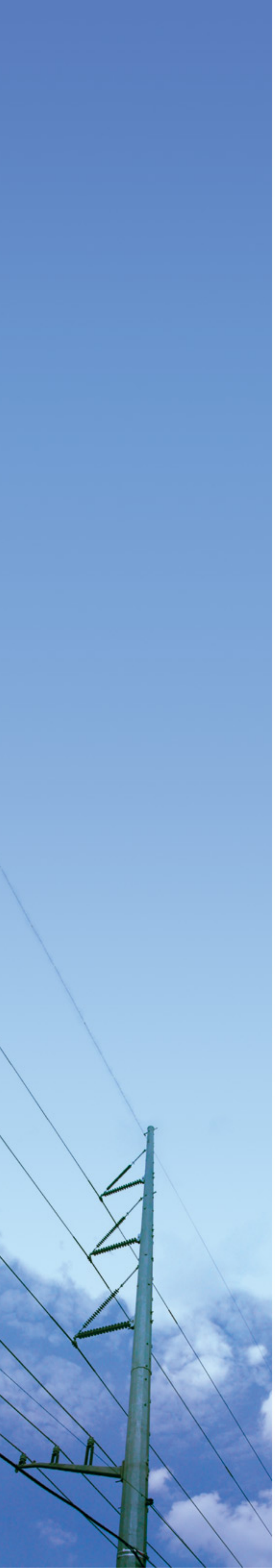

Definitive Interconnection System Impact Study for GEN-2009-017

Southwest Power Pool
Engineering Department
Tariff Studies – Generation Interconnection

(DISIS-2009-001 Study)
February 2010

SPP RESTRICTED

Executive Summary

SPP has conducted this Definitive Interconnection System Impact Study (DISIS) for the GEN-2009-017 interconnection request. The GEN-2009-017 interconnection request is an interconnection request of 150 MW for a wind generation facility on the Caprock (NewCorp) transmission system. The interconnection request had a requested in service date of June 1, 2011[1]. The GEN-2009-017 interconnection request was included in the DISIS-2009-001 cluster study as appropriate under the Tariff.

Power flow and stability analysis has indicated that the GEN-2009-017 interconnection request cannot be interconnected at 150 MW due to stability issues associated with the distance of the proposed generation facility from the backbone of the SPP transmission system. The maximum amount the GEN-2009-017 interconnection request can be interconnected for is 60MW. 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.

The total estimated minimum cost for interconnecting the GEN-2009-017 interconnection request is $2,000,000. This estimate will be refined by Caprock during the Facility Study, if a Facility Study Agreement is executed by the Customer. Interconnection Service to GEN-2009-017 interconnection customers is contingent upon higher queued customers paying for certain required network upgrades. The in service date for the GEN-2009-017 customers may need to be deferred until the construction of these network upgrades can be completed.

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 H.

Network Constraints listed in Appendix H are in the local area of the new generation when this generation is injected throughout the SPP footprint for the Energy Resource (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 E, 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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[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.

For the interconnection customer to continue with this Interconnection request, an executed Facility Study Agreement will need to be executed within 30 days of the submittal of this report. Caprock, as the transmission owner, will be responsible for conducting the Facility Study for this interconnection request.

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Introduction

SPP has conducted this Definitive Interconnection System Impact Study (DISIS) for the GEN-2009-017 interconnection request. The GEN-2009-017 interconnection request is an interconnection request of 150 MW for a wind generation facility on the Caprock (NewCorp) transmission system. The interconnection request had a requested in service date of June 1, 2011[2].

Caprock has designated SPP as an Affected Transmission System as defined in the SPP LGIP. SPP has agreed to conduct this study for Caprock to evaluate the GEN-2009-017 interconnection request.

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

Model Development

Interconnection Requests Included in the GEN-2009-017 Study

SPP has included all interconnection requests that submitted a Definitive Interconnection System Impact Study request no later than September 30, 2009 and were subsequently accepted by Southwest Power Pool under the terms of the Large Generation Interconnection Procedures (LGIP) that became effective June 2, 2009. GEN-2009-017 was included in the DISIS-2009-001 study.

The interconnection requests that are included in this study are listed in Appendix A.

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 and associated upgrades were assumed to be in-service and added to the Base Case models. These projects were dispatched as Energy Resources with equal distribution across the SPP footprint.

Development of Base Cases

Powerflow - The 2009 series Transmission Service Request (TSR) Models 2010 spring and 2014 summer and winter peak scenario 0 peak cases were used for this study. After the 2010 spring and the 2014 summer and winter peak cases were developed, each of the control areas' resources were then re-dispatched using current dispatch orders.

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

Stability – The 2009 series SPP Model Development Working Group (MDWG) Models 2009 winter and 2010 summer were used for this study.

Base Case Upgrades

The following facilities are part of the SPP Transmission Expansion Plan or the Balanced Portfolio. These facilities have been approved or are in construction stages and were assumed to be in-service at the time of dispatch and added to the base case models. The DISIS-2009-001 Customers have no potential cost for the below listed projects. However, the DISIS-2009-001 Customers Generation Facilities in service dates may need to be delayed until the completion of the following upgrades. If for some reason, construction on these projects is discontinued, additional restudies will be needed to determine the interconnection needs of the DISIS customers.

- Hitchland 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.
- Tuco – Woodward 345kV line approved by the SPP Board of Directors as part of the Balanced Portfolio and issued an NTC in June, 2009
- Spearville – Knoll- Axtell 345kV line approved by the SPP Board of Directors as part of the Balanced Portfolio and issued an NTC in June, 2009

Contingent Upgrades

The following facilities do not yet have approval. These facilities have been assigned to higher queued interconnection customers. These facilities have been included in the models for the DISIS-2009-001 study and are assumed to be in service. The DISIS-2009-001 Customers at this time do not have responsibility for these facilities but may later be assigned the cost of these facilities if higher queued customers terminate their LGIA or withdraw from the interconnection queue. The DISIS-2009-001 Customer Generation Facilities in service dates may need to be delayed until the completion of the following upgrades.

- Finney – Holcomb 345kV Ckt #2 line assigned to GEN-2006-044 interconnection customer. This customer is currently in suspension[5].

[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
[5] Based on Facility Study Posting November 2008

- Hitchland – Woodward 345kV line assigned to GEN-2006-049 interconnection customer for in service date yet to be determined
- Stevens County – Gray County 345kV line assigned to 1st Cluster Interconnection Customers
- Central Plains – Setab 115kV transmission line assigned to GEN-2007-013 interconnection customer.
- Spearville – Comanche 345kV line assigned to 1st Cluster Interconnection Customers
- Comanche – Wichita 345kV line assigned to 1st Cluster Interconnection Customers
- Comanche – Woodward 345kV line assigned to 1st Cluster Interconnection Customers
- Conway – Wheeler County 345kV line assigned to 1st Cluster Interconnection Customers
- Wheeler County 345/230/13.2kV autotransformer assigned to 1st Cluster Interconnection Customers
- Wheeler County – Anadarko 345kV line assigned to 1st Cluster Interconnection Customers
- Conway 345/115kV autotransformer assigned to 1st Cluster Interconnection Customers
- Grassland 230/115kV autotransformer #2 assigned to 1st Cluster Interconnection Customers (100% to GEN-2008-016)

Potential Upgrades Not in the Base Case

Any potential upgrades that do not have a Notification to Construct (NTC) 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 sections.

Regional Groupings

Due to its remoteness, GEN-2009-017 was grouped by itself in the DISIS-2009-001 study. It is located in Group 6.

Powerflow – For group 6, GEN-2009-017 was modeled at 80% nameplate of maximum generation. The wind generating plants in the other areas were modeled at 20% nameplate of maximum generation. The interconnection requests 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. Per cluster study procedure, each interconnection request was also modeled separately at 100% nameplate for certain analyses.

Peaking units were not dispatched in the 2010 spring model. To study peaking units' impacts, the 2014 summer and winter 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 – GEN-2009-017 was 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. . These projects were dispatched as Energy Resources with equal distribution across the SPP footprint.

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 2014 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 impact 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:

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

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

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

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

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

- 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 60 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 by upgrade. Interconnection Facilities specific to each generation interconnection request are listed in Appendix E and F.

Other Network Constraints in the AEPW, MIDW, MIPU, MKEC, NPPD, OKGE, SPS, SUNC, AND WERE transmission systems that were identified are shown in Appendix H. With a defined source and sink in a TSR, this list of Network Constraints will be refined and expanded to account for all Network Upgrade requirements.

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 American Electric Power West (AEPW), Empire District Electric (EMDE), Grand River Dam Authority (GRDA), Kansas City Power & Light (KCPL), Midwest Energy (MIDW), MIPU, MKEC, Nebraska Public Power District (NPPD), OG&E Electric Services (OKGE), Omaha Public Power District (OPPD), Southwest Public Service (SPS), Sunflower Electric (SUNC), Westar Energy (WERE), Western Farmers Electric Cooperative (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 2014 summer and winter peak models. The output of the Interconnection Customer's facility was offset in each model by a reduction in output of existing online SPP generation. This method allows the request to be studied as an Energy Resource (ER) Interconnection Request. The available seasonal models used were through the 2014 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 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.

GEN-2009-017 Cluster Group 6 (South Panhandle/New Mexico)

Cluster Group 6 (which included only GEN-2009-017) initially had 150 MW of interconnection requests in addition to the 1,238 MW of previously queued interconnection requests. The major constraints for GEN-2009-017 included the Grassland Interchange 230/115kV transformer, the Grassland Interchange – Lynn County Interchange 115kV line, and the Hobbs Interchange 230/115kV transformer.

As discussed in the stability section, the wind farm in Group 6 was not able to meet FERC low voltage ride through (LVRT) requirements at its requested output level. After the request was lowered to 60 MW, powerflow analysis showed no new constraints were found in this area and no further mitigation was needed beyond the upgrades identified in the first cluster study. .

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.

GEN-2009-017 Cluster Group 6 (South Panhandle Area)

The Group 6 stability study was conducted by ABB Consulting Inc. (ABB). It was determined that the GEN-2009-017 interconnection request in Group 6 would not meet low voltage ride through requirements of FERC Order #661A. The maximum amount of wind generation that can be accommodated is 60 MW. It was determined that the GEN-2009-017 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 reduction to 60MW, the power factor requirements and all network upgrades in service, all interconnection requests in Group 6 will meet FERC Order #661A low voltage ride through (LVRT) requirements.

Conclusion

The minimum cost of interconnecting all of the interconnection requests included in this Impact Cluster Study is estimated at $2,000,000 for the Allocated Network Upgrades and Transmission Owner Interconnection Facilities are listed in Appendix E, F, and G These costs do not include the cost of upgrades of other transmission facilities listed in Appendix H which are Network Constraints.

These interconnection costs do not include any cost of Network Upgrades determined to be required by short circuit analysis. These studies will be performed as part of the Interconnection System Facility Study that the customer will be required to execute.

