 (560973) tripped for low voltage at 1.271 s
	GEN-2001-033 (560975) tripped for low voltage at 1.283 s
FLT21-3PH	GEN-2001-033 (560961) tripped for low voltage at 0.754 s
	GEN-2001-033 (560963) tripped for low voltage at 0.754 s
	GEN-2001-033 (560965) tripped for low voltage at 0.754 s
	GEN-2001-033 (560967) tripped for low voltage at 0.754 s
	GEN-2001-033 (560969) tripped for low voltage at 0.754 s
	GEN-2001-033 (560971) tripped for low voltage at 0.754 s
	GEN-2001-033 (560973) tripped for low voltage at 0.754 s
	GEN-2001-033 (560975) tripped for low voltage at 0.754 s
FLT22-1PH	GEN-2001-033 (560961) tripped for low voltage at 1.521 s
	GEN-2001-033 (560963) tripped for low voltage at 1.521 s
	GEN-2001-033 (560965) tripped for low voltage at 1.521 s
	GEN-2001-033 (560967) tripped for low voltage at 1.521 s
	GEN-2001-033 (560969) tripped for low voltage at 1.521 s

Name	Wind Projects Dynamic Performance
	GEN-2001-033 (560971) tripped for low voltage at 1.521 s
	GEN-2001-033 (560973) tripped for low voltage at 1.521 s
	GEN-2001-033 (560975) tripped for low voltage at 1.521 s
FLT23-3PH	GEN-2001-033 (560961) tripped for low voltage at 1.521 s
	GEN-2001-033 (560963) tripped for low voltage at 1.521 s
	GEN-2001-033 (560965) tripped for low voltage at 1.521 s
	GEN-2001-033 (560967) tripped for low voltage at 1.521 s
	GEN-2001-033 (560969) tripped for low voltage at 1.521 s
	GEN-2001-033 (560971) tripped for low voltage at 1.521 s
	GEN-2001-033 (560973) tripped for low voltage at 1.521 s
	GEN-2001-033 (560975) tripped for low voltage at 1.521 s
FLT33-3PH	GEN-2001-033 (560961) tripped for low voltage at 1.521 s
	GEN-2001-033 (560963) tripped for low voltage at 1.521 s
	GEN-2001-033 (560965) tripped for low voltage at 1.521 s
	GEN-2001-033 (560967) tripped for low voltage at 1.521 s
	GEN-2001-033 (560969) tripped for low voltage at 1.521 s
	GEN-2001-033 (560971) tripped for low voltage at 1.521 s
	GEN-2001-033 (560973) tripped for low voltage at 1.521 s
FLT35-3PH	GEN-2005-010 (560963) tripped for low voltage at 1.104 s
	GEN-2005-010 (560967) tripped for low voltage at 1.104 s
	GEN-2007-027 (1271) tripped for low voltage at 5.44 s
FLT37-3PH	GEN-2001-033 (560961) tripped for low voltage at 1.188 s
	GEN-2001-033 (560963) tripped for low voltage at 1.183 s
	GEN-2001-033 (560965) tripped for low voltage at 1.188 s
	GEN-2001-033 (560967) tripped for low voltage at 1.188 s
	GEN-2001-033 (560969) tripped for low voltage at 1.188 s
	GEN-2001-033 (560971) tripped for low voltage at 1.188 s
	GEN-2001-033 (560973) tripped for low voltage at 1.188s
	GEN-2001-033 (560975) tripped for low voltage at 1.196 s
	GEN-2007-027 (1271) tripped for low voltage at 3.3 s
FLT39-3PH	GEN-2001-033 (560961) tripped for low voltage at 1.521 s
	GEN-2001-033 (560963) tripped for low voltage at 1.521 s
	GEN-2001-033 (560965) tripped for low voltage at 1.521 s
	GEN-2001-033 (560967) tripped for low voltage at 1.521 s
	GEN-2001-033 (560969) tripped for low voltage at 1.521 s
	GEN-2001-033 (560971) tripped for low voltage at 1.521 s
	GEN-2001-033 (560973) tripped for low voltage at 1.521 s

Name	Wind Projects Dynamic Performance
	GEN-2007-027 (1271) tripped for low voltage at 3.7 s
	GEN-2001-033 (560975) tripped for low voltage at 1.521 s
FLT55-3PH	07-08G2 (560044) tripped for over voltage at 1 s
FLT57-3PH	GEN-2008-007 (1071) tripped for over voltage at 1.6625s
	GEN-2008-016 (1161) tripped for over voltage at 1.7500 s
	GEN-2008-016 (1162) tripped for over voltage at 1.7500 s
	07-08G1 (560043) tripped for over voltage at 1 s
	07-08G2 (560044) tripped for over voltage at 1 s
FLT58-3PH	GEN-2008-007 (1071) tripped for over voltage at 1.6375 s
	GEN-2008-016 (1161) tripped for over voltage at 1.7250 s
	GEN-2008-016 (1162) tripped for over voltage at 1.7250 s
FLT71-3PH	GEN-2008-014 (1141) tripped for over frequency at 1.7 s
	GEN-2008-015 (1151) tripped for over frequency at 1.7 s
FLT72-1PH	GEN-2008-014 (1141) tripped for over frequency at 2.25 s
	GEN-2008-015 (1151) tripped for over frequency at 2.25 s

Table 4-5: Results Obtained – Winter Peak Base Case

Name	Wind Projects Dynamic Performance
FLT03-3PH	GEN-2007-027 (1271) tripped for low voltage at 1.55 s
FLT04-1PH	GEN-2007-027 (1271) tripped for low voltage at 1.504s
FLT05-3PH	GEN-2007-027 (1271) tripped for low voltage at 3.3 s
FLT07-3PH	GEN-2001-033 (560961) tripped for low voltage at 1.521 s
	GEN-2001-033 (560963) tripped for low voltage at 1.521 s
	GEN-2001-033 (560965) tripped for low voltage at 1.521 s
	GEN-2001-033 (560967) tripped for low voltage at 1.521 s
	GEN-2001-033 (560969) tripped for low voltage at 1.521 s
	GEN-2001-033 (560971) tripped for low voltage at 1.521 s
	GEN-2001-033 (560973) tripped for low voltage at 1.521 s
	GEN-2007-027 (1271) tripped for low voltage at 3.3 s
FLT09-3PH	GEN-2001-033 (560963) tripped for low voltage at 1.904 s
	GEN-2001-033 (560967) tripped for low voltage at 1.908 s
	GEN-2001-033 (560973) tripped for low voltage at 1.913 s
	GEN-2007-027 (1271) tripped for low voltage at 2.51 s
FLT11-3PH	GEN-2001-033 (560963) tripped for low voltage at 1.913 s
	GEN-2001-033 (560967) tripped for low voltage at 1.917 s
	GEN-2001-033 (560973) tripped for low voltage at 1.917 s

Name	Wind Projects Dynamic Performance
	GEN-2007-027 (1271) tripped for low voltage at 3.3 s
FLT13-3PH	GEN-2007-027 (1271) tripped for low voltage at 3.3 s
FLT17-3PH	GEN-2001-033 (560961) tripped for low voltage at 1.521 s
	GEN-2001-033 (560963) tripped for low voltage at 1.521 s
	GEN-2001-033 (560965) tripped for low voltage at 1.521 s
	GEN-2001-033 (560967) tripped for low voltage at 1.521 s
	GEN-2001-033 (560969) tripped for low voltage at 1.521 s
	GEN-2001-033 (560971) tripped for low voltage at 1.521 s
	GEN-2001-033 (560973) tripped for low voltage at 1.521 s
	GEN-2001-033 (560975) tripped for low voltage at 1.521 s
	GEN-2007-027 (1271) tripped for low voltage at 3.3 s
FLT19-3PH	GEN-2001-033 (560961) tripped for low voltage at 0.754 s
	GEN-2001-033 (560963) tripped for low voltage at 0.754 s
	GEN-2001-033 (560965) tripped for low voltage at 0.754 s
	GEN-2001-033 (560967) tripped for low voltage at 0.754 s
	GEN-2001-033 (560969) tripped for low voltage at 0.754 s
	GEN-2001-033 (560971) tripped for low voltage at 0.754 s
	GEN-2001-033 (560973) tripped for low voltage at 0.754 s
	GEN-2001-033 (560975) tripped for low voltage at 0.754 s
FLT20-1PH	GEN-2001-033 (560961) tripped for low voltage at 1.271 s
	GEN-2001-033 (560963) tripped for low voltage at 1.271 s
	GEN-2001-033 (560965) tripped for low voltage at 1.271 s
	GEN-2001-033 (560967) tripped for low voltage at 1.271 s
	GEN-2001-033 (560969) tripped for low voltage at 1.271 s
	GEN-2001-033 (560971) tripped for low voltage at 1.271 s
	GEN-2001-033 (560973) tripped for low voltage at 1.271 s
	GEN-2001-033 (560975) tripped for low voltage at 1.271 s
FLT33-3PH	GEN-2001-033 (560963) tripped for low voltage at 1.521 s
	GEN-2001-033 (560967) tripped for low voltage at 1.521 s
	GEN-2001-033 (560973) tripped for low voltage at 1.521 s
FLT35-3PH	GEN-2005-010 (560977) tripped for low voltage at 0.6042 s
	GEN-2005-010 (560979) tripped for low voltage at 0.6042 s
	GEN-2001-033 (560961) tripped for low voltage at 1.104 s
	GEN-2001-033 (560963) tripped for low voltage at 1.104 s
	GEN-2001-033 (560965) tripped for low voltage at 1.104 s
	GEN-2001-033 (560967) tripped for low voltage at 1.104 s
	GEN-2001-033 (560969) tripped for low voltage at 1.104 s

Name	Wind Projects Dynamic Performance
	GEN-2001-033 (560971) tripped for low voltage at 1.104 s
	GEN-2001-033 (560973) tripped for low voltage at 1.104 s
	GEN-2001-033 (560975) tripped for low voltage at 1.104 s
FLT37-3PH	GEN-2005-010 (560977) tripped for low voltage at 0.6042 s
	GEN-2005-010 (560979) tripped for low voltage at 0.6042 s
	GEN-2001-033 (560961) tripped for low voltage at 1.183 s
	GEN-2001-033 (560963) tripped for low voltage at 1.183 s
	GEN-2001-033 (560965) tripped for low voltage at 1.183 s
	GEN-2001-033 (560967) tripped for low voltage at 1.183 s
	GEN-2001-033 (560969) tripped for low voltage at 1.183 s
	GEN-2001-033 (560971) tripped for low voltage at 1.183 s
	GEN-2001-033 (560973) tripped for low voltage at 1.183s
	GEN-2001-033 (560975) tripped for low voltage at 1.183 s
	GEN-2007-027 (1271) tripped for low voltage at 3.3 s
FLT39-3PH	GEN-2001-033 (560961) tripped for low voltage at 1.521 s
	GEN-2001-033 (560963) tripped for low voltage at 1.521 s
	GEN-2001-033 (560965) tripped for low voltage at 1.521 s
	GEN-2001-033 (560967) tripped for low voltage at 1.521 s
	GEN-2001-033 (560969) tripped for low voltage at 1.521 s
	GEN-2001-033 (560971) tripped for low voltage at 1.521 s
	GEN-2001-033 (560973) tripped for low voltage at 1.521 s
	GEN-2001-033 (560975) tripped for low voltage at 1.521 s
	GEN-2007-027 (1271) tripped for low voltage at 3.3 s
FLT43-3PH	GEN-2008-008 (1081) tripped for over frequency at 0.7417 s
FLT44-3PH	GEN-2008-008 (1081) tripped for over frequency at 0.7542 s
FLT57-3PH	GEN-2008-007 (1071) tripped for over voltage at 1.6417 s
	GEN-2008-016 (1161) tripped for over voltage at 1.7292 s
	GEN-2008-016 (1162) tripped for over voltage at 1.7292 s
FLT58-3PH	GEN-2008-007 (1071) tripped for over voltage at 1.6167 s
	GEN-2008-016 (1161) tripped for over voltage at 1.7042 s
	GEN-2008-016 (1162) tripped for over voltage at 1.7042 s
FLT71-3PH	GEN-2008-014 (1141) tripped for over frequency at 1.7 s
	GEN-2008-015 (1151) tripped for over frequency at 1.7 s
FLT72-1PH	GEN-2008-014 (1141) tripped for over frequency at 1.6209 s
	GEN-2008-015 (1151) tripped for over frequency at 1.6209 s

The results indicate that reactive support is required to address the trips due to LVRT. Table 4-6 presents the capacitor banks added for each proposed wind project.

Table 4-6: Capacitor Banks to Address the LVRT Issues

Project	Point of Interconnection	Requirements
GEN-2007-027	Curry – Tucumcari 115 kV	15 Mvar at 34.5 kV
GEN-2007-034	Tolk – Eddy County 345 kV	-
GEN-2007-055	Tolk – Eddy County 345 kV	-
GEN-2008-007	Grassland – Jones 230 kV	30 Mvar at 34.5 kV
GEN-2008-008	Graham 69 kV	-
GEN-2008-009	San Juan Mesa 230 kV	10 Mvar at 34.5 kV
GEN-2008-014	Tuco – Oklaunion 345 kV	20 Mvar at 34.5 kV
GEN-2008-015	Tuco – Oklaunion 345 kV	20 Mvar at 34.5 kV
GEN-2008-016	Grassland 230 Kv	2 x 20 Mvar at 34.5 kV

It is important to note that the capacitor banks added to address the LVRT issues are merely indicative. For the reactive support requirement, Table 4-5 is the reference that must be achieved using the wind turbine generator (WTG) capabilities and/or adding capacitor banks to the system.

The contingency analysis was conducted again, after including the capacitor banks for reactive support indicated above. The results obtained show:

- The new proposed projects, did not trip during any of the contingencies tested. That is, no trips occurred due to LVRT.
- All other generators in the monitored areas were stable and remained in synchronism during all contingencies and the system conditions considered.
- Acceptable damping and voltage recovery was observed, within applicable standards.

Additional plots of selected system variables documenting the stability simulations are included in Appendix B.

Section

5

Conclusion

The nine projects of ICS-2008-001 Group 6 have been evaluated to determine the system requirements to meet the requirements associated with FERC Order 661-A Guidelines for Low Voltage Ride Through (LVRT) and therefore, for them to deliver their full power to the SPP transmission system.

Steady state and stability analysis were carried out to evaluate the system performance under contingencies

The power factor analysis determined the amount of reactive support required to maintain the scheduled voltages at each one of the points of interconnection. The amount of reactive power indicated by Table 4-5 must be achieved using the wind turbine generator (WTG) capabilities and/or adding capacitor banks to the system.

The stability results indicate that reactive support is also required to address the trips due to LVRT as shown by Table 4-6. However, including the reactive support indicated for each proposed wind project, there are no trips occurred due to LVRT. None of the Group 6 projects have an adverse impact on the stability of the SPP system, for the contingencies and system conditions tested.

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P: Stability Study for Group 7

Cluster Group 7
System Impact Study

Submitted to:

Southwest Power Pool
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Little Rock, AR 72205

Submitted by:

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6/17/2009

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EXECUTIVE SUMMARY

The Southwest Power Pool (SPP), on behalf of several generation interconnection customers, desires a generation interconnection impact study for a group of generators in southwestern Oklahoma collectively referred to as "Cluster Group 7". Cluster Group 7 is made of the following generators:

- GEN-2007-032. 150 MW wind farm (Acciona 1.5 MW turbines) connected to the Clinton Jct-Clinton 138 kV line. This line is an AEPW-WFEC tie line, and the tap point is in the AEPW control area.
- GEN-2007-043. 300 MW wind farm (General Electric 1.5 MW turbines) connected to the OKGE Cimarron-Anadarko 345 kV line.
- GEN-2007-049. 60 MW wind farm (Vestas V90 turbines) connected to the WFEC Carter Junction 69 kV substation.
- GEN-2007-052. 150 MW gas turbines (General Electric LM 6000) connected to the WFEC Anadarko 138 kV substation.

The following previously queued generators were also monitored and their dynamic responses were graphed for each fault:

- Blue Canyon I & II (74 MW induction wind turbines and 151 MW Vestas V80 wind turbines, respectively, at the WFEC Washita 138 kV substation.)
- Weatherford (147 MW of GE 1.5 MW wind turbines at the AEPW Weatherford 138 kV substation.)
- GEN-2003-005 (100 MW GE 1.5 MW wind turbines at the WFEC Anadarko-Paradise 138 kV line.)
- GEN-2006-002, GEN-2006-035, GEN-2006-043 (150 MW Gamesa, 224 MW Gamesa, and 99 MW GE 1.5 MW wind turbines, respectively, at the proposed AEPW Beckham County 345 kV substation.)

SPP requested a stability analysis and a power factor analysis for the queued generator projects in Cluster Group 7. SPP did not request an Available Transfer Capability (ATC) study as part of this study.

Stability analysis shows no new problems with the dynamic response of study generation in the region of interest

Low Voltage Ride Through (LVRT) analysis showed no generators tripping offline due to low voltage.

Power factor analysis also shows no generators tripping offline due to voltage collapse. It also gives the following power factor requirements at the Points of Interconnection (POI) within Cluster Group 7:

a. GEN-2007-032: 0.997 leading – 0.999 lagging
b. GEN-2007-043: 0.968 leading – 0.999 lagging
c. GEN-2007-049: 0.994 leading – 1.000
d. GEN-2007-052: 0.958 leading – 0.998 lagging

The power factor ranges for the wind turbines (a) through (c) are within the capability of the selected wind turbine models.

In addition, the gas turbines at GEN-2007-052 need to meet a 0.95 leading - 0.95 lagging power factor range as is required in the Southwest Power Pool Large Generation Interconnection Agreement (LGIA).

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1.0 INTRODUCTION

The Southwest Power Pool (hereafter referred to as "SPP") commissioned AMEC Earth and Environmental (hereafter referred to as "AMEC") to study the impact of a group of generators in the SPP interconnection queue referred to as Cluster Group 7. The 4 sites studied are all in southwestern Oklahoma, within approximately 75 miles of Oklahoma City.

The sites studied were:

1. GEN-2007-032. 150 MW wind generation (100 x 1.5 MW Acciona wind turbines) connected to the Clinton Jct-Clinton 138 kV line. This line is an AEPW-WFEC tie line, and the tap point is in the AEPW control area.

2. GEN-2007-043. 300 MW wind generation (200 x 1.5 MW GE wind turbines) connected to the OKGE Cimarron-Anadarko 345 kV line.

3. GEN-2007-049. 60 MW wind generation (33 x 1.8 MW Vestas V90 wind turbines) connected to the WFEC Carter Jct. 69 kV substation.

4. GEN-2007-052. 150 MW gas turbines (comprised of three GE LM6000) connected to the WFEC Anadarko 138 kV substation.

SPP did not request an Available Transfer Capability (ATC) study. The ATC study will be required when the generation companies request transmission service.

SPP requested a stability analysis and a power factor analysis. Given SPP's list of faults, AMEC performed a dynamics study and a power factor study. The results of the study are given below.

2.0 APPROACH

SPP furnished 2010 summer peak load and 2010 winter peak load cases in PSS/E format. The investigators simulated three-phase and single-phase faults on this case as prescribed in the scope of work.

All line faults were simulated in the following fashion:

a. Apply fault to a line near one of its buses.

b. Clear fault after 5 cycles by tripping the faulted line.

c. Wait 20 cycles and reclose the tripped line into the fault.

d. Leave fault on for 5 cycles, then trip the line and remove the fault.

All transformer faults were simulated in the following fashion:

a. Apply fault at one of the transformer buses. In this analysis, the only transformer faults involve the Elk City 230/138/13.8 kV and the Elk City 138/69/13.8 kV 3-winding transformers. All Elk City transformer faults are simulated at the 138 kV bus.

b. Clear fault after 5 cycles by tripping the faulted transformer. (No reclosing occurs for transformer faults in this study.)

All faults were simulated in 3Φ and 1Φ versions. Odd numbered faults are 3Φ, and even numbered faults are 1Φ.

Following is a summary of the faults simulated in this analysis.

Table 1: Fault Descriptions

Fault Numbers	Description
1 & 2	GEN-2007-043 (210431) to Cimarron (514901) 345 kV line near GEN-2007-043
3 & 4	GEN-2007-043 (210431) to Anadarko (521210) 345kV line, near GEN-2007-043
5 & 6	Cimarron (514901) to Draper (514934) 345kV line, near Cimarron
7 & 8	Cimarron (514901) to Northwest (514880) 345kV line, near Cimarron
9 & 10	Cimarron (514901) to Woodring (514715) 345kV line, near Cimarron
11 & 12	Northwest (514880) to Arcadia (514908) 345kV line, near Northwest
13 & 14	Anadarko (521210) to Lawton Eastside (511468) 345kV line, near Anadarko
15 & 16	Anadarko (521210) to Beckham Co. (560019) 345kV line, near Anadarko
17 & 18	Lawton Eastside (511468) to Sunnyside (515136) 345kV line, near Lawton Eastside
19 & 20	Lawton Eastside (511468) to Oklaunion (511456) 345kV line, near Lawton Eastside
21 & 22	Anadarko (520814) to Pocasset (521031) 138kV line, near Anadarko
23 & 24	Anadarko (520814) to Washita (521089) 138kV line, near Anadarko
25 & 26	Anadarko (520814) to Southwest (511477) 138kV line, near Anadarko
27 & 28	Anadarko (520814) to Cornville Tap (520867) 138kV line, near Anadarko
29 & 30	Anadarko (520814) to Georgia St. (520923) 138kV line, near Anadarko
31 & 32	Anadarko (520814) to GEN-2003-005 (560916) 138kV line, near Anadarko
33 & 34	Southwest (511477) to Washita (521089) 138kV line, near Southwest
35 & 36	Southwest (511477) to Verden (511421) 138kV line, near Southwest
37 & 38	Southwest (511477) to Elgin Jct. (511486) 138kV line, near Southwest
39 & 40	GEN-2007-032 (560939) to Clinton (520856) 138kV line, near GEN-2007-032
41 & 42	GEN-2007-032 (560939) to Clinton Jct. (511485) 138kV line, near GEN-2007-032
43 & 44	Clinton Jct. (511485) to Clinton NG (511534) 138kV line, near Clinton Jct
45 & 46	Clinton Jct. (511485) to Elk City (511458) 138kV line, near Clinton Jct
47 & 48	Weatherford Wind (511506) to Weatherford Tap (511536) 138kV line, near Weatherford Wind

Fault Numbers	Description
49 & 50	Elk City (511458) to Red Hill (200) 138kV line, near Elk City
51 & 52	SKIPPED per SPP's advice
53 & 54	Elk City (511458) to Clinton Jct. (511485) 138kV line, near Elk City
55 & 56	Elk City (511458) to Clinton AF (511446) 138kV line, near Elk City
57 & 58	Elk City 138 kV (511458) to 230 kV (511490) to 13.8 kV (511482) 3-winding transformer, near the 138 kV bus
59 & 60	Elk City 138 kV (511458) to 69 kV (511459) to 13.8 kV (511493) 3-winding transformer, near the 138 kV bus
61 & 62	Carter Jct. (520846) to Dill Jct. (520876) 69kV line, near Carter Jct
63 & 64	Carter Jct. (520846) to Lake Creek (520978) 69kV line, near Carter Jct
65 & 66	Lake Creek (520978) to Lone Wolf (520982) 69kV line, near Lake Creek
67 & 68	Lake Creek (520978) to Granite (520927) 69kV line, near Lake Creek

3.0 PROJECT LOCATIONS AND DIAGRAMS

Following is a table of all proposed wind farms and gas turbines in Cluster Group 7.

Table 2: Points of Interconnection for Cluster Group 7

Request	Size (MW)	Turbine Model	Point Of Interconnection		
			Common Name	Bus #	Name in Model
GEN-2007-032	150	Acciona 1.5 MW	Clinton Jct.-Clinton 138 kV	560939	TAP_CLJN-CL 138
GEN-2007-043	300	GE 1.5 MW	Cimarron-Anadarko 345 kV	210430	WFSS 345
GEN-2007-049	60	Vestas V90	Carter Jct. 69 kV	520846	CARTERJ2 69
GEN-2007-052	150	Gas Turbine	Anadarko 138 kV	520814	ANADARK4 138

All of the following one-line diagrams use this color code for nominal voltages:

Gray **34.5 kV and lower**
Purple **69 kV**
Black **138 kV**
Red **345 kV**

Following are one-line diagrams of the interconnections of GEN-2007-032, GEN-2007-043, GEN-2007-049, and GEN-2007-052, respectively. All voltages and line flows are from the Summer 2010 base case.

