SYSTEM IMPACT STUDY FOR INTERCONNECTING THE 160 MW [redacted] WIND FARM

Final Report

REPORT NO.: Consulting 2002-10596-2.R01
March 25, 2003

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Technical Report

Southwest Power Pool	**No. 2002-10596-2.R01**		
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Author(s):

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Summary

>Omitted Text< has requested the interconnection of a 160 MW wind generation plant in Woodward County, Oklahoma. The proposed plant called [redacted] will tap into the existing 138 kV tie-line between the Mooreland (Western Farmers Electric Cooperative, WFEC) and Glass Mountain (Oklahoma Gas and Electric, OKGE) 138 kV buses at a distance of 2.2 miles from the Mooreland 138 kV substation.

Southwest Power Pool (SPP) requested ABB Consulting to perform an interconnection study to evaluate the impact of the proposed plant on the SPP transmission system and determine if any network reinforcements would be required for this interconnection. The present report focuses on the impact of the proposed plant from a steady-state and stability standpoint only.

Based on the results of this study, it is concluded that operating the proposed plant at 160 MW would lead to operational (i.e., generation restrictions) and capital costs (i.e., transmission system reinforcements and dynamic reactive support). Results from the stability study suggest that without adequate dynamic reactive support (170 MVAr), post-fault voltage recovery is poor. This causes the proposed wind farm and other nearby wind farms to trip on undervoltages.

Studies show that limiting the output of the proposed wind farm would eliminate most of the thermal overloads and improve voltage recovery. Depending on the plant output, dynamic reactive support may or may not be required. In order to provide the required dynamic reactive support, >Omitted Text< may consider the use doubly-fed induction generators (DFIGs) in their wind farm instead of squirrel-cage induction generators. Unlike squirrel-cage units that consume reactive power (thereby depressing system voltages), DFIGs can exchange reactive power with the grid to regulate terminal voltages (similar to SVC function). It is to be noted that if >Omitted Text<decides to use doubly-fed induction generators in their wind farm, another system impact study would be required.

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. #	**Revision;** Final Report	**Date** March 25, 2003	**Author** S. Pillutla	**Reviewed**	**Approved**
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1. INTRODUCTION

>Omitted Text< has requested the interconnection of a 160 MW wind generation plant in Woodward County, Oklahoma. The proposed plant called [redacted] (hereinafter referred to as >Omitted Text<Wind) will tap into the existing 138 kV tie-line between the Mooreland (Western Farmers Electric Cooperative, WFEC) and Glass Mountain (Oklahoma Gas and Electric, OKGE) 138 kV buses at a distance of 2.2 miles from the Mooreland 138 kV substation. The projected in-service date for the plant is November 30, 2003.

According to information furnished by >Omitted Text<, the proposed plant will consist of Mitsubishi MWT-300 squirrel-cage induction generators, each with a rated terminal voltage of 480 V. Each induction generator will be connected to a 34.5 kV network within the wind farm through a 480V/34.5 kV step-up transformer. The 34.5 kV feeders within the wind farm will be brought together at a 34.5 kV collector bus where voltage is stepped up to 138 kV through two parallel 34.5kV/138 kV step-up transformers. >Omitted Text< will build a new 138 kV switching station at the point of interconnection on the Mooreland - Glass Mountain 138 kV line. At the time of conducting this study, the layout of the switching station was not available. Therefore a three-breaker ring bus was assumed (See Figure 1.1).

Southwest Power Pool (SPP) requested ABB Consulting to perform an interconnection study to evaluate the impact of the proposed plant on the SPP transmission system and determine if any network reinforcements would be required for this interconnection. The present report focuses on the impact of the proposed plant from a steady-state and stability standpoint only. Short-circuit analysis to determine the impact of the proposed plant on fault current levels at select OKGE and WFEC substations in the immediate vicinity of the proposed plant has yet to be performed.

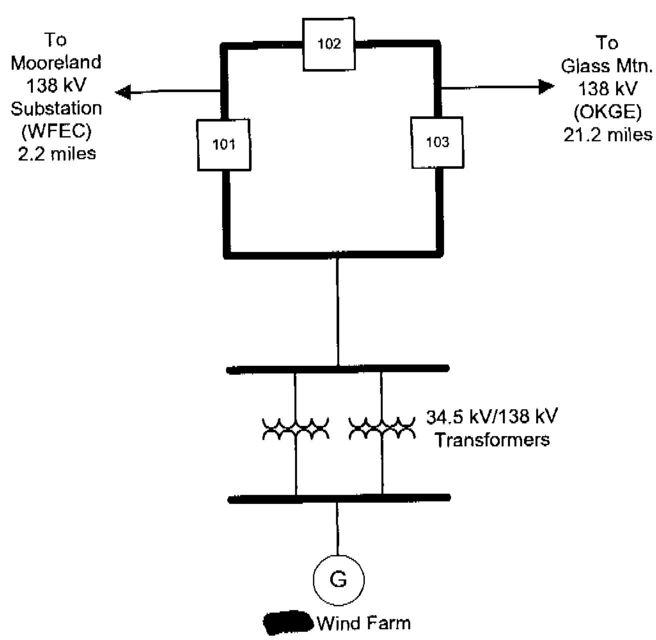

Figure 1.1: Proposed Interconnection of [redacted] Wind Farm

2. STEADY-STATE ANALYSIS

The steady-state analysis portion of the study evaluates the thermal impact of the proposed plant on the SPP transmission system under base (all lines in) and contingency case conditions. Also, transmission system bus voltages are monitored for possible voltage violations.

2.1 Powerflow Case and Modeling of Proposed Wind Farm

SPP provided a powerflow case representative of Winter 2003 peak load conditions (case G011BC-03WP.sav). The proposed point of interconnection on the WFEC Mooreland - OKGE Glass Mountain 138 kV line was already modeled in this case (bus 56105).

The proposed wind farm is modeled as a single aggregate unit (operating at 160 MW) at a new 34.5 kV bus (bus 56106) that is tied to the 138 kV switching station (bus 56105) through two parallel 34.5kV/138 kV transformers. The impedances of these transformers are increased to account for feeder and 480V/34.5 kV generator step-up transformer reactances located within the wind farm[1]. Individual wind turbine generators and the 34.5 kV network within the wind farm are not modeled.