The required interconnection costs listed in Appendices E, and F, and G 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-2006-037N	100.5	NPPD	VALENTINE 115kV	VALENTINE 115kV	
GEN-2006-037N1	75	NPPD	BROKEN BOW 115kV	BROKEN BOW 115kV	1/1/2010
GEN-2006-044N	40.5	NPPD	TAP NELIGH-PETERSBURG 115kV	TAP NELIGH-PETERSBURG 115kV	1/1/2010
GEN-2007-011N06	75	NPPD	TAP NELIGH-PETERSBURG 115kV	PETERSBURG 115kV	1/1/2010
GEN-2007-011N09	75	NPPD	BLOOMFIELD 115kV	BLOOMFIELD 115kV	
GEN-2007-040	200	SUNC	Tap Holcomb – Spearville 345kV	Tap Holcomb – Spearville 345kV	12/15/2010
GEN-2008-021	42	WERE	WOLF CREEK 25kV	WOLF CREEK 25kV	5/16/2011
GEN-2008-023	150	AEPW	HOBART JUNCTION 138kV	HOBART JUNCTION 138kV	12/31/2012
GEN-2008-025	101.2	SUNC	RULETON 115kV	RULETON 115kV	11/1/2009
GEN-2008-029	250.5	OKGE	WOODWARD EHV 138kV	WOODWARD EHV 138kV	1/1/2010
GEN-2008-038	144	AEPW	TAP SHIDLER-WEST PAWHUSKA 138kV	TAP SHIDLER-WEST PAWHUSKA 138kV	12/1/2010
GEN-2008-051	322	SPS	POTTER 345kV	POTTER 345kV	12/31/2010
GEN-2008-079	100.5	MKEC	TAP JUDSON LARGE-CUDAHY 115kV	TAP JUDSON LARGE-CUDAHY 115kV	12/1/2010
GEN-2008-086N02	200	NPPD	TAP FT RANDALL-COLUMBUS 230kV	TAP FT RANDALL-COLUMBUS 230kV	
GEN-2008-092	201	MIDW	KNOLL 115kV	KNOLL 115kV	12/1/2011
GEN-2008-124	200.1	MKEK	SPEARVILLE 230kV	SPEARVILLE 230kV	11/30/2011
GEN-2008-127	200.1	WERE	TAP SOONER-ROSE HILL 345kV	TAP SOONER-ROSE HILL 345kV	10/31/2011
GEN-2008-129	80	MIPU	PLEASANT HILL 161kV	PLEASANT HILL 161kV	5/1/2009
GEN-2009-006	60	AEPW	SE FAYETTEVILLE 161kV	SE FAYETTEVILLE 161kV	12/31/2010
GEN-2009-011	50	SUNC	TAP PLAINVILLE-PHILLIPSBURG 115kV	TAP PLAINVILLE-PHILLIPSBURG 115kV	7/31/2011
GEN-2009-016	140	MKEC	FALCON ROAD 138kV	FALCON ROAD 138kV	12/1/2011
GEN-2009-017**	151.8	SPS	TAP PEMBROOK-STILES 138kV	TAP PEMBROOK-STILES 138kV	6/1/2011
GEN-2009-025	60	OKGE	KAYCOOP 69kV	KAYCOOP 69kV	12/31/2011
GROUPED TOTAL	**2,679.2**				

** Interconnection on Caprock Electric tested for impacts on SPP

***** 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	100	OKGE	Windfarm Switching 138kV	On-Line
GEN-2001-039A	105	MKEC	Greensburg - Judson-Large 115kV	On Schedule for 2011
GEN-2001-039M	100	SUNC	Leoti – City Services 115kV	On-Line
GEN-2002-004	200	WERE	Latham 345kV	On-Line
GEN-2002-005	120	WFEC	Morewood - Elk City 138kV	On-Line
GEN-2002-006	150	SPS	Texas County 115kV	IA Executed/On Schedule 12/31/2010
GEN-2002-008	240	SPS	*Hitchland 345kV	On-Line at 120MW
GEN-2002-009	80	SPS	Hansford County 115kV	On-Line
GEN-2002-022	240	SPS	Bushland 230kV	On-Line at 160MW
GEN-2002-025A	150	MKEC	Spearville 230kV	On-Line at 100MW
GEN-2003-005	100	WFEC	Anadarko - Paradise 138kV	On Line
GEN-2003-006A	200	MKEC	Elm Creek 230kV	On-Line
GEN-2003-013	198	SPS	*Hitchland - Finney 345kV	On Schedule for 2012
GEN-2003-019	250	MIDW	Smoky Hills Tap 230kV	On-Line
GEN-2003-020	160	SPS	Martin 115kV	On-Line at 80MW
GEN-2003-021N	75	NPPD	Ainsworth Wind Tap	On-Line
GEN-2003-022	120	AEPW	Washita 138kV	On-Line
GEN-2004-003	240	SPS	Conway 115kV	On Suspension
GEN-2004-005N	30	NPPD	St. Francis 115kV	IA Pending
GEN-2004-010	300	WERE	Latham 345kV	On-Line
GEN-2004-014	155	MKEC	Spearville 230kV	On Schedule for 2011
GEN-2004-020	27	AEPW	Washita 138kV	On-Line
GEN-2005-005	18	OKGE	Windfarm Tap 138kV	pending
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-2005-013	201	WERE	Tap Latham - Neosho	On Suspension
GEN-2005-015	150	SPS	Tuco - Oklaunion 345kV	On Suspension
GEN-2005-016	150	WFEC	Tap Latham - Neosho	12/31/2006
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-2006-006	206	MKEC	Spearville 230kV	Under Study (ICS-2008-001)
GEN-2006-014	300	MIPU	Tap Maryville – Clarinda 161kV	5/31/2008
GEN-2006-017	300	MIPU	Tap Maryville – Clarinda 161kV	On Suspension
GEN-2006-020	18.9	SPS	DWS Frisco Tap	IA Executed/On Schedule 12/31/2009
GEN-2006-020N	42	NPPD	Bloomfield 115kV	1/1/2009
GEN-2006-021	101	WPEK	Flat Ridge Tap 138kV	On-Line (100MW)
GEN-2006-022	150	WPEK	Ninnescah Tap 115kV	On Suspension

Request	Amount	Area	Requested/Proposed Point of Interconnection	Status or In-Service Date
GEN-2006-024	20	WFEC	South Buffalo Tap 69kV	On-Line
GEN-2006-031	75	MIDW	Knoll 115kV	On-Line
GEN-2006-032	200	MIDW	South Hays 230kV	On Schedule for 2012
GEN-2006-034	81	SUNC	Kanarado - Sharon Springs 115kV	On Suspension
GEN-2006-035	225	AEPW	Grapevine - Elk City 230kV	On Suspension
GEN-2006-038N005	80	NPPD	Broken Bow 115kV	On-Line
GEN-2006-038N019	80	NPPD	Petersburg 115kV	5/1/2011
GEN-2006-039	400	SPS	Tap and Tie both Potter County - Plant X 230kV and Bushland - Deaf Smith 230kV	On Suspension
GEN-2006-040	108	SUNC	Mingo 115kV	On Suspension
GEN-2006-043	99	AEPW	Grapevine - Elk City 230kV	On schedule for 2009
GEN-2006-044	370	SPS	*Hitchland 345kV	On Suspension
GEN-2006-045	240	SPS	Tap and Tie both Potter County - Plant X 230kV and Bushland - Deaf Smith 230kV	On Suspension
GEN-2006-046	131	OKGE	Dewey 138kV	On Schedule for 2010
GEN-2006-047	240	SPS	Tap and Tie both Potter County - Plant X 230kV and Bushland - Deaf Smith 230kV	On Schedule for 2013
GEN-2006-049	400	SPS	*Hitchland - Finney 345kV	IA Pending
GEN-2007-002	160	SPS	Grapevine 115kV	On Suspension
GEN-2007-005	200	SPS	Pringle 115kV	Under Study (ICS-2008-001)
GEN-2007-006	160	OKGE	Roman Nose 138kV	On Suspension
GEN-2007-008	300	SPS	Grapevine EHV 230kV	Under Study (ICS-2008-001)
GEN-2007-011	135	SUNC	Syracuse 115kV	On Schedule
GEN-2007-011N08	81	NPPD	Bloomfield 115kV	On-Line
GEN-2007-013	99	SUNC	Selkirk 115kV	IA Pending
GEN-2007-015	135	WERE	Tap Humboldt – Kelly 161kV	IA Pending
GEN-2007-017	101	MIPU	Tap Maryville – Clarinda 161kV	12/31/2009
GEN-2007-021	201	OKGE	*Tatonga 345kV	Under Study (ICS-2008-001)
GEN-2007-025	300	WERE	Tap Woodring – Wichita 345kV	Under Study (ICS-2008-001)
GEN-2007-032	150	WFEC	Tap Clinton Junction – Clinton 138kV	Under Study (ICS-2008-001)
GEN-2007-034	150	SPS	Tap Eddy – Tolk 345kV	Under Study (ICS-2008-001)
GEN-2007-038	200	SUNC	Spearville 345kV	Under Study (ICS-2008-001)
GEN-2007-043	300	AEPW	Tap Lawton Eastside – Cimarron 345kV	Under Study (ICS-2008-001)
GEN-2007-044	300	OKGE	*Tatonga 345kV	Under Study (ICS-2008-001)
GEN-2007-045	171	SPS	Conway 115kV	Under Study (ICS-2008-001)
GEN-2007-046	200	SPS	*Hitchland 115kV	Under Study (ICS-2008-001)
GEN-2007-048	400	SPS	Tap Amarillo South – Swisher 230kV	Under Study (ICS-2008-001)
GEN-2007-050	170	OKGE	*Woodward 138kV	Under Study (ICS-2008-001)
GEN-2007-051	200	WFEC	Mooreland 138kV	Under Study (ICS-2008-001)
GEN-2007-052	150	WFEC	Anadarko 138kV	Under Study (ICS-2008-001)
GEN-2007-053	110	MIPU	Tap Maryville – Clarinda 161kV	Under Study (ICS-2008-001)

Request	Amount	Area	Requested/Proposed Point of Interconnection	Status or In-Service Date
GEN-2007-057	35	SPS	Moore County East 115kV	Under Study (ICS-2008-001)
GEN-2007-062**	765	OKGE	*Woodward 345kV	Under Study (ICS-2008-001)
GEN-2008-003	101	OKGE	*Woodward EHV 138kV	Under Study (ICS-2008-001)
GEN-2008-008	60	SPS	Graham 115kV	Under Study (ICS-2008-001)
GEN-2008-009	60	SPS	San Juan Mesa Tap 230kV	Under Study (ICS-2008-001)
GEN-2008-013	300	OKGE	Tap Woodring – Wichita 345kV	Under Study (ICS-2008-001)
GEN-2008-014	150	SPS	Tap Tuco – Oklaunion 345kV	Under Study (ICS-2008-001)
GEN-2008-016	248	SPS	Grassland 230kV	Under Study (ICS-2008-001)
GEN-2008-017	300	SUNC	Setab 345kV	Under Study (ICS-2008-001)
GEN-2008-018	405	SUNC	Finney 345kV	Under Study (ICS-2008-001)
GEN-2008-019**	300	OKGE	*Tatonga 345kV	Under Study (ICS-2008-001)
GEN-2008-119O	60	OPPD	Tap Humboldt – Kelly 161kV	On-Line
Broken Bow	8.3	NPPD	Broken Bow 115kV	On-Line
Ord	13.9	NPPD	Ord 115kV	On-Line
Stuart	2.1	NPPD	Stuart 115kV	On-Line
Genoa	4	NPPD	Genoa 115kV	On-Line
AECI-1	400	AECI	Tap Cooper – Fairport 345kV	On-Line
AECI-2	99	AECI	Lathrop 161kV	On-Line
AECI-3	201	AECI	Osborn 161kV	On-Line
AECI-4	150	AECI	Tap Fairfax – Fairfax Tap 138kV	On-Line
AECI-5	100	AECI	Maryville 161kV	On-Line
Llano Estacado	80	SPS	Llano Wind Farm Tap 115kV	On-Line
Distribution Wind	90	SPS	DUMAS_19ST 115kV	On-Line
			Etter 115kV	On-Line
			Sherman 115kV	On-Line
			Spearman 115kV	On-Line
			Texas County 115kV	On-Line
Blue Canyon II	153	WFEC	Washita 138kV (GEN-2003-004)	On-Line
			Washita 138kV (GEN-2004-023)	On-Line
			Washita 138kV (GEN-2005-003)	On-Line
Montezuma	110	MKEC	Haggard 115kV	On-Line
GROUPED TOTAL	**17,830.2**			