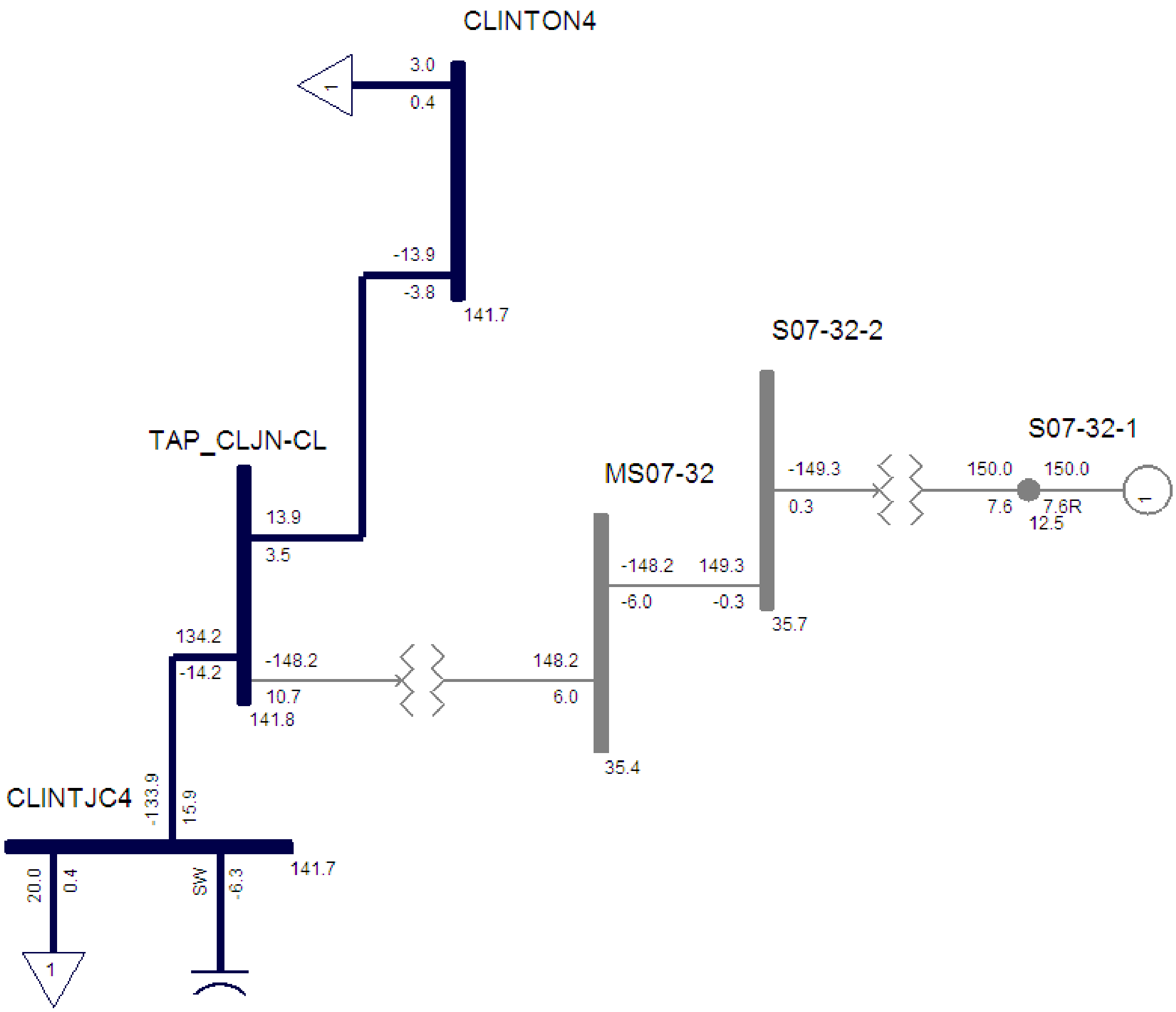

Figure 1: GEN-2007-032 Interconnection One-Line Diagram

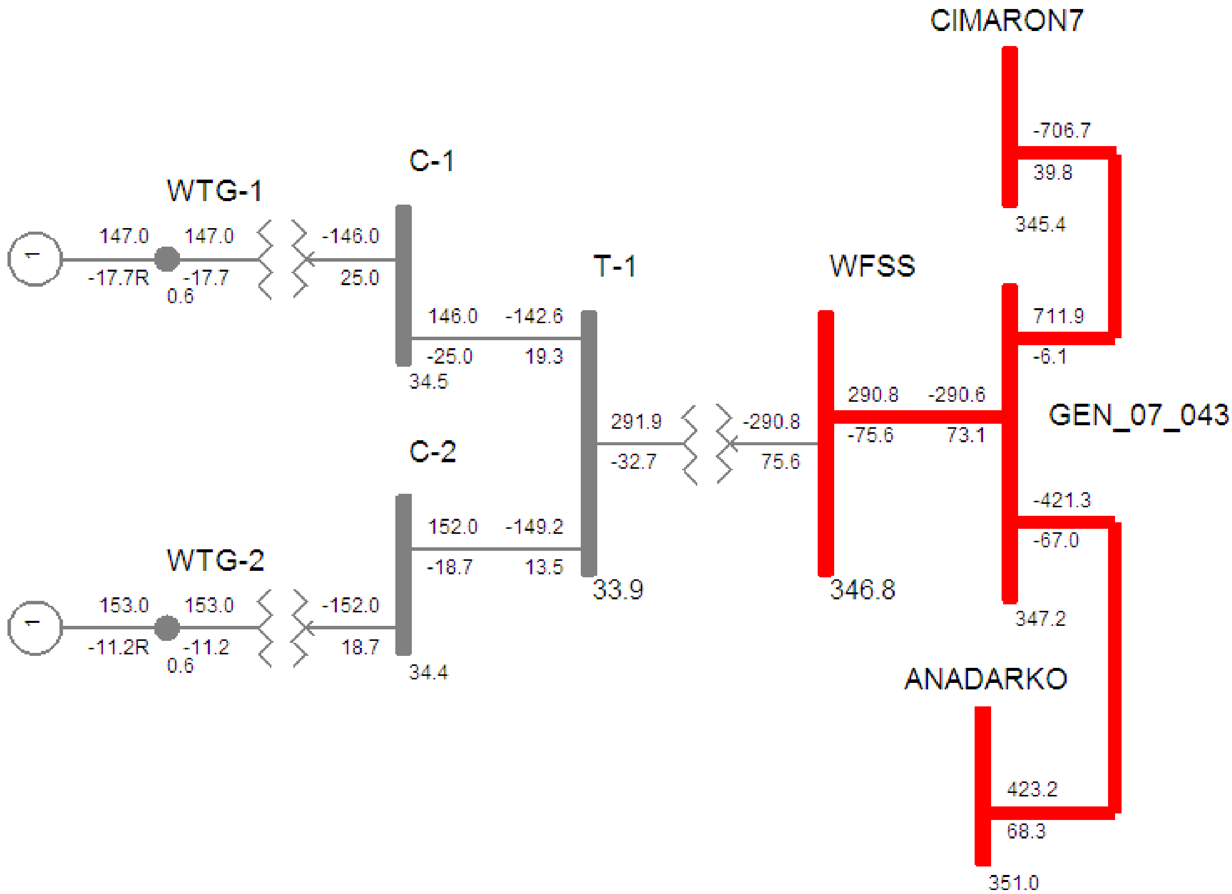

Figure 2: GEN-2007-043 Interconnection One-Line Diagram

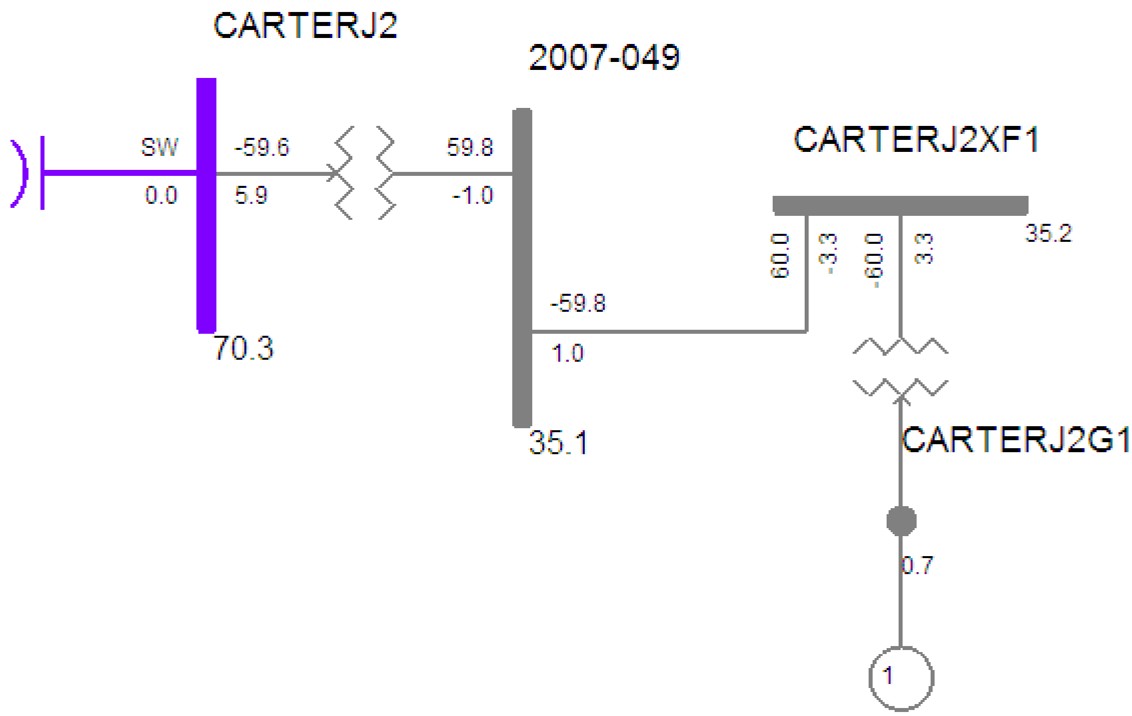

Figure 3: GEN-2007-049 Interconnection One-Line Diagram

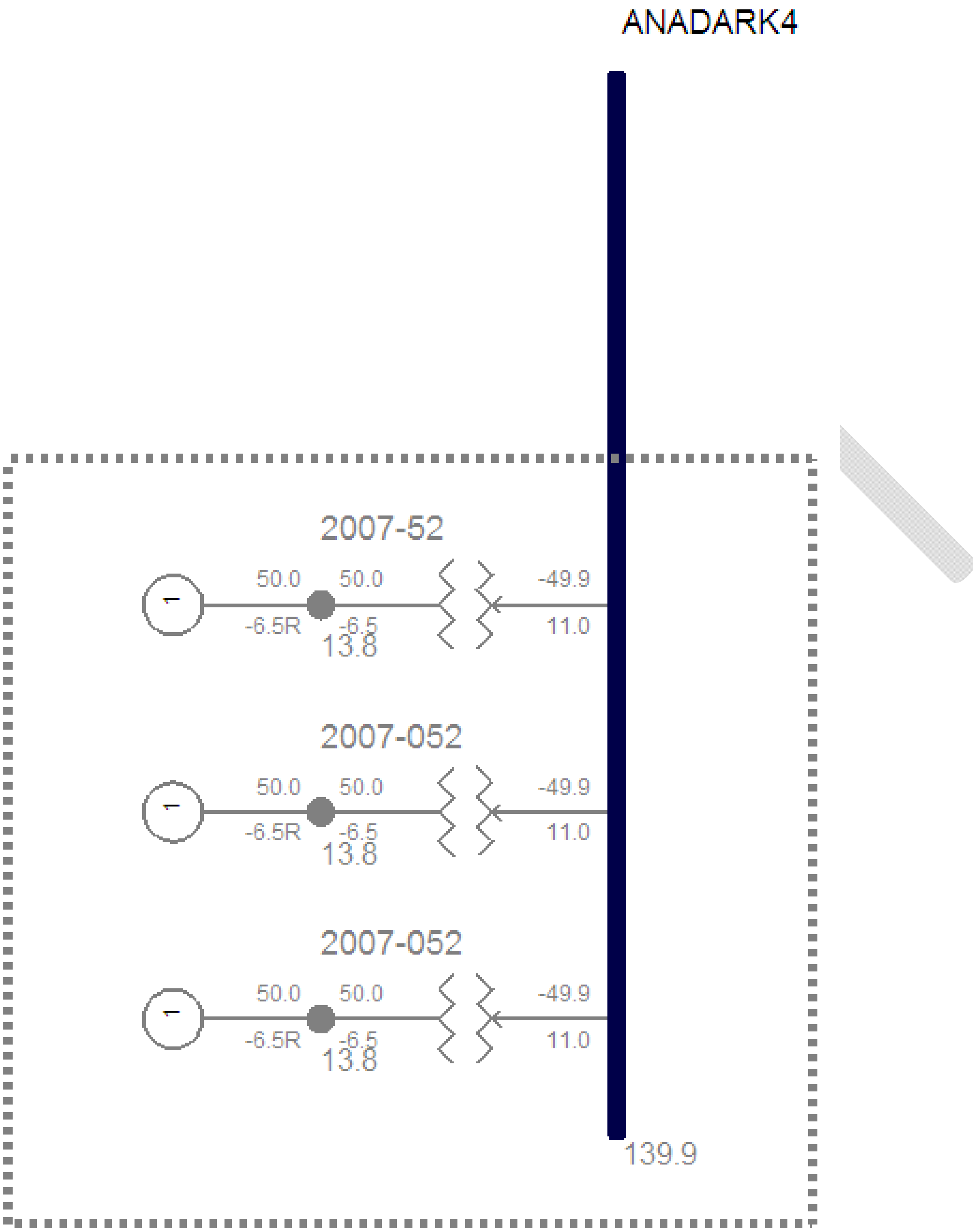

Figure 4: GEN-2007-052 Interconnection One-Line Diagram

As illustrated below, all the sites in Cluster Group 7 are within approximately 75 miles to the west and south of Oklahoma City.

Figure 5: Geographical location of Cluster Group 7 Projects

4.0 POWER FACTOR RESULTS

At each Point of Interconnection (POI), a continuously variable shunt VAR generator was placed into the model for the power factor analysis. Then, a contingency analysis was run using all faults described above. The shunt was set to regulate the post-contingency voltage to the pre-contingency value or 1.0 pu, whichever was greater. (In practice, that meant regulating the voltage to the pre-contingency value.) By comparing the required MVAR injection to the MW injection, a required power factor was estimated for each generator in Cluster Group 7.

Following are details on the Point of Interconnection for the 3 wind farms and 1 gas turbine site studied as Cluster Group 7. All MVAR injections are the sum of the generation MVARs and the MVARs from a continuously regulating shunt as described in the previous paragraph. For example, assume a generator or wind farm is injecting 200 MW and drawing 30 MVAR from the POI, but a switched shunt is injecting 80 MVAR into the POI. The net injection at the POI will then be reported as 200 MW & 50 MVAR, or 206.2 MVA at a 0.970 lagging power factor.

For all generation queue requests, the first row displays the Base Case power factor at the POI. The second and third rows show the power factors are for the contingencies that require the most and fewest MVARs, respectively, at the POI to regulate the voltage to pre-contingency levels. All bus injections are as measured at the high voltage side (345 kV, 138 kV, or 69 kV). Due to rounding, “Total MVAR” may be 0.1 MVAR different from the sum of “Gen MVAR” and “Shunt MVAR”.

In the case of GEN-2007-043, the shunt was assumed to be installed at bus 210430 (WFSS 345 kV) and set to regulate voltage at bus 210431 (GEN_07_043 345 kV). Bus 210431 is the tap point for GEN-2007-043 on the Cimarron-Anadarko 345 kV line, and the tap point is proposed to be connected via a new 5-mile radial line to the wind farm site at bus 210430.

Table 3: Required Power Factor at POI (Summer Peak Case)

Request & POI	Contingency	POI Voltage (pu)	POI BUS INJECTION (Summer Peak)						
			MW	Gen MVAR	Shunt MVAR	Total MVAR	MVA	PF	Lead or Lag
GEN-2007-032 Clinton Jct-Clinton 138 kV	Base Case	1.02757	148.2	-10.7	0	-10.7	148.5	0.997	Lead
	FLT41 & 42	1.02757	148.2	-10.7	14.6	3.9	148.2	1.000	Lag
	FLT57 & 58	1.02757	148.2	-10.7	-1.7	-12.4	148.7	0.997	Lead
GEN-2007-043 Cimarron-Anadarko 345 kV	Base Case	1.00643	290.8	-75.6	0	-75.5	300.4	0.968	Lead
	FLT03 & 04	1.00643	290.8	-78.3	86.5	8.1	290.9	1.000	Lag
	FLT49 & 50 and others	1.00643	290.8	-75.6	0	-75.6	300.5	0.968	Lead
GEN-2007-049 Carter Jct. 69 kV	Base Case	1.01952	59.6	-5.9	0	-5.9	59.9	0.995	Lead
	FLT59 & 60	1.01952	59.6	-5.9	5.6	-0.3	59.6	1.000	Lead
	FLT05 & 06 and others	1.01952	59.6	-5.9	0	-5.9	59.9	0.995	Lead
GEN-2007-052 Anadarko 138 kV	Base Case	1.01370	149.7	-33.1	0.1	-33.0	153.3	0.977	Lead
	FLT33 & 34	1.01370	149.7	-33.1	43.2	10.1	150.1	0.998	Lag
	FLT57 & 58	1.01370	149.7	-33.1	-3.4	-36.5	154.1	0.972	Lead

Table 4: Required Power Factor at POI (Winter Peak Case)

Request & POI	Contingency	POI Voltage (pu)	POI BUS INJECTION (Winter Peak)						
			MW	Gen MVAR	Shunt MVAR	Total MVAR	MVA	PF	Lead or Lag
GEN-2007-032 Clinton Jct-Clinton 138 kV	Base Case	1.02390	148.2	-7.8	0	-7.8	148.4	0.999	Lead
	FLT01 & 02	1.02390	148.2	-7.8	15.0	7.3	148.3	0.999	Lag
	FLT57 & 58	1.02390	148.2	-7.8	-1.7	-9.5	148.5	0.998	Lead
GEN-2007-043 Cimarron-Anadarko 345 kV	Base Case	1.00061	290.8	-67.8	0	-67.8	298.6	0.974	Lead
	FLT17 & 18	1.00061	290.8	-70.4	82.1	11.7	291.0	0.999	Lag
	FLT49 & 50 and 59 & 60	1.00061	290.8	-67.8	0	-67.8	298.6	0.974	Lead
GEN-2007-049 Carter Jct. 69 kV	Base Case	1.03166	59.0	-6.4	0	-6.4	59.4	0.994	Lead
	FLT59 & 60	1.03166	59.0	-6.4	5.6	-0.8	59.0	1.000	Lead
	FLT17 & 18	1.03166	59.0	-6.4	-0.3	-6.7	59.4	0.994	Lead
GEN-2007-052 Anadarko 138 kV	Base Case	1.01818	149.7	-40.8	0	-40.8	155.2	0.965	Lead
	FLT01 & 02	1.01818	149.7	-40.8	43.8	3.0	149.8	1.000	Lag
	FLT57 & 58	1.01818	149.7	-40.8	-3.7	-44.5	156.2	0.958	Lead

Combining the results for the summer and winter cases yields Table 5, which summarizes the reactive power requirements at the POIs. For each generation interconnection request, the first row is the season and contingency combination that requires the least MVAR injection or the greatest MVAR draw at the POI. The second row for each request indicates the greatest MVAR injection or least MVAR draw at the POI.

Table 5: Required Power Factor at POI (Summary-Worst Cases)

Request	Point Of Interconnection	Season	Contingency	POI BUS INJECTION (Worst Cases)				
				MW	MVAR	MVA	PF	Lead or Lag
GEN-2007-032	Clinton Jct.-Clinton 138 kV	Summer	FLT57 & 58	148.2	-12.4	148.7	0.997	Lead
		Winter	FLT01 & 02	148.2	7.3	148.3	0.999	Lag
GEN-2007-043	Cimarron-Anadarko 345 kV	Summer	FLT59 & 60	290.8	-75.6	300.5	0.968	Lead
		Winter	FLT17 & 18	290.8	11.7	291.0	0.999	Lag
GEN-2007-049	Carter Jct. 69 kV	Winter	FLT17 & 18	59.0	-6.7	59.4	0.994	Lead
		Summer	FLT59 & 60	59.6	-0.3	59.6	1.000	Lead
GEN-2007-052	Anadarko 138 kV	Winter	FLT57 & 58	149.7	-44.5	156.2	0.958	Lead
		Summer	FLT33 & 34	149.7	10.1	150.1	0.998	Lag

In summary, to regulate voltages at each POI to the pre-contingency levels, the following power factor ranges are required as measured at each POI:

a. GEN-2007-032: 0.997 leading – 0.999 lagging
b. GEN-2007-043: 0.968 leading – 0.999 lagging
c. GEN-2007-049: 0.994 leading – 1.000
d. GEN-2007-052: 0.958 leading – 0.998 lagging

GEN-2007-032 has enough reactive capability to meet the requirements at the Clinton Jct. - Clinton 138 kV POI. GEN-2007-032 (Acciona 1.5) is rated for a power factor of 0.95 lagging – 0.95 leading as measured at the output terminals. Allowing for 26 MVAR of losses in the collector system and transformers, GEN-2007-032 is capable of drawing up to 75 MVAR from the POI or supplying up to 23 MVAR to the POI (0.894 leading – 0.988 leading at the POI.)

GEN-2007-043 has enough reactive capability to meet the requirements at the Cimarron-Anadarko 345 kV POI, with or without the WindVAR option. GEN-2007-043 (GE 1.5) is rated for a power factor of 0.95 lagging – 0.95 leading at the output terminals without the WindVAR option and 0.90 lagging – 0.90 leading at the output terminals with WindVAR. Allowing for 66 MVAR of losses in the collector system and transformers, and without the WindVAR option, GEN-2007-043 is capable of drawing up to 165 MVAR from the POI or supplying up to 33 MVAR to the POI (0.876 leading – 0.994 lagging at the POI). With the WindVAR option and 66 MVAR of losses, GEN-2007-043 is capable of drawing up to 211 MVAR from the POI or supplying up to 79 MVAR to the POI (0.818 leading - 0.967 lagging at the POI.)

GEN-2007-049 has enough reactive capability to meet the requirements at the Carter Jct. 69 kV POI. GEN-2007-049 (Vestas V90) is rated for a power factor of 0.96 leading – 0.98 lagging as measured at the output terminals. Allowing for 10 MVAR of losses in the collector system and transformers, GEN-2007-049 is capable of supplying up to 2.2 MVAR to the POI or drawing up to 17.5 MVAR from the POI (0.960 leading – 0.999 lagging at the POI).

GEN-2007-052 is not a wind generation facility and must follow Section 9.6.1 of the SPP LGIA in that it must meet a 0.95 leading – 0.95 lagging power factor for all contingencies.

Because manufacturer's specifications are subject to change, all specifications should be verified with the respective manufacturer prior to committing to a purchase.

5.0 VOLTAGE RECOVERY RESULTS

Dynamic simulations were performed using each fault noted in Section 2.0. All faults were cleared after 5 cycles. Faulted transmission lines were reclosed into the fault 20 cycles after the initial clearing, then cleared and locked out after 5 more cycles. Faulted transformers were not reclosed.

Voltage recovery as determined via dynamic simulation was checked against all contingencies. If the voltage recovers post-fault to a steady-state level consistent with the steady-state simulation, the generator interconnection is considered stable from a voltage standpoint.

In these dynamic simulations, real loads are modeled as constant current and reactive loads are modeled as constant admittance; i.e. MW loads are proportional to voltage and MVAR loads are proportional to voltage squared. In contrast, loads are modeled as constant MW and constant MVAR in steady-state simulations. Therefore, due to differences in load modeling, minor differences in voltages are to be expected between dynamic and steady-state simulations.

Table 6: Post-Fault Voltage Recovery by Dynamic Simulation

		SUMMER		WINTER	
Request	**Point Of Interconnection**	**Contingency**	**POI Voltage (pu)**	**Contingency**	**POI Voltage (pu)**
GEN-2007-032	Clinton Jct.-Clinton 138 kV	Base Case	1.0276	Base Case	1.024
		FLT43 & 44	1.0364	FLT43 & 44	1.0338
		FLT41 & 42	0.95347	FLT41	0.98471
GEN-2007-043	Cimarron-Anadarko 345 kV	Base Case	1.0064	Base Case	1.0006
		FLT01 & 02	1.0135	FLT01 & 02	1.0047
		FLT03	0.99471	FLT17	0.99065
GEN-2007-049	Carter Jct. 69 kV	Base Case	1.0196	Base Case	1.0317
		FLT67 & 68	1.0335	FLT67 & 68	1.0399
		FLT59 & 60	0.94253	FLT59 & 60	0.98433
GEN-2007-052	Anadarko 138 kV	Base Case	1.0137	Base Case	1.0183
		FLT21 & 22	1.0147	FLT39 & 40	1.0189
		FLT34	1.0068	FLT34	1.0095

In addition, the progress of the dynamic simulations was monitored to determine if any generators trip offline due to failure of Low Voltage Ride Through (LVRT). No generators tripped offline due to LVRT failure. For GEN-2007-049 (studied as part of Cluster Group 7) and GEN-2008-015 (not studied as part of Cluster Group 7), the following message was found in the progress output.

Under voltage 3 trip at bus XXXX machine Y at time = ZZZZZZZZ
(Trip function overridden by user setting) at time = ZZZZZZZZ

This occurred for GEN-2007-049 (generator bus 1042, and faults FLT21-3Φ through FLT46-1Φ, FLT49-3Φ, FLT50-1Φ, and FLT53-3Φ through FLT68-1Φ), and for GEN-2008-014 and GEN-2008-015 (generator buses 1141 & 1151, and faults FLT17-3Φ through FLT20-1Φ). These generators use a user-defined Vestas wind turbine model as supplied by SPP, with LVRT activated. The above message was interpreted as meaning that LVRT functioned as intended in the simulation.

Vestas' literature claimed LVRT capability for the V90 turbine, but they did not specify the required clearing time for a zero voltage or low voltage fault. To verify LVRT, the fault time was increased to determine when, if ever, the generators trip offline and stay offline due to low voltage. GEN-2007-049 tripped on low voltage and stayed offline after a 0.7917 second fault (47.5 cycles) at Carter Jct. 69 kV. GEN-2008-014 and GEN-2008-015 tripped on low voltage and stayed offline after a 0.4917 second fault (29.5 cycles) at G05-15 345 kV (between Oklaunion and Tuco—not on original fault list).

In summary, the dynamic voltage analysis did not reveal any problems in the voltage recovery at the interconnection points in Cluster Group 7 for the originally specified faults.

6.0 DYNAMICS RESULTS

Based on the dynamics results, none of the Cluster Group 7 generation interconnections cause any new stability problems. For the faults studied, no generators pulled out of synchronism with the grid. However, the study reveals possible pre-existing oscillatory response of the Blue Canyon I and Blue Canyon II wind farms to nearby faults if Blue Canyon I is assumed to remain online for all faults. However, because Blue Canyon I consists of induction machines without a power converter and will trip off for severe faults. SPP's experience has been that this is a modeling issue within the Vestes V80 dynamic model.

Below are the worst-case faults for each generator to be studied in Cluster Group 7, as determined by visual inspection of the rotor speed graphs from PSS/E dynamic analysis.

Table 7: Worst Faults for Dynamic Behavior within Cluster Group 7 (Summer Peak)

Generator	Worst Fault	Worst Fault Description
GEN-2007-032	FLT39-3Φ	GEN-2007-032 - Clinton 138 kV near GEN-2007-032
GEN-2007-043-1	FLT03-3Φ	GEN-2007-043 - Anadarko 345 kV near GEN-2007-043
GEN-2007-043-2	FLT03-3Φ	GEN-2007-043 - Anadarko 345 kV near GEN-2007-043
GEN-2007-049	FLT63-3Φ	Carter Jct - Lake Creek 69 kV near Carter Jct
GEN-2007-052-1	FLT21-3Φ	Anadarko - Poccaset 138 kV near Anadarko
GEN-2007-052-2	FLT21-3Φ	Anadarko - Poccaset 138 kV near Anadarko
GEN-2007-052-3	FLT21-3Φ	Anadarko - Poccaset 138 kV near Anadarko

Following are graphs of the rotor speeds or electrical power for Cluster Group 7 after applying the respective worst-case faults to the summer peak case. Rotor speeds are shown for all generators except GEN-2007-049. GEN-2007-049 performance is documented via the electrical power output graph, because the rotor speed is not available from the Vestas V90 model. GEN-2007-049 is deemed stable for the worst-case fault (FLT63-3Φ) based on the electrical power output recovering to pre-fault level (0.6 pu, or 60 MW on a 100 MVA base).