Since squirrel-cage induction generators do not have an internal excitation source, they absorb reactive power from the system. Typically, the reactive requirements of squirrel-cage induction generators in wind farms are provided by fixed capacitor banks placed at the terminals of each generator (i.e., each generator is fully compensated). Furthermore, additional shunt compensation may be required and deployed at the collector bus and/or at the switching station connecting the wind farm to the 138 kV transmission system. In this study, the aggregate unit is assumed to be fully compensated and is therefore modeled with zero MVAr output. However, a 25.5 MVAr shunt is placed at the 34.5 kV collector bus (bus 56106) in order to supply the reactive requirements of the 34.5 kV/138 kV transformers and thus maintain a unity power factor at the point of interconnection (bus 56105).

The proposed wind farm is dispatched by scaling down generation in area 147 (TVA). Figures A.1.1 and A.1.2 in Appendix A depict system conditions in the vicinity of the Mooreland 138 kV bus both prior to and after the addition of the proposed wind farm respectively.

2.2 Study Criteria

SPP criteria were used to assess the impact of the proposed plant on the transmission system. Normal conditions with all lines in and outage conditions were tested and evaluated for cases with and without the proposed plant on line. The contingencies under consideration include single element outages (transmission lines and transformers) within areas 524 (OKGE), 525 (WFEC), and 520 (zone 204 AEP West) as well as tie-lines out of these areas. All facilities loaded above 95% of their normal ratings (RATEA) under normal conditions or above 95% of their emergency ratings (RATEB) for outage conditions were recorded. Buses rated 138 kV and higher were monitored for voltage violations and flagged if their voltages were less than or equal to 0.95 pu or greater than or equal to 1.05 pu.

[1] >Omitted Text< did not provide any information on the layout of the wind farm, feeder impedances, and 480V/34.5 kV generator step-up transformer impedances. Thus typical data are assumed. The net impedance between the generator terminals and the 138 kV collector bus (>Omitted Text<138 kV bus) is assumed to be 22% on generator MVA base.

2.3 Discussion of Results

Results of the thermal analysis are presented in Table 2.1. Only those transmission facilities that are impacted by proposed plant are listed (i.e., facilities with pre-existing overloads as well as facilities whose loadings are less than 95% are not listed). Results indicate that the proposed plant impacts the following transmission facilities:

- >Omitted Text< - Elk City 138 kV line: Worst case overload is 13.4% with all lines in. Not overloaded prior to >Omitted Text<.

- >Omitted Text<- Mooreland 138 kV line: Worst post-contingency overload is 24.6% following the loss of the >Omitted Text<- Glass Mtn. Tap 138 kV segment. Not overloaded prior to the addition of the proposed >Omitted Text<plant.

- >Omitted Text<- Glass Mtn. 138 kV line: Worst post-contingency overload is 13.8% following the loss of the >Omitted Text<- Mooreland 138 kV line. Not overloaded prior to >Omitted Text<.

- Morewood 138/69 kV transformer: With >Omitted Text<, post-contingency overload is 14.9% following the loss of the >Omitted Text< - Elk City 138 kV line. Not overloaded prior to >Omitted Text<.

From the above results, it is clear that with all lines in and >Omitted Text<generating its full output of 160 MW, there is a base case overload of 13.4% on the 138 kV line between >Omitted Text< and Elk City. WFEC noted that the conductor is 556 ACSR with a normal/emergency rating of 130/170 MVA (the 600 A CTs at Elk City limit the first contingency to 158 MVA). In order to resolve this overload, it is proposed that the line be reconductored to have a rating of at least 165/190 MVA (allowing for a 10% safety margin). If line reconductoring is considered, the CTs at Elk City should also be replaced.

Post-contingency tripping of a portion of the >Omitted Text<plant following outages of any one of the 138 kV line sections between Mooreland and Imo Tap could alleviate the post-contingency overloads on the 138 kV lines out of Mooreland (i.e., >Omitted Text<- Mooreland and >Omitted Text<- Glass Mountain). However, the application of generator tripping must be discussed with SPP and the transmission owners to ensure adequate availability of system spinning reserves. The Mooreland - >Omitted Text<- Glass Mountain conductor is 267 ACSR with a rating of 133/153 MVA (CTs at Mooreland limit the first contingency to 123 MVA). In order to have >Omitted Text<deliver its proposed output of 160 MW, this line should be reconductored to have an emergency rating of at least 172 MVA (allowing for a 10% safety margin). If line reconductoring is considered, the CTs at Mooreland should also be replaced.

The Morewood 138/69 kV transformer is rated at 50 MVA. Prior to the addition of >Omitted Text<, this transformer is loaded at 98.1% following the loss of the >Omitted Text< - Elk City 138 kV line. With >Omitted Text<generating its full output of 160 MW, the loading increases to 114.9%. In order to alleviate the overload on this transformer, a post-contingency reduction of the output of the >Omitted Text<plant may be considered (studies show that a post-contingency reduction of >Omitted Text<to 40 MW brings the loading on the transformer to 99.3%). Another option is to upgrade the transformer to have an MVA rating of 65 MVA or higher.

With >Omitted Text<operating at 160 MW, overvoltages were observed at the >Omitted Text<and Glass Mountain 138 kV buses (1.1494 pu and 1.0730 pu respectively) following the loss of the 138 kV line

connecting Mooreland with the >Omitted Text<switching station. The loss of this line could be synchronized with tripping the fixed shunt at >Omitted Text<Wind. Other contingencies caused small overvoltages at the >Omitted Text<and Ft. Supply 138 kV buses (in the range 1.0542 pu to 1.0586 pu). Given the uncertainties in the loadflow model (generation patterns, loading levels etc.) these small overvoltages can be considered marginal and therefore neglected.

It is concluded that operating >Omitted Text<at its full output of 160 MW would lead to operational (i.e., generation restrictions) and capital (share of transmission system reinforcements) costs.

Sensitivity studies showed that limiting the output of >Omitted Text<to 70 MW would alleviate all the above overloads except the overload on the Morewood 138/69 kV transformer that would still need to be addressed.

SPP will be responsible for preparing cost estimates for any transmission system reinforcements.