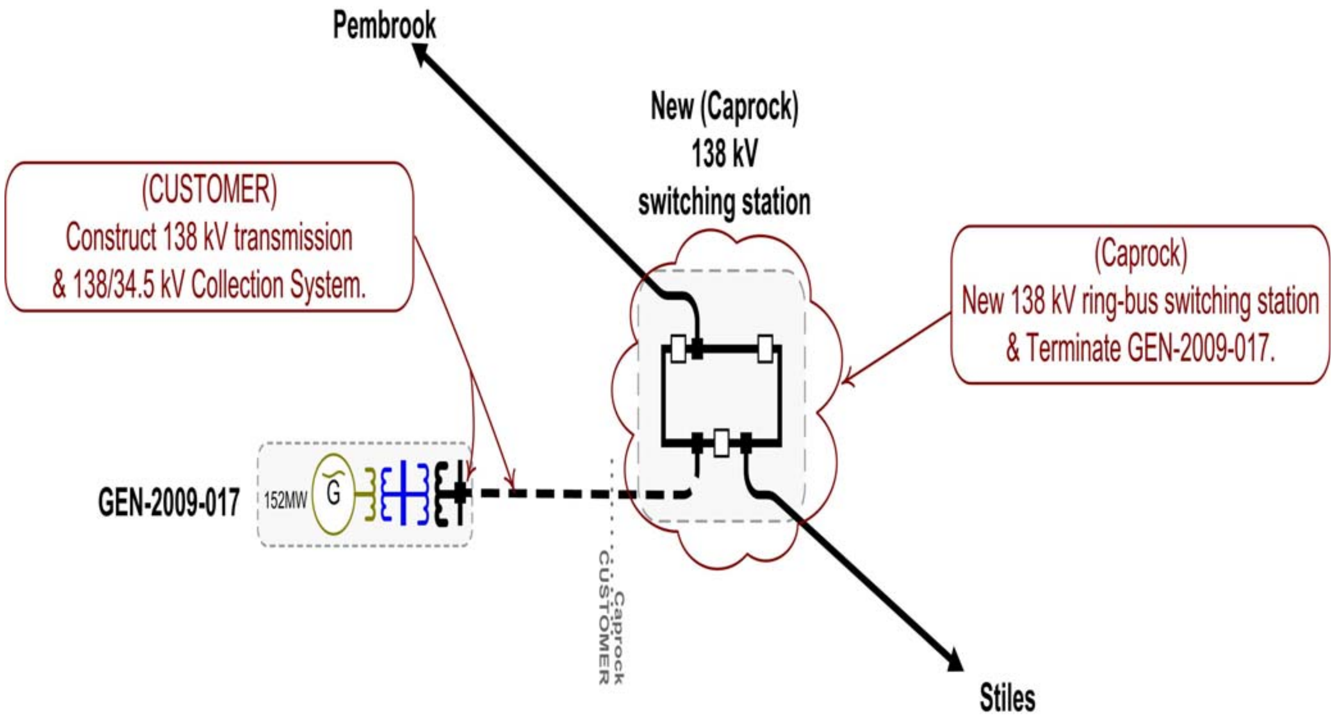
***** Planned Facility

C: Study Groupings

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	Norton 115kV
	GEN-2005-010	160	SPS	Tap Roosevelt County - Tolk West 230kV (Single Ckt Tap)
	GEN-2005-015	150	SPS	Tap TUCO - Oklaunion 345kV
	GEN-2007-034	150	SPS	Tap Eddy – Tolk 345kV
	GEN-2008-008	60	SPS	Graham 115kV
	GEN-2008-009	60	SPS	San Juan Mesa Tap 230kV
	GEN-2008-014	150	SPS	Tap Tuco – Oklaunion 345kV
	GEN-2008-016	248	SPS	Grassland 230kV
	PRIOR QUEUED SUBTOTAL	**1,238**		
Cluster	**Request**	**Amount**	**Area**	**Proposed Point of Interconnection**
S Pandle	GEN-2009-017	151.8	SPS	Tap Pembrook – Stiles 138kV
	SOUTH PANHANDLE/NM SUBTOTAL	**151.8**		
	AREA SUBTOTAL	**1,389.8**		

D: Proposed Point of Interconnection One line Diagrams

GEN-2009-017



E: Cost Allocation per Interconnection Request

This section shows each Generation Interconnection Request Customer and their Direct Assigned Facilities and Network Upgrades upon which they have an impact in this study assuming all prior queued projects remain in the queue and achieve commercial operation.

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

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

Appendix E. - Cost Allocation Per Request

Interconnection Request	Allocated Costs	E + C Costs
GEN-2009-017		
GEN-2009-017 Interconnection Costs**	$2,000,000.00	$2,000,000.00
See Oneline Diagram. **Final costs TBD by Caprock.		
Total	**$2,000,000.00**	

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

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

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

If a higher queued interconnection request (listed in Appendix B.) withdraws or terminates their LGIA the Network Upgrades assigned to the higher queued requests may be reallocated to the remaining requests that have an impact on the Network Upgrade under a restudy. The actual costs allocated to each Generation Interconnection Request Customer will be determined at the time of a restudy.

Additionally, Expansion Plan (STEP), Aggregate Study, and Balanced Portfolio assigned projects are also included in this table so that the Customer will know that interconnection service may be delayed until the completion of these projects.

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

Appendix F. - Cost Allocation Per Request

(Including Previously Allocated Network Upgrades*)

Interconnection Request	Upgrade Type	Allocated Costs	E + C Costs
GEN-2009-017			
GEN-2009-017 Interconnection Costs** See Oneline Diagram. **Final costs TBD by Caprock.	Current Study Allocation	$2,000,000.00	$2,000,000.00
GRASSLAND 230/115KV TRANSFORMER Per Cluster I Impact Restudy	Previously Assigned		$3,000,000.00
GRASSLAND 230/115KV TRANSFORMER Per Cluster 1 Impact Restudy	Previously Assigned		$3,000,000.00
Anadarko - Midpoint(Wheeler) 345KV CKT 1 Per Cluster I Impact Restudy	Previously Allocated		$130,000,000.00
Medicine Lodge - Wichita 345KV CKT 1 Per Cluster I Impact Restudy	Previously Allocated		$90,000,000.00
Comanche - Medicine Lodge 345KV CKT 1 Per Cluster I Impact Restudy	Previously Allocated		$60,000,000.00
Knoll - Spearville 345KV CKT 1 Total E & C Cost for Spearville-Knoll-Axtell Project	Previously Allocated		$236,000,000.00
Sunnyside - Hugo 345KV CKT 1 Per 2006-AG3-AFS11	Previously Allocated		$120,000,000.00
	Current Study Total	**$2,000,000.00**	

* Current Study Requests' Costs of Previously Allocated Network Upgrades will be determined by a restudy, if neccesary.

G: Cost Allocation per Proposed Study Network Upgrade

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

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

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

Appendix G. - Cost Allocation Per Upgrade Facility

Upgrade Facility		Allocated Costs	E + C Costs
GEN-2009-017 Interconnection Costs**			**$2,000,000.00**
See Oneline Diagram. **Final costs TBD by Caprock.			
GEN-2009-017		$2,000,000.00	
	Total	**$2,000,000.00**	

H: <u>FCITC Analysis at 150MW (No Upgrades)</u>

See Attachment

Source	Sink	Element	Direction	TDF	Rating	Loading	Contingency
G09_017	FOOTPRINT_IM	'GRASSLAND INTERCHANGE 230/115KV TRANSFORMER CKT 1'	FROM->TO	0.39544	115	128.7965	'GRASSLAND INTERCHANGE - JONES_BUS2 6230.00 23(
G09_017	FOOTPRINT_IM	'GRASSLAND INTERCHANGE - LYNN COUNTY INTERCHANGE 115KV CKT 1'	FROM->TO	0.39376	159.6	107.2456	'GRASSLAND INTERCHANGE - JONES_BUS2 6230.00 23(
G09_017	FOOTPRINT_IM	'HOBBS_INT 6 230.00 230/115KV TRANSFORMER CKT 1'	FROM->TO	0.38736	148.7	101.2132	'HOBBS_INT 6 230.00 - LEA COUNTY INTERCHANGE 230

I: Stability Study for Group 6

POWER SYSTEMS DIVISION
GRID SYSTEMS CONSULTING

System Impact Study for SPP DISIS-2009-001 Group 6

REPORT NO.: 2009-E4032-01R0
Issued On: January 12, 2010
Revised On: January 29, 2010

Prepared for:
Southwest Power Pool, Inc.

ABB Inc.
Power Systems Division
Grid Systems Consulting
940 Main Campus Drive, Suite 300
Raleigh, NC 27606

Legal Notice

ABB Inc – Grid Systems Consulting **Technical Report**

Southwest Power Pool, Inc.	**No.** 2009-E4032-01R1	
System Impact Study for SPP DISIS-2009-017 Group 6	Date: 01/12/2010	# Pages 39

Author(s): Sheng Yang

Reviewed by: Amit Kekare

Approved by: Willie Wong

Executive Summary

Southwest Power Pool, Inc. (SPP) has commissioned ABB Inc. to perform a system impact study for 150 MW of wind-based generation (known as DISIS-2009-001 Group 6) on the SPP system. The proposed wind farm project is located in West Texas. Below are the details of the DISIS-2009-001 Group 6 wind farm project:

Request	Size	Wind Turbine Technology	Point of Interconnection	County
GEN-2009-017	150	Siemens 2.3 MW	Tap Pembrook (522960) – Stiles (522966) 138kV. Bus # 570917	Reagan, Texas

The main objectives of this study were

1) To determine the need of reactive power compensation, if any, for the proposed wind farm
2) To determine the impact of proposed GEN-2009-017 (150 MW) generation on system stability and the nearby transmission system and generating stations.
3) To validate the compliance with FERC LVRT requirement for wind farm.

To achieve these objectives the following analyses were performed on the 2010 Summer Peak and 2009 Winter Peak system conditions with GEN-2009-017 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 DISIS-2009-001 Group6 wind farm project GEN-2009-017. The results of power factor analysis indicated that the proposed GEN-2009-017 project would require 60 Mvar of additional shunt compensation (e.g. shunt capacitor) to meet the power factor requirement.

Power factor analysis for Reduced Size GEN-2009-017 Wind Farm (60MW)

The results indicated that the reduced size GEN-2009-017 wind farm (60MW) 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. No additional reactive power support (e.g. shunt capacitor) is needed at the POI.

Stability Analysis

The stability analysis was performed to determine the impact, if any, of the proposed DISIS-2009-001 Group 6 project (GEN-2009-017) on the stability of the SPP system. The significant results of stability analysis are as follows:

Wind farms tripping due to undervoltage

GEN-2005-010 tripped following two (2) faults in 2010 Summer Peak and 2009 Winter Peak conditions in both WITH and WITHOUT GEN-2009-017 project. Similarly, GEN-2008-014 tripped following one (1) fault in the 2009 Winter Peak system condition in both WITH and WITHOUT the GEN-2009-017 project.

The proposed GEN-2009-017 wind farm tripped due to undervoltage/overfrequency protection following fifteen (15) faults for both 2010 Summer Peak and 2009 Winter Peak system conditions, and one (1) faults for only the 2009 Winter Peak system condition..

Local area voltage and GEN-2009-017 parameter oscillation

Undamped oscillations were observed in local area voltages following several faults for both 2010 Summer Peak and 2009 Winter Peak conditions. Such undamped oscillations were not observed WITHOUT the proposed GEN-2009-017 project.

Stability Analysis for Reduced Size GEN-2009-017 Wind Farm (60MW)

Per SPP request the Group 6 (GEN-2009-017) project output was reduced to 60 MW. All the faults were repeated on both, summer peak and winter peak, system conditions. The results indicated that the system would be STABLE following all the faults with the GEN-2009-017 at reduced output (60 MW).