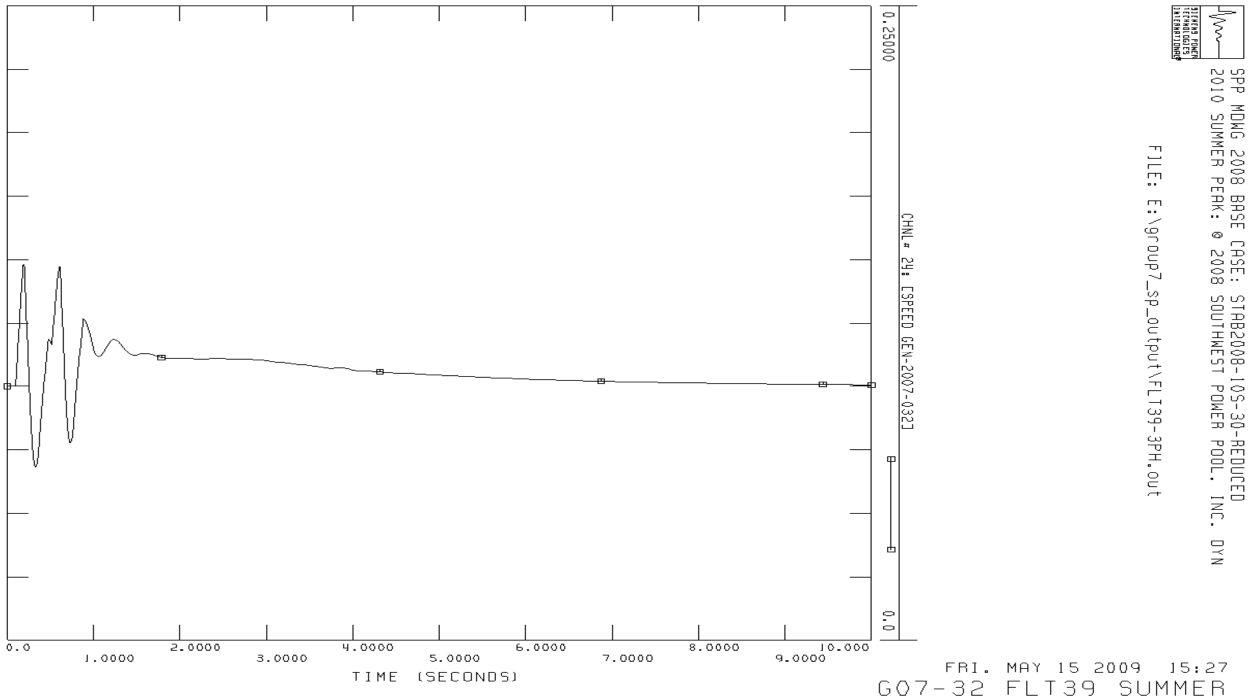

Figure 6: GEN-2007-032 Response to FLT39-3Φ, Summer Peak

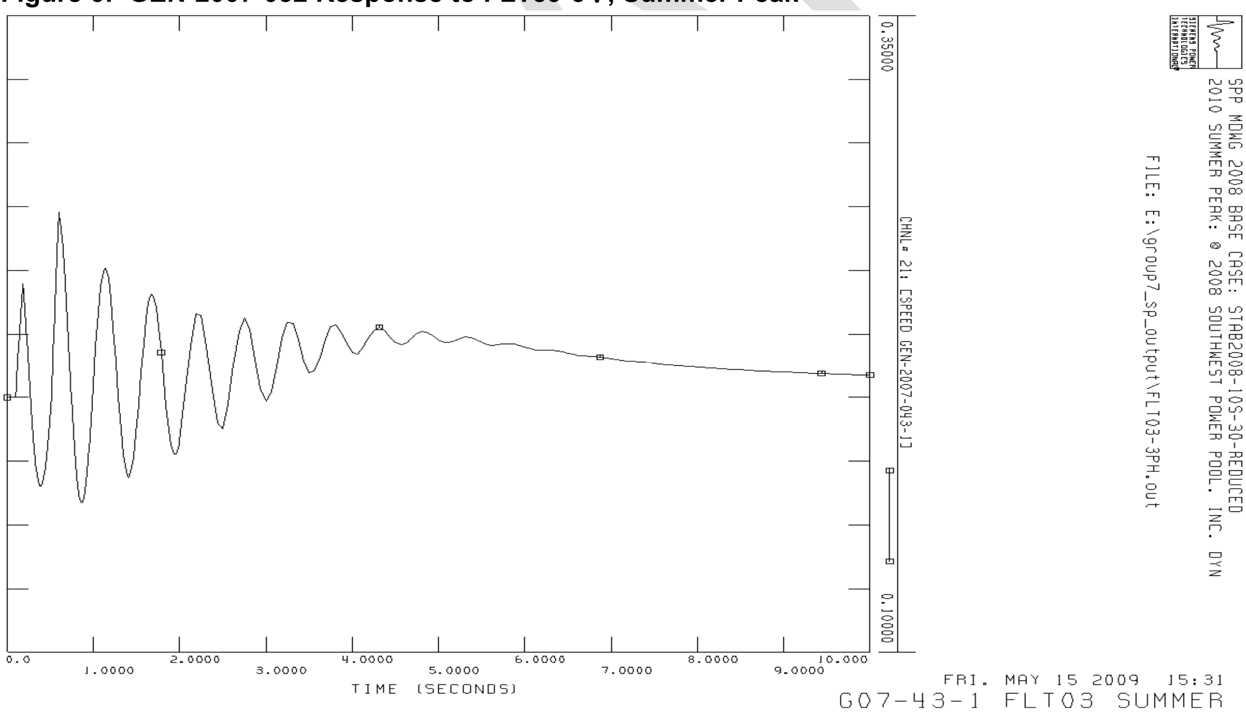

Figure 7: GEN-2007-043-1 Response to FLT03-3Φ, Summer Peak

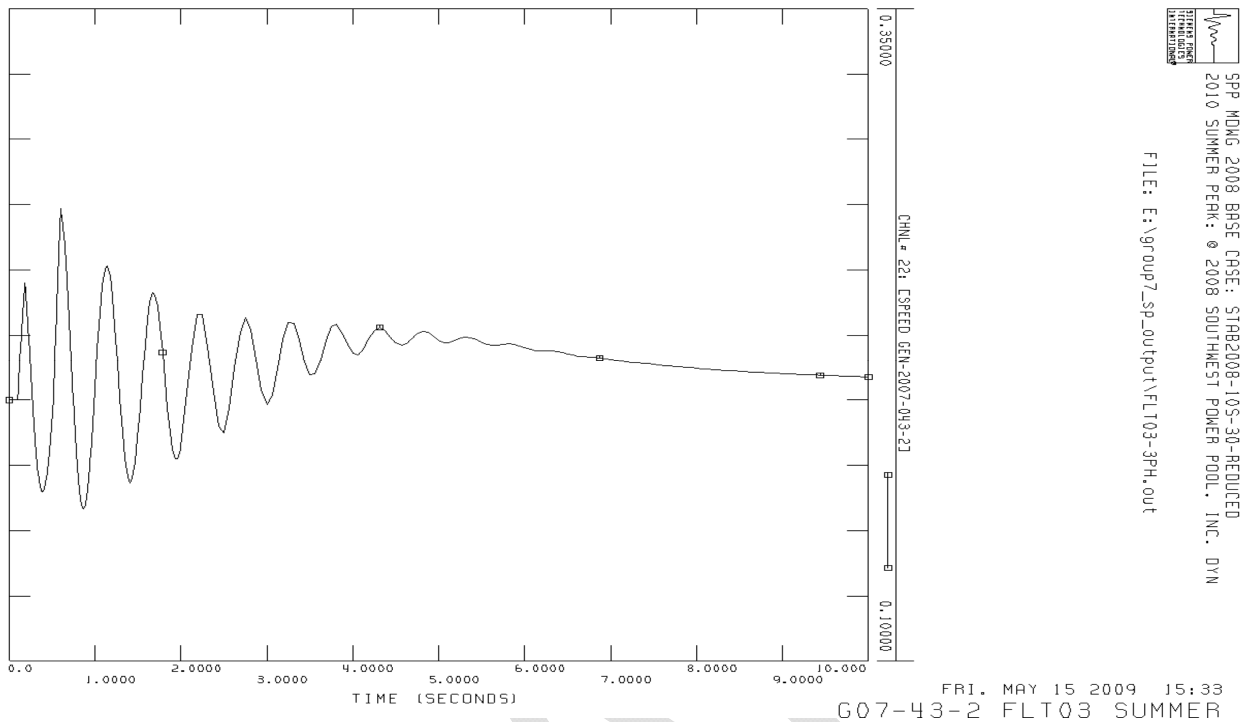

Figure 8: GEN-2007-043-2 Response to FLT03-3Φ, Summer Peak

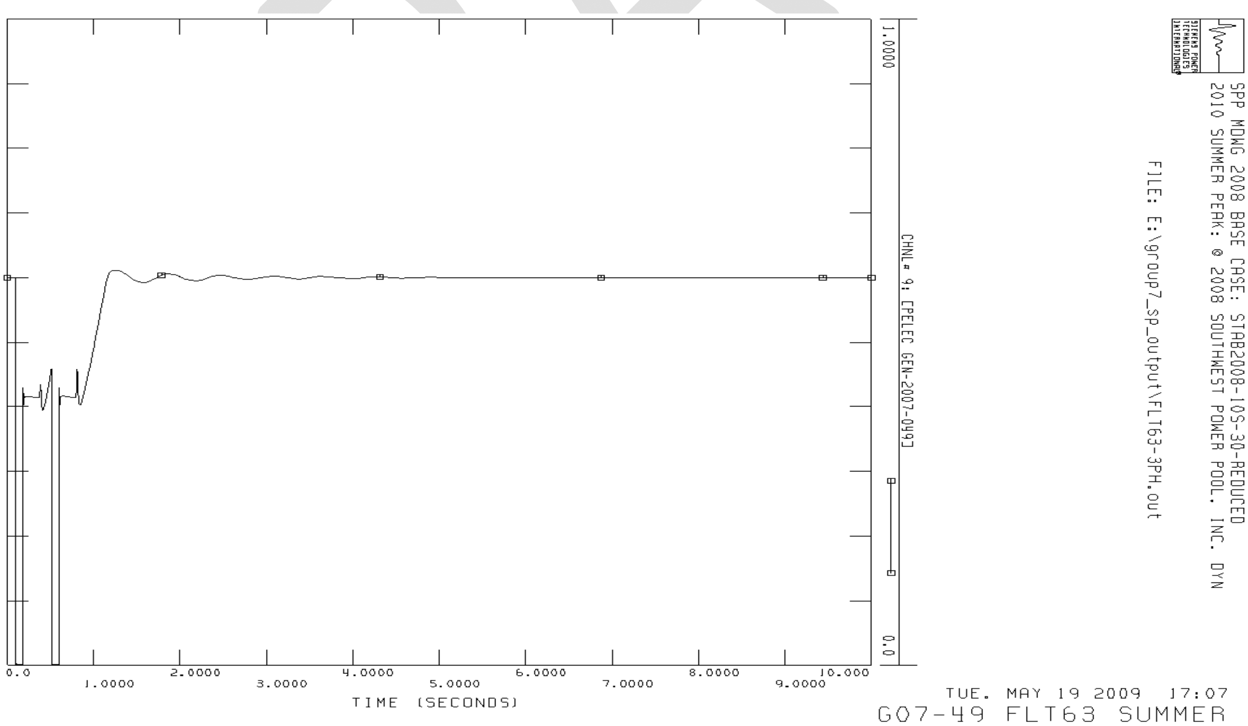

Figure 9: GEN-2007-049 Response to FLT63-3Φ, Summer Peak

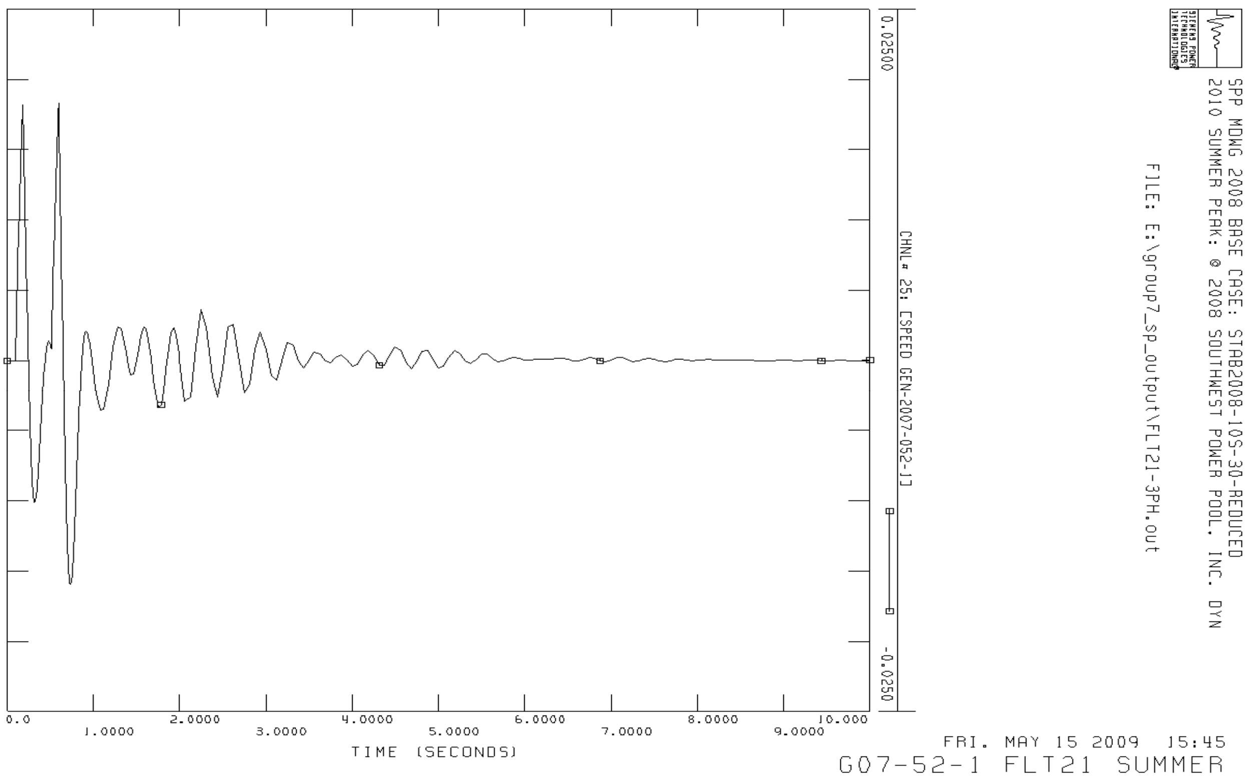

Figure 10: GEN-2007-052-1 Response to FLT21-3Φ, Summer Peak

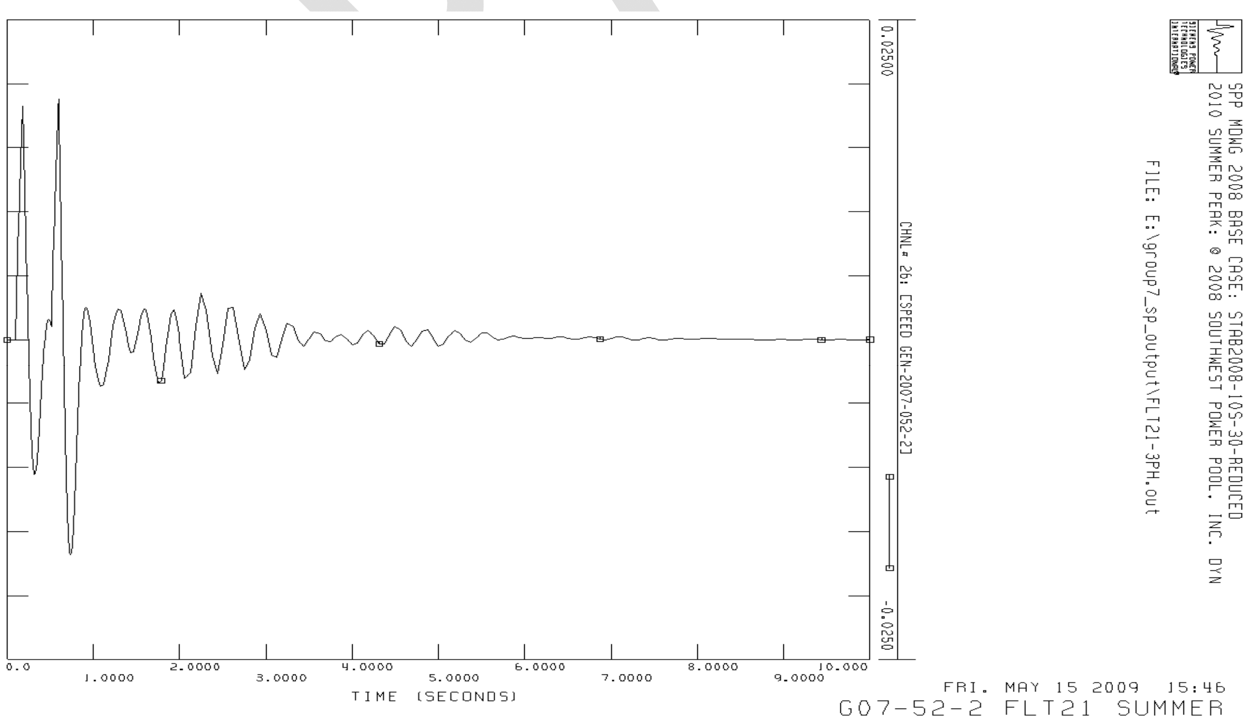

Figure 11: GEN-2007-052-2 Response to FLT21-3Φ, Summer Peak

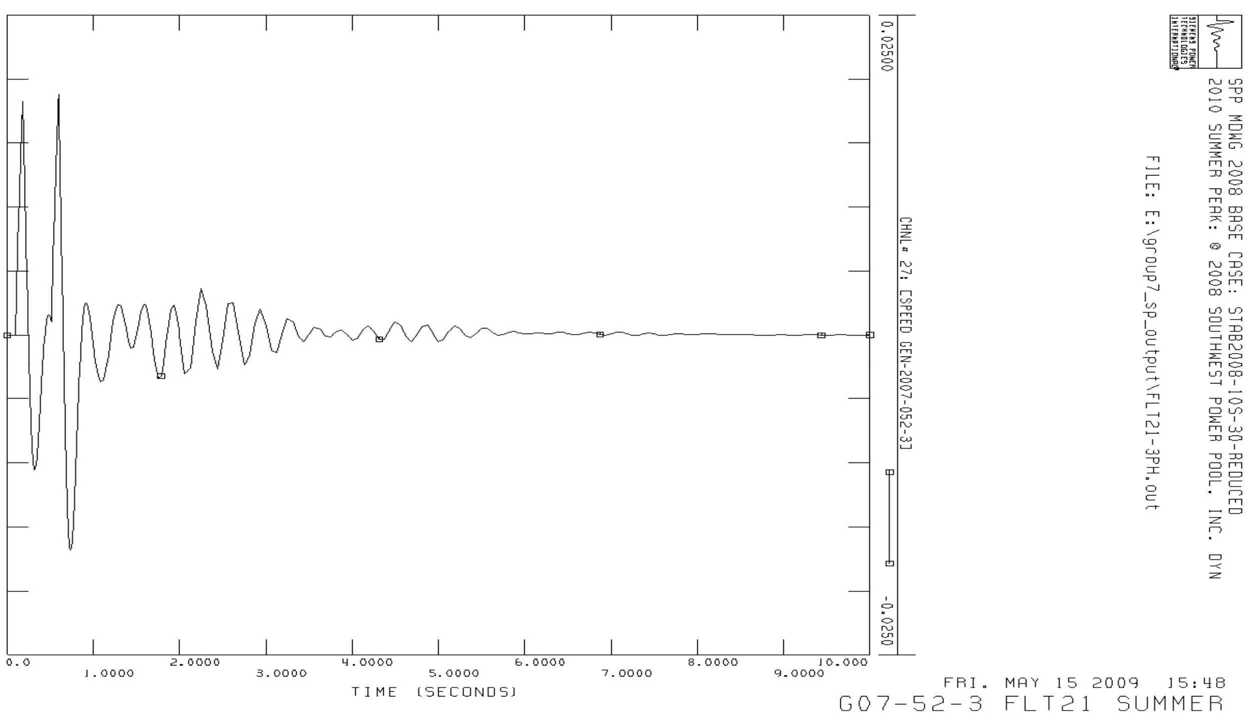

Figure 12: GEN-2007-052-3 Response to FLT21-3Φ, Summer Peak

Similar results were obtained in dynamic analysis of the winter peak case. The worst-case faults for the winter peak case are shown below. Except for GEN-2007-032, the worst-case faults are the same for the winter and summer peak cases for Cluster Group 7.

In addition, electrical power instead of rotor speed was plotted at GEN-2007-049, because the Vestas V90 model does not provide rotor speed. As with the summer case, GEN-2007-049 was considered stable for the worst-case fault (FLT63-3Φ) based on the electrical power output recovering to the pre-fault level.

Table 8: Worst Faults for Dynamic Behavior within Cluster Group 7 (Winter Peak)

Generator	Worst Fault	Worst Fault Description
GEN-2007-032	FLT45-3Φ	Clinton Jct--Elk City 138 kV near Clinton Jct
GEN-2007-043-1	FLT03-3Φ	GEN-2007-043--Anadarko 345 kV near GEN-2007-043
GEN-2007-043-2	FLT03-3Φ	GEN-2007-043--Anadarko 345 kV near GEN-2007-043
GEN-2007-049	FLT63-3Φ	Carter Jct-Lake Creek 69 kV, near Carter Jct
GEN-2007-052-1	FLT23-3Φ	Anadarko-Washita 138 kV near Anadarko
GEN-2007-052-2	FLT23-3Φ	Anadarko-Washita 138 kV near Anadarko
GEN-2007-052-3	FLT23-3Φ	Anadarko-Washita 138 kV near Anadarko