Table 2.1: Results of Thermal Analysis

Limiting Element	Contingency	Rating (MVA)	Loading% With >Omitted Text< 160 MW	Loading% Without >Omitted Text<
54786 GLASMTP4 138 56105 >Omitted Text< 138 1 LN	55999 MOORLND4 138 56105 >Omitted Text< 138 1	123.0	113.8	-
54795 KNOBHIL4 138 55999 MOORLND4 138 1 LN	54778 CLEOCOR4 138 54788 GLASMTN4 138 1	59.0	96.4	-
54795 KNOBHIL4 138 55999 MOORLND4 138 1 LN	54786 GLASMTP4 138 54788 GLASMTN4 138 1	59.0	97.4	-
54795 KNOBHIL4 138 55999 MOORLND4 138 1 LN	54786 GLASMTP4 138 56105 >Omitted Text< 138 1	59.0	97.5	-
55234 PECANCK5 161 55235 PECANCK7 345 1 TR	55224 MUSKOGE7 345 55302 FTSMITH7 345 1	369.0	95.1	-
56001 MORWODS4 138 56000 MORWODS269.0 1 TR	54121 ELKCTY-4 138 56103 >OMITTED TEXT< 138 1	50.0	114.9	98.2
56103 >OMITTED TEXT< 138 54121 ELKCTY-4 138 1 LN	** Base Case **	130.0	113.4	-
56103 >OMITTED TEXT< 138 54121 ELKCTY-4 138 1 LN	54731 SO4TH4 4 138 54790 IMO TAP4 138 1	158.0	101.6	-
56103 >OMITTED TEXT< 138 54121 ELKCTY-4 138 1 LN	54778 CLEOCOR4 138 54788 GLASMTN4 138 1	158.0	105.1	-
56103 >OMITTED TEXT< 138 54121 ELKCTY-4 138 1 LN	54778 CLEOCOR4 138 54789 MENOTAP4 138 1	158.0	104.3	-
56103 >OMITTED TEXT< 138 54121 ELKCTY-4 138 1 LN	54786 GLASMTP4 138 54788 GLASMTN4 138 1	158.0	105.5	-
56103 >OMITTED TEXT< 138 54121 ELKCTY-4 138 1 LN	54786 GLASMTP4 138 56105 >Omitted Text< 138 1	158.0	105.5	-
56103 >OMITTED TEXT< 138 54121 ELKCTY-4 138 1 LN	54787 DEWEY 4 138 54822 SOUTHRD4 138 1	158.0	106.8	-
56103 >OMITTED TEXT< 138 54121 ELKCTY-4 138 1 LN	54789 MENOTAP4 138 54790 IMO TAP4 138 1	158.0	103.7	-
56103 >OMITTED TEXT< 138 54121 ELKCTY-4 138 1 LN	54819 EL RENO4 138 54823 ROMNOSE4 138 1	158.0	101.7	-
56103 >OMITTED TEXT< 138 54121 ELKCTY-4 138 1 LN	54822 SOUTHRD4 138 54823 ROMNOSE4 138 1	158.0	104.2	-
56103 >OMITTED TEXT< 138 54121 ELKCTY-4 138 1 LN	54880 NORTWST7 345 54881 SPRNGCK7 345 1	158.0	98.5	-
56103 >OMITTED TEXT< 138 54121 ELKCTY-4 138 1 LN	54787 DEWEY 4 138 56065 TALOGA 4 138 1	158.0	109.1	-
56103 >OMITTED TEXT< 138 54121 ELKCTY-4 138 1 LN	54794 KNOBHIL269.0 54795 KNOBHIL4 138 1	158.0	96.8	-
56103 >OMITTED TEXT< 138 54121 ELKCTY-4 138 1 LN	54795 KNOBHIL4 138 55999 MOORLND4 138 1	158.0	96.9	-
56103 >OMITTED TEXT< 138 54121 ELKCTY-4 138 1 LN	55848 CEDRDAL4 138 55999 MOORLND4 138 1	158.0	103.5	-
56103 >OMITTED TEXT< 138 54121 ELKCTY-4 138 1 LN	55848 CEDRDAL4 138 56016 OKEENE 4 138 1	158.0	103.2	-
56103 >OMITTED TEXT< 138 54121 ELKCTY-4 138 1 LN	55882 DOVERSW4 138 56016 OKEENE 4 138 1	158.0	99.8	-
56103 >OMITTED TEXT< 138 54121 ELKCTY-4 138 1 LN	55999 MOORLND4 138 56065 TALOGA 4 138 1	158.0	101	-
56103 >OMITTED TEXT< 138 54121 ELKCTY-4 138 1 LN	56000 MORWODS269.0 56001 MORWODS4 138 1	158.0	99.3	-
56103 >OMITTED TEXT< 138 54121 ELKCTY-4 138 1 LN	54121 ELKCTY-4 138 54153 ELKCITY6 230 1	158.0	103.6	-
56103 >OMITTED TEXT< 138 54121 ELKCTY-4 138 1 LN	54130 L.E.S.-4 138 54131 L.E.S.-7 345 1	158.0	96.8	-
56103 >OMITTED TEXT< 138 54121 ELKCTY-4 138 1 LN	50827 GRAPEVN6 230 54153 ELKCITY6 230 1	158.0	103.6	-
56103 >OMITTED TEXT< 138 54121 ELKCTY-4 138 1 LN	54140 S.W.S.-4 138 54208 SWS3-1 24.0 1	158.0	100.1	-
56105 >Omitted Text< 138 55999 MOORLND4 138 1 LN	54778 CLEOCOR4 138 54788 GLASMTN4 138 1	123.0	122.4	-
56105 >Omitted Text< 138 55999 MOORLND4 138 1 LN	54778 CLEOCOR4 138 54789 MENOTAP4 138 1	123.0	101.6	-
56105 >Omitted Text< 138 55999 MOORLND4 138 1 LN	54786 GLASMTP4 138 54788 GLASMTN4 138 1	123.0	124.5	-
56105 >Omitted Text< 138 55999 MOORLND4 138 1 LN	54786 GLASMTP4 138 56105 >Omitted Text< 138 1	123.0	124.6	-
56105 >Omitted Text< 138 55999 MOORLND4 138 1 LN	54789 MENOTAP4 138 54790 IMO TAP4 138 1	123.0	99.5	-

3. STABILITY ANALYSIS

The stability study investigates the stability of the system for different transmission system faults in the vicinity of the proposed wind farm. The faults involve three-phase faults cleared by primary protection, three-phase faults that are compounded by breaker failure and cleared by backup protection, and single-phase faults with breaker failure and backup clearing.

3.1 Study Model

The study model consists of the powerflow case as well as the dynamics database.

3.1.1 Powerflow Case

SPP provided a set of two powerflow cases for the stability study. Case TS05S2X.SAV is representative of 2005 Summer Peak conditions and case TS03G1X.SAV is representative of 2003 Spring Peak conditions.