FERC Order 661A Compliance

Selected faults were simulated at the Point of Interconnection (POI) of the proposed GEN-2009-017 wind farm to determine the compliance with FERC 661 – A post-transition period LVRT standard. The results indicated that the proposed project DOES NOT meet the FERC LVRT requirement for wind farms.

Next, these selected faults were repeated at the POI with the Group 6 (GEN-2009-017) project with reduced output (60 MW). The results indicated that the reduced size wind farm project GEN-2009-017 meets the FERC LVRT criteria for the interconnection of the wind farm generation (FERC Order 661 – A).

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	01/12/10	S.Yang	A. Kekare	W. Wong
1	Updated results with reduced project size	01/29/10	S.Yang	A. Kekare	W. Wong
DISTRIBUTION: Charles Hendrix – Southwest Power Pool, Inc. Ray Offenbacker – Southwest Power Pool, Inc. Juliano Schramm Freitas – 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 150 MW of wind-based generation (known as DISIS-2009-001 Group 6) on the SPP system. The proposed wind farm is located in West Texas. Figure 1-1 shows the locations of the project.

The study evaluated the impact of the DISIS-2009-001 Group 6 generation project GEN-2009-017 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 farm.
2) To determine the impact of proposed GEN-2009-017 (150 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 2009 Winter Peak system conditions with GEN-2009-017 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.

The study was performed on 2010 Summer Peak and 2009 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 6 Projects

Request	Size	Wind Turbine Model	Point of Interconnection	County
GEN-2009-017	150	Siemens 2.3 MW	Tap Pembrook (522960) – Stiles (522966) 138kV. Bus # 570917	Reagan, Texas

1.1 REPORT ORGANIZATION

This report is organized as follows:

Section 2: Description of GEN-2009-017
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.

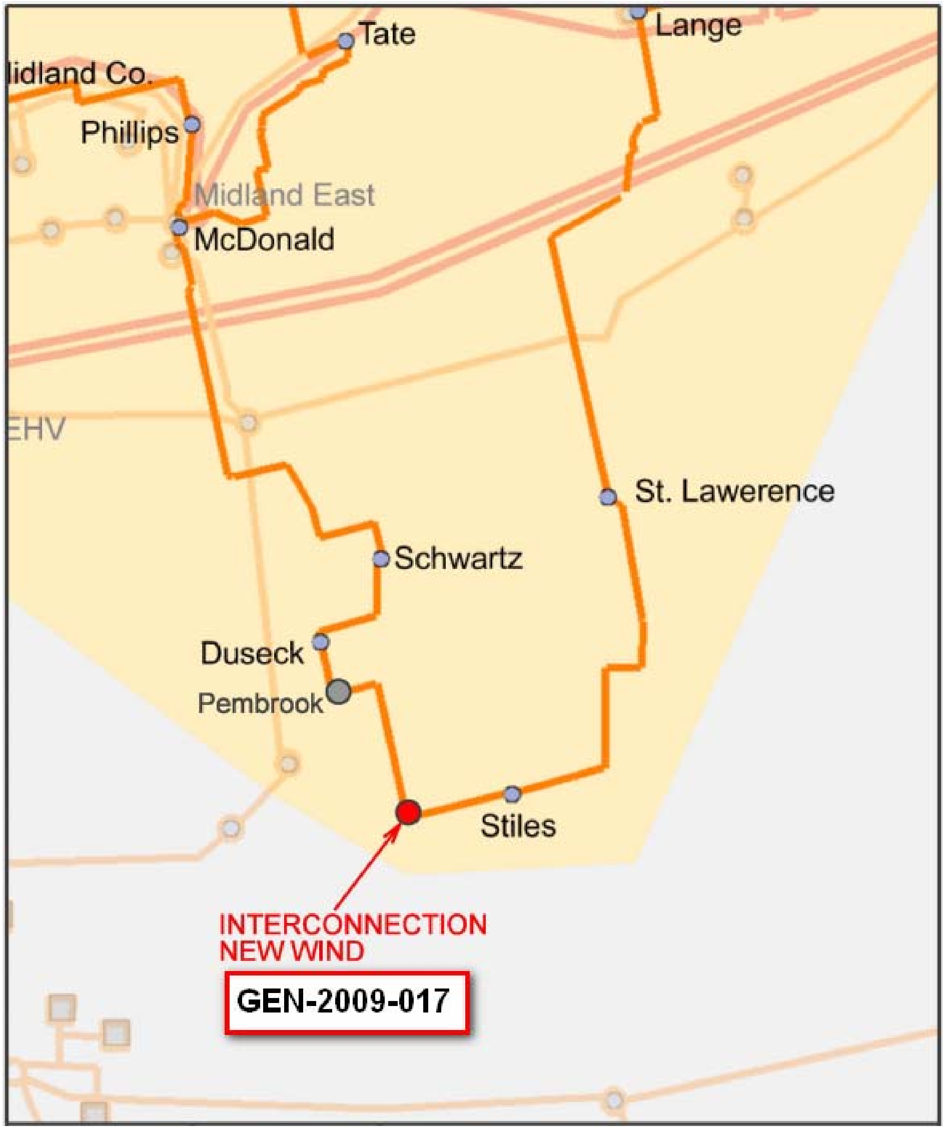


Figure 1-1: Group 6 Project GEN-09-017 Location

2 DESCRIPTION OF GEN-2009-017

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

Gen-2009-017

- Wind farm rating: 150 MW
- Interconnection:
  - Voltage: 138 kV
  - Location: Interconnection via a 138 kV radial transmission line into a new 138 kV interconnection bus (POI #570917) on Pembrook – Stiles 138 kV line in Reagan county, Texas
  - Transformer: One (1) 3-winding transformer connecting to the 138 kV
  - MVA: 100/133/167 MVA
  - Voltage: 138/34.5/13.8 kV
  - Z: 9 % on 100 MVA; X/R=40
- Wind Turbines:
  - Number: Sixty-six (66)
  - Manufacturer: SIEMENS
  - Type: Asynchronous

  Machine Terminal voltage: 690 V
  - Rated Power: 2.3 MW
  - Frequency: 60 Hz
  - Generator Step-up Transformer
    - MVA: 2.6 MVA
    - High voltage: 34.5 kV,
    - Low voltage: 0.69 kV
    - Z: 6% on 2.6 MVA; X/R=7.1
- Fault Ride-through: Default manufacturer under/over voltage and frequency protection.
- PSSE Model Used: SMK203_model

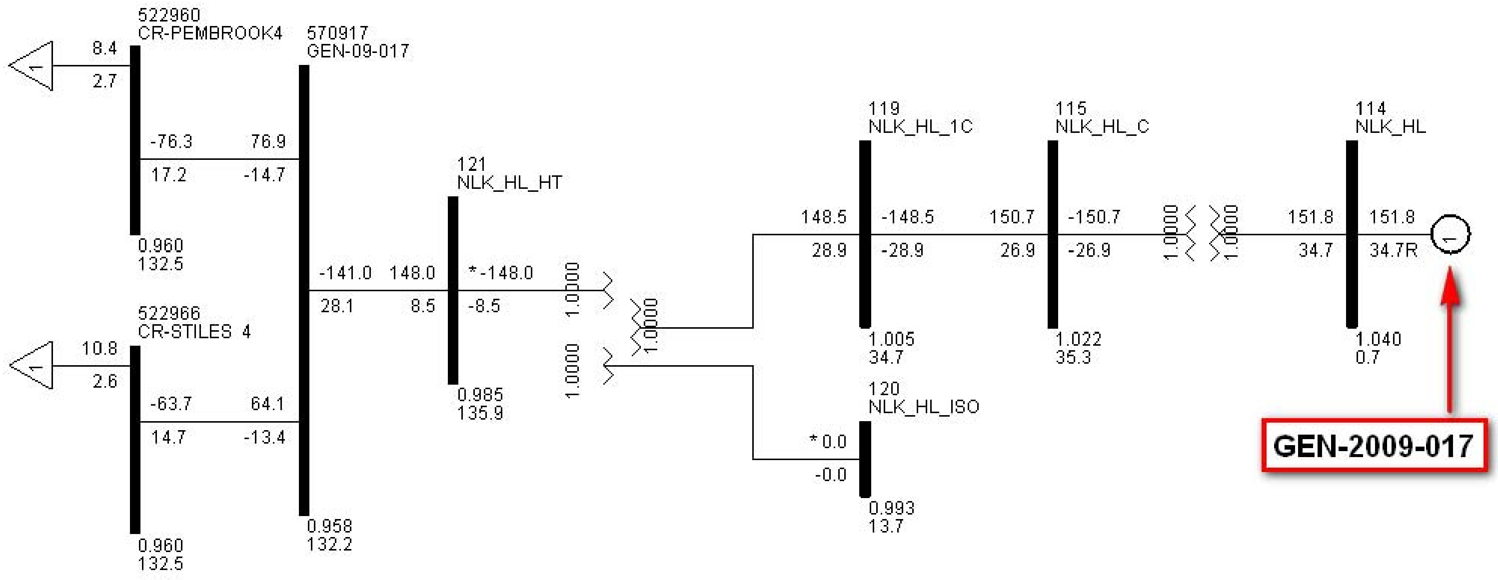


Figure 2-1: One-line Diagram for GEN-2009-017 Project

3 STUDY METHODOLOGY

3.1 POWER FACTOR ANALYSIS

SPP transmission planning criteria[1] requires the generation interconnection projects to maintain the power factor at the Point of Interconnection (POI) to near-unity for system intact conditions and within lead/lag 0.95 p.f. range in post-contingency conditions.

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 project will meet the power factor requirement at the Point of Interconnection (POI) in system intact and contingency conditions.

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 wind farm 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 wind farm 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 impact, if any, of the GEN-2009-017 wind farm project 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:

"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."

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

Stability analysis was performed using Siemens-PTI's PSS/E^{TM} dynamics program V30.3.3. 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 GEN-2009-017 Project.

4 MODEL DEVELOPMENT

Two power flow cases – “DISIS_10SP-G6.sav” and “DISIS_09WP-G6.sav” – representing the 2010 Summer Peak and 2009 Winter Peak system conditions were provided by SPP. The base cases included the GEN-2009-017 (150 MW) wind farm project. These cases were used for performing the studies.

Figure 4-1 and Figure 4-2 show the one-line diagram in the local area of GEN-2009-017 project for 2010 Summer Peak and 2009 Winter Peak system conditions respectively.