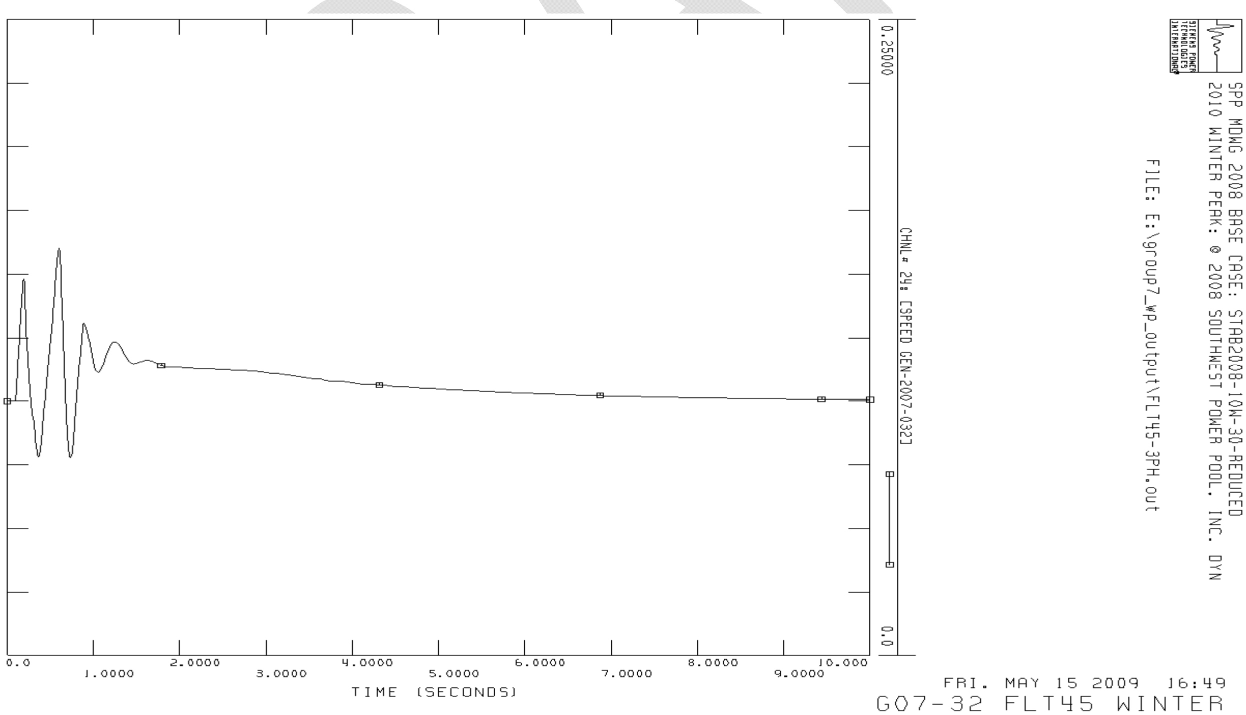

Figure 13: GEN-2007-032 Response to FLT45-3Φ, Winter Peak

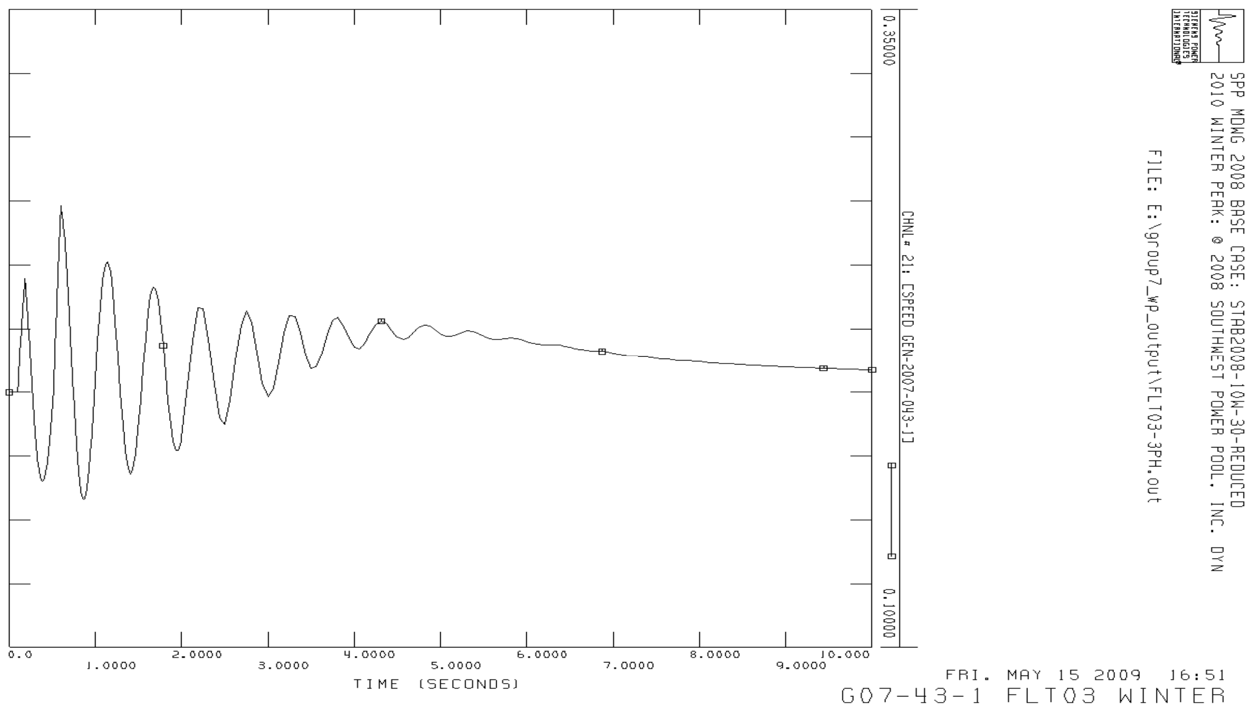

Figure 14: GEN-2007-043-1 Response to FLT03-3Φ, Winter Peak

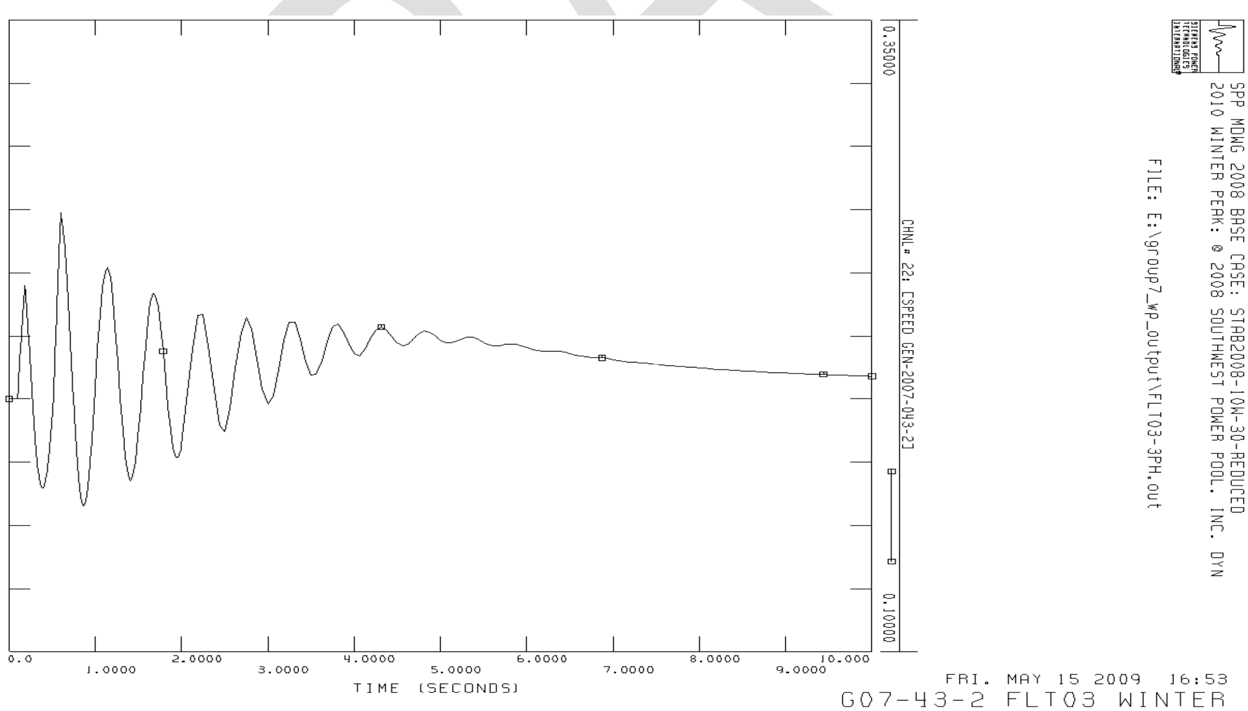

Figure 15: GEN-2007-043-2 Response to FLT03-3Φ, Winter Peak

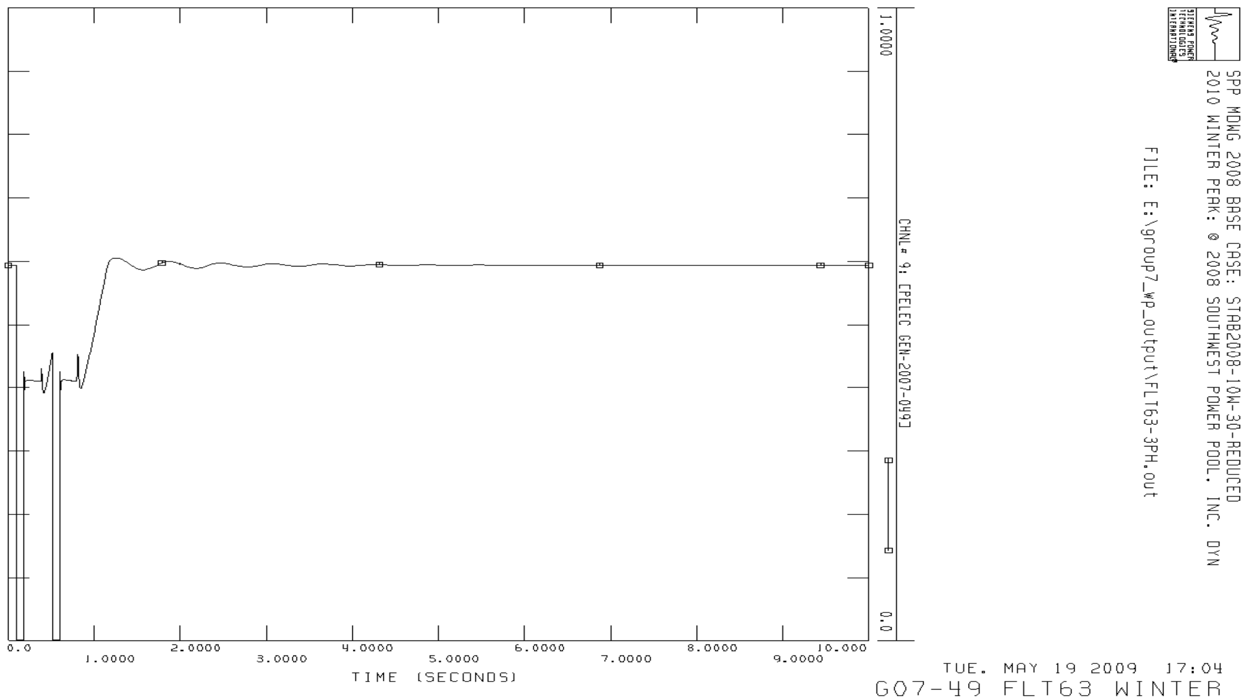

Figure 16: GEN-2007-049 Response to FLT63-3Φ, Winter Peak

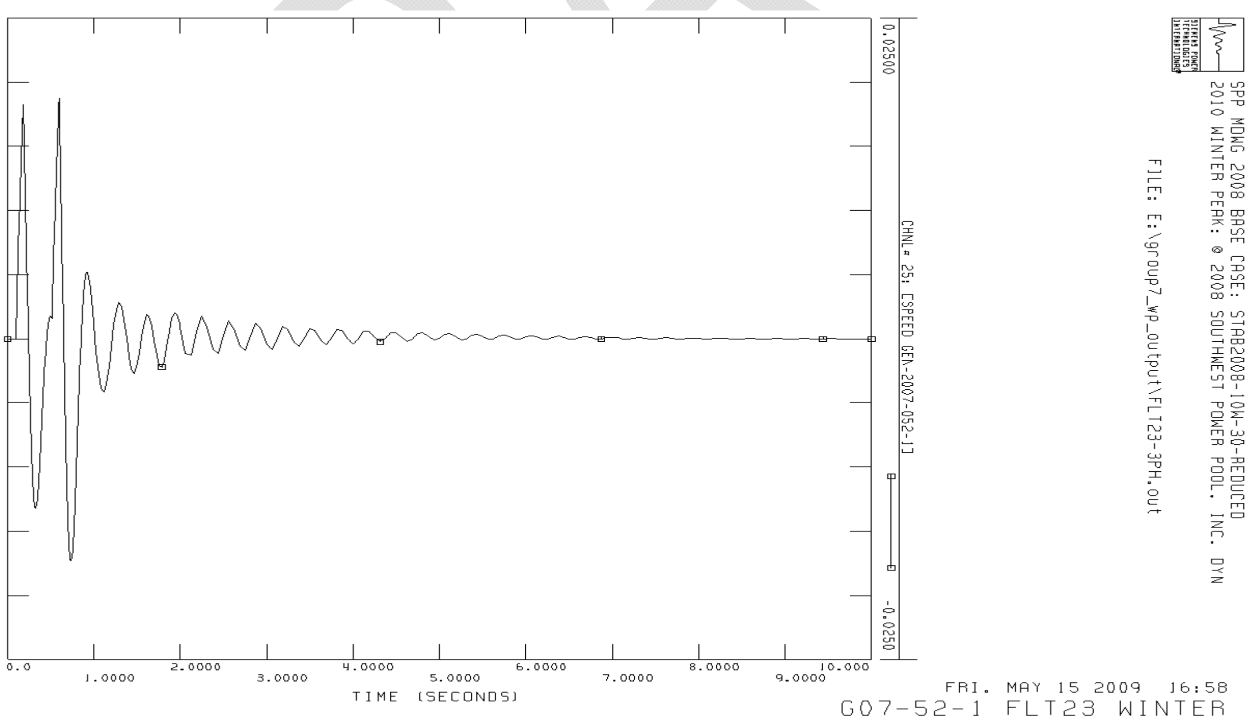

Figure 17: GEN-2007-052-1 Response to FLT23-3Φ, Winter Peak

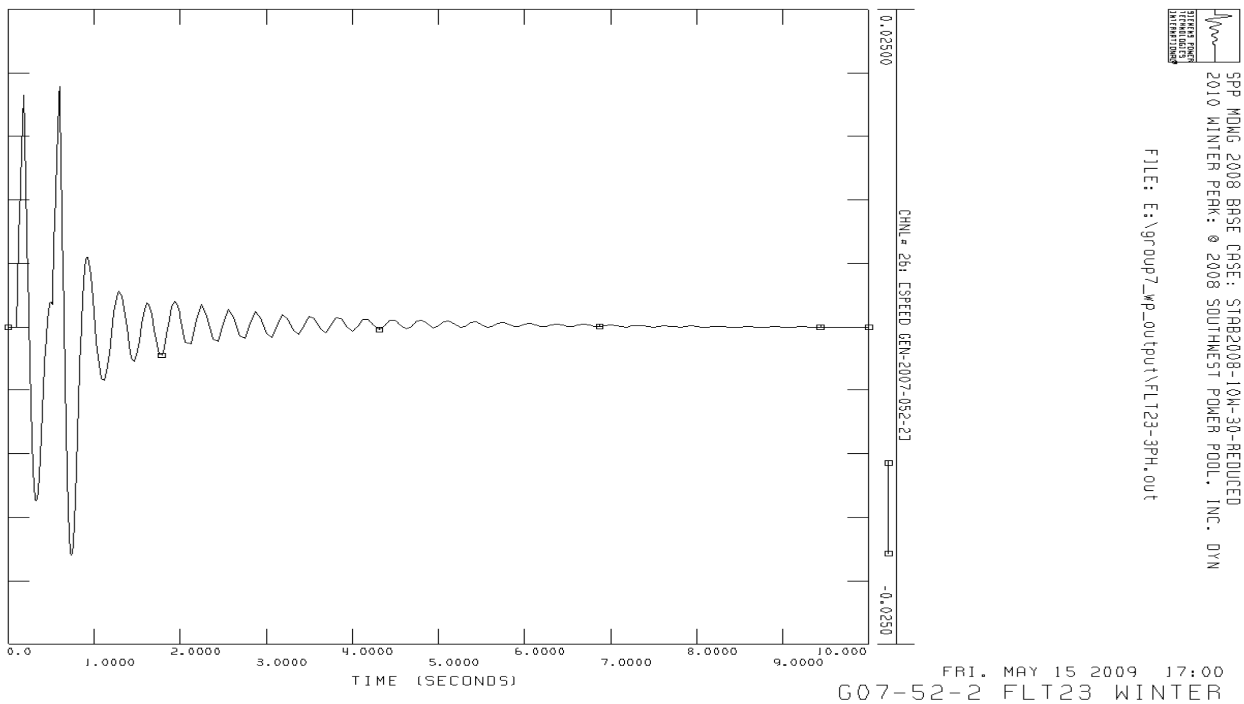

Figure 18: GEN-2007-052-2 Response to FLT23-3Φ, Winter Peak

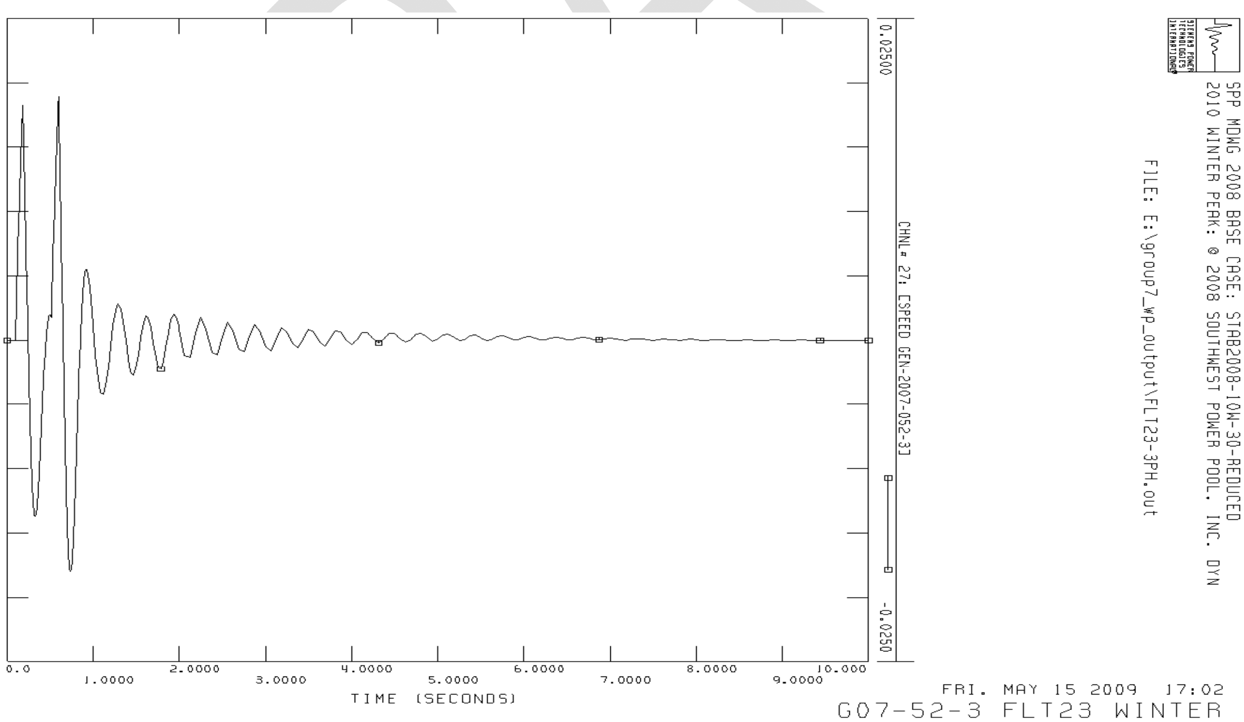

Figure 19: GEN-2007-052-3 Response to FLT23-3Φ, Winter Peak

7.0 CONCLUSIONS

Based on the results of Cluster Group 7 studies, neither the post-fault voltage recovery nor the post-fault rotor speed of all generators studies suffer from instability. If Blue Canyon I is assumed to remain online for faults near the Southwest 138 kV bus, oscillation is observed at Blue Canyon I & II, whether or not Cluster Group 7 generation is added. However, because Blue Canyon I consists of induction machines that interface directly with the grid (i.e. without a power converter), it is much more likely that Blue Canyon I will trip offline for nearby faults.
In addition, all generators appear capable of meeting the interconnection voltage and LVRT requirements.

Appendix A: Required Generation Power Factors at POI, Summer Case

Blue highlighting indicates the contingencies with the most leading (or least lagging) power factor for a given interconnection.
Yellow highlighting indicates the contingencies with the most lagging (or least leading) power factor for a given interconnection.

	2007-032 Clinton Jct 138 kV (V=1.02757)					2007-043 Cimarron-Anadarko 345 kV (V=1.00643)					2007-049 Carter Jct 69 kV (V=1.01952)					2007-052 Anadarko 138 kV (V=1.01370)				
FAULT	P	Q	MVA	PF		P	Q	MVA	PF		P	Q	MVA	PF		P	Q	MVA	PF	
BASE CASE	148.2	-10.7	148.5	**0.997**	**Lead**	290.8	-75.5	300.4	**0.968**	**Lead**	59.6	-5.9	59.9	**0.995**	**Lead**	149.7	-33.0	153.3	**0.977**	**Lead**
'FLT01&02'	148.2	2.2	148.2	**1.000**	**Lag**	290.8	-40.7	293.6	**0.990**	**Lead**	59.6	-5.8	59.9	**0.995**	**Lead**	149.7	6.5	149.9	**0.999**	**Lag**
'FLT03&04'	148.2	-4.2	148.2	**1.000**	**Lead**	290.8	8.1	290.9	**1.000**	**Lag**	59.6	-5.6	59.9	**0.996**	**Lead**	149.7	-12.8	150.3	**0.996**	**Lead**
'FLT05&06'	148.2	-10.5	148.5	**0.997**	**Lead**	290.8	-73.5	299.9	**0.970**	**Lead**	59.6	-5.9	59.9	**0.995**	**Lead**	149.7	-29.3	152.6	**0.981**	**Lead**
'FLT07&08'	148.2	-10.0	148.5	**0.998**	**Lead**	290.8	-34.4	292.8	**0.993**	**Lead**	59.6	-5.8	59.9	**0.995**	**Lead**	149.7	-32.2	153.2	**0.978**	**Lead**
'FLT09&10'	148.2	-10.6	148.5	**0.997**	**Lead**	290.8	-57.7	296.5	**0.981**	**Lead**	59.6	-5.9	59.9	**0.995**	**Lead**	149.7	-32.5	153.2	**0.977**	**Lead**
'FLT11&12'	148.2	-10.5	148.5	**0.998**	**Lead**	290.8	-75.1	300.3	**0.968**	**Lead**	59.6	-5.8	59.9	**0.995**	**Lead**	149.7	-30.1	152.7	**0.980**	**Lead**
'FLT13&14'	148.2	-10.7	148.5	**0.997**	**Lead**	290.8	-31.8	292.5	**0.994**	**Lead**	59.6	-5.9	59.9	**0.995**	**Lead**	149.7	-33.0	153.3	**0.977**	**Lead**
'FLT15&16'	148.2	-7.3	148.3	**0.999**	**Lead**	290.8	-19.1	291.4	**0.998**	**Lead**	59.6	-5.3	59.8	**0.996**	**Lead**	149.7	-29.3	152.6	**0.981**	**Lead**
'FLT17&18'	148.2	-7.4	148.3	**0.999**	**Lead**	290.8	-13.6	291.1	**0.999**	**Lead**	59.6	-5.6	59.9	**0.996**	**Lead**	149.7	-9.1	150.0	**0.998**	**Lead**
'FLT19&20'	148.2	-8.3	148.4	**0.998**	**Lead**	290.8	-54.7	295.9	**0.983**	**Lead**	59.6	-5.1	59.8	**0.996**	**Lead**	149.7	-32.2	153.2	**0.978**	**Lead**
'FLT21&22'	148.2	-5.6	148.3	**0.999**	**Lead**	290.8	-60.0	296.9	**0.979**	**Lead**	59.6	-5.3	59.8	**0.996**	**Lead**	149.7	-7.3	149.9	**0.999**	**Lead**
'FLT23&24'	148.2	-10.5	148.5	**0.997**	**Lead**	290.8	-75.2	300.4	**0.968**	**Lead**	59.6	-5.9	59.9	**0.995**	**Lead**	149.7	-28.0	152.3	**0.983**	**Lead**
'FLT25&26'	148.2	-10.6	148.5	**0.997**	**Lead**	290.8	-75.1	300.3	**0.968**	**Lead**	59.6	-5.9	59.9	**0.995**	**Lead**	149.7	-10.3	150.1	**0.998**	**Lead**
'FLT27&28'	148.2	-9.4	148.5	**0.998**	**Lead**	290.8	-72.4	299.7	**0.970**	**Lead**	59.6	-5.6	59.9	**0.996**	**Lead**	149.7	-19.3	151.0	**0.992**	**Lead**
'FLT29&30'	148.2	-9.1	148.4	**0.998**	**Lead**	290.8	-71.2	299.4	**0.971**	**Lead**	59.6	-5.5	59.9	**0.996**	**Lead**	149.7	-19.2	150.9	**0.992**	**Lead**
'FLT31&32'	148.2	-10.6	148.5	**0.997**	**Lead**	290.8	-75.2	300.4	**0.968**	**Lead**	59.6	-5.0	59.8	**0.996**	**Lead**	149.7	-32.5	153.2	**0.977**	**Lead**
'FLT33&34'	148.2	-3.1	148.2	**1.000**	**Lead**	290.8	-74.9	300.3	**0.968**	**Lead**	59.6	-5.4	59.9	**0.996**	**Lead**	149.7	10.1	150.1	**0.998**	**Lag**
'FLT35&36'	148.2	-9.3	148.4	**0.998**	**Lead**	290.8	-71.2	299.4	**0.971**	**Lead**	59.6	-5.7	59.9	**0.995**	**Lead**	149.7	-8.8	150.0	**0.998**	**Lead**
'FLT37&38'	148.2	-8.5	148.4	**0.998**	**Lead**	290.8	-74.3	300.1	**0.969**	**Lead**	59.6	-5.3	59.8	**0.996**	**Lead**	149.7	-17.0	150.7	**0.994**	**Lead**
'FLT39&40'	148.2	-6.5	148.3	**0.999**	**Lead**	290.8	-75.5	300.4	**0.968**	**Lead**	59.6	-5.8	59.9	**0.995**	**Lead**	149.7	-33.0	153.3	**0.977**	**Lead**
'FLT41&42'	148.2	3.9	148.2	**1.000**	**Lag**	290.8	-75.1	300.3	**0.968**	**Lead**	59.6	-5.2	59.8	**0.996**	**Lead**	149.7	-12.5	150.2	**0.997**	**Lead**
'FLT43&44'	148.2	-3.2	148.2	**1.000**	**Lead**	290.8	-74.0	300.1	**0.969**	**Lead**	59.6	-5.8	59.9	**0.995**	**Lead**	149.7	-31.2	152.9	**0.979**	**Lead**
'FLT45&46'	148.2	-4.7	148.2	**1.000**	**Lead**	290.8	-75.3	300.4	**0.968**	**Lead**	59.6	-4.7	59.8	**0.997**	**Lead**	149.7	-30.9	152.9	**0.979**	**Lead**
'FLT47&48'	148.2	-8.8	148.4	**0.998**	**Lead**	290.8	-65.4	298.1	**0.976**	**Lead**	59.6	-4.3	59.8	**0.997**	**Lead**	149.7	-22.5	151.4	**0.989**	**Lead**
'FLT49&50'	148.2	-5.5	148.3	**0.999**	**Lead**	290.8	-75.6	300.4	**0.968**	**Lead**	59.6	-3.8	59.7	**0.998**	**Lead**	149.7	-33.0	153.3	**0.977**	**Lead**
'FLT53&54'	148.2	-4.7	148.2	**1.000**	**Lead**	290.8	-75.3	300.4	**0.968**	**Lead**	59.6	-4.7	59.8	**0.997**	**Lead**	149.7	-30.9	152.9	**0.979**	**Lead**
'FLT55&56'	148.2	-9.0	148.4	**0.998**	**Lead**	290.8	-74.9	300.3	**0.968**	**Lead**	59.6	-5.0	59.8	**0.996**	**Lead**	149.7	-31.4	153.0	**0.979**	**Lead**

FAULT	2007-032 Clinton Jct 138 kV (V=1.02757)					2007-043 Cimarron-Anadarko 345 kV (V=1.00643)					2007-049 Carter Jct 69 kV (V=1.01952)					2007-052 Anadarko 138 kV (V=1.01370)				
	P	Q	MVA	PF		P	Q	MVA	PF		P	Q	MVA	PF		P	Q	MVA	PF	
'FLT57&58'	148.2	-12.4	148.7	**0.997**	**Lead**	290.8	-68.8	298.8	**0.973**	**Lead**	59.6	-4.3	59.8	**0.997**	**Lead**	149.7	-36.5	154.1	**0.972**	**Lead**
'FLT59&60'	148.2	-12.2	148.7	**0.997**	**Lead**	290.8	-75.6	300.5	**0.968**	**Lead**	59.6	-0.3	59.6	**1.000**	**Lead**	149.7	-33.5	153.4	**0.976**	**Lead**
'FLT61&62'	148.2	-10.7	148.5	**0.997**	**Lead**	290.8	-75.3	300.4	**0.968**	**Lead**	59.6	-3.5	59.7	**0.998**	**Lead**	149.7	-31.4	153.0	**0.979**	**Lead**
'FLT63&64'	148.2	-8.2	148.4	**0.998**	**Lead**	290.8	-75.0	300.3	**0.968**	**Lead**	59.6	-3.2	59.7	**0.999**	**Lead**	149.7	-31.1	152.9	**0.979**	**Lead**
'FLT65&66'	148.2	-10.7	148.5	**0.997**	**Lead**	290.8	-75.6	300.4	**0.968**	**Lead**	59.6	-4.6	59.8	**0.997**	**Lead**	149.7	-32.8	153.3	**0.977**	**Lead**
'FLT67&68'	148.2	-9.1	148.4	**0.998**	**Lead**	290.8	-75.3	300.4	**0.968**	**Lead**	59.6	-0.9	59.6	**1.000**	**Lead**	149.7	-29.4	152.6	**0.981**	**Lead**

Appendix B: Required Generation Power Factors at POI, Winter Case

Blue highlighting indicates the contingencies with the most leading (or least lagging) power factor for a given interconnection.
Yellow highlighting indicates the contingencies with the most lagging (or least leading) power factor for a given interconnection.