The following four plants were added to both cases by scaling down generation in area 147 (TVA): >OMITTED TEXT< Wind (100 MW), Red Hills Wind (120 MW), >Omitted Text< S. Buffalo Wind (25.5 MW), and >Omitted Text< Sleeping Bear Wind (96 MW).

As in the steady-state portion of the study, the proposed wind farm is modeled as a single aggregate unit at the 34.5 kV bus (bus 56106) with an active and reactive power output of 160 MW and 0 MVAr respectively. A 27.1 MVAr shunt is modeled at the 34.5 kV bus to maintain a unity power factor at the point of interconnection (bus 56105).

The proposed wind farm is dispatched by scaling down generation in area 147 (TVA). Minor modifications were made to the powerflow case in preparation for stability simulations. Figures A.2.1 and A.2.2 in Appendix A depict system conditions in the vicinity of the proposed plant for the 2005 Summer Peak case. Figures A.2.3 and A.2.4 depict corresponding conditions for the 2003 Spring Peak case.

3.1.2 Stability Database

SPP provided the stability database in the form of two PSS/E dynamics data input files (dyre files). Also provided were dyre files containing stability data for the >OMITTED TEXT< Wind, >Omitted Text< S. Buffalo Wind, and >Omitted Text< Sleeping Bear Wind plants. SPP indicated these three wind farms comprise wind turbine generators based on doubly-fed induction generator (DFIG) technology[2]. An examination of dyre files for >OMITTED TEXT< Wind, >Omitted Text< S. Buffalo Wind, and >Omitted Text< Sleeping Bear Wind plants suggested that each wind farm is modeled by a CIMTR3 induction generator model along with a CSVGN1 SVC model.

Since >Omitted Text< did not provide stability data for the proposed plant, ABB, with SPP's approval, suggested the use of typical squirrel-cage induction generator data. The data used in this study is actually

[2] A DFIG is essentially a wound-rotor induction generator whose rotor is fed from a three-phase variable frequency source. The variable-frequency supply to the DFIG rotor is attained via the use of two voltage-source converters linked via a capacitor. Unlike squirrel-cage induction generators that are constant speed units, wind turbines based on DFIG technology can operate at a variety of speeds in order to optimize the transfer of power from the wind to the turbine blades. Also unlike squirrel-cage induction generators, DFIGs can exchange reactive power with the grid to regulate power factor and/or terminal voltages (similar to SVC function).

for a 1.5 MW NEG Micon NM72C-1500UL squirrel-cage induction generator (courtesy NEG Micon) and is shown in Appendix B. The same set of data is assumed for the [redacted] Wind plant for which no data was available at the time of conducting this study.

It should be noted that wind farms generally cannot ride-through a transmission system fault without jeopardizing the integrity of the units/controls and/or their converters (the latter applies to doubly-fed induction generators). Wind turbine generators are generally tripped when the voltages at their terminals drop below 0.7 pu for a specified period. This period generally ranges from 6 to 10 cycles depending on wind turbine generator design as well as protection system coordination between the plant operator and the interconnecting utility. At SPP's request, undervoltage protection was modeled at all wind farms in the area. A trip setting of 0.7 pu for 10 cycles was assumed.

3.2 Contingencies Tested

In order to investigate the stability of the system for different faults in the vicinity of the proposed plant, three types of contingencies were simulated:

- 3-ph line-end faults with normal clearing[3]
- 3-ph faults with delayed clearing assuming three-phase stuck breaker conditions[4]
- SLG faults with delayed clearing assuming three-phase stuck breaker conditions[5]

For normal clearing conditions, SPP suggested using a clearing time of 5 cycles from the instant of fault inception.

Contingencies with delayed clearing assume failure of all three poles of a circuit breaker that would normally be required to operate. In such instances, SPP suggested that backup relaying and circuit breakers clear the fault at 15 cycles from the instant of fault inception. It is to be noted that these contingencies are very severe and involve the loss of multiple components. Since the probability of occurrence of these contingencies is very low, they are evaluated for risks and consequences only.

In all simulations, faults are applied at time t= 0.1 seconds. All simulations are terminated at time t=10 seconds or if the rotor angle spread exceeds 999 degrees.

Table 3.1 and Figure 3.1 summarize the contingencies tested in this study. In order to determine the impact of the proposed plant on the stability of the system, simulation studies were performed both with and without the >Omitted Text<plant in service.

[3] NERC Category B faults. These faults involve loss of a single component.
[4] NERC Category D faults. These faults involve loss of multiple components.
[5] NERC Category C faults. These faults involve loss of multiple components but are less severe than Category D faults.