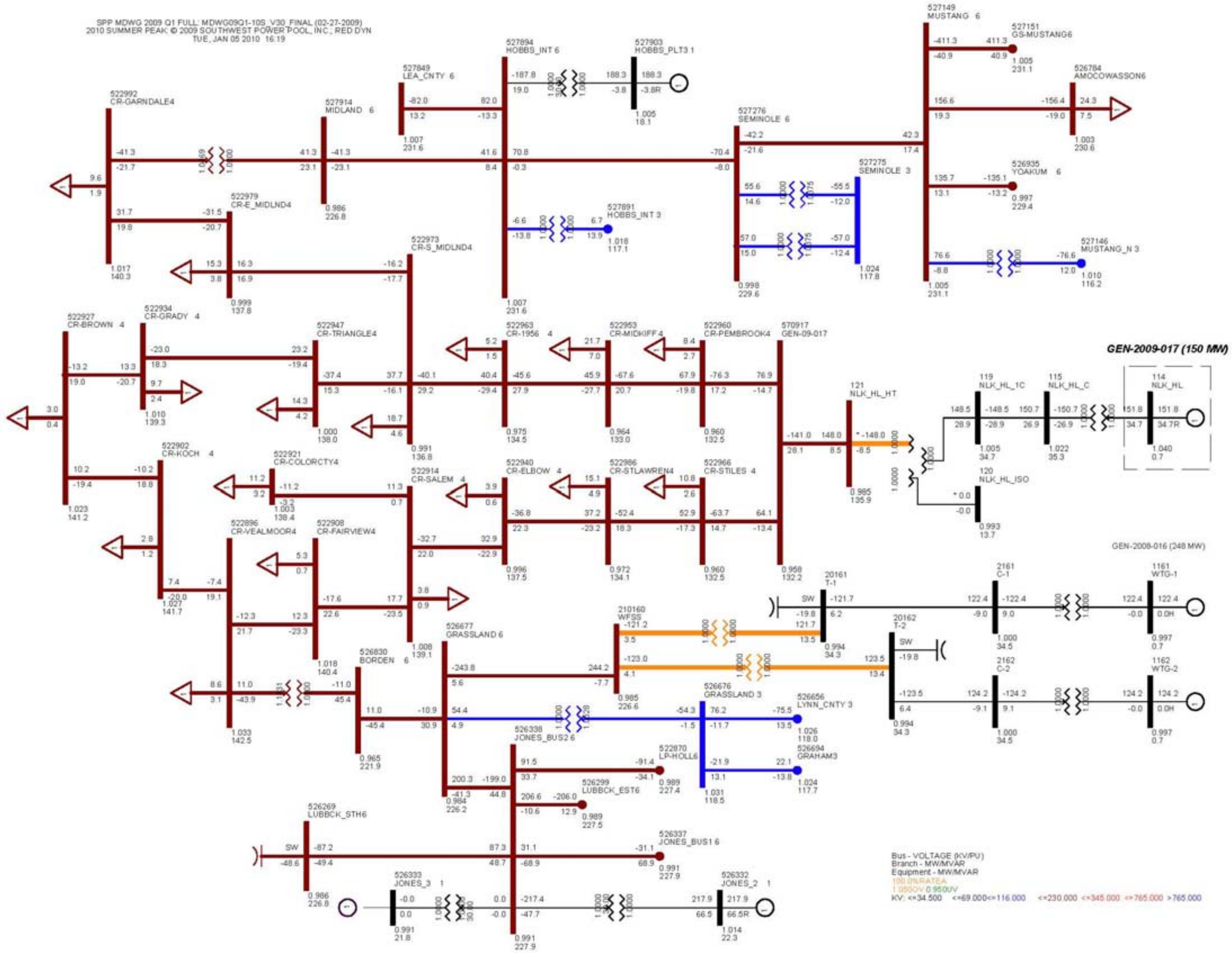


Figure 4-1: One-line Diagram of the local area with GEN-2009-017 (2010 Summer Peak)

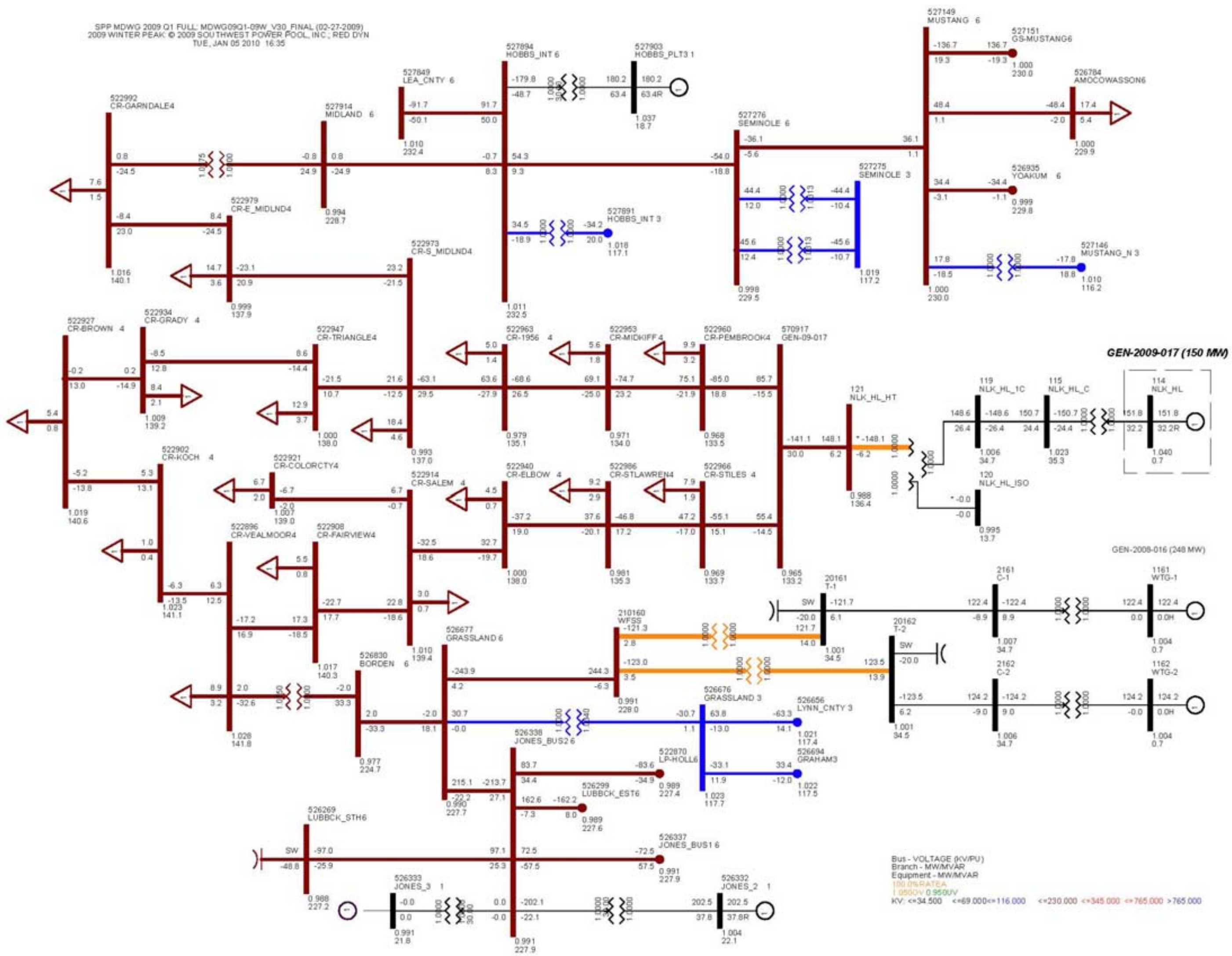


Figure 4-2: One-line Diagram of the local area with GEN-2009-017 (2009 Winter Peak)

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	Contingency Description
CONT_01	527802 EDDY_CNTY 7 345 - 527800 EDDY_CNTY 6 230 - 527796 EDDY_TER 13.2 ckt 1
CONT_02	210340 2007-34T 345 - 527802 EDDY_CNTY 7 345 ckt 1
CONT_03	210340 2007-34T 345 - 525549 TOLK 7 345 ckt 1
CONT_04	525549 TOLK 7 345 - 525543 TOLK_TAP 6 230 - 525537 TOLK_TER 13.2 ckt 1
CONT_05	525524 TOLK_EAST 6 230 - 525830 TUCO_INT 6 230 ckt 1
CONT_06	526656 LYNN_CNTY 3 115 - 526676 GRASSLAND 3 115 ckt 1
CONT_07	526677 GRASSLAND 6 230 - 526676 GRASSLAND 3 115 ckt 1
CONT_08	526677 GRASSLAND 6 230 - 526830 BORDEN 6 230 ckt 1
CONT_09	526677 GRASSLAND 6 230 - 526338 JONES_BUS2 6 230 ckt 1
CONT_10	526299 LUBBCK_EST6 230 - 526338 JONES_BUS2 6 230 ckt 1
CONT_11	525830 TUCO_INT 6 230 - 526337 JONES_BUS1 6 230 ckt 1
CONT_12	525213 SWISHER 6 230 - 525830 TUCO_INT 6 230 ckt 1
CONT_13	525832 TUCO_INT 7 345 - 525830 TUCO_INT 6 230 - 525824 TUCO_TER 1 13.2 ckt 1 525832 TUCO_INT 7 345 - 525830 TUCO_INT 6 230 - 525825 TUCO_2 13.2 ckt 2
CONT_14	525832 TUCO_INT 7 345 - 560813 G05-15 345 ckt 1
CONT_15	511456 O.K.U.-7 345 - 560813 G05-15 345 ckt 1
CONT_16	511456 O.K.U.-7 345 - 511468 L.E.S.-7 345 ckt 1
CONT_17	525832 TUCO_INT 7 345 - 525835 MIDPT_BUS 345 ckt 1
CONT_18	522960 CR-PEMBROOK4 138 - 570917 GEN-09-017 138 ckt 1
CONT_19	522966 CR-STILES 4 138 - 570917 GEN-09-017 138 ckt 1
CONT_20	527849 LEA_CNTY 6 230 - 527894 HOBBS_INT 6 230 ckt 1
CONT_21	527276 SEMINOLE 6 230 - 527894 HOBBS_INT 6 230 ckt 1
CONT_22	527894 HOBBS_INT 6 230 - 527914 MIDLAND 6 230 ckt 1
CONT_23	522947 CR-TRIANGLE4 138 - 522973 CR-S_MIDLND4 138 ckt 1
CONT_24	522896 CR-VEALMOOR4 138 - 522902 CR-KOCH 4 138 ckt 1

5.1 Power Factor Analysis results for GEN-2009-017

The proposed GEN-2009-017 wind farm (150 MW) will be comprised of Siemens 2.3 MW wind turbine generators. These wind turbine generators are asynchronous induction generators with a reactive power capability of lead/lag 0.90 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 (GEN-2009-017 138 kV). The VAR generator was set to hold the 138 kV POI voltage consistent with the pre-contingency voltage schedule in the provided base cases or 1.0 p.u. (whichever was higher). 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 2009 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-2009-017 POI (MVAR)

Contingency	2010 Summer Peak	2009 Winter Peak
SYSTEM INTACT (ALL LINES IN-SERVICE)	56.2(1)	51.6(1)
CONT_01	55.5	51.6
CONT_02	55.5	51.6
CONT_03	56.6	51.6
CONT_04	56.6	51.6
CONT_05	58.3	52.0
CONT_06	56.0	52.2
CONT_07	55.3	51.4
CONT_08	79.1	70.0
CONT_09(2)	**---**	**---**
CONT_10	56.0	51.6
CONT_11	55.4	51.5
CONT_12	56.2	51.6
CONT_13	55.5	51.6
CONT_14	56.1	51.6
CONT_15	55.9	51.6
CONT_16	55.8	51.6
CONT_17	55.9	51.6
CONT_18	**90.7**	**93.2**
CONT_19	75.6	72.5
CONT_20	56.8	51.7
CONT_21	56.5	51.6
CONT_22	68.3	64.6
CONT_23	60.8	55.3
CONT_24	60.8	55.8

Note:-

1. The reactive power capability of the wind farm was set to unity p.f at machine terminal (i.e Qmax=Qmin=Qgen= 0 Mvar).
2. Solution Not Converged WITH and WITHOUT GEN-2009-017

The results indicated that the '*CONT_18*' involving loss of GEN-09-017 POI – Pembrook 138 kV line will yield the maximum reactive power output 2010 Summer Peak and 2009 Winter Peak conditions.

In addition to the above analysis, the list of contingencies was repeated without the VAR generator at the POI. The reactive power capability of the wind farm was enabled and the voltage at the POI was monitored. The results of the contingency analysis are included in Appendix B. The '*CONT_09*' and '*CONT_18*' did not converge without the VAR generator at the POI.

Per SPP suggestion to meet the Power Factor criteria, a shunt compensation (e.g. shunt capacitor bank) was added at the 138 kV POI bus (new tap on Pembrook – Stiles 138 kV). The most limiting contingency '*CONT_18*' was repeated. Table 5-3 summarizes the results. The results indicated that the proposed GEN-2009-017 will require 60 Mvar of additional shunt compensation (e.g. shunt capacitor) at the POI 138 kV bus to meet the power factor requirement.