	2007-032					2007-043					2007-049					2007-052				
	Clinton Jct 138 kV (V=1.02390)					Cimarron-Anadarko 345 kV (V=1.00061)					Carter Jct 69 kV (V=1.03166)					Anadarko 138 (V=1.01818)				
FAULT	P	Q	MVA	PF		P	Q	MVA	PF		P	Q	MVA	PF		P	Q	MVA	PF	
BASE CASE	148.2	-7.8	148.4	**0.999**	**Lead**	290.8	-67.8	298.6	**0.974**	**Lead**	59.0	-6.4	59.4	**0.994**	**Lead**	149.7	-40.8	155.2	**0.965**	**Lead**
'FLT01&02'	148.2	7.3	148.3	**0.999**	**Lag**	290.8	-38.6	293.4	**0.991**	**Lead**	59.0	-6.2	59.4	**0.994**	**Lead**	149.7	3.0	149.8	**1.000**	**Lag**
'FLT03&04'	148.2	0.1	148.2	**1.000**	**Lag**	290.8	-3.0	290.8	**1.000**	**Lead**	59.0	-6.2	59.3	**0.995**	**Lead**	149.7	-17.3	150.7	**0.993**	**Lead**
'FLT05&06'	148.2	-7.3	148.3	**0.999**	**Lead**	290.8	-48.6	294.9	**0.986**	**Lead**	59.0	-6.3	59.4	**0.994**	**Lead**	149.7	-35.2	153.8	**0.974**	**Lead**
'FLT07&08'	148.2	-7.6	148.3	**0.999**	**Lead**	290.8	-41.0	293.7	**0.990**	**Lead**	59.0	-6.4	59.4	**0.994**	**Lead**	149.7	-40.7	155.1	**0.965**	**Lead**
'FLT09&10'	148.2	-7.3	148.3	**0.999**	**Lead**	290.8	-33.0	292.7	**0.994**	**Lead**	59.0	-6.4	59.4	**0.994**	**Lead**	149.7	-39.8	154.9	**0.967**	**Lead**
'FLT11&12'	148.2	-7.3	148.3	**0.999**	**Lead**	290.8	-67.6	298.6	**0.974**	**Lead**	59.0	-6.3	59.4	**0.994**	**Lead**	149.7	-37.4	154.3	**0.970**	**Lead**
'FLT13&14'	148.2	-7.4	148.3	**0.999**	**Lead**	290.8	-27.7	292.1	**0.996**	**Lead**	59.0	-6.3	59.4	**0.994**	**Lead**	149.7	-39.4	154.8	**0.967**	**Lead**
'FLT15&16'	148.2	-2.5	148.2	**1.000**	**Lead**	290.8	-10.2	291.0	**0.999**	**Lead**	59.0	-5.4	59.3	**0.996**	**Lead**	149.7	-36.3	154.1	**0.972**	**Lead**
'FLT17&18'	148.2	-3.9	148.2	**1.000**	**Lead**	290.8	11.7	291.0	**0.999**	**Lag**	59.0	-6.7	59.4	**0.994**	**Lead**	149.7	-16.2	150.6	**0.994**	**Lead**
'FLT19&20'	148.2	-2.1	148.2	**1.000**	**Lead**	290.8	-44.8	294.2	**0.988**	**Lead**	59.0	-4.7	59.2	**0.997**	**Lead**	149.7	-40.2	155.0	**0.966**	**Lead**
'FLT21&22'	148.2	-4.8	148.2	**0.999**	**Lead**	290.8	-50.8	295.2	**0.985**	**Lead**	59.0	-6.3	59.4	**0.994**	**Lead**	149.7	-27.6	152.2	**0.983**	**Lead**
'FLT23&24'	148.2	-7.5	148.3	**0.999**	**Lead**	290.8	-67.3	298.5	**0.974**	**Lead**	59.0	-6.4	59.4	**0.994**	**Lead**	149.7	-39.3	154.8	**0.967**	**Lead**
'FLT25&26'	148.2	-7.7	148.4	**0.999**	**Lead**	290.8	-67.6	298.6	**0.974**	**Lead**	59.0	-6.4	59.4	**0.994**	**Lead**	149.7	-31.6	153.0	**0.978**	**Lead**
'FLT27&28'	148.2	-7.1	148.3	**0.999**	**Lead**	290.8	-64.8	298.0	**0.976**	**Lead**	59.0	-6.3	59.4	**0.994**	**Lead**	149.7	-35.3	153.8	**0.973**	**Lead**
'FLT29&30'	148.2	-7.0	148.3	**0.999**	**Lead**	290.8	-63.6	297.7	**0.977**	**Lead**	59.0	-6.2	59.3	**0.995**	**Lead**	149.7	-40.6	155.1	**0.965**	**Lead**
'FLT31&32'	148.2	-7.0	148.3	**0.999**	**Lead**	290.8	-66.8	298.4	**0.975**	**Lead**	59.0	-5.4	59.3	**0.996**	**Lead**	149.7	-33.6	153.4	**0.976**	**Lead**
'FLT33&34'	148.2	-3.0	148.2	**1.000**	**Lead**	290.8	-67.3	298.5	**0.974**	**Lead**	59.0	-5.9	59.3	**0.995**	**Lead**	149.7	-5.1	149.8	**0.999**	**Lead**
'FLT35&36'	148.2	-7.1	148.3	**0.999**	**Lead**	290.8	-63.9	297.7	**0.977**	**Lead**	59.0	-6.4	59.4	**0.994**	**Lead**	149.7	-26.1	152.0	**0.985**	**Lead**
'FLT37&38'	148.2	-7.3	148.3	**0.999**	**Lead**	290.8	-67.4	298.5	**0.974**	**Lead**	59.0	-6.2	59.4	**0.994**	**Lead**	149.7	-34.7	153.7	**0.974**	**Lead**
'FLT39&40'	148.2	-3.4	148.2	**1.000**	**Lead**	290.8	-65.9	298.2	**0.975**	**Lead**	59.0	-5.5	59.3	**0.996**	**Lead**	149.7	-36.6	154.1	**0.971**	**Lead**
'FLT41&42'	148.2	-0.7	148.2	**1.000**	**Lead**	290.8	-65.9	298.2	**0.975**	**Lead**	59.0	-5.8	59.3	**0.995**	**Lead**	149.7	-27.8	152.3	**0.983**	**Lead**
'FLT43&44'	148.2	0.4	148.2	**1.000**	**Lag**	290.8	-65.7	298.1	**0.975**	**Lead**	59.0	-6.3	59.4	**0.994**	**Lead**	149.7	-39.2	154.8	**0.967**	**Lead**
'FLT45&46'	148.2	5.1	148.2	**0.999**	**Lag**	290.8	-67.0	298.4	**0.974**	**Lead**	59.0	-5.8	59.3	**0.995**	**Lead**	149.7	-39.6	154.9	**0.967**	**Lead**
'FLT47&48'	148.2	-6.7	148.3	**0.999**	**Lead**	290.8	-57.5	296.4	**0.981**	**Lead**	59.0	-4.8	59.2	**0.997**	**Lead**	149.7	-31.2	152.9	**0.979**	**Lead**
'FLT49&50'	148.2	-3.3	148.2	**1.000**	**Lead**	290.8	-67.8	298.6	**0.974**	**Lead**	59.0	-4.5	59.2	**0.997**	**Lead**	149.7	-40.8	155.2	**0.965**	**Lead**
'FLT53&54'	148.2	5.1	148.2	**0.999**	**Lag**	290.8	-67.0	298.4	**0.974**	**Lead**	59.0	-5.8	59.3	**0.995**	**Lead**	149.7	-39.6	154.9	**0.967**	**Lead**

'FLT55&56'	148.2	-6.0	148.3	**0.999**	**Lead**	290.8	-65.8	298.2	**0.975**	**Lead**	59.0	-5.8	59.3	**0.995**	**Lead**	149.7	-39.5	154.8	**0.967**	**Lead**
'FLT57&58'	148.2	-9.5	148.5	**0.998**	**Lead**	290.8	-61.2	297.2	**0.979**	**Lead**	59.0	-4.8	59.2	**0.997**	**Lead**	149.7	-44.5	156.2	**0.958**	**Lead**
'FLT59&60'	148.2	-9.3	148.4	**0.998**	**Lead**	290.8	-67.8	298.6	**0.974**	**Lead**	59.0	-0.8	59.0	**1.000**	**Lead**	149.7	-41.4	155.3	**0.964**	**Lead**
'FLT61&62'	148.2	-7.3	148.3	**0.999**	**Lead**	290.8	-67.4	298.5	**0.974**	**Lead**	59.0	-5.9	59.3	**0.995**	**Lead**	149.7	-38.4	154.6	**0.969**	**Lead**
'FLT63&64'	148.2	-4.4	148.2	**1.000**	**Lead**	290.8	-67.0	298.4	**0.974**	**Lead**	59.0	-5.8	59.3	**0.995**	**Lead**	149.7	-40.3	155.1	**0.966**	**Lead**
'FLT65&66'	148.2	-7.4	148.3	**0.999**	**Lead**	290.8	-67.7	298.6	**0.974**	**Lead**	59.0	-4.3	59.2	**0.997**	**Lead**	149.7	-39.7	154.9	**0.967**	**Lead**
'FLT67&68'	148.2	-6.3	148.3	**0.999**	**Lead**	290.8	-67.6	298.6	**0.974**	**Lead**	59.0	-3.4	59.1	**0.998**	**Lead**	149.7	-38.8	154.7	**0.968**	**Lead**

Appendix C: Post-Fault Voltage Recovery, Summer Case

Yellow highlighting indicates the highest post-fault voltage for a given interconnection.
Blue highlighting indicates the lowest post-fault voltage for a given interconnection.

FAULT	2007-032 Clinton Jct 138 kV	2007-043 Cimarron - Anadarko 345 kV	2007-049 Carter Jct 69 kV	2007-052 Anadarko 138 kV
Base Case	1.0276	1.0064	1.0196	1.0137
FLT01	1.0187	1.0135	1.0157	1.0084
FLT02	1.0187	1.0135	1.0157	1.0084
FLT03	1.0241	0.99471	1.0199	1.0121
FLT04	1.0241	0.99472	1.0199	1.0121
FLT05	1.0275	1.0059	1.0194	1.0133
FLT06	1.0275	1.0059	1.0194	1.0133
FLT07	1.027	1.0018	1.0191	1.0135
FLT08	1.027	1.0018	1.0191	1.0135
FLT09	1.0273	1.0041	1.0192	1.0136
FLT10	1.0273	1.0041	1.0192	1.0136
FLT11	1.0275	1.0066	1.0194	1.0133
FLT12	1.0275	1.0066	1.0194	1.0133
FLT13	1.0275	1.001	1.0197	1.0138
FLT14	1.0275	1.001	1.0197	1.0138
FLT15	1.024	0.99914	1.0156	1.012
FLT16	1.024	0.99914	1.0156	1.012
FLT17	1.0247	0.99892	1.0188	1.0107
FLT18	1.0247	0.99893	1.0188	1.0107
FLT19	1.0248	1.0035	1.0157	1.0129
FLT20	1.0249	1.0035	1.0157	1.0129
FLT21	1.0237	1.0039	1.0162	1.0147
FLT22	1.0237	1.0039	1.0162	1.0147
FLT23	1.0276	1.0064	1.0195	1.0133
FLT24	1.0276	1.0064	1.0195	1.0133
FLT25	1.0279	1.0064	1.0197	1.0116
FLT26	1.0279	1.0064	1.0197	1.0116
FLT27	1.0259	1.0058	1.0178	1.0137
FLT28	1.0259	1.0058	1.0178	1.0137
FLT29	1.0257	1.0053	1.0171	1.0136
FLT30	1.0257	1.0053	1.0171	1.0136
FLT31	1.0274	1.0064	1.0172	1.0137
FLT32	1.0274	1.0064	1.0172	1.0137
FLT33	1.0195	1.0065	1.0147	1.009
FLT34	1.0173	1.0063	1.0134	1.0068
FLT35	1.0267	1.0057	1.0186	1.012
FLT36	1.0267	1.0057	1.0186	1.012

FAULT	2007-032 Clinton Jct 138 kV	2007-043 Cimarron - Anadarko 345 kV	2007-049 Carter Jct 69 kV	2007-052 Anadarko 138 kV
FLT37	1.0257	1.0062	1.0168	1.0121
FLT38	1.0257	1.0062	1.0168	1.0121
FLT39	1.0319	1.0065	1.0204	1.0136
FLT40	1.0319	1.0065	1.0204	1.0136
FLT41	0.95347	1.0056	1.0146	1.0075
FLT42	0.95347	1.0056	1.0146	1.0075
FLT43	1.0364	1.0063	1.0222	1.0138
FLT44	1.0364	1.0063	1.0222	1.0138
FLT45	1.023	1.0064	1.0157	1.0132
FLT46	1.023	1.0064	1.0157	1.0132
FLT47	1.02	1.0048	1.0115	1.0115
FLT48	1.02	1.0048	1.0115	1.0115
FLT49	1.0243	1.0064	1.0143	1.0135
FLT50	1.0243	1.0064	1.0143	1.0135
FLT53	1.023	1.0064	1.0157	1.0132
FLT54	1.023	1.0064	1.0157	1.0132
FLT55	1.0303	1.0063	1.0238	1.0136
FLT56	1.0303	1.0063	1.0238	1.0136
FLT57	1.0269	1.006	1.016	1.0141
FLT58	1.0269	1.006	1.0161	1.0141
FLT59	1.0294	1.0063	0.94253	1.0134
FLT60	1.0294	1.0063	0.94253	1.0134
FLT61	1.027	1.0064	0.99394	1.0133
FLT62	1.027	1.0064	0.99394	1.0133
FLT63	1.0267	1.0063	1.0292	1.0134
FLT64	1.0267	1.0063	1.0292	1.0134
FLT65	1.0273	1.0064	1.0156	1.0138
FLT66	1.0273	1.0064	1.0156	1.0138
FLT67	1.0276	1.0063	1.0335	1.0133
FLT68	1.0276	1.0063	1.0335	1.0133

Appendix D: Post-Fault Voltage Recovery, Winter Case

Yellow highlighting indicates the highest post-fault voltage for a given interconnection.
Blue highlighting indicates the lowest post-fault voltage for a given interconnection.

FAULT	2007-032 Clinton Jct 138 kV	2007-043 Cimarron - Anadarko 345 kV	2007-049 Carter Jct 69 kV	2007-052 Anadarko 138 kV
Base Case	1.024	1.0006	1.0317	1.0183
FLT01	1.012	1.0047	1.0245	1.0096
FLT02	1.012	1.0047	1.0245	1.0096
FLT03	1.0189	0.99091	1.0305	1.0152
FLT04	1.0189	0.99091	1.0305	1.0152
FLT05	1.0231	0.99807	1.0308	1.0172
FLT06	1.0231	0.99806	1.0308	1.0172
FLT07	1.0235	0.99722	1.0314	1.018
FLT08	1.0235	0.99722	1.0314	1.018
FLT09	1.0232	0.99632	1.0311	1.0177
FLT10	1.0232	0.9963	1.0311	1.0177
FLT11	1.0232	0.99984	1.0309	1.0174
FLT12	1.0232	0.99981	1.0309	1.0174
FLT13	1.0237	0.99534	1.0319	1.0182
FLT14	1.0237	0.99535	1.0319	1.0182
FLT15	1.018	0.9924	1.025	1.0151
FLT16	1.018	0.99243	1.025	1.0151
FLT17	1.0199	0.99065	1.0298	1.014
FLT18	1.0199	0.99068	1.0298	1.014
FLT19	1.0181	0.99754	1.0239	1.0167
FLT20	1.018	0.99747	1.0238	1.0167
FLT21	1.0218	0.99807	1.0303	1.0184
FLT22	1.0218	0.99807	1.0303	1.0184
FLT23	1.0237	1.0005	1.0315	1.0182
FLT24	1.0237	1.0005	1.0315	1.0182
FLT25	1.0242	1.0006	1.0319	1.0175
FLT26	1.0242	1.0006	1.0319	1.0175
FLT27	1.0229	0.99999	1.0307	1.0176
FLT28	1.0229	1	1.0307	1.0177
FLT29	1.0226	0.99953	1.0299	1.0169
FLT30	1.0226	0.99953	1.0299	1.0169
FLT31	1.0229	1.0003	1.0286	1.0172
FLT32	1.0229	1.0004	1.0286	1.0172
FLT33	1.0176	1.0006	1.0273	1.0137
FLT34	1.0139	1.0001	1.0248	1.0095
FLT35	1.0238	1	1.0315	1.0174
FLT36	1.0238	1	1.0315	1.0174
FLT37	1.0239	1.0004	1.0312	1.018

FAULT	2007-032 Clinton Jct 138 kV	2007-043 Cimarron - Anadarko 345 kV	2007-049 Carter Jct 69 kV	2007-052 Anadarko 138 kV
FLT38	1.0239	1.0004	1.0312	1.018
FLT39	1.0208	1.0005	1.0286	1.0189
FLT40	1.0208	1.0005	1.0286	1.0189
FLT41	0.98471	1.0001	1.0277	1.0131
FLT42	0.98472	1.0001	1.0277	1.0131
FLT43	1.0338	1.0006	1.0348	1.0184
FLT44	1.0338	1.0006	1.0348	1.0184
FLT45	1.0117	1.0005	1.0334	1.0176
FLT46	1.0117	1.0005	1.0334	1.0176
FLT47	1.0155	0.99875	1.0228	1.0152
FLT48	1.0155	0.99876	1.0228	1.0152
FLT49	1.0209	1.0006	1.027	1.018
FLT50	1.0209	1.0006	1.027	1.018
FLT53	1.0117	1.0005	1.0334	1.0176
FLT54	1.0117	1.0005	1.0334	1.0176
FLT55	1.0241	1.0004	1.0342	1.0182
FLT56	1.0241	1.0004	1.0342	1.0182
FLT57	1.0233	0.99995	1.0265	1.0188
FLT58	1.0233	0.99995	1.0265	1.0188
FLT59	1.025	1.0005	0.98433	1.018
FLT60	1.025	1.0005	0.98433	1.018
FLT61	1.0232	1.0006	1.0364	1.0179
FLT62	1.0232	1.0006	1.0364	1.0179
FLT63	1.0213	1.0004	1.0277	1.018
FLT64	1.0213	1.0004	1.0277	1.018
FLT65	1.0232	1.0006	1.0256	1.0184
FLT66	1.0232	1.0006	1.0256	1.0184
FLT67	1.0236	1.0005	1.0399	1.018
FLT68	1.0236	1.0005	1.0399	1.018

Q: Stability Study for Group 8

Pterra Consulting

Technical Report R110-09

Impact Study for Generation Interconnection Request GEN-2007-025

Submitted to

Southwest Power Pool

May 2009

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Contents

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Executive Summary

This report presents the impact study comprising of power factor and stability simulation of proposed interconnection GEN-2007-025 (the "Project"). The Project has a nominal 300 MW max rating studied using Clipper 2.5 MW wind turbine generators ("WTGs"). The Point of Interconnection ("POI") is a new 345 kV substation on the existing Comanche-Wichita 345 kV line.

The analysis was conducted through the Southwest Power Pool ("SPP") Tariff. Power factor analysis and transient stability simulations were conducted with the Project in service at full output of 300 MW.

Two base cases for 2010 summer and winter conditions, each comprising of a power flow and corresponding dynamics database, were provided by SPP. In order to integrate the proposed 300 MW wind farm into the SPP system, the existing generation in the SPP footprint was re-dispatched as specified by SPP.

The results of the Power Factor analysis showed that with the MVAR capability of the Clipper WTG and without reactive compensation, the wind farm will not be able to keep the voltage schedule at the POI consistent with the voltage schedule in the provided power flow cases for summer and winter. Additional VAR compensating devices need to be installed in order to control he power factor at the POI to be within ±-0.95 range.

Sixty eight (68) disturbances were considered for the transient stability simulations which included 3-phase faults, as well as, 1-phase to ground faults, at the locations defined by SPP. The Clipper WTGs were modeled with voltage and frequency ride through protection set to manufacturer default settings. The results of the simulations showed no angular or voltage instability problems for the 68 disturbances. The study finds that the interconnection of the proposed 300 MW Project does not impact stability performance of the SPP system for the contingencies tested on the supplied base cases.

1.1. Project Overview

This report presents the impact study comprising of power factor and stability simulation of proposed interconnection GEN-2007-025 (the "Project"). The Project has a nominal 300 MW max rating studied using Clipper 2.5 MW wind turbine generators ("WTGs"). The Project's Point of Interconnection ("POI") is at a new 345 kV Substation on the existing Comanche-Wichita 345 kV line. Figure 1-1 shows a conceptual interconnection diagram of the Project to the 345 kV transmission network.

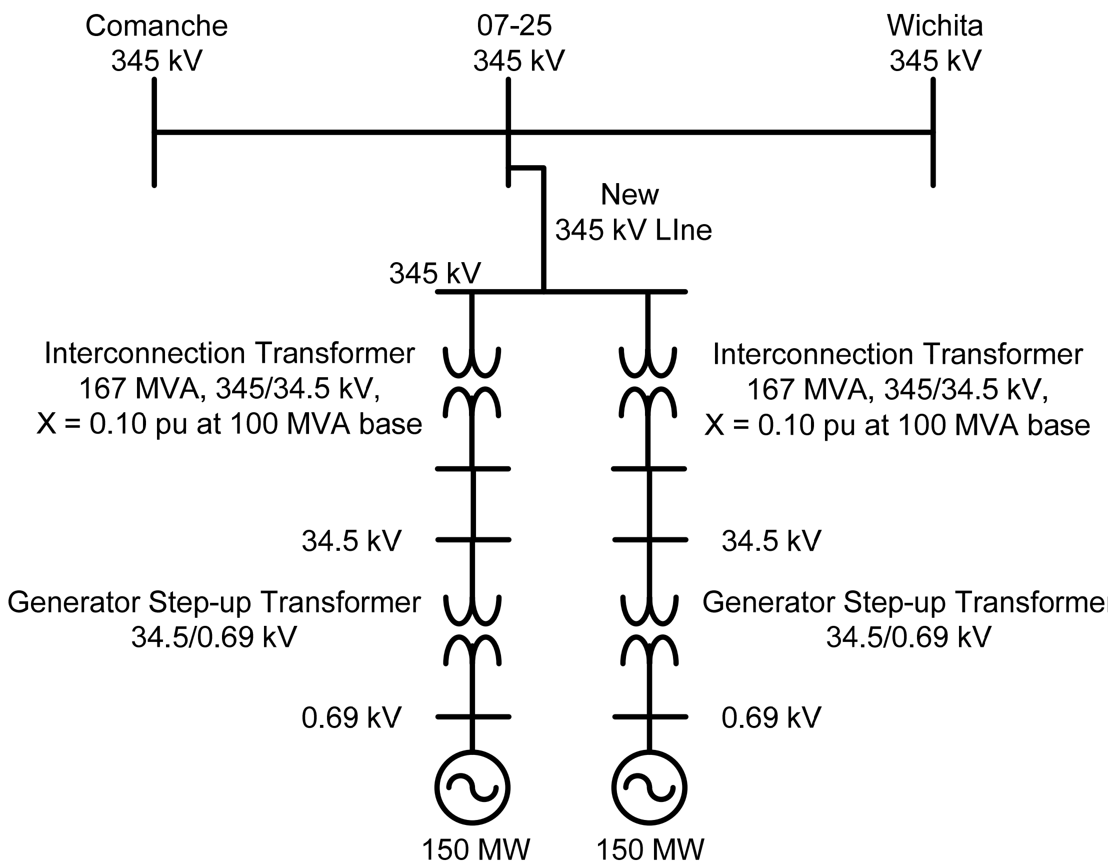


Figure 1-1 Interconnection Plan for the Project to SPP's 345 kV System

In order to integrate the proposed 300 MW wind farm in SPP system as an Energy Resource, existing generation in the SPP footprint was redispatched to maintain area interchange totals.

To simplify the model of the wind farm while capturing the effect of the different impedances of cables (due to change of the conductor size and length), the wind turbines connected to the same 34.5 kV feeder end points were aggregated into one equivalent unit. An equivalent impedance of that feeder was represented by taking the equivalent series impedances of the different feeders connecting the wind turbines. SPP modeled the proposed 300 MW wind farm in the provided power flow cases with 2 equivalent units, each generating 150 MW, as shown in Figure 1-1.

1.2. Objectives

The objectives of the study are to conduct power factor analysis and to determine the impact on system stability of interconnecting a proposed 300 MW wind farm to SPP’s 345 kV transmission system.

Section 2. Power Factor Analysis

2.1. Methodology

Power factor analysis was conducted for the Project using a methodology which is summarized as follows:

1. Model a VAR generator at the Project's 345 kV bus. 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).

2. Steady state contingency analysis is conducted to determine the power factor necessary at the POI for each contingency.

3. According to the contingency analysis results, determine whether capacitors are required for the Project or not.

4. If the required power factor at the POI is beyond the capability of the studied wind turbines to meet (at the POI) capacitor banks are considered. The preference is to locate the capacitance banks is on the 34.5 kV Customer side. Factors to sizing capacitor banks include:

   4.1. The ability of the wind farm to meet FERC Order 661A (low voltage ride through) with and without capacitor banks.

   4.2. The ability of the wind farm to meet FERC Order 661A (wind farm recovery to pre-fault voltage).

   4.3. If wind farms trips on high voltage, power factor lower than unity may be required.

2.2. Analysis

A VAR generator was modeled in the provided power flow cases for summer and winter at the POI. The VAR generator was set to hold a voltage schedule at the POI consistent with the voltage schedule in the provided power flow cases for summer and winter. These values are 1.028 pu and 1.03 pu, for summer and winter power flow cases respectively.

Contingency analysis was run for all the contingencies listed in the fault definition table (Table 3-4). A summary of the contingency analysis results, according to Table 2-1, for both summer and winter power flow cases is as follows:

1. The loss of the 345 kV line from Wichita to the POI showed that the VAR generator is absorbing 98 MVAR and 82.6 MVAR in summer and winter power flow cases, respectively.

2. The loss of any other 345 kV line in the contingency list showed that the VAR generator is delivering MVAR to the system to hold a voltage schedule at the POI

consistent with the voltage schedule in the provided power flow cases for summer and winter. The maximum MVAR output is associated with the loss of the 345 kV line from the POI to Comanche. The VAR generator is delivering 96.6 MVAR and 74.2 MVAR in both summer and winter power flow cases, respectively.

3. With the MVAR capability of the Clipper WTG and without reactive compensation, the wind farm will not be able to keep the voltage schedule at the POI consistent with the voltage schedule in the provided power flow cases for summer and winter.