Table 3.1: Summary of Contingencies Tested

Contingency	Description	Time (cycles)
C-1	3-phase fault at >Omitted Text<end of 138 kV line to Mooreland Trip the >Omitted Text<- Mooreland 138 kV line	0 5
C-2	3-phase fault at >Omitted Text<end of 138 kV line to Glass Mtn. Trip the 138 kV line between >Omitted Text<and So. 4th. Also trip the 138/69 kV transformer at the Cleo Corner substation	0 5
C-2a**	3-phase fault at Mooreland end of 138 kV line to So. 4th. Trip the 138 kV line between Mooreland and So. 4th. Also trip the 138/69 kV transformer at the Cleo Corner substation	0 5
C-3	3-phase fault at Mooreland end of 138 kV line to Iodine and Ft. Supply Trip the Mooreland - Iodine - Ft. Supply 138 kV line. Trip 26 MW of generation at >Omitted Text< Sleeping Bear (to account for trip scheme proposed by >Omitted Text< following loss of above 138 kV line).	0 5
C-4	3-phase fault at Mooreland end of 138 kV line to Knob Hill Trip the Mooreland - Knob Hill 138 kV line and 138/69 kV transformer at Knob Hill	0 5
C-5	3-phase fault at Mooreland end of 138 kV line to >OMITTED TEXT< Wind switching station Trip all lines connected to >OMITTED TEXT< switching station and trip >OMITTED TEXT< Wind plant.	0 5
C-6	3-phase fault on 138 kV side of Mooreland 138/69 kV transformer Trip the Mooreland 138/69 kV transformer	0 5
C-7	3-phase fault at Mooreland end of 138 kV line to Morewood Trip the Mooreland - Morewood 138 kV line	0 5
C-8	3-phase fault at Mooreland end of 138 kV line to Cedardale Trip the Mooreland - Cedardale - Okeene 138 kV line	0 5
C-9	3-phase fault at Mooreland end of 138 kV line to Taloga Trip the Mooreland - Taloga 138 kV line	0 5
C-10	3-phase fault at Mooreland end of 138 kV line to >Omitted Text<. Open breakers 101 and 102 at >Omitted Text<138 kV end. Mooreland breaker 662 is stuck (all three phases). Open Mooreland breakers 462, 962, 1162, 1262, 1362 and trip Mooreland generator G1.	0 5 15
C-10a**	3-phase fault at Mooreland end of 138 kV line to So. 4th. Open breaker 110 at So. 4th. Also trip 138/69 kV line at the Cleo Corner substation. Mooreland breaker 662 is stuck (all three phases). Open Mooreland breakers 462, 962, 1162, 1262, 1362 and trip Mooreland generator G1.	0 5 15
C-11	3-phase fault at Mooreland end of 138 kV line to Taloga. Open breaker 172 at Taloga 138 kV end. Mooreland breaker 1062 is stuck (all three phases). Open Mooreland breakers 762, 862,962 and trip Mooreland generators G2, G3.	0 5 15
C-12	3-phase bus fault at Mooreland 138 kV east bus Open breakers 162, 462, 662, 1162, 1262 and 1362 at Mooreland 138 kV east bus and corresponding breakers at >Omitted Text<Wind, >OMITTED TEXT< Switching Station, Knob Hill, and Ft. Supply 138 kV buses. Also trip >OMITTED TEXT< Wind. Mooreland tie-breaker 962 is stuck (all three phases) Trip Mooreland 138 kV west bus.	0 5 15
C-12a**	3-phase bus fault at Mooreland 138 kV east bus Open breakers 162, 462, 662, 1162, 1262 and 1362 at Mooreland 138 kV east bus and corresponding breakers at So. 4th, >OMITTED TEXT< Switching Station, Knob Hill, and Ft. Supply 138 kV buses. Also trip >OMITTED TEXT< Wind. Mooreland tie-breaker 962 is stuck (all three phases) Trip Mooreland 138 kV west bus.	0 5 15
C-13	3-phase bus fault at Mooreland 138 kV west bus Open breakers 262, 362, 762, 862, and 1062 at Mooreland 138 kV west bus and corresponding breakers at Okeene, Morewood, and Taloga 138 kV buses. Mooreland tie-breaker 962 is stuck (all three phases) Trip Mooreland 138 kV east bus.	0 5 15

** Contingencies 2a, 10a, and 12a are valid only for the pre->Omitted Text<case and are variants of contingencies 2,10, and 12 respectively.

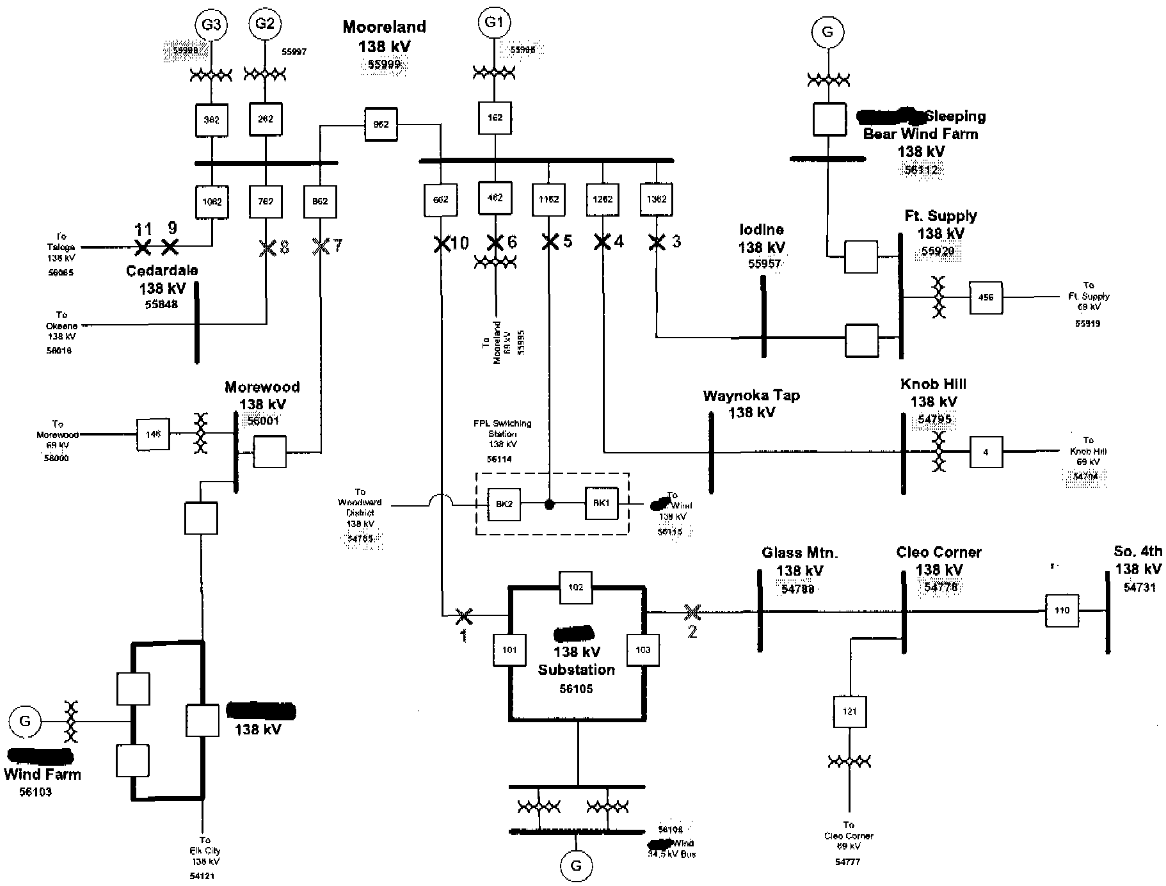

Figure 3.1: System One-line Showing Locations of Faults to be Simulated

3.3 Discussion of Stability Results

3.3.1 Stability Results Without >Omitted Text<Wind

Simulation studies were performed on the base case (i.e., without the proposed plant in-service). Results are shown in Table 3.2.