Table 5-3: Voltage & p.f. at POI with the shunt compensation: GEN-2009-017

System Condition		Voltage (p.u.)	P.F.
2010 Summer Peak	System Intact	1.005	0.9610
	Post-contingency (1)	1.001	0.9628
2009 Winter Peak	System Intact	1.004	0.9616
	Post-contingency (1)	1.009	0.9591

(1)'*CONT_18*': Loss of GEN-2009-017 POI – Pembrook 138 kV line

5.2 POWER FACTOR ANALYSIS RESULTS FOR REDUCED SIZE GROUP 6 PROJECT

Per SPP input, the size of DISIS-2009-001 Group 6 (GEN-2009-017 wind farm project) was reduced to **60 MW**. The contingencies from Table 5-1 were repeated on 2010 Summer Peak and 2009 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-2009-017 (60MW) POI (MVAR)

Contingency	2010 Summer Peak	2009 Winter Peak
SYSTEM INTACT (ALL LINES IN-SERVICE)	0.0	0.0
CONT_01	0.0	0.0
CONT_02	0.0	0.0
CONT_03	0.0	0.0
CONT_04	0.0	0.0
CONT_05	0.0	0.0
CONT_06	0.0	0.0
CONT_07	0.0	0.0
CONT_08	**22.2**	8.5
CONT_09	1.5	**13.1**
CONT_10	0.0	0.0
CONT_11	0.0	0.0
CONT_12	0.0	0.0

Contingency	2010 Summer Peak	2009 Winter Peak
CONT_13	0.0	0.0
CONT_14	0.0	0.0
CONT_15	0.0	0.0
CONT_16	0.0	0.0
CONT_17	0.0	0.0
CONT_18	0.0	0.0
CONT_19	0.0	0.0
CONT_20	0.0	0.0
CONT_21	0.0	0.0
CONT_22	11.5	0.0
CONT_23	0.0	0.0
CONT_24	1.2	0.0

The results indicated that the '*CONT_08*' involving loss of Grassland – Borden 230 kV line will yield the maximum reactive power output for the 2010 Summer Peak condition, and the '*CONT_09*' involving loss of Grassland – Jones 230 kV line will yield the maximum reactive power output for the 2009 Winter Peak condition,

Hence, the '*CONT_08*' and *'CONT_09'* were 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 reduced size GEN-2009-017 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, the reduced size GEN-2009-017 wind farm does not require any additional reactive power support (e.g. shunt capacitor).

Table 5-5: Voltage & p.f. at POI: Reduced size GEN-2009-017

System Condition		Voltage (p.u.)	P.F.
2010 Summer Peak	System Intact	1.011	1.0000
	Post-contingency (1)	0.966	0.9762
2009 Winter Peak	System Intact	1.037	0.9902
	Post-contingency (2)	0.994	0.9963

(1)'*CONT_08*': Loss of Grassland – Borden 230 kV line
(2)'*CONT_09*': Loss of Grassland – Jones 230 kV line

6 STABILITY ANALYSIS RESULTS

6.1 STABILITY ANALYSIS RESULTS

Stability simulations were performed to examine the transient behavior of the DISIS-2009-001 Group 6 (GEN-2009-017) and its impact 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
115/138/230/345	5 cycles	20 cycles

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

Twenty-four (24) three phase and twenty-four (24) 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 6 GEN-09-017

Fault No.	Fault Name	Description
1	FLT01-3PH	3 phase fault on the Eddy Co. 230kV (527800) to 345kV (527802) transformer, near the 230kV bus. a. Apply fault at the Eddy Co. 230kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
2	FLT02-1PH	*Single phase fault and sequence like previous*
3	FLT03-3PH	3 phase fault on the GEN-2007-034 (210340) to Eddy County (527802) 345kV line, near GEN-2007-034. a. Apply fault at the GEN-2007-034 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 GEN-2007-034 (210340) to Tolk (525549) 345kV line, near GEN-2007-034. a. Apply fault at the GEN-2007-034 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 Tolk 230kV (525543) to 345kV (525549) transformer, near the 230kV bus. a. Apply fault at the Tolk 230kV 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 the Tolk E (525524) to Tuco (525830) 230kV line, near Tolk E. a. Apply fault at the Tolk E 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
10	FLT10-1PH	*Single phase fault and sequence like previous*
11	FLT11-3PH	3 phase fault on the Grassland (526676) to Lynn Co. (526656) 115kV line, near Grassland. a. Apply fault at the Grassland 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
12	FLT12-1PH	*Single phase fault and sequence like previous*

Fault No.	Fault Name	Description
15	FLT15-3PH	3 phase fault on the Grassland 230kV (526677) to 115kV (526676) transformer, near the 230kV bus. a. Apply fault at the Grassland 230kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
16	FLT16-1PH	*Single phase fault and sequence like previous*
17	FLT17-3PH	3 phase fault on the Grassland (526677) to Borden (526830) 230kV line, near Grassland. a. Apply fault at the Grassland 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
18	FLT18-1PH	*Single phase fault and sequence like previous*
19	FLT19-3PH	3 phase fault on the Grassland (526677) to Jones (526338) 230kV line, near Grassland. a. Apply fault at the Grassland 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
20	FLT20-1PH	*Single phase fault and sequence like previous*
21	FLT21-3PH	3 phase fault on the Jones (526338) to Lubbock E (526299) 230kV line, near Jones Bus2. a. Apply fault at the Jones 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 Jones (526337) to Tuco (525830) 230kV line, near Jones Bus1. a. Apply fault at the Jones 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 Tuco (525830) to Swisher (525213) 230kV line, near Tuco. a. Apply fault at the Tuco 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 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.
28	FLT28-1PH	*Single phase fault and sequence like previous*
29	FLT29-3PH	3 phase fault on the GEN-2005-015 (560813) to Tuco (525832) 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.
30	FLT30-1PH	*Single phase fault and sequence like previous*
31	FLT31-3PH	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.
32	FLT32-1PH	*Single phase fault and sequence like previous*
33	FLT33-3PH	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.
34	FLT34-1PH	*Single phase fault and sequence like previous*
35	FLT35-3PH	3 phase fault on the Tuco (525832) to Wheeler/Midpoint (525835) 345kV line, near Tuco. a. Apply fault at the Tuco 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
36	FLT36-1PH	*Single phase fault and sequence like previous*

Fault No.	Fault Name	Description
37	FLT37-3PH	3 phase fault on the GEN-2009-017 (570917) to Pembrook (522960) 138kV line, near GEN-2009-017. a. Apply fault at the GEN-2009-017 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.
38	FLT38-1PH	*Single phase fault and sequence like previous*
39	FLT39-3PH	3 phase fault on the GEN-2009-017 (570917) to Stiles (522966) 138kV line, near GEN-2009-017. a. Apply fault at the GEN-2009-017 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.
40	FLT40-1PH	*Single phase fault and sequence like previous*
41	FLT41-3PH	3 phase fault on the Hobbs (527894) to Lea County (527849) 230kV line, near Lea County. a. Apply fault at the Lea County 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
42	FLT42-1PH	*Single phase fault and sequence like previous*
43	FLT43-3PH	3 phase fault on the Hobbs (527894) to Seminole (527276) 230kV line, near Seminole. a. Apply fault at the Seminole 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
44	FLT44-1PH	*Single phase fault and sequence like previous*
45	FLT45-3PH	3 phase fault on the Hobbs (527894) to Midland (527914) 230kV line, near Midland. a. Apply fault at the Midland 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
46	FLT46-1PH	*Single phase fault and sequence like previous*
47	FLT47-3PH	3 phase fault on the South Midland (522973) to Triangle (522947) 138kV line, near South Midland. a. Apply fault at the South Midland 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.
48	FLT48-1PH	*Single phase fault and sequence like previous*
49	FLT49-3PH	3 phase fault on the Vealmore (522896) to Koch (522902) 138kV line, near Koch. a. Apply fault at the Koch 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.
50	FLT50-1PH	*Single phase fault and sequence like previous*

Table 6-3 summarizes the stability analysis results for 2010 Summer Peak and 2009 Winter Peak system conditions. The plots for all the stability simulations are included in Appendix C.

Table 6-3: Results of stability analysis

FAULT	2010 Summer Peak		2009 Winter Peak	
	Without GEN-09-017	With GEN-09-017	Without GEN-09-017	With GEN-09-017
FLT01-3PH	STABLE	STABLE[4]	STABLE	STABLE[4]
FLT02-1PH	---	STABLE	---	STABLE
FLT03-3PH	---	STABLE	---	STABLE
FLT04-1PH	---	STABLE	---	STABLE
FLT05-3PH	---	STABLE	---	STABLE
FLT06-1PH	---	STABLE	---	STABLE
FLT07-3PH	GEN-05-10 tripped	GEN-05-10 tripped	GEN-05-10 tripped	GEN-05-10 tripped
FLT08-1PH	---	STABLE	---	STABLE
FLT09-3PH	GEN-05-10 tripped	GEN-05-10 tripped	GEN-05-10 tripped	GEN-05-10 tripped
FLT10-1PH	---	STABLE	---	STABLE
FLT11-3PH	---	STABLE	---	STABLE
FLT12-1PH	---	STABLE	---	STABLE
FLT15-3PH	STABLE	GEN-09-17 tripped[3]	STABLE	GEN-09-17 tripped[3]
FLT16-1PH	---	STABLE	---	STABLE
FLT17-3PH	STABLE[1]	GEN-09-17 tripped[2]	STABLE	GEN-09-17 tripped[2]
FLT18-1PH	STABLE	GEN-09-17 tripped[2]	STABLE	GEN-09-17 tripped[2]
FLT19-3PH	STABLE[1]	GEN-09-17 tripped[2]	STABLE	GEN-09-17 tripped[2]
FLT20-1PH	STABLE[4]	GEN-09-17 tripped[2]	STABLE	GEN-09-17 tripped[3]
FLT21-3PH	STABLE	GEN-09-17 tripped[2]	STABLE	GEN-09-17 tripped[2]
FLT22-1PH	---	STABLE	---	STABLE
FLT23-3PH	STABLE	GEN-09-17 tripped[2]	STABLE	GEN-09-17 tripped[2]
FLT24-1PH	STABLE	STABLE[4]	STABLE	STABLE[4]
FLT25-3PH	STABLE	STABLE[4]	STABLE	STABLE[4]
FLT26-1PH	---	STABLE	---	STABLE
FLT27-3PH	---	STABLE	---	STABLE
FLT28-1PH	---	STABLE	STABLE	STABLE
FLT29-3PH	---	STABLE	---	STABLE
FLT30-1PH	---	STABLE	---	STABLE
FLT31-3PH	---	STABLE	---	STABLE
FLT32-1PH	---	STABLE	---	STABLE
FLT33-3PH	---	STABLE	---	STABLE
FLT34-1PH	---	STABLE	---	STABLE
FLT35-3PH	STABLE	STABLE[4]	STABLE	STABLE[4]
FLT36-1PH	---	STABLE	---	STABLE
FLT37-3PH	STABLE	GEN-09-17 tripped[2]	STABLE	GEN-09-17 tripped[2]
FLT38-1PH	STABLE	GEN-09-17 tripped[2]	STABLE	GEN-09-17 tripped[2]
FLT39-3PH	STABLE	GEN-09-17 tripped[2]	STABLE	GEN-09-17 tripped[2]
FLT40-1PH	STABLE	GEN-09-17 tripped[2]	STABLE	GEN-09-17 tripped[2]
FLT41-3PH	STABLE	GEN-09-17 tripped[2]	STABLE	GEN-09-17 tripped[3]
FLT42-1PH	STABLE	STABLE[4]	STABLE	STABLE[4]
FLT43-3PH	STABLE	STABLE[4]	STABLE	STABLE[4]
FLT44-1PH	---	STABLE	---	STABLE
FLT45-3PH	STABLE	GEN-09-17 tripped[2]	STABLE	GEN-09-17 tripped[2]
FLT46-1PH	---	STABLE	STABLE	GEN-09-17 tripped[2]
FLT47-3PH	STABLE	GEN-09-17 tripped[3]	STABLE	GEN-09-17 tripped[2]
FLT48-1PH	STABLE	STABLE[4]	STABLE	STABLE[4]
FLT49-3PH	STABLE	GEN-09-17 tripped[3]	STABLE	GEN-09-17 tripped[2]
FLT50-1PH	STABLE	STABLE[4]	STABLE	STABLE[4]

1: Local area voltages drop down to 0.8 pu
2: Generator tripped by over frequency relay
3: Generator tripped by under voltage relay
4. Undamped oscillations in local area voltages

ABB

Wind farms tripping due to undervoltage

GEN-2005-010 tripped following two (2) faults in 2010 Summer Peak and 2009 Winter Peak conditions in both WITH and WITHOUT GEN-2009-017 project. Similarly, GEN-2008-014 tripped following one (1) fault in the 2009 Winter Peak system condition in both WITH and WITHOUT GEN-2009-017 project.