Table 2-1 VAR Generator Output in Summer and winter Peak Power Flow Cases

SEASON	CONTINGENCY DESCRIPTION	PF @POI	PF	MW @POI	MVAR @POI
10SP	Base Case	0.992	Lead	296.3	37.5
	532781 07-25 345 532796 WICHITA7 345 1	0.950	Lead	296.3	98.0
	532781 07-25 345 531487 COMANCHE 345 1	0.951	Lag	296.3	-96.6
	531469 SPERVIL7 345 539695 SPEARVL6 230 1	0.983	Lead	296.3	55.5
	531449 HOLCOMB7 345 531448 HOLCOMB3 115 1	0.988	Lead	296.3	45.7
	531487 COMANCHE 345 515375 WOODWRD7 345 1	0.994	Lag	296.3	-31.4
	532796 WICHITA7 345 532791 BENTON 7 345 1	0.995	Lead	296.3	29.7
	539695 SPEARVL6 230 539679 MULGREN6 230 1	0.998	Lag	296.3	-20.0
	523097 HITCHLAN 345 515375 WOODWRD7 345 1	0.998	Lag	296.3	-19.3
	523961 POTTER_C 345 523772 GRAPEVIN 345 1	0.998	Lag	296.3	-18.9
	531449 HOLCOMB7 345 210400 GEN_2004345 1	0.999	Lead	296.3	15.3
	210400 GEN_2004345 531487 COMANCHE 345 1	0.999	Lag	296.3	-14.1
	531451 MINGO 7 345 530700 KNOLL 345 1	0.999	Lag	296.3	-13.7
	515375 WOODWRD7 345 523098 BEAVERCO 345 1	0.999	Lead	296.3	13.5
	531449 HOLCOMB7 345 531465 SETAB 7 345 1	0.999	Lag	296.3	-12.8
	560029 G03-13 345 210400 GEN_2004345 1	0.999	Lag	296.3	-12.1
	523961 POTTER_C 345 523959 POTTER_C 230 1	0.999	Lead	296.3	11.9
	539679 MULGREN6 230 532871 CIRCLE 6 230 1	0.999	Lag	296.3	-11.1
	51700 05-017 345. 523961 OTTER_CO345. 1	1.000	Lead	296.3	9.3
	530558 KNOLL 6 230 530592 SMOKYHLL 230 1	1.000	Lag	296.3	-8.4
	531469 SPERVIL7 345 531487 COMANCHE 345 1	1.000	Lag	296.3	-7.8
	560029 G03-13 345 523097 HITCHLAN 345 1	1.000	Lag	296.3	-6.7
	523097 HITCHLAN 345 523098 BEAVERCO 345 1	1.000	Lag	296.3	-6.2
	210400 GEN_2004345 531469 SPERVIL7 345 1	1.000	Lag	296.3	-5.0
	523097 HITCHLAN 345 51700 05-017 345. 1	1.000	Lead	296.3	4.9
	539671 JUD-LRG3 115 103 [S AR_4 5.00 1	1.000	Lag	296.3	-3.4
	515375 WOODWRD7 345 515378 TATONGA 345 1	1.000	Lag	296.3	-2.7
	539695 SPEARVL6 230 539694 SPEARVL3 115 2	1.000	Lead	296.3	1.7
	539679 MULGREN6 230 530582 S HAYS6 230 1	1.000	Lag	296.3	-0.5
	523853 FINNEY7 345 531449 HOLCOMB7 345 1	1.000	Lead	296.3	0.4
	539671 JUD-LRG3 115 539659 CUDAHY 3 115 1	1.000	Lead	296.3	0.4

SEASON	CONTINGENCY DESCRIPTION	PF @POI	PF	MW @POI	MVAR @POI
10WP	Base Case	0.992	Lead	296.3	37.1
	532781 07-25 345 532796 WICHITA7 345 1	0.963	Lead	296.3	82.6
	532781 07-25 345 531487 COMANCHE 345 1	0.970	Lag	296.3	-74.2
	531469 SPERVIL7 345 539695 SPEARVL6 230 1	0.979	Lead	296.3	61.1
	531449 HOLCOMB7 345 531448 HOLCOMB3 115 1	0.987	Lead	296.3	49.0
	531487 COMANCHE 345 515375 WOODWRD7 345 1	0.996	Lag	296.3	-26.4
	531449 HOLCOMB7 345 210400 GEN_2004345 1	0.997	Lead	296.3	24.1
	523961 POTTER_C 345 523772 GRAPEVIN 345 1	0.998	Lag	296.3	-17.5
	523961 POTTER_C 345 523959 POTTER_C 230 1	0.998	Lead	296.3	16.6
	51700 05-017 345. 523961 OTTER_CO345. 1	0.999	Lead	296.3	15.2
	523097 HITCHLAN 345 515375 WOODWRD7 345 1	0.999	Lag	296.3	-12.8
	532796 WICHITA7 345 532791 BENTON 7 345 1	0.999	Lead	296.3	12.4
	523097 HITCHLAN 345 51700 05-017 345. 1	0.999	Lead	296.3	11.2
	539695 SPEARVL6 230 539679 MULGREN6 230 1	0.999	Lag	296.3	-10.3
	539695 SPEARVL6 230 539694 SPEARVL3 115 2	0.999	Lag	296.3	-9.5
	523853 FINNEY7 345 531449 HOLCOMB7 345 1	1.000	Lag	296.3	-8.1
	539671 JUD-LRG3 115 539659 CUDAHY 3 115 1	1.000	Lag	296.3	-7.5
	539679 MULGREN6 230 530582 S HAYS6 230 1	1.000	Lag	296.3	-7.2
	515375 WOODWRD7 345 523098 BEAVERCO 345 1	1.000	Lag	296.3	-7.1
	531451 MINGO 7 345 530700 KNOLL 345 1	1.000	Lag	296.3	-5.7
	539671 JUD-LRG3 115 103 [S AR_4 5.00 1	1.000	Lag	296.3	-5.6
	539679 MULGREN6 230 532871 CIRCLE 6 230 1	1.000	Lag	296.3	-5.4
	210400 GEN_2004345 531487 COMANCHE 345 1	1.000	Lag	296.3	-5.1
	560029 G03-13 345 210400 GEN_2004345 1	1.000	Lag	296.3	-4.1
	210400 GEN_2004345 531469 SPERVIL7 345 1	1.000	Lead	296.3	3.6
	531449 HOLCOMB7 345 531465 SETAB 7 345 1	1.000	Lag	296.3	-2.5
	530558 KNOLL 6 230 530592 SMOKYHLL 230 1	1.000	Lag	296.3	-1.8
	523097 HITCHLAN 345 523098 BEAVERCO 345 1	1.000	Lag	296.3	-1.8
	560029 G03-13 345 523097 HITCHLAN 345 1	1.000	Lag	296.3	-1.3
	515375 WOODWRD7 345 515378 TATONGA 345 1	1.000	Lag	296.3	-0.6
	531469 SPERVIL7 345 531487 COMANCHE 345 1	1.000	Lag	296.3	-0.2

2.3. Conclusions

In order to hold a voltage schedule at the POI consistent with the voltage schedule in the provided power flow cases, the wind farm should control the power factor at the POI to be within the ± 0.95 range.

3.1. Modeling of the Clipper 2.5 MW Wind Turbine Generators

For the stability simulations, the Clipper 2.5 MW wind turbine generators were modeled using the provided Clipper 2.5 MW wind turbine dynamic model set. Table 3-1 shows the data for Clipper 2.5 MW WTG.

Table 3-1 Clipper 2.5 MW Wind Generator Data

Parameter	Value
BASE KV	0.69
WTG MBASE	2.50
TRANSFORMER MBASE	2.75
TRANSFORMER R ON TRANSFORMER BASE	0.00945
TRANSFORMER X ON TRANSFORMER BASE	0.05672
GTAP	1.00
PMAX (MW)	2.50

The Clipper WTGs have ride-through capability for voltage and frequency. Detailed ride through relays' manufacturer settings are shown in Table 3-2 and Table 3-3.

Table 3-2 Over/Under Frequency Relay Settings for Clipper 2.5 MW

Frequency Settings in Hertz	Time Delay in Seconds
$F \leq 57.0$	1.0
$F \geq 63.0$	1.0

Table 3-3 Over/Under Voltage Relay Settings for Clipper 2.5 MW

Voltage Settings Per Unit	Time Delay in Seconds
$0.0 < V \leq 0.10$	0.15
$0.10 < V \leq 0.90$	3.0
$1.10 < V \leq 1.20$	5.0
$1.2 < V \leq 1.30$	0.50
$V > 1.30$	0.034

3.2. Assumptions

The following assumptions were adopted for the dynamic simulations:

1. Constant maximum and uniform wind speed for the entire period of study.
2. Wind turbine control models with their default values.
3. Under/over voltage/frequency protection use manufacturer settings.

3.3. Faults Simulated

Sixty eight (68) 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 to represent the effect of the negative and zero sequence networks on the positive sequence network.

The fault impedance was computed to give a positive sequence voltage at the specified fault location of approximately 60% of pre-fault voltage. This method is in agreement with SPP current practice. Prior queued projects shown in **Error! Reference source not found.** and units in areas 520, 524, 525, 526, 531, and 534, and 536 were monitored in the simulations. Table 3-4 shows the list of simulated contingencies. The table also shows the fault clearing time and the time delay before re-closing for all the study contingencies.

Table 3-4 List of the Simulated Faults

Cont. No.	Cont. Name	Description
1	FLT09-3PH	3 phase fault on one of the Finney (523853) to Holcomb (531449) 345kV lines, 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.
2	FLT10-1PH	*Single phase fault and sequence like previous*
3	FLT11-3PH	3 phase fault on one of the Holcomb (531449) to Finney (523853) 345kV lines, 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.
4	FLT12-1PH	*Single phase fault and sequence like previous*
5	FLT13-3PH	3 phase fault on the Holcomb (531449) to Setab (531465) 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.
6	FLT14-1PH	*Single phase fault and sequence like previous*
7	FLT15-3PH	3 phase fault on the Holcomb (531449) to GEN-2007-040 (210400) 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	FLT16-1PH	*Single phase fault and sequence like previous*
9	FLT17-3PH	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. b. Clear fault after 5 cycles by tripping the faulted transformer.
10	FLT18-1PH	*Single phase fault and sequence like previous*
11	FLT19-3PH	3 phase fault on the GEN-2007-040 (210400) to Holcomb (531449) 345kV line, near GEN-2007-040. a. Apply fault at the GEN-2007-040 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	FLT20-1PH	*Single phase fault and sequence like previous*
13	FLT21-3PH	3 phase fault on the GEN-2007-040 (210400) to Spearville (531469) 345kV line, near GEN-2007-040. a. Apply fault at the GEN-2007-040 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	FLT22-1PH	*Single phase fault and sequence like previous*

Cont. No.	Cont. Name	Description
15	FLT23-3PH	3 phase fault on the Spearville (531469) to GEN-2007-040 (210400) 345kV line, 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.
16	FLT24-1PH	*Single phase fault and sequence like previous*
17	FLT25-3PH	3 phase fault on the Spearville (531469) to Comanche (531487) 345kV line, 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	FLT26-1PH	*Single phase fault and sequence like previous*
19	FLT27-3PH	3 phase fault on the Spearville 345kV (531469) to 230kV (539695) transformer, near the 345 kV bus. a. Apply fault at the Spearville 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
20	FLT28-1PH	*Single phase fault and sequence like previous*
21	FLT29-3PH	3 phase fault on the Spearville 230kV (539695) to 345kV (531469) transformer, near the 230 kV bus. a. Apply fault at the Spearville 230kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
22	FLT30-1PH	*Single phase fault and sequence like previous*
23	FLT31-3PH	3 phase fault on the Spearville 230kV (539695) to 115kV (539694) transformer #2, near the 230 kV bus. a. Apply fault at the Spearville 230kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
24	FLT32-1PH	*Single phase fault and sequence like previous*
25	FLT33-3PH	3 phase fault on the Spearville (539695) to Mullergren (539679) 230kV line, near Spearville. a. Apply fault at the Spearville 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	FLT34-1PH	*Single phase fault and sequence like previous*
27	FLT35-3PH	3 phase fault on the Mullergren (539679) to South Hays (530582) 230kV line, near Mullergren. a. Apply fault at the Mullergren 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.
28	FLT36-1PH	*Single phase fault and sequence like previous*
29	FLT37-3PH	3 phase fault on the Mullergren (539679) to Circle (532871) 230kV line, near Mullergren. a. Apply fault at the Mullergren 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	FLT38-1PH	*Single phase fault and sequence like previous*
31	FLT39-3PH	3 phase fault on the GEN-2007-025 (532781) to Wichita (532796) 345kV line, near GEN-2007-025. a. Apply fault at the GEN-2007-025 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.
32	FLT40-1PH	*Single phase fault and sequence like previous*

Cont. No.	Cont. Name	Description
33	FLT41-3PH	3 phase fault on the GEN-2007-025 (532781) to Comanche (531487) 345kV line, near GEN-2007-025. a. Apply fault at the GEN-2007-025 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.
34	FLT42-1PH	*Single phase fault and sequence like previous*
35	FLT43-3PH	3 phase fault on the Wichita (532796) to Benton (532791) 345kV line, near Wichita. a. Apply fault at the Wichita 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
36	FLT44-1PH	*Single phase fault and sequence like previous*
37	FLT45-3PH	3 phase fault on the Comanche (531487) to Woodward (515375) 345kV line, near Comanche. a. Apply fault at the Comanche 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.
38	FLT46-1PH	*Single phase fault and sequence like previous*
39	FLT47-3PH	3 phase fault on the Judson Large (539671) to S Star (103) 115kV line, near Judson Large. a. Apply fault at the Judson Large 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	FLT48-1PH	*Single phase fault and sequence like previous*
41	FLT49-3PH	3 phase fault on the Judson Large (539671) to Cudahy (539659) 115kV line, near Judson Large. a. Apply fault at the Judson Large 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	FLT50-1PH	*Single phase fault and sequence like previous*
43	FLT51-3PH	3 phase fault on the GEN-2003-013 (560029) to Hitchland (523097) 345kV line, near GEN-2003-013. a. Apply fault at the GEN-2003-013 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.
44	FLT52-1PH	*Single phase fault and sequence like previous*
45	FLT53-3PH	3 phase fault on the Hitchland (523097) to Woodward (515375) 345kV line, near Hitchland. a. Apply fault at the Hitchland 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
46	FLT54-1PH	*Single phase fault and sequence like previous*
47	FLT55-3PH	3 phase fault on the Hitchland (523097) to GEN-2005-017 (51700) 345kV line, near Hitchland. a. Apply fault at the Hitchland 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
48	FLT56-1PH	*Single phase fault and sequence like previous*
49	FLT57-3PH	3 phase fault on the GEN-2005-017 (51700) to Potter Co. (523961) 345kV line, near GEN-2005-017. a. Apply fault at the GEN-2005-017 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.

Cont. No.	Cont. Name	Description
50	FLT58-1PH	*Single phase fault and sequence like previous*
51	FLT59-3PH	3 phase fault on the Potter Co. (523961) to Grapevine (523772) 345kV line, near Potter Co. a. Apply fault at the Potter Co. 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.
52	FLT60-1PH	*Single phase fault and sequence like previous*
53	FLT61-3PH	3 phase fault on the Potter Co. 345kV (523961) to 230kV (523959) transformer, near the 345 kV bus. a. Apply fault at the Potter Co. 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
54	FLT62-1PH	*Single phase fault and sequence like previous*
55	FLT63-3PH	3 phase fault on the Woodward (515375) to Tatonga (515378) 345kV line, near Woodward. a. Apply fault at the Woodward 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.
56	FLT64-1PH	*Single phase fault and sequence like previous*
57	FLT65-3PH	3 phase fault on the Mingo (531451) to Knoll (530700) 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.
58	FLT66-1PH	*Single phase fault and sequence like previous*
59	FLT67-3PH	3 phase fault on the Knoll (530558) to Smoky Hills (530592) 230kV line, near Knoll. a. Apply fault at the Knoll 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
60	FLT68-1PH	*Single phase fault and sequence like previous*
61	FLT107-3PH	3 phase fault on the Hitchland (523097) to Beaver County (523098) 345kV line, near Beaver County. a. Apply fault at the Beaver 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.
62	FLT70-1PH	*Single phase fault and sequence like previous*
63	FLT71-3PH	3 phase fault on the GEN-2003-013 (560019) to GEN-2007-040 (210400) 345kV line, near GEN-2003-013. a. Apply fault at the GEN-2003-013 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.
64	FLT72-1PH	*Single phase fault and sequence like previous*
65	FLT73-3PH	3 phase fault on the GEN-2007-040 (210400) to Comanche (531487) 345kV line, near GEN-2007-040. a. Apply fault at the GEN-2007-040 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.
66	FLT74-1PH	*Single phase fault and sequence like previous*
67	FLT75-3PH	3 phase fault on the Woodward (515375) to Beaver County (523098) 345kV line, near Beaver County. a. Apply fault at the Beaver 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.
68	FLT76-1PH	*Single phase fault and sequence like previous*

Simulations were performed with a 0.1-second steady-state run followed by the appropriate disturbance as described in Table 3-4. Simulations were run for a minimum 10-second duration to confirm proper machine damping.

3.4. Simulation Results

The simulations conducted in the study using the Clipper 2.5 MW WTGs did not find any angular or voltage instability problems for the 68 disturbances. The study finds that the interconnection of the proposed 300 MW Project does not impact stability performance of the SPP system for the contingencies tested on the supplied base cases.

Section 4. Conclusions

The findings of the impact study for proposed interconnection Gen-2007-025 (the "Project") considered at 100% the proposed 300 MW installed capacity are:

1. The results of the Power Factor analysis showed that with the MVAR capability of the Clipper WTG and without reactive compensation, the wind farm will not be able to keep the voltage schedule at the POI consistent with the voltage schedule in the provided power flow cases for summer and winter. Additional VAR compensating devices need to be installed in order to control he power factor at the POI to be within ±-0.95 range.
2. Using Clipper 2.5 MW WTGs, the stability simulations for 68 specified test disturbances did not find any angular or voltage instability problems in the SPP system. The study finds that the interconnection of the proposed 300 MW Project does not impact stability performance of the SPP system for the contingencies tested on the supplied base cases.

R: Electrically Isolated Interconnection Request Impact Studies

Impact Study For Generation Interconnection Request GEN-2007-028

SPP Tariff Studies
(#GEN-2007-028)

July 2009

Summary

Pursuant to the tariff and at the request of Southwest Power Pool (SPP), Black & Veatch performed the following Impact Study to satisfy the Impact Study Agreement executed by the requesting customer and SPP for SPP Generation Interconnection request GEN-2007-028. The request for interconnection was placed with SPP in accordance SPP's Open Access Transmission Tariff, which covers new generation interconnections on SPP's transmission system.

<OMITTED TEXT> (Customer) has requested an Impact Study for the purpose of interconnecting 200 MW of wind generation within the control area of Mid Kansas Electric Company (MKEC) Cloud County, Kansas. The proposed method of interconnection is to add five breakers to upgrade a three-breaker ring bus to an eight-breaker breaker-and-a-half bus at the Cloud Tap 230 kV switch station which is located on the Concordia – East Manhattan 230 kV transmission line. Additionally, a new 230 kV transmission line from Cloud Tap to Summit is needed for the interconnection of this generation.

Power Factor Requirements

The Customer has requested to study Vestas V90 3.0 MW wind turbines for this generation interconnection request. The impact study determined that the Customer will need to be able to provide unity power factor at the point of interconnection for any system configuration. This requires that a total of 38 MVAR capacitor bank(s) be installed on the low voltage side of its 230/34.5 kV transformer(s).

Interconnection Facilities

The requirements for interconnection of the 200 MW consist of adding five breakers to upgrade the three-breaker ring bus at the Cloud Tap 230 kV substation to an eight-breaker breaker-and-a-half bus. This station is owned by MKEC.

In addition, a new 230 kV transmission line from Cloud Tap to Summit will be constructed for the interconnection of this request. This line is needed to avoid system stability issues and to avoid under voltage tripping of Customer generators for an outage of the existing circuit from Cloud Tap to East Manhattan 230 kV line. These facilities are shown in Figure 1.

The Customer did not propose a specific route of its 230 kV line to serve its 230/34.5 kV collection system facilities. It is assumed that obtaining all necessary right-of-way for construction of the Customer 230 kV transmission line and the 230/34.5 kV collector substation will not be a significant expense.

Low Voltage Ride Through Analysis

Transient stability analysis has indicated that the wind turbines will meet FERC Order 661A low voltage ride through (LVRT) requirements when the Cloud Tap – Summit 230 kV line is in place.

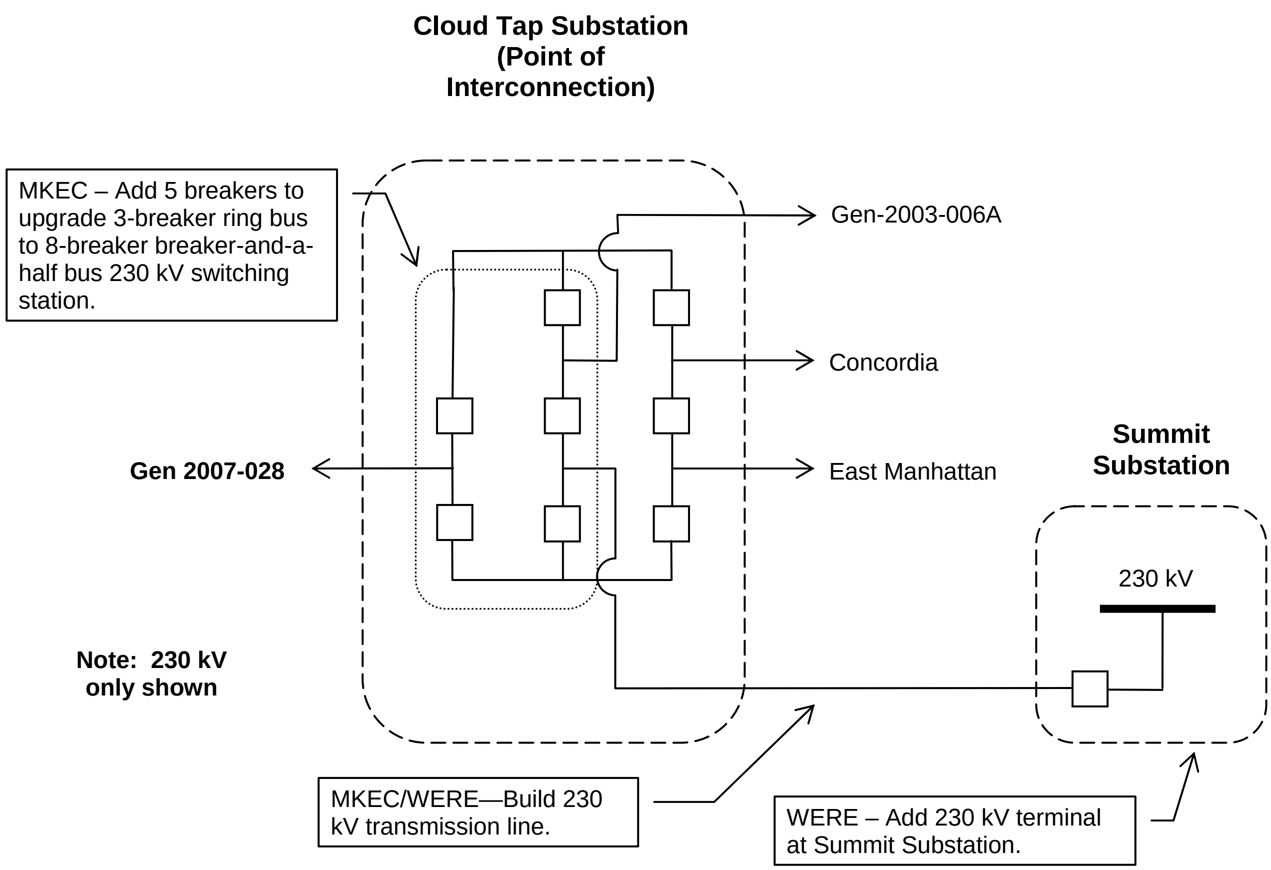


Figure 1: Proposed Method of Interconnection

(Final design to be determined)

Table 1: Interconnection Facilities

FACILITY	ESTIMATED COST (2008 DOLLARS)
CUSTOMER – (1) 230/34.5 kV Customer collector substation facilities.	*
CUSTOMER – (1) 230 kV transmission line from Customer collector substation to Cloud Tap.	*
MKEC – (5) breakers to upgrade 3-breaker ring bus to 8-breaker breaker-and-a-half 230 kV bus at Cloud Tap	$3,500,000
MKEC/WERE – (1) 230kV transmission line from Cloud Tap to Summit	$24,000,000
WERE – (1) 230 kV termination at Summit	$2,000,000
TOTAL	**$29,500,000**

Conclusion

<OMITTED TEXT> (Customer) has requested an Impact Study for the purpose of interconnecting 200 MW of wind generation within the control area of Mid Kansas Electric Company in Cloud County, Kansas. The proposed method of interconnection is to add five breakers to upgrade a three-breaker ring bus to an eight-breaker breaker-and-a-half bus at the Cloud Tap 230 kV switch station which is located on the Concordia – East Manhattan 230 kV transmission line. The GEN-2007-028 interconnection request has exhibited stability issues for certain contingencies. The mitigation for the stability issues is to construct a 230 kV transmission line from the Cloud Tap to Summit substations.

The Customer generation facility utilizing Vestas V90 3.0 MW wind turbines will comply with FERC Order 661A low voltage ride through (LVRT) requirements when the Cloud Tap – Summit 230 kV line is in place.

IMPACT STUDY FOR SPP GENERATION QUEUE POSITION GEN-2007-028

SOUTHWEST POWER POOL (SPP)

By

BLACK & VEATCH

Table of Contents

EXECUTIVE SUMMARY

A transient stability study was performed for Southwest Power Pool (SPP) Interconnection Queue Position GEN-2007-028 as part of the System Impact Study. The Interconnection Queue Position GEN-2007-028 is a wind farm of 200 MW capacity proposed to be connected to a substation in Cloud County, Kansas owned by Mid Kansas Electric Company LLC (MKEC). The proposed Interconnection substation is located on the Concordia – East Manhattan 230 kV line.

Transient Stability studies were conducted with the full output of 200 MW (100%). The wind farm was considered to contain Vestas V90 turbines.

The 2012 summer load flow case and 2008 winter load flow case together with the SPP MDWG 2006 stability model were used as the base case for the transient stability analysis. The study was performed using PTI's PSS/E program, which is an industry-wide accepted power system simulation program. The wind farm was modeled using the V90 wind turbine models provided by the customer.

Transient Stability studies were conducted with the GEN-2007-028 output at 200 MW (100%) for two scenarios, i.e., (i) summer peak load and (ii) winter peak load. Twenty four (24) contingencies were considered for each of the scenarios.

System instability and Gen-2007-028 generator tripping were found for faults on Cloud Tap – East Manhattan 230 kV line. Gen-2007-028 output was reduced to test whether the system would be stable under reduced Gen-2007-028 output, but the system instability was still encountered.

Loss of Cloud Tap – East Manhattan 230 kV line weakens the system and leads to system instability. This necessitates a new 230 kV line between Cloud Tap – Concordia. Simulations were carried out with this new line in place and Gen-2007-028 generators were found to stay connected to the grid for all of the contingencies that were studied and also there was no angular instability encountered.

If any of the previously queued projects that were included in this study drop out, then this System Impact Study may have to be revised to determine the impacts of this Interconnection Customer's project on MKEC transmission facilities.

1. INTRODUCTION

This report discusses the results of a transient stability study performed for Southwest Power Pool (SPP) Interconnection Queue Position GEN-2007-028.

The Interconnection Queue Position GEN-2007-028 is a wind farm of 200 MW capacity proposed to be connected to a substation in Cloud County, Kansas owned by Mid Kansas Electric Company LLC (MKEC). The proposed Interconnection substation is located on the Concordia – East Manhattan 230 kV line. The system one line diagram of the area near the Queue Position GEN-2007-028 is shown below.