All normally cleared faults resulted in stable system conditions. Simulation plots for many normally cleared faults suggest that although system voltages recover close to their pre-fault levels, voltage recovery is sluggish. The manner in which voltages recover indicates that the system is stressed and can be explained as follows. It should be noted that there is approximately 340 MW of wind generation in the vicinity of Mooreland (other than the peakers at Mooreland, there are no other generating facilities nearby). Faults at the Mooreland 138 kV bus depress system voltages to such an extent that they cause the induction generators in these wind farms to accelerate (i.e., their slip increases). With increasing slip, the stator current and hence the reactive power consumption of these wind farms increases. Although the SVCs at >OMITTED TEXT< Wind, >Omitted Text< S. Buffalo Wind, and >Omitted Text< Sleeping Bear Wind hit their ceilings instantaneously, the reactive demand of the wind farms is large and voltage recovery is sluggish. For example, Figure 3.2 illustrates the system voltages following contingency C-7. Since SPP noted that they do not have specific criteria for assessing voltage recovery, NERC/WECC voltage criteria were used as a guide. None of the normally cleared faults are in violation of NERC/WECC voltage criteria.

Contingencies C-10a to C-13 (as well as their corresponding SLG contingencies) are very severe because they involve the loss of multiple components. Figure 3.3 shows the system voltages following contingency C-10a-SLG. Note that the voltages at Ft. Supply and Woodward 138 kV buses fail to recover. The underlying 69 kV network is unable to support the voltages. However, as noted in Section 3.2, the probability of occurrence of such contingencies is very low. These contingencies are therefore evaluated for risks and consequences only.

Table 3.2: Stability Results Without >Omitted Text<Wind

Contingency	2005 Summer Peak Case			2003 Spring Peak Case		
	Result	**Units Tripped on Undervoltage**	**Total MW Tripped**	**Result**	**Units Tripped on Undervoltage**	**Total MW Tripped**
C-2a	Stable	-	-	Stable	-	-
C-3	Stable	-	-	Stable	-	-
C-4	Stable	-	-	Stable	-	-
C-5	Stable	-	-	Stable	-	-
C-6	Stable	-	-	Stable	-	-
C-7	Stable	-	-	Stable	-	-
C-8	Stable	-	-	Stable	-	-
C-9	Stable	-	-	Stable	-	-
C-10a	Mooreland Unstable	>OMITTED TEXT< Wind, >Omitted Text< Sleeping Bear, >Omitted Text< S. Buffalo	221.5	Stable	>OMITTED TEXT< Wind, >Omitted Text< Sleeping Bear, >Omitted Text< S. Buffalo	221.5
C-11	Mooreland Unstable	>OMITTED TEXT< Wind, >Omitted Text< Sleeping Bear, >Omitted Text< S. Buffalo	221.5	Stable	>OMITTED TEXT< Wind, >Omitted Text< Sleeping Bear, >Omitted Text< S. Buffalo	221.5
C-12a	Stable (2)	>Omitted Text< Sleeping Bear, >Omitted Text< S. Buffalo	121.5	Stable (2)	>Omitted Text< Sleeping Bear, >Omitted Text< S. Buffalo	121.5
C-13	Stable (2)	>OMITTED TEXT< Wind, >Omitted Text< Sleeping Bear, >Omitted Text< S. Buffalo	221.5	Stable (2)	>OMITTED TEXT< Wind, >Omitted Text< Sleeping Bear, >Omitted Text< S. Buffalo	221.5
C-10a-SLG (1)	Stable (2)	>OMITTED TEXT< Wind, >Omitted Text< Sleeping Bear, >Omitted Text< S. Buffalo	221.5	Stable	>OMITTED TEXT< Wind, >Omitted Text< Sleeping Bear, >Omitted Text< S. Buffalo	221.5
C-11-SLG (1)	Stable	>OMITTED TEXT< Wind	100.0	Stable	>OMITTED TEXT< Wind	100.0
C-12a-SLG (1)	Stable (2)	-	-	Stable	-	-
C-13-SLG (1)	Stable (2)	>OMITTED TEXT< Wind, >Omitted Text< Sleeping Bear, >Omitted Text< S. Buffalo	221.5	Stable (2)	>OMITTED TEXT< Wind, >Omitted Text< Sleeping Bear, >Omitted Text< S. Buffalo	221.5

Notes:

(1) Contingencies C-10a-SLG through C-13-SLG are the same as contingencies C-10a through C-13 respectively with single-line-to-ground faults applied instead of three-phase faults.

(2) Although the system is stable, these contingencies are in violation of voltage criteria listed in the NERC/WECC Planning Standards (see www.wecc.biz/documents/standards/recently_approved/WSCC_Reliability_Criteria_wsccps_402.pdf). According to these criteria,

- For NERC Category B events (loss of a single component), the transient voltage dip is not to exceed 25% at load buses or 30% at non-load buses. Not to exceed 20% for more than 20 cycles at load buses.

- For NERC Category C events (loss of two or more components), the transient voltage dip is not to exceed 30% at any bus. Not to exceed 20% for more than 40 cycles at load buses.