The proposed GEN-2009-017 wind farm tripped due to undervoltage/overfrequency protection following fifteen (15) faults for both 2010 Summer Peak and 2009 Winter Peak system conditions, and one (1) faults for only the 2009 Winter Peak system condition.

Undamped oscillations in local area voltages

Undamped oscillations were observed in local area voltages following FLT01-3PH, FLT-24-1PH, FLT25-3PH, FLT35-3PH, FLT42-1PH, FLT43-3PH, FLT48-1PH, and FLT50-1PH for both 2010 Summer Peak and 2009 Winter Peak conditions with proposed DISIS-2009-001.

Figure 6-1 through Figure 6-3 show the response of GEN-09-017 and the Pembrook 138 kV bus voltage following the FLT01-3PH: Loss of 3-winding Transformer Eddy CO 345/230/13.8 kV. The undamped oscillations were not observed in the case WITHOUT the proposed GEN-2009-017 project.

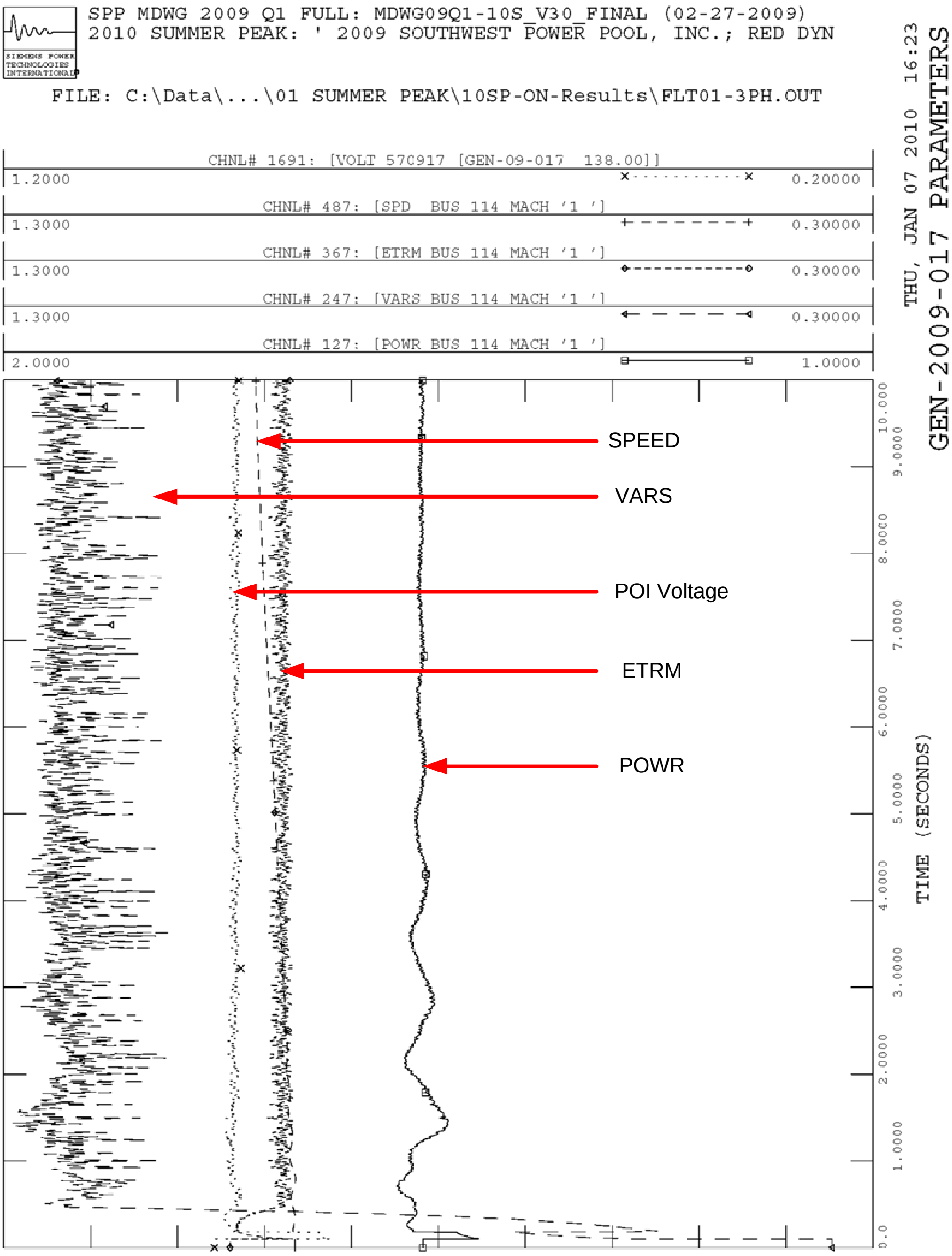


Figure 6-1: GEN-2009-017 Responses Following FLT01-3PH: Loss of 3-winding Transformer Eddy CO 345/230/13.8 kV

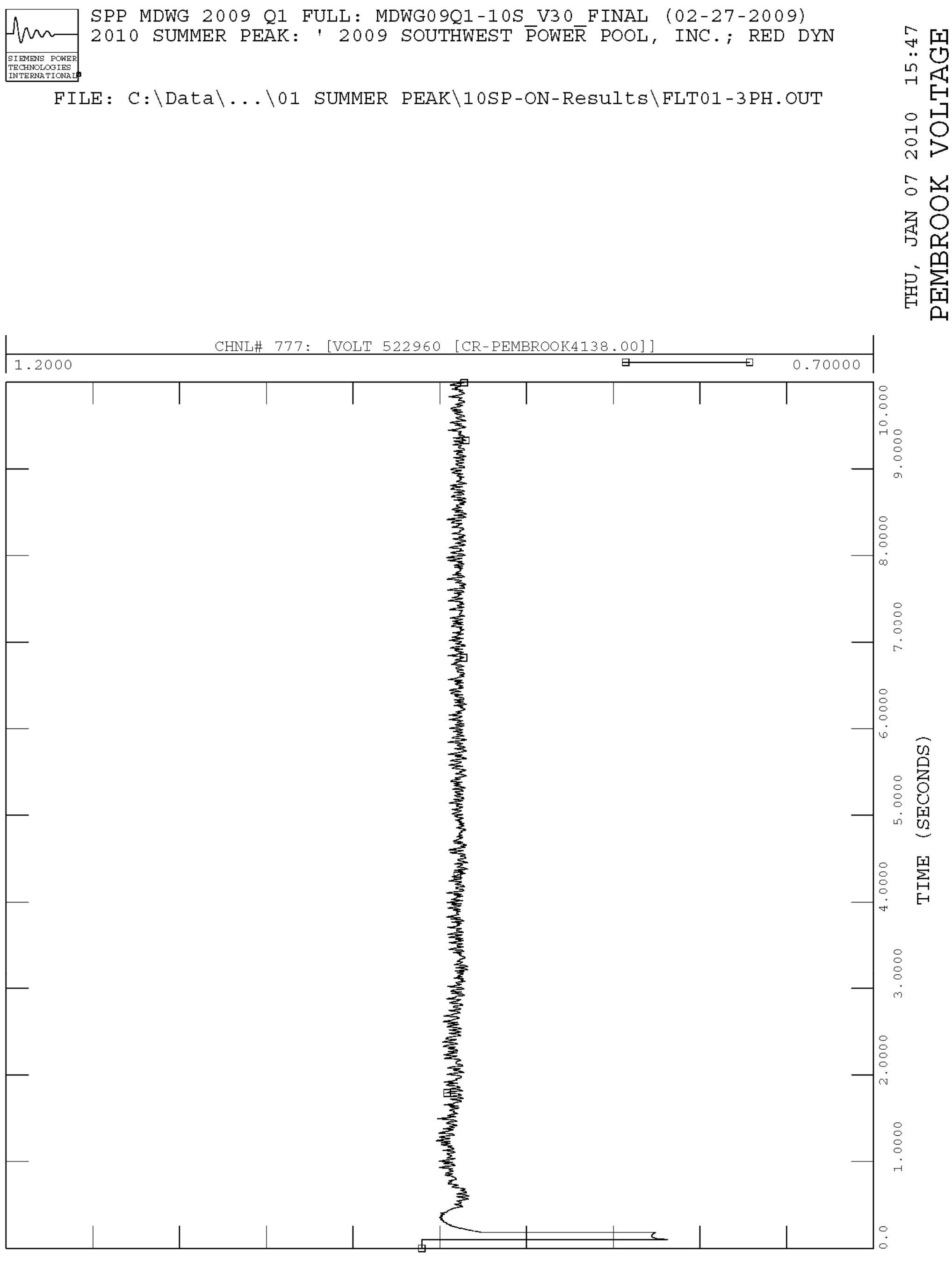


Figure 6-2: Pembrook 138 kV Bus Voltage Following FLT01-3PH <u>WITH</u> GEN-2009-017