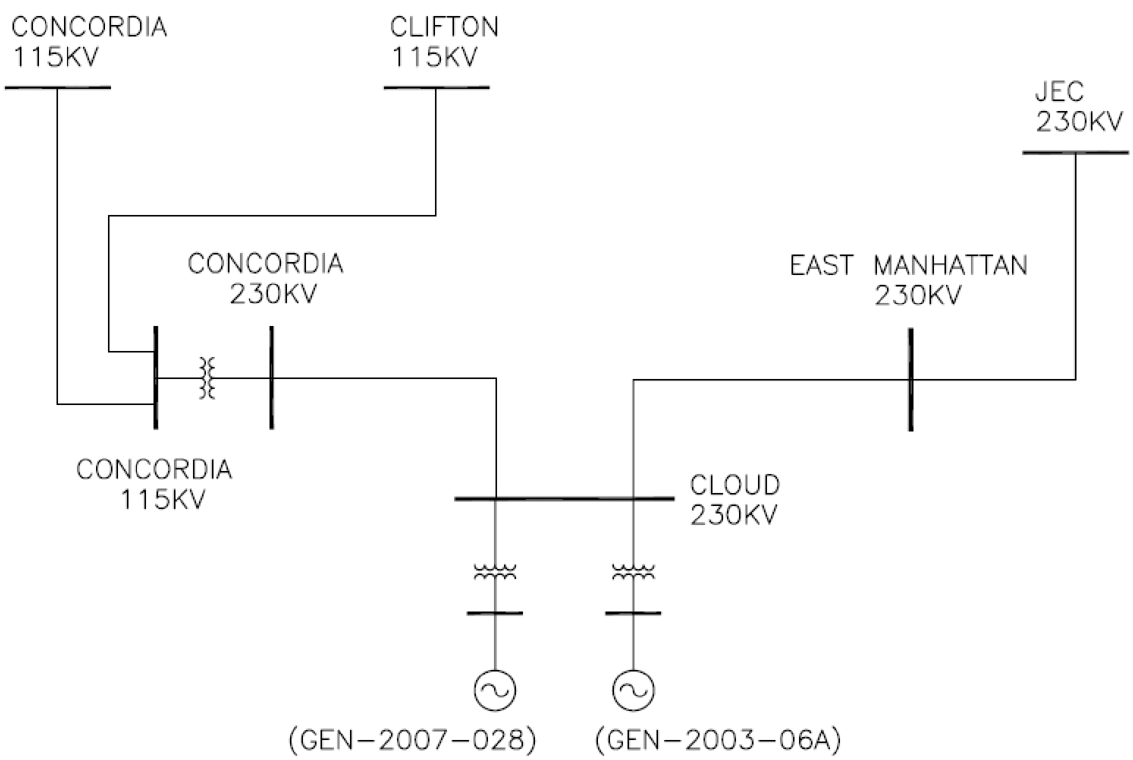


Figure 1: System One Line Diagram near GEN-2007-028

Transient Stability studies were conducted with the full output of 200 MW (100%). The wind farm was considered to contain Vestas V90 wind turbines in the study.

2. STABILITY STUDY CRITERIA

The 2012 summer peak load flow and 2008 winter peak load flow cases together with the SPP MDWG 2006 stability model were used as the base case for the transient stability analysis. These models were provided by SPP.

Using Planning Standards approved by NERC, the following stability definition was applied in the Transient Stability Analysis:

“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.”

Disturbances such as three phase and single phase line faults were simulated for a specified duration and the synchronous machine rotor angles were monitored for their synchronism following the fault removal.

The ability of the wind generators to stay connected to the grid during the disturbances and during the fault recovery was also monitored.

3. SIMULATION CASES

Transient Stability studies were conducted with the GEN-2007-028 output at 200 MW for (i) 2012 summer peak and (ii) 2008 winter peak load flow cases.

Table 1 indicates the contingencies which were studied for each of the two cases.

Fault	Fault Definition
FLT13PH	Three phase fault at Concordia on 115 kV line to Clifton.
FLT21PH	Single phase-to-ground fault on 115 kV line to Clifton, breaker failure at Concordia.
FLT33PH	Three phase fault at Cloud Tap on 230 kV line to East Manhattan.
FLT41PH	Single phase-to-ground fault at Cloud tap on 230 kV line to East Manhattan, breaker failure at East Manhattan.
FLT53PH	Three phase fault at East Manhattan on 230 kV line to Cloud tap.
FLT61PH	Single phase-to-ground fault East Manhattan on 230 kV line to Cloud tap, breaker failure at Cloud tap.
FLT73PH	Three phase fault at Cloud tap on 230 kV line to

	Concordia.
FLT81PH	Single phase-to-ground fault at Cloud tap on 230 kV line to Concordia.
FLT93PH	Three phase fault at East Manhattan on the line to JEC.
FLT101PH	Single phase-to-ground fault at East Manhattan on the line to JEC.
FLT133PH	Three phase fault at Concordia on 115 kV line to Jewell.
FLT141PH	Single phase-to-ground fault at Concordia on 115 kV line to Jewell.
FLT153PH	Three phase fault at Concordia on 115 kV line to Glen Elder.
FLT161PH	Single phase-to-ground fault at Concordia on 115 kV line to Glen Elder.
FLT173PH	Three phase fault at Smith Center on 115 kV line to Phillipsburgh.
FLT181PH	Single phase-to-ground fault at Smith Center on 115 kV line to Phillipsburgh.
FLT193PH	Three phase fault on the Gen-2007-015 wind farm to Kelley 161 kV line, near Kelley.
FLT201PH	Single phase-to-ground fault on the Gen-2007-015 wind farm to Kelley 161 kV line, near Kelley.
FLT213PH	Three phase fault on the Kelley to Tec. Hill 161 kV line, near Kelley.
FLT221PH	Single phase-to-ground fault on the Kelley to Tec. Hill 161 kV line, near Kelley.
FLT233PH	Three phase fault on the Kelley to Seneca 115 kV line, near the Kelley bus.
FLT241PH	Single phase-to-ground fault on the Kelley to Seneca 115 kV line, near the Kelley bus.
FLT253PH	Three phase fault on the Clay Center – Greenleaf, near Greenleaf.
FLT261PH	Single phase-to-ground fault on the Clay Center – Greenleaf, near Greenleaf.

Table 1: Study Cases

4. SIMULATION MODEL

The customer requested to use Vestas V90 Wind turbine for the System Impact Study. The V90 turbines are a double fed induction generator with the stator winding connected directly to the grid and the rotor winding connected to the grid through a bidirectional power electronic converter. The following are the main electrical parameters of the V90 wind turbine.

Rated Power : 3.0 MW
Operating Nominal Voltage : 1000 V
Operating Power Factor : 0.98 Lead to 0.96 Lag.

The models of the Wind Farm equipment such as generators, transformers and cables were added to the base case for the purpose of this study. The equivalent generators of the wind farm were based on the number of collector circuits shown on the Customer provided single line diagram. Figure 2 shows the one line diagram of GEN-2007-028 modeled.

Table 2 provides the number of V90 wind generators modeled as equivalents at each collector buses of the wind farm.

Collector Bus	**No. of generators aggregated**
Gen1_12-31	8
Gen2_32-33	2
Gen2_35-40	6
Gen3_41	1
Gen3_42	1
Gen3_43-49	7
Gen4_51-53	3
Gen4_50-67	6
Gen5_64-66	3
Gen6_4-7	4
Gen6_20	1
Gen6_1-3	3
Gen7_21-23	3
Gen7_26-27	3
Gen7_26-27	2
Gen7_24-25	2
Gen7_34	1
Gen8_8-19	8

Table 2: Equivalent Generators with V90 Wind Turbines

The Customer provided the wind turbine feeder conductor types, lengths and impedance values. Table 3 indicates the transmission line parameters, as provided by the Customer, were used in the model for the underground lines within the Wind Farm.

		(Ohms/1000')				nS/1000'
	Ampacity	R1	X1	R0	X0	Bc
4/0 AWG	321	0.207	0.030	0.207	0.030	17720
500 MCM	452	0.065	0.069	0.171	0.024	23830
750 MCM	517	0.054	0.059	0.115	0.021	27810
1000 MCM flat	600	0.041	0.06304	0.151	0.019	30970
1250 MCM flat	630	0.038	0.058	0.122	0.01799	36040

Table 3: Cable impedance per 1000 feet

The PSS/E model for V90 wind turbines was provided by the customer.

The base case power flow diagram for the project GEN-2007-028 is shown in Figure 2.

The prior queued projects Gen-2003-006A, Gen-2003-019, Gen-2004-016, Gen-2006-032, Gen-2006-033 and Gen-2007-015 were also included in the study model.

5. STUDY ASSUMPTIONS

The following assumptions were made in the Study:

1. The wind speed over the entire wind farm was assumed to be uniform and constant during the study period.
2. From the wind turbine data sheets the protection settings were used as and are shown in Table 4.
3. The other generators in the SPP control area were scaled down to accommodate the new generation as indicated in Table 5.

Protective Function	**Protection Setting**	**Time Delay**
Over Frequency	62.0 Hz	0 seconds
Under Frequency	57.0 Hz	0 seconds
Under Voltage	15%	0.04 seconds
Under Voltage	30%	0.625 second
Under Voltage	45%	1.1 second
Under Voltage	60%	1.575 seconds
Under Voltage	75%	2.05 seconds
Under Voltage	90%	2.55 seconds
Over Voltage	110%	0.06 second

Table 4: Protective functions and settings for V90 Turbines

Scenario	Generation within SPP	
	Summer	Winter
Without the Wind Farms	43046	30051
GEN-2007-028 at 100% output with the prior queued projects	43246	30251

Table 5: Generation in SPP Area

6. SIMULATION RESULTS

Initial simulation was carried out without any disturbance to verify the numerical stability of the model and was confirmed to be stable.

System instability and Gen-2007-028 generator tripping were found for faults on Cloud Tap – East Manhattan 230 kV line. Gen-2007-028 output was reduced to test whether the system would be stable under reduced Gen-2007-028 output, but the system instability was still encountered.

Loss of Cloud Tap – East Manhattan 230 kV line weakens the system and leads to system instability. This necessitates a new 230 kV line between Cloud Tap – Concordia. Simulations were carried out with this new line in place and Gen-2007-028 generators were found to stay connected to the grid for all of the contingencies that were studied and also there was no angular instability encountered.

Table 6 provides the summary of the stability studies for GEN-2007-028.

Fault Number	Summer Peak Load Case	Winter Peak Load Case	Summer Peak Load Case (with Cloud Tap – Concordia 230 kV line)	Winter Peak Load Case (with Cloud Tap – Concordia 230 kV line)
FLT13PH	- -	- -	- -	- -
FLT21PH	S	S	- -	- -
FLT33PH	S, UV	S, UV	- -	- -
FLT41PH	S, UV	S, UV	- -	- -
FLT53PH	S, UV	S, UV	- -	- -
FLT61PH	S, UV	S, UV	- -	- -
FLT73PH	S	S	- -	- -
FLT81PH	S	S	- -	- -

FLT93PH	- -	S	- -	- -
FLT101PH	S	S	- -	- -
FLT133PH	- -	- -	- -	- -
FLT141PH	- -	- -	- -	- -
FLT153PH	- -	- -	- -	- -
FLT161PH	- -	- -	- -	- -
FLT173PH	- -	- -	- -	- -
FLT181PH	- -	- -	- -	- -
FLT193PH	- -	- -	- -	- -
FLT201PH	- -	- -	- -	- -
FLT213PH	- -	- -	- -	- -
FLT221PH	- -	- -	- -	- -
FLT233PH	- -	- -	- -	- -
FLT241PH	- -	- -	- -	- -
FLT253PH	- -	- -	- -	- -
FLT261PH	- -	- -	- -	- -

UV : GEN-2007-028 Tripped due to low voltage
OV : GEN-2007-028 Tripped due to high voltage
UF : Tripped due to low frequency
OF : Tripped due to high frequency
PQ : Prior Queued Projects Tripped
S : Stability issues encountered
- - : Wind Farm did not trip

Table 6: Stability Study Results Summary

The system responses corresponding to FLT21PH are shown in Figure 3 and 4 for the cases without and with the new line respectively.

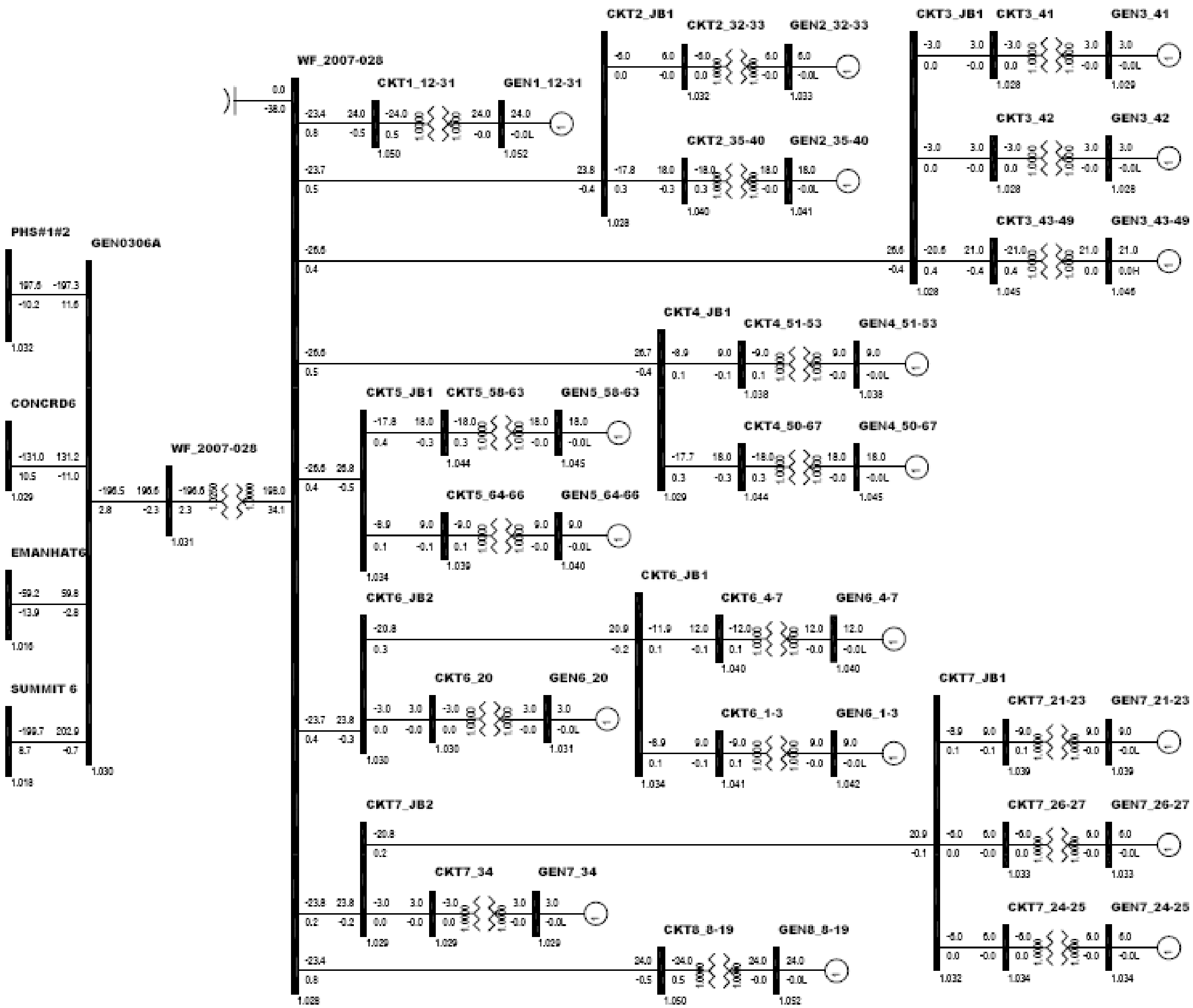


Figure 2: 100% Power Flow Base Case for GEN-2007-028

7. SUMMARY

A transient stability analysis was conducted for the SPP Interconnection Generation Queue Position GEN-2007-028 consisting of Vestas V-90 wind turbines, for an aggregate output of 200 MW. The study was conducted for two different power flow scenarios, i.e., one for summer peak and one for winter peak load cases.

The study has not indicated any angular or voltage instability problem due to the addition of GEN-2007-028 for the contingencies that were analyzed, provided a new Cloud Tap – Concordia 230 kV line is in place.

Disclaimer

If any previously queued projects that were included in this study drop out, then this System Impact Study may have to be revised to determine the impacts of this Interconnection Customer's project on MKEC transmission facilities. Since this is also a preliminary System Impact Study, not all previously queued projects were assumed to be in service in this System Impact Study. If any of those projects are constructed, then this System Impact Study may have to be revised to determine the impacts of this Interconnection Customer's project on MKEC transmission facilities. In accordance with FERC and SPP procedures, the study cost for restudy shall be borne by the Interconnection Customer.

Figure 3 : System Responses for FLT21 – without the new line

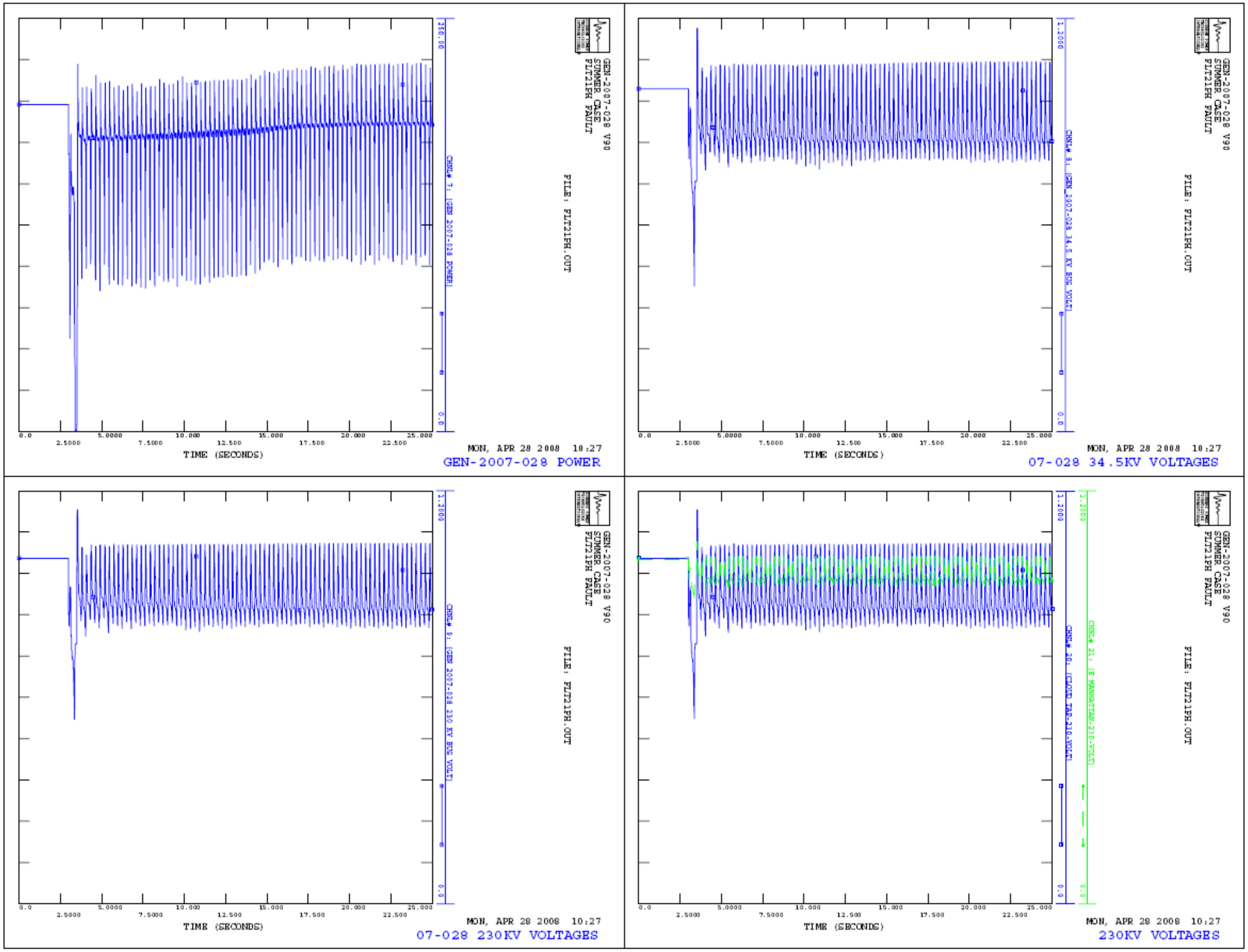


Figure 3 : System Responses for FLT21PH – without the new line (Cont'd)

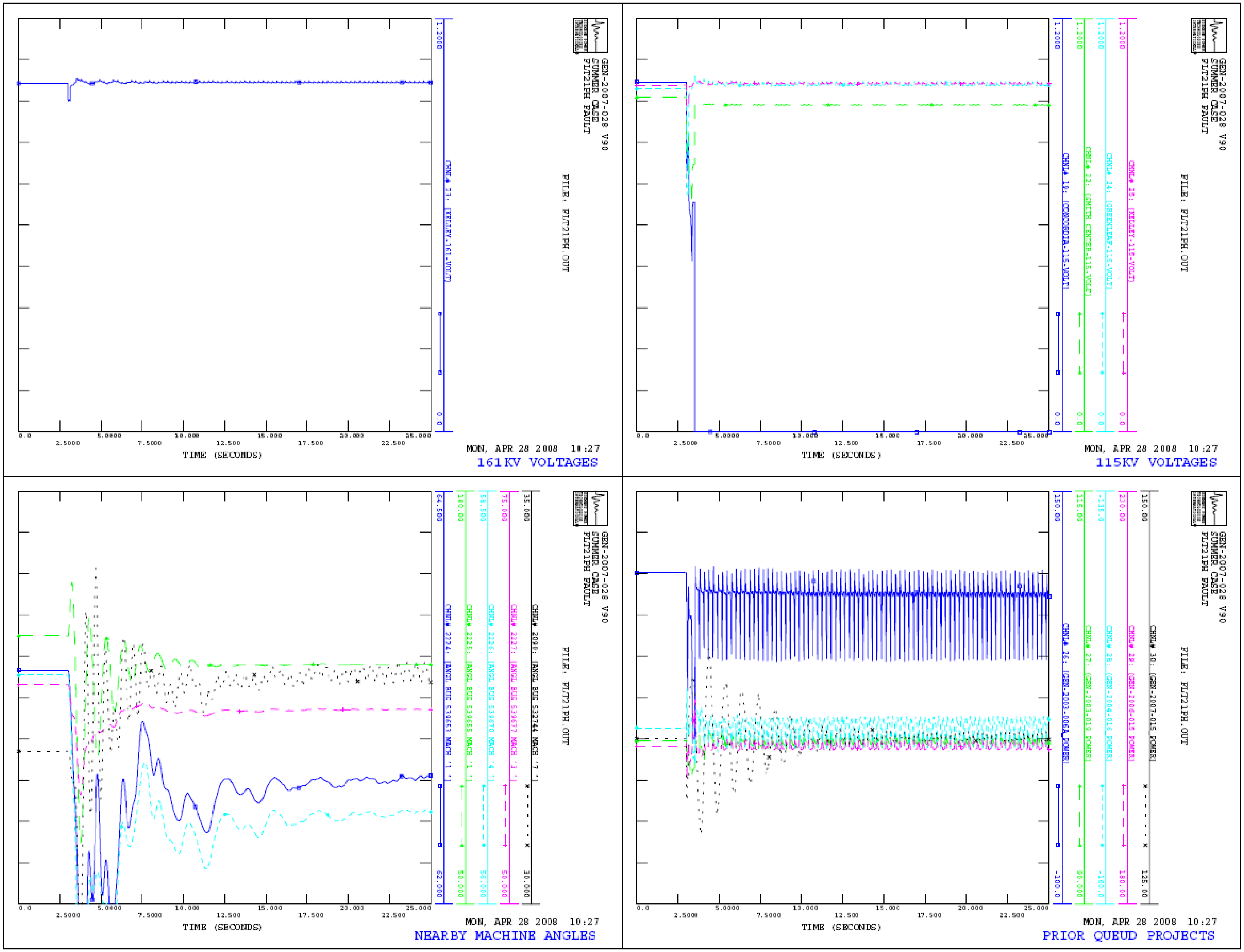


Figure 4 : System Responses for FLT21 – with the new line

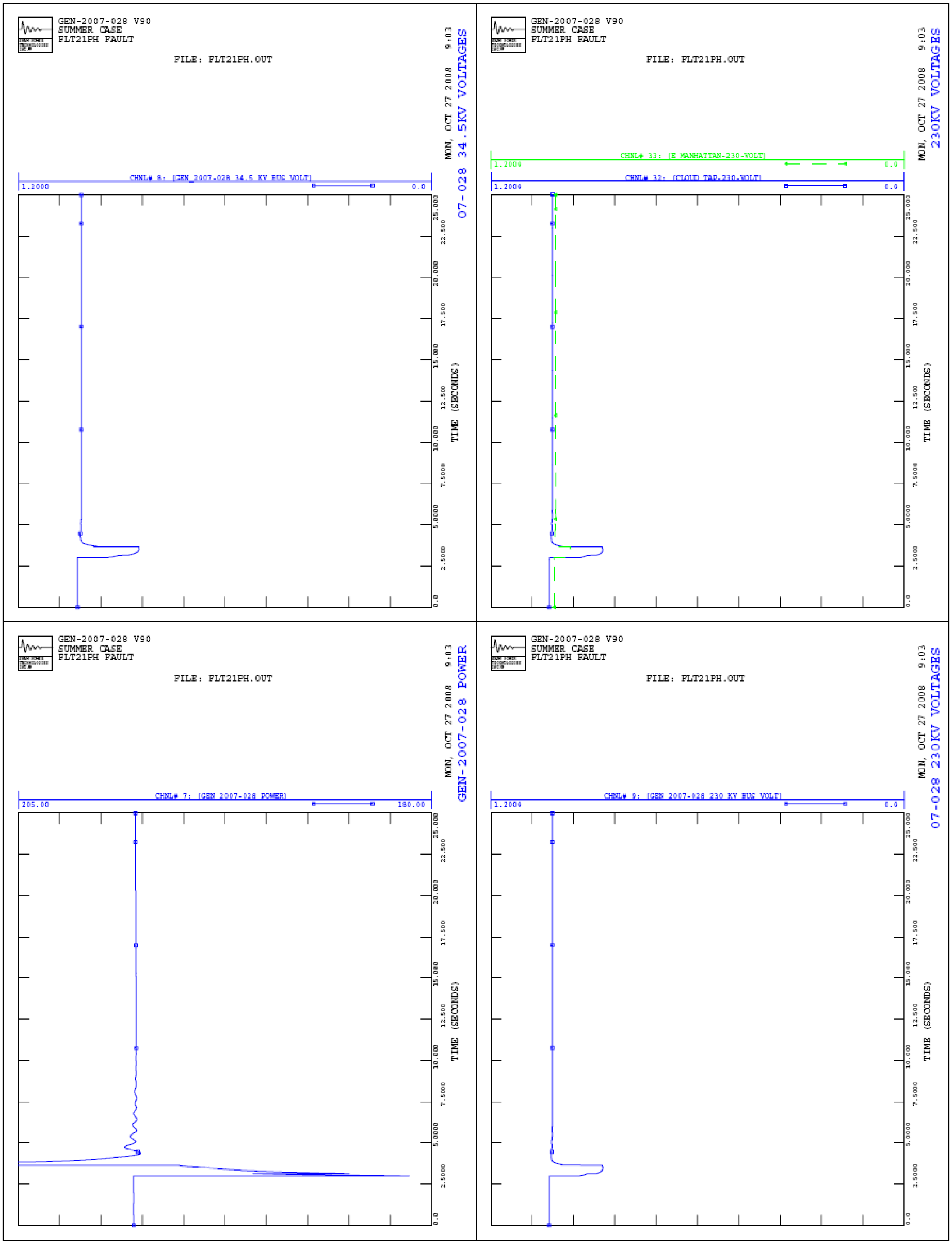
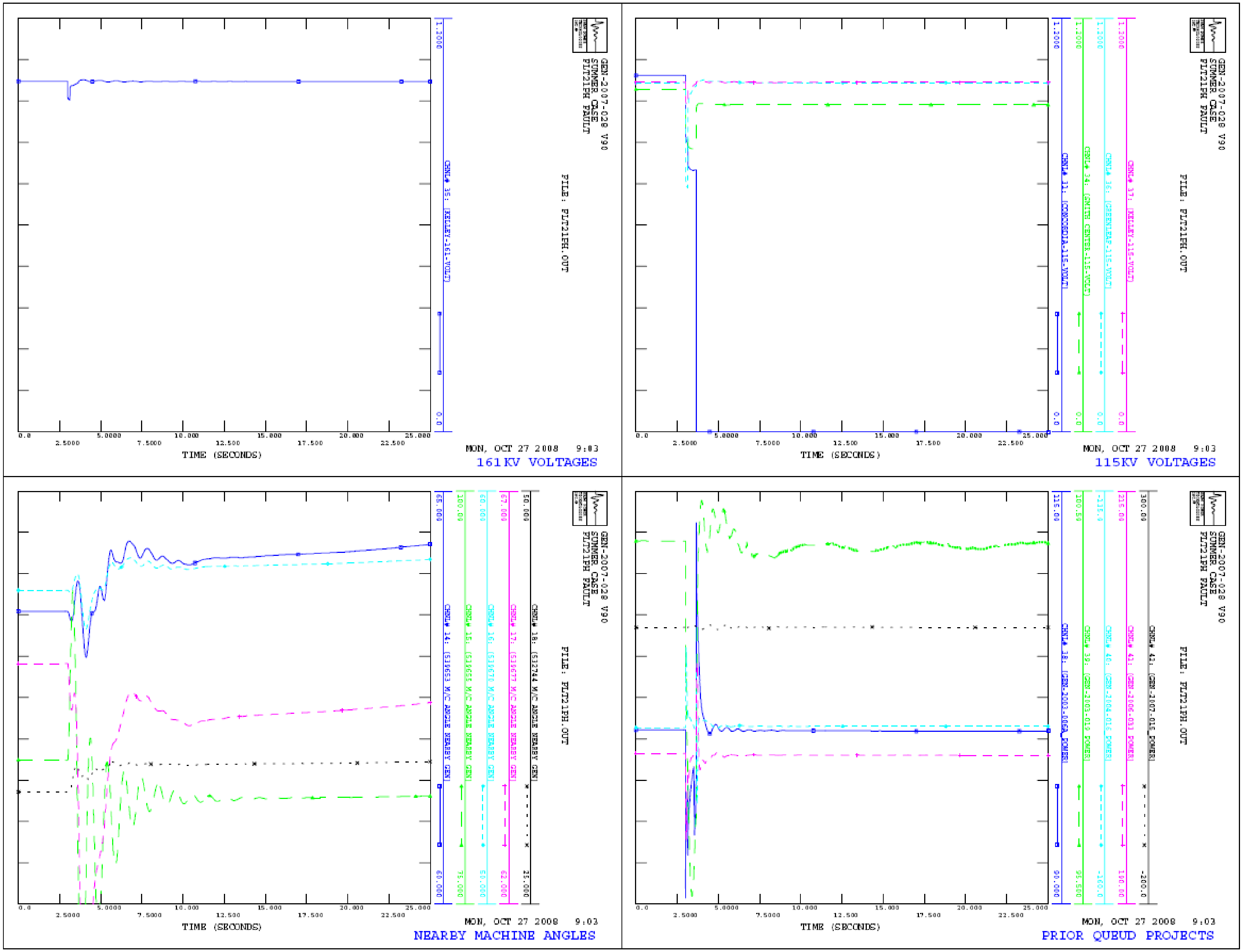