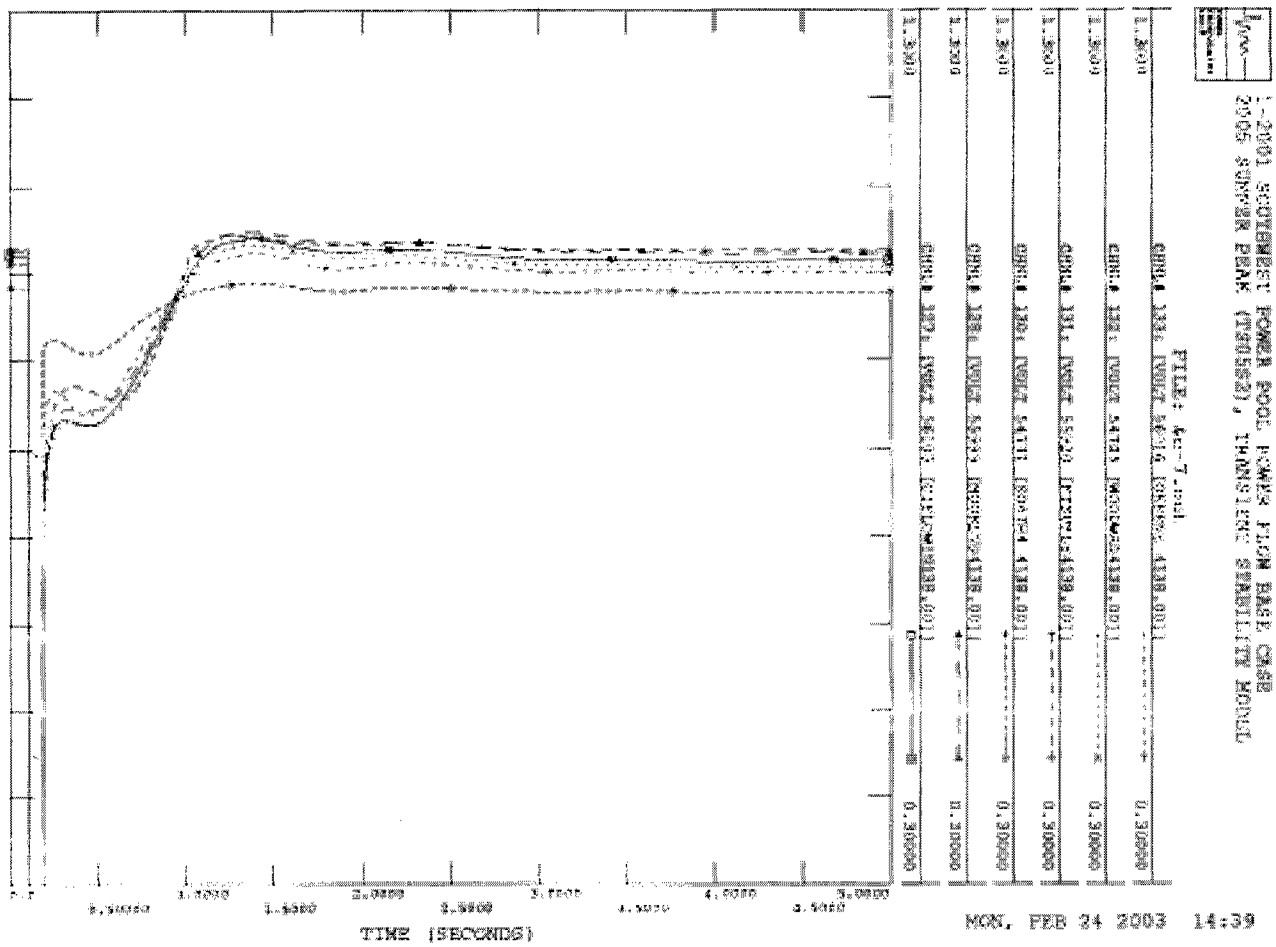

Figure 3.2: 138 kV Bus Voltages Following Contingency C-7 (>Omitted Text<OFF)

ABB

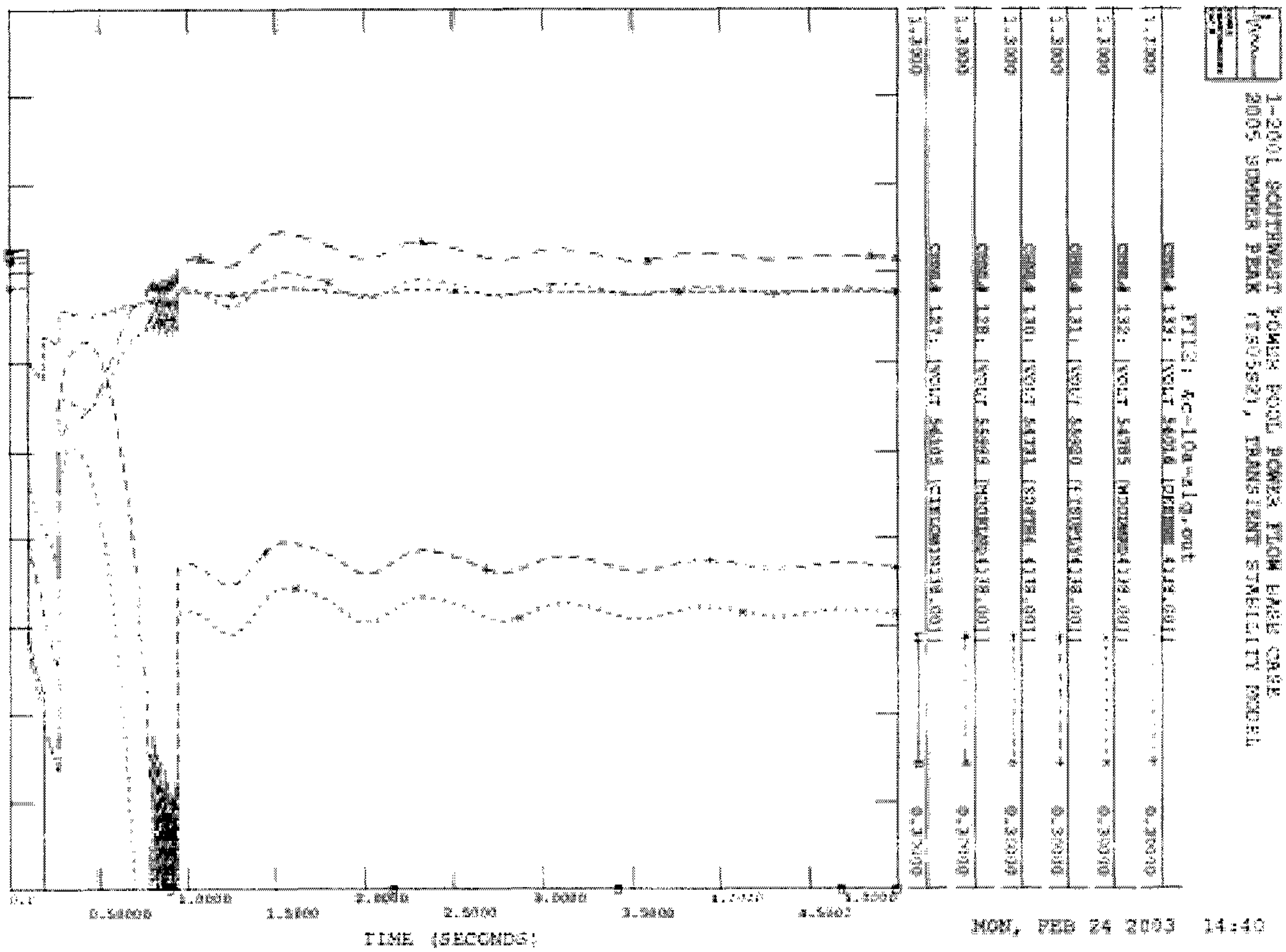

Figure 3.3: 138 kV Bus Voltages Following Contingency C-10a-SLG (>Omitted Text<OFF)

3.3.2 Stability Results With >Omitted Text<Wind

Simulation studies were performed with >Omitted Text<operating at 160 MW. Results are tabulated in Table 3.3. Note that the results of the 2005 Summer Peak case are considerably worse than corresponding results of the 2003 Spring Peak case. Therefore the remainder of the analysis focuses on the 2005 Summer Peak case only.