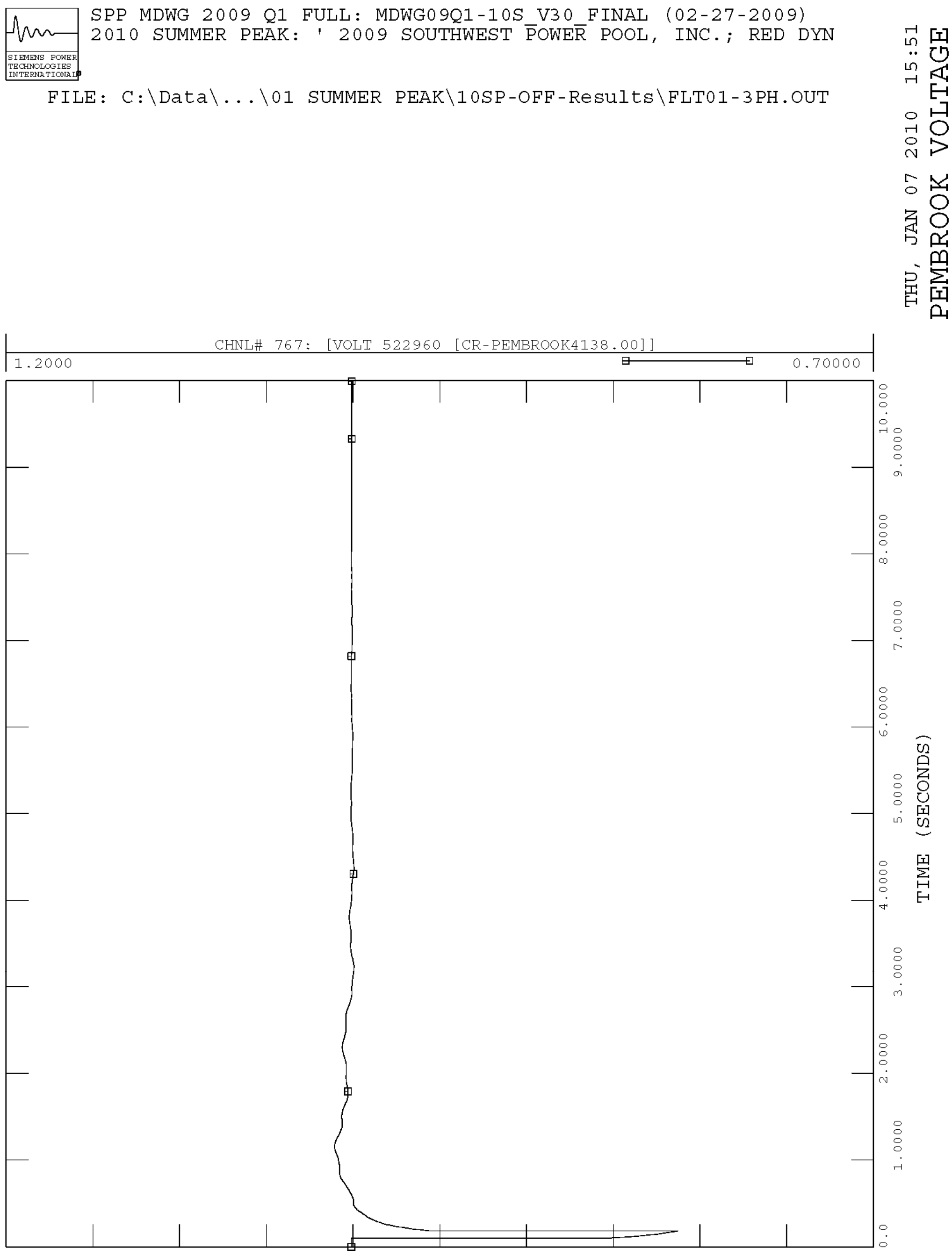


Figure 6-3: Pembrook 138 kV Bus Voltage Following FLT01-3PH WITHOUT GEN-2009-017

6.2 FERC LVRT Compliance

As explained in section 2, the proposed DISIS-2009-001 Group 6 (GEN-2009-017 wind farm project) was modeled with the low voltage ride through capacity. To determine the compliance of the wind farm projects total of four (4) faults were simulated. Faults were simulated at the POI of the wind farm project and normally cleared by tripping one transmission element. Table 6-4 lists the faults simulated for LVRT analysis.

Table 6-4: List of faults for FERC LVRT compliance

Fault Name	Description
FLT51-3PH-LVRT	3 phase fault on the GEN-2009-017 (570917) to Pembrook (522960) 138kV line, near GEN-2009-017. a. Apply fault at the GEN-2009-017 138kV bus. b. Clear fault after 9 cycles by tripping the faulted line.
FLT52-1PH-LVRT	Single phase fault on the GEN-2009-017 (570917) to Pembrook (522960) 138kV line, near GEN-2009-017. a. Apply fault at the GEN-2009-017 138kV bus. b. Clear fault after 15 cycles by tripping the faulted line.
FLT53-3PH-LVRT	3 phase fault on the GEN-2009-017 (570917) to Stiles (522966) 138kV line, near GEN-2009-017. a. Apply fault at the GEN-2009-017 138kV bus. b. Clear fault after 9 cycles by tripping the faulted line.
FLT54-1PH-LVRT	Single phase fault on the GEN-2009-017 (570917) to Stiles (522966) 138kV line, near GEN-2009-017. a. Apply fault at the GEN-2009-017 138kV bus. b. Clear fault after 15 cycles by tripping the faulted line.

Table 6-5 lists the results of LVRT analysis. It was observed that GEN-09-017 wind farm will trip in all faults at the POI bus in both 2010 Summer Peak and 2009 Winter Peak conditions. The results of the simulations indicated that the wind farm project GEN-09-017 DOES NOT meet the FERC LVRT criteria for the interconnection of the wind farm generation (FERC Order 661 – A). Plots for all the LVRT simulations are included in Appendix D.

Table 6-5: Results of analysis for FERC LVRT compliance

Fault Name	2010 Summer Peak	2009 Winter Peak
FLT51-3PH-LVRT	GEN-09-017 tripped by over frequency relay	GEN-09-017 tripped by over frequency relay
FLT52-1PH-LVRT	GEN-09-017 tripped by over frequency relay	GEN-09-017 tripped by over frequency relay
FLT53-3PH-LVRT	GEN-09-017 tripped by under voltage relay	GEN-09-017 tripped by under voltage relay
FLT54-1PH-LVRT	GEN-09-017 tripped by under voltage relay	GEN-09-017 tripped by under voltage relay

6.3 Stability Analysis for Reduced Size Group 6 Project

Per SPP input, the size of DISIS-2009-001 Group 6 (GEN-2009-017 wind farm project) was reduced to **60 MW**. All the faults from Table 6-2 were repeated. Table 6-6 summarizes the stability analysis results for the reduced size GEN-2009-017 wind farm for 2010 Summer Peak and 2009 Winter Peak system conditions. The plots for all stability simulations with reduced project size are included in Appendix E.

Table 6-6: Results of stability analysis for Reduced size GEN-2009-017

FAULT	2010 Summer Peak		2009 Winter Peak	
	Without GEN-09-017	With GEN-09-017	Without GEN-09-017	With GEN-09-017
FLT01-3PH	---	STABLE	---	STABLE
FLT02-1PH	---	STABLE	---	STABLE
FLT03-3PH	---	STABLE	---	STABLE
FLT04-1PH	---	STABLE	---	STABLE
FLT05-3PH	---	STABLE	---	STABLE
FLT06-1PH	---	STABLE	---	STABLE
FLT07-3PH	GEN-05-10 tripped	GEN-05-10 tripped	GEN-05-10 tripped	GEN-05-10 tripped
FLT08-1PH	---	STABLE	---	STABLE
FLT09-3PH	GEN-05-10 tripped	GEN-05-10 tripped	GEN-05-10 tripped	GEN-05-10 tripped
FLT10-1PH	---	STABLE	---	STABLE
FLT11-3PH	---	STABLE	---	STABLE
FLT12-1PH	---	STABLE	---	STABLE
FLT15-3PH	---	STABLE	---	STABLE
FLT16-1PH	---	STABLE	---	STABLE
FLT17-3PH	---	STABLE	---	STABLE
FLT18-1PH	---	STABLE	---	STABLE
FLT19-3PH	---	STABLE	---	STABLE
FLT20-1PH	---	STABLE	---	STABLE
FLT21-3PH	---	STABLE	---	STABLE
FLT22-1PH	---	STABLE	---	STABLE
FLT23-3PH	---	STABLE	---	STABLE
FLT24-1PH	---	STABLE	---	STABLE
FLT25-3PH	---	STABLE	---	STABLE
FLT26-1PH	---	STABLE	---	STABLE
FLT27-3PH	---	STABLE	STABLE	STABLE
FLT28-1PH	---	STABLE	STABLE	STABLE
FLT29-3PH	---	STABLE	---	STABLE
FLT30-1PH	---	STABLE	---	STABLE
FLT31-3PH	---	STABLE	---	STABLE
FLT32-1PH	---	STABLE	---	STABLE
FLT33-3PH	---	STABLE	---	STABLE
FLT34-1PH	---	STABLE	---	STABLE
FLT35-3PH	---	STABLE	---	STABLE
FLT36-1PH	---	STABLE	---	STABLE
FLT37-3PH	---	STABLE	---	STABLE
FLT38-1PH	---	STABLE	---	STABLE
FLT39-3PH	---	STABLE	---	STABLE
FLT40-1PH	---	STABLE	---	STABLE
FLT41-3PH	---	STABLE	---	STABLE
FLT42-1PH	---	STABLE	---	STABLE
FLT43-3PH	---	STABLE	---	STABLE
FLT44-1PH	---	STABLE	---	STABLE

FAULT	2010 Summer Peak		2009 Winter Peak	
	Without GEN-09-017	With GEN-09-017	Without GEN-09-017	With GEN-09-017
FLT45-3PH	---	STABLE	---	STABLE
FLT46-1PH	---	STABLE	---	STABLE
FLT47-3PH	---	STABLE	---	STABLE
FLT48-1PH	---	STABLE	---	STABLE
FLT49-3PH	---	STABLE	---	STABLE
FLT50-1PH	---	STABLE	---	STABLE

The results indicated that the reduced size GEN-2009-017 wind farm is stable following all faults for 2010 Summer Peak and 2009 Winter Peak conditions. Prior-queued windfarm project (GEN-2005-010) tripped following two (2) faults in 2010 Summer Peak and 2009 Winter Peak conditions in both WITH and WITHOUT Group 6 (GEN-2009-017) project.

In order to verify whether the proposed Group 6 (GEN-2009-017) project, at reduced output (60 MW), will meet the FERC LVRT criteria, all faults listed in Table 6-4 repeated. The results of simulations indicated that the reduced size wind farm project GEN-2009-017 meets the FERC LVRT criteria for the interconnection of the wind farm generation (FERC Order 661 – A). The plots for all LVRT simulations with reduced project size are included in Appendix F.

7 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 GEN-2009-017 (150 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 2009 Winter Peak cases, provided by SPP.

To achieve these objective the following analyses were performed on the 2010 Summer Peak and 2009 Winter Peak system conditions

- 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:

Power factor analysis

The power factor analysis was performed to determine the need of additional reactive power compensation, if any, for the DISIS-2009-001 Group6 wind farm project GEN-2009-017. The results of power factor analysis indicated that the proposed GEN-2009-017 project would require 60 Mvar of additional shunt compensation (e.g. shunt capacitor) to meet the power factor requirement.

Power factor analysis for Reduced Size GEN-2009-017 Wind Farm (60MW)

The results indicated that the reduced size GEN-2009-017 wind farm (60MW) 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. No additional reactive power support (e.g. shunt capacitor) is needed at the POI.

Stability Analysis

The stability analysis was performed to determine the impact, if any, of the proposed DISIS-2009-001 Group 6 project (GEN-2009-017) on the stability of the SPP system. The significant results of stability analysis are as follows:

Wind farms tripping due to undervoltage

GEN-2005-010 tripped following two (2) faults in 2010 Summer Peak and 2009 Winter Peak conditions in both WITH and WITHOUT GEN-2009-017 project.

The proposed GEN-2009-017 wind farm tripped due to undervoltage/overfrequency protection following fifteen (15) faults for both 2010 Summer Peak and 2009 Winter Peak system conditions, and one (1) faults for only the 2009 Winter Peak system condition.

Local area voltage and GEN-2009-017 parameter oscillation
Undamped oscillations were observed in local area voltages following several faults for both 2010 Summer Peak and 2009 Winter Peak conditions. Such undamped oscillations were not observed WITHOUT the proposed GEN-2009-017 project.

Stability Analysis for Reduced Size GEN-2009-017 Wind Farm (60MW)
Per SPP request the Group 6 (GEN-2009-017) project output was reduced to 60 MW. All the faults were repeated on both, summer peak and winter peak, system conditions. The results indicated that the system would be STABLE following all the faults with the GEN-2009-017 at reduced output (60 MW).

FERC Order 661A Compliance
Selected faults were simulated at the Point of Interconnection (POI) of the proposed GEN-2009-017 wind farm to determine the compliance with FERC 661 – A post-transition period LVRT standard. The results indicated that the proposed project DOES NOT meet the FERC LVRT requirement for wind farms.

Next, these selected faults were repeated at the POI with the Group 6 (GEN-2009-017) project with reduced output (60 MW). The results indicated that the reduced size wind farm project GEN-2009-017 meets the FERC LVRT criteria for the interconnection of the wind farm generation (FERC Order 661 – A).

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.