Figure 4 : System Responses for FLT21 – with the new line (cont'd)



Southwest Power Pool

Impact Study for Generation Interconnection Request GEN–2008–012

SPP Tariff Studies
(#GEN-2008-012)

June 2009

Summary

Pursuant to the tariff and at the request of the Southwest Power Pool (SPP), Pterra Consulting performed the following Impact Study to satisfy the Impact Study Agreement executed by the requesting customer and SPP for SPP Generation Interconnection request GEN-2008-012. The request for interconnection was placed with SPP in accordance SPP's Open Access Transmission Tariff, which covers new generation interconnections on SPP's transmission system. The Impact Study for GEN-2008-012 was studied with G.E. 1.5 MW wind turbines.

Power Factor Requirements

The wind farm will need to be able to keep the prescribed voltage schedule at the point of interconnection consistent with the system conditions. Additional VAR compensating devices may need to be installed in order to control the power factor at the point of interconnection to within the required 0.97 leading (absorbing) to 0.99 lagging (supplying).

Interconnection Facilities

The Customer has requested interconnecting a 150 MW of wind generation within the control area of Empire District Electric Company (EMDE) located in Benton County, Arkansas. The proposed method of interconnection is a new 161 kV line terminal and breaker to be installed at a new ring-bus switching station to be located on the existing Noel – Decatur 161 kV transmission line, owned by EMDE. The proposed in-service date of this request is October, 2010.

The minimum cost of adding a new 161 kV three-breaker ring-bus switching station serving GEN-2008-012 facilities is estimated at $2,500,000. These costs are listed in Tables 1 and 2. This cost does not include building the Customer's 161 kV transmission line extending from the point of interconnection to serve its 161/34.5 kV collection facilities. This cost also does not include the Customer's 161/34.5 kV collector substation or the need for reactive compensation, all of which should be determined by the Customer. The Customer is responsible for these 161 kV – 34.5 kV facilities up to the point of interconnection.

The Facility Study currently being conducted for this interconnection request will provide more detailed estimates for these facilities.

Table 1. Interconnection Facilities

FACILITY	ESTIMATED COST (2008 DOLLARS)
CUSTOMER – (1) 161/34.5 kV Customer collector substation facilities.	*
CUSTOMER – (1) 161 kV transmission line from Customer collector substation to the proposed station to be located on the Noel – Decatur 161 kV transmission line.	*
CUSTOMER – Reactive compensation	*
CUSTOMER – Right-of-Way for all Customer facilities.	*
TOTAL	*

* Determined by Customer

Table 2. Network Upgrades

FACILITY	ESTIMATED COST (2008 DOLLARS)
EMDE – (1) 161 kV three-breaker ring-bus switching station to be built for GI Request #GEN-2008-012 on the Noel – Decatur 161 kV transmission line. Work to include associated switches, control relaying, high speed communications, metering and related equipment and all related structures.	$2,500,000
TOTAL	**$2,500,000**

Pterra Consulting

Technical Report R114-09

Impact Study for Generation Interconnection Request GEN-2008-012

Submitted to

Southwest Power Pool

June 2009

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Contents

Executive Summary

This report presents the impact study comprising of power factor and stability simulation of proposed interconnection GEN-2008-012 (the "Project"). The Project has a nominal 150 MW max rating studied using GE 1.5 MW wind turbine generators ("WTGs"). The Point of Interconnection ("POI") is a new a proposed 161 kV substation on the existing Decatur – Noel 161 kV line in the Empire District Electric transmission system (EMDE).

The analysis was conducted through the Southwest Power Pool ("SPP") Tariff. Power factor analysis and transient stability simulations were conducted with the Project in service at full output of 150 MW.

Two base cases for 2010 summer and winter conditions, each comprising of a power flow and corresponding dynamics database, were provided by SPP. In order to integrate the proposed 150 MW wind farm into the SPP system, the existing generation in the SPP footprint was re-dispatched as specified by SPP.

With the MVAR capability of the GE 1.5 MW WTG and without reactive compensation, the wind farm will not be able to keep the voltage schedule at the POI consistent with the voltage schedule in the provided power flow cases for summer and winter. Additional VAR compensating devices need to be installed in order to control he power factor at the POI to be within -0.97 and +0.999 range.

Thirty (30) disturbances were considered for the transient stability simulations which included 3-phase faults, as well as, 1-phase to ground faults, at the locations defined by SPP. The GE WTGs were modeled with voltage and frequency ride through protection set to manufacturer default settings. The results of the simulations showed no angular or voltage instability problems for the 68 disturbances. The study finds that the interconnection of the proposed 150 MW Project does not impact stability performance of the SPP system for the contingencies tested on the supplied base cases.

1.1. Project Overview

This report presents the impact study comprising of power factor and stability simulation of proposed interconnection GEN-2008-012 (the "Project"). The Project has a nominal 150 MW max rating studied using GE 1.5 MW wind turbine generators ("WTGs"). The Project's Point of Interconnection ("POI") is at a new 161 kV Substation on the existing Decatur – Noel 161 kV line. Figure 1-1 shows a conceptual interconnection diagram of the Project to the 161 kV transmission network.

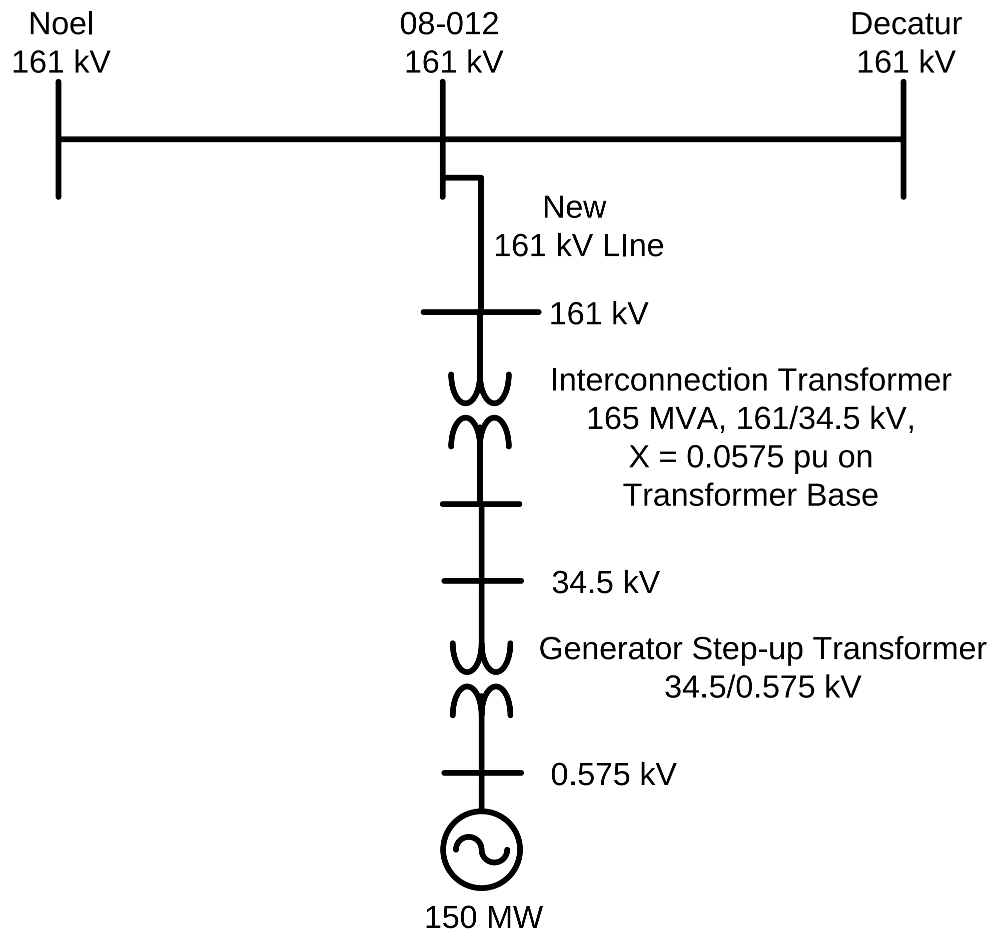

Figure 1-1 Interconnection Plan for the Project to SPP's 161 kV System

In order to integrate the proposed 150 MW wind farm in SPP system as an Energy Resource, existing generation in the SPP footprint was redispatched to maintain area interchange totals.

To simplify the model of the wind farm while capturing the effect of the different impedances of cables (due to change of the conductor size and length), the wind turbines connected to the same 34.5 kV feeder end points were aggregated into one equivalent unit. An equivalent impedance of that feeder was represented by taking the equivalent series impedances of the different feeders connecting the wind turbines. Using this approach, the proposed 150 MW wind farm was modeled with 37 equivalent units (GE 1.5 MW WTGs). SPP provided the impedance values for the different feeders at 34.5kV level. SPP provided the data for the following equipment:

1. 34.5 kV feeders
2. WTG step up transformers
3. 161/34.5 kV transformer

1.2. Objectives

The objectives of the study are to conduct power factor analysis and to determine the impact on system stability of interconnecting a proposed 150 MW wind farm to SPP's 161 kV transmission system.

2.1. Methodology

Power factor analysis was conducted for the Project using a methodology which is summarized as follows:

4. Model a VAR generator at the Project's 161 kV bus. 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).

5. Steady state contingency analysis is conducted to determine the power factor necessary at the POI for each contingency.

6. According to the contingency analysis results, determine whether capacitors are required for the Project or not.

7. If the required power factor at the POI is beyond the capability of the studied wind turbines to meet (at the POI) capacitor banks are considered. The preference is to locate the capacitance banks is on the 34.5 kV Customer side. Factors to sizing capacitor banks include:

   7.1. The ability of the wind farm to meet FERC Order 661A (low voltage ride through) with and without capacitor banks.

   7.2. The ability of the wind farm to meet FERC Order 661A (wind farm recovery to pre-fault voltage).

   7.3. If wind farms trips on high voltage, power factor lower than unity may be required.

2.2. Analysis

A VAR generator was modeled in the provided power flow cases for summer and winter at the POI. The VAR generator was set to hold a voltage schedule at the POI consistent with the voltage schedule in the provided power flow cases for summer and winter. These values are 1.014 pu and 1.018 pu, for summer and winter power flow cases respectively.

Contingency analysis was run for all the contingencies listed in the fault definition table (Table 3-3). A summary of the contingency analysis results for both summer and winter power flow cases is shown in Table 2-1. According to the contingency analysis summary the following conclusions can be made:

1. The VAR generator is absorbing MVAR for several contingencies; the highest MVAR absorption is because of the loss of the 161 kV line from Noel to the POI where the VAR generator is absorbing 39 MVAR and 29.2 MVAR in summer and winter power flow cases, respectively. A reactor is required to hold a voltage

schedule at the POI consistent with the voltage schedule in the provided power flow cases for summer and winter.

2. The VAR generator is delivering MAVR to the system for several contingencies; the highest MVAR delivery is 0.9 MVAR for the loss of the 161 kV line from Flint Creek to Tontitown in the summer peak case and 5.4 MAVAR for the loss of the 345 kV line from Flint Creek to Mon in the winter peak power flow case. Capacitor banks with MVAR range of 0.4 - 5.4 will be needed to hold a voltage schedule at the POI consistent with the voltage schedule in the provided power flow cases for summer and winter.

Table 2-1 Summary of the VAR Generator Outputs for the Studied Contingencies for the Summer and Winter Peak Power Flow Cases

Season	CONTINGENCY DESCRIPTION	PF @POI	PF	MW @POI	MVAR @POI
10SP	Base Case	0.977	Lag	148.1	-32.60
	999 2008-012 161 547496 NOL435 5 161 1	0.967	Lead	148.1	39.00
	547496 NOL435 5 161 547471 NEO184 5 161 1	0.988	Lead	148.1	23.00
	510402 GROVE 4 138 510411 GROVE 5 161 1	0.995	Lead	148.1	15.00
	547496 NOL435 5 161 510411 GROVE 5 161 1	0.996	Lead	148.1	14.00
	999 2008-012 161 547484 DEC392 5 161 1	0.997	Lead	148.1	11.00
	506935 FLINTCR7 345 547481 MON383 7 345 1	0.999	Lead	148.1	5.00
	506934 FLINTCR5 161 504201 GENTRY 161 1	1.000	Lead	148.1	3.00
	506945 CHAMSPR7 345 509745 CLARKSV7 345 1	1.000	Lead	148.1	1.00
	506935 FLINTCR7 345 512650 GRDA1 7 345 1	1.000	Lead	148.1	1.00
	506934 FLINTCR5 161 506935 FLINTCR7 345 1	1.000	Lead	148.1	0.40
	506945 CHAMSPR7 345 506959 TONTITN7 345 1	1.000	Lead	148.1	0.10
	506934 FLINTCR5 161 504202 SILOAMSP 161 1	1.000	Lag	148.1	-0.40
	504202 SILOAMSP 161 506944 CHAMSPR5 161 1	1.000	Lag	148.1	-0.40
	506944 CHAMSPR5 161 504020 FARMNGTN 161 1	1.000	Lag	148.1	-0.40
	506934 FLINTCR5 161 506957 TONTITN5 161 1	1.000	Lag	148.1	-0.90
10WP	Base Case	0.982	Lag	148.1	-28.10
	999 2008-012 161 547496 NOL435 5 161 1	0.981	Lead	148.1	29.20
	999 2008-012 161 547484 DEC392 5 161 1	0.993	Lead	148.1	18.00
	547496 NOL435 5 161 547471 NEO184 5 161 1	0.993	Lead	148.1	17.80
	510402 GROVE 4 138 510411 GROVE 5 161 1	0.997	Lead	148.1	10.80
	547496 NOL435 5 161 510411 GROVE 5 161 1	0.998	Lead	148.1	9.00
	506935 FLINTCR7 345 512650 GRDA1 7 345 1	1.000	Lead	148.1	1.60
	506945 CHAMSPR7 345 509745 CLARKSV7 345 1	1.000	Lead	148.1	1.40
	506934 FLINTCR5 161 506935 FLINTCR7 345 1	1.000	Lead	148.1	0.40
	506945 CHAMSPR7 345 506959 TONTITN7 345 1	1.000	Lag	148.1	-0.10
	506944 CHAMSPR5 161 504020 FARMNGTN 161 1	1.000	Lag	148.1	-0.60
	506934 FLINTCR5 161 504202 SILOAMSP 161 1	1.000	Lag	148.1	-0.70
	504202 SILOAMSP 161 506944 CHAMSPR5 161 1	1.000	Lag	148.1	-0.70
	506934 FLINTCR5 161 506957 TONTITN5 161 1	1.000	Lag	148.1	-1.50
	506934 FLINTCR5 161 504201 GENTRY 161 1	1.000	Lag	148.1	-4.30
	506935 FLINTCR7 345 547481 MON383 7 345 1	0.999	Lag	148.1	-5.40

2.3. Conclusion

With the MVAR capability of the GE 1.5 MW WTG and without reactive compensation, the wind farm will need to be able to keep the voltage schedule at the POI consistent with the voltage schedule in the provided power flow cases for summer and winter. Additional VAR compensating devices may need to be installed in order to control he power factor at the POI to be within -0.97 and +0.999 range.

3.1. Modeling of the GE 1.5 MW Wind Turbine Generators

For the stability simulations, the GE 1.5 MW wind turbine generators were modeled using the provided GE 1.5 MW wind turbine dynamic model set. Table 3-1 shows the data for GE 1.5 MW WTG.

Table 3-1 GE 1.5 MW Wind Generator Data

Parameter	Value
BASE KV	0.575 kV
WTG MBASE	1.67 MVAR
TRANSFORMER MBASE	1.75 MVA
TRANSFORMER Impedance ON TRANSFORMER BASE	5.75%
X/R Ratio	7.5
GTAP	1.00
Pmax (MW)	1.5 MW
Pmin	0.07 MW
Qmax	0.726 MVAR
Qmin	-0.726 MVAR

The GE WTGs have ride-through capability for voltage. Detailed ride through relays' manufacturer settings are shown in Table 3-2.

Table 3-2Over/Under Voltage Relay Settings for GE 1.5 MW

Voltage Settings Per Unit	Time Delay in Seconds
0.15 >V	0.2
0.15 <V ≤ 0.30	0.7
0.30 < V ≤ 0.50	1.2
0.50 < V ≤ 0.75	1.9
1.1 < V ≤ 1.15	1.0
1.15 < V ≤ 1.30	0.1
V > 1.30	0.02

3.2. Assumptions

The following assumptions were adopted for the dynamic simulations:

1. Constant maximum and uniform wind speed for the entire period of study.
2. Wind turbine control models with their default values.
3. Under/over voltage/frequency protection use manufacturer settings.

3.3. Faults Simulated

Thirty (30) 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 to represent the effect of the negative and zero sequence networks on the positive sequence network. The fault impedance was computed to give a positive sequence voltage at the specified fault location of approximately 60% of pre-fault voltage. This method is in agreement with SPP current practice. Prior queued projects shown in **Error! Reference source not found.** and units in areas 520, 523, 524, 544, 546, 130, 151, 635, and 640 were monitored in the simulations. Table 3-3 shows the list of simulated contingencies. The table also shows the fault clearing time and the time delay before re-closing for all the study contingencies.

Table 3-3 List of the Simulated Faults

Cont. No.	*Cont. Name*	*Description*
1	*FLT13PH*	3 phase fault on the Wind Farm (XXX) - Decatur (547484) 161kV line, near the wind farm. a. Apply fault at the Wind Farm (XXX). b. Clear fault after 5 cycles by tripping the line from the Wind Farm – Decatur. c. Wait 20 cycles, and then re-close 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	FLT21PH	*Single phase fault and sequence like Cont. No. 1*
3	*FLT33PH*	3 phase fault on the Wind Farm (XXX) - Noel (547496) 161kV line, near the wind farm. a. Apply fault at the Wind Farm. b. Clear fault after 5 cycles by tripping the line from the Wind Farm – Noel. c. Wait 20 cycles, and then re-close 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	FLT41PH	*Single phase fault and sequence like Cont. No.3*
5	FLT53PH	3 phase fault on the Flint Creek (506934) to Gentry (504201) 161kV line, near Flint Creek. a. Apply fault at the Flint Creek. b. Clear fault after 5 cycles by tripping the line from Flint Creek – Gentry. c. Wait 20 cycles, and then re-close 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	FLT61PH	*Single phase fault and sequence like Cont. No.5*
7	FLT73PH	3 phase fault on the Flint Creek (506934) to Siloam Springs (504202) 161kV line, near Flint Creek. a. Apply fault at Flint Creek. b. Clear fault after 5 cycles by tripping the line from Flint Creek - Siloam Springs. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Cont. No.	Cont. Name	Description
8	FLT81PH	*Single phase fault and sequence like Cont. No.7*
9	FLT93PH	3 phase fault on the Flint Creek (506934) to Tontitown (506957) 161kV line, near Flint Creek. a. Apply fault at the Flint Creek. b. Clear fault after 5 cycles by tripping the line from Flint Creek – Tontitown. c. Wait 20 cycles, and then re-close 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	FLT101PH	*Single phase fault and sequence like Cont. No.9*
11	FLT113PH	3 phase fault on the Flint Creek 345/161kV autotransformer a. Apply fault at Flint Creek 345kV (506935). b. Clear fault after 5 cycles by tripping the auto. c. no reclose.
12	FLT121PH	*Single phase fault and sequence like Cont. No.11*
13	FLT133PH	3 phase fault on the Flint Creek (506935) – GRDA (512650) 345kV line, near the Flint Creek. a. Apply fault at the Flint Creek. b. Clear fault after 5 cycles by tripping the line from the Flint Creek – GRDA. c. Wait 20 cycles, and then re-close 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	FLT141PH	*Single phase fault and sequence like Cont. No.13*
15	FLT153PH	3 phase fault on the Flint Creek (506935) – MON383 (547481) 345kV line, near the Flint Creek. a. Apply fault at the Flint Creek. b. Clear fault after 5 cycles by tripping the line from the Flint Creek – MON383. c. Wait 20 cycles, and then re-close 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	FLT161PH	*Single phase fault and sequence like Cont. No.15*
17	FLT173PH	3 phase fault on the Noel (547496) to Grove (510411) 161kV line, near Noel. a. Apply fault at the Noel. b. Clear fault after 5 cycles by tripping the line from Noel – Grove. c. Wait 20 cycles, and then re-close 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	FLT181PH	*Single phase fault and sequence like Cont. No.17*

Cont. No.	*Cont. Name*	*Description*
19	FLT193PH	3 phase fault on the Noel (547496) to Neosho (547471) 161kV line, near Noel. a. Apply fault at the Noel. b. Clear fault after 5 cycles by tripping the line from Noel – Neosho. c. Wait 20 cycles, and then re-close 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	FLT201PH	*Single phase fault and sequence like Cont. No.19*
21	FLT213PH	3 phase fault on the Grove 161/138kV autotransformer a. Apply fault at Grove 161kV (510411). b. Clear fault after 5 cycles by tripping the auto. c. no reclose.
22	FLT221PH	*Single phase fault and sequence like Cont. No.21*
23	FLT233PH	3 phase fault on the Chamber Springs (506944) to Farmington (504020) 161kV line, near Chamber Springs. a. Apply fault at the Chamber Springs. b. Clear fault after 5 cycles by tripping the line from Chamber Springs – Farmington. c. Wait 20 cycles, and then re-close 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	FLT241PH	*Single phase fault and sequence like Cont. No.23*
25	FLT253PH	3 phase fault on the Siloam Springs (504202) to Chamber Springs (506944) 161kV line, near Siloam Springs. a. Apply fault at the Siloam Springs. b. Clear fault after 5 cycles by tripping the line from Siloam Springs – Chamber Springs. c. Wait 20 cycles, and then re-close 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	FLT261PH	*Single phase fault and sequence like Cont. No.25*
27	FLT273PH	3 phase fault on the Chamber Springs (506945) to Tontitown (506959) 345kV line, near Chamber Springs. a. Apply fault at the Chamber Springs. b. Clear fault after 5 cycles by tripping the line from Chamber Springs – Tontitown. c. Wait 20 cycles, and then re-close 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	FLT281PH	*Single phase fault and sequence like Cont. No.27*

Cont. No.	Cont. Name	Description
29	FLT293PH	3 phase fault on the Chamber Springs (506945) to Clarksville (509745) 345kV line, near Chamber Springs. a. Apply fault at the Chamber Springs. b. Clear fault after 5 cycles by tripping the line from Chamber Springs – Clarksville. c. Wait 20 cycles, and then re-close 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	FLT301PH	*Single phase fault and sequence like Cont. No.29*

Simulations were performed with a 0.1-second steady-state run followed by the appropriate disturbance as described in Table 3-3. Simulations were run for a minimum 10-second duration to confirm proper machine damping.

3.4. Simulation Results

The simulations conducted in the study using the GE 1.5 MW WTGs did not find any angular or voltage instability problems for the 68 disturbances. The study finds that the interconnection of the proposed 150 MW Project does not impact stability performance of the SPP system for the contingencies tested on the supplied base cases.

Section 4. Conclusions

The findings of the impact study for proposed interconnection Gen-2008-012 (the "Project") considered at 100% the proposed 150 MW installed capacity are:

1. With the MVAR capability of the GE 1.5 MW WTG and without reactive compensation, the wind farm will not be able to keep the voltage schedule at the POI consistent with the voltage schedule in the provided power flow cases for summer and winter. Additional VAR compensating devices need to be installed in order to control he power factor at the POI to be within -0.97 and +0.999 range.

2. Using GE 1.5 MW WTGs, the stability simulations for thirty specified test disturbances did not find any angular or voltage instability problems in the SPP system. The study finds that the interconnection of the proposed 150 MW Project does not impact stability performance of the SPP system for the contingencies tested on the supplied base cases.