As shown in Table 3.3, results from the 2005 Summer Peak case indicate that with the exception of contingencies C-2 and C-5, all other normally cleared faults result in >Omitted Text<being tripped on undervoltages. The addition of the >Omitted Text<plant contributes to an overall increase in the reactive power demand, which causes system voltages to be further depressed. Unlike the pre->Omitted Text<case, other wind farms in the area now trip on undervoltages (total loss of generation including the >Omitted Text<plant is 381.5 MW). Also, as shown in Table 3.3, contingencies C-3 through C-9 violate NERC/WECC voltage criteria. Figure 3.4 illustrates the system voltages following contingency C-7. Comparing this against Figure 3.2 confirms that the addition of the >Omitted Text<plant has an adverse impact on voltage recovery following fault clearing.

In order to prevent >Omitted Text<and the other wind farms from tripping on undervoltages, it is necessary to provide dynamic reactive support. Since >Omitted Text<comprises squirrel-cage induction generators it does not have the ability to provide such support and therefore other solutions are needed. In this study, a solution involving a static var compensator (SVC) modeled at the >Omitted Text<34.5 kV bus was investigated[6]. The SVC was sized such that >Omitted Text<and the other wind farms do not trip for normally cleared faults (i.e., contingencies C-1 to C-9). Sensitivity studies showed that a 170 MVAr SVC is required to keep >Omitted Text<and the other wind farms from tripping on undervoltages[7]. Figure 3.5 compares the voltages at select 138 kV buses following contingency C-7 both with and without the 170 MVAr SVC. When compared to the plant size, the size of the SVC is quite large. It can be concluded that operating >Omitted Text<at 160 MW without adequate dynamic reactive support stresses the system further and causes other wind farms in the vicinity to trip on undervoltages.

Sensitivity studies were conducted to determine whether limiting the plant output to 70 MW would improve stability results (steady-state analysis results in Section 2.3 suggested that limiting the output of the proposed plant to 70 MW would alleviate all thermal overloads caused due to the addition of the proposed plant with the exception of the Morewood 138/69 kV transformer). Studies suggested that even when the plant output is reduced to 70 MW, >Omitted Text<as well as another nearby wind farm (>OMITTED TEXT< Wind) trip for a small number of normally cleared faults (C-7 through C-9).

Even with >Omitted Text<operating at 70 MW, it is clear that additional dynamic VAR support is required to prevent loss of generation. A 35 MVAr SVC was added in lieu of the 27.1 MVAr fixed shunt[8] (the SVC was sized such that for normally cleared faults there is no loss of generation). Simulation results show that the SVC is effective at preventing >Omitted Text<and other wind farms from tripping. Figure

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[6] Other options such as mechanically switched capacitors (MSC) were also investigated. However owing to mechanical switching delays, MSCs are much slower than SVCs. Switching times for MSCs are on the order of 6 to 8 cycles following the initiation of a switching command compared to SVCs that respond almost instantaneously. It was seen that the response time of the MSC is too slow to significantly impact simulation results.

[7] In loadflow, the 27.1 MVAr fixed shunt was replaced with the SVC. The SVC was modeled as a switched shunt on continuous control with a voltage setpoint such that unity power factor is maintained at the >Omitted Text<138 kV bus (the SVC generates about 27.1 MVAr to achieve this). In dynamics, the SVC was modeled using the PSS/E CSSCS1 model with parameters designed to achieve a full excursion for a 1% reduction in voltage, and a 25 rad/sec loop speed. In other words, the SVC was designed to provide instantaneous dynamic reactive support.

[8] In loadflow, the SVC generates about 6 MVAr in order to maintain unity power factor at the >Omitted Text<138 kV bus. As before, the SVC was designed to provide instantaneous dynamic reactive support.

3.6 compares the voltages at select 138 kV buses following contingency C-7 both with and without the 35 MVAr SVC.

From the above analysis, it is clear that additional dynamic reactive support at the >Omitted Text<farm helps support system voltages and prevent generator tripping. Although the SVC solution was illustrated here, >Omitted Text< may consider other solutions, for instance using doubly-fed induction generators (DFIGs) in their wind farm instead of squirrel-cage induction generators. Unlike squirrel-cage units that consume reactive power (thereby depressing system voltages), DFIGs can exchange reactive power with the grid to regulate terminal voltages (similar to SVC function).

Finally, sensitivity studies were conducted with the output of the >Omitted Text<plant reduced further. Studies show that when the plant output is reduced to 40 MW, there is no need for dynamic reactive compensation. There is no loss of generation for normally cleared faults and voltage recovery is comparable to the pre->Omitted Text<case (see Figure 3.7). Finally, as in the loadflow studies, tripping the 138 kV line between Mooreland and >Omitted Text<(contingency C-1) resulted in overvoltages at the >Omitted Text<34.5 kV bus. Simulation results show that overvoltages can be avoided if the loss of this line is synchronized with tripping the 27.1 MVAr fixed shunt at >Omitted Text<Wind.

Table 3.3: Stability Results With >Omitted Text<Wind

Contingency	2005 Summer Peak Case			2003 Spring Peak Case		
	Result	Units Tripped on Undervoltages	Total MW Tripped	Result	Units Tripped on Undervoltages	Total MW Tripped
C-1	Stable	>Omitted Text<Wind	160.0	Stable	>Omitted Text<Wind	160.0
C-2	Stable	-	-	Stable	-	-
C-3	Stable [2]	>Omitted Text<Wind	160.0	Stable	-	-
C-4	Stable [2]	>Omitted Text<Wind, >OMITTED TEXT< Wind	260.0	Stable	-	-
C-5	Stable	-	-	Stable	-	-
C-6	Stable [2]	>Omitted Text<Wind, >OMITTED TEXT< Wind	260.0	Stable	-	-
C-7	Stable [2]	>Omitted Text<Wind, >OMITTED TEXT< Wind, >Omitted Text< Sleeping Bear, >Omitted Text< S. Buffalo	381.5	Stable	-	-
C-8	Stable [2]	>Omitted Text<Wind, >OMITTED TEXT< Wind, >Omitted Text< Sleeping Bear, >Omitted Text< S. Buffalo	381.5	Stable	-	-
C-9	Stable [2]	>Omitted Text<Wind, >OMITTED TEXT< Wind, >Omitted Text< Sleeping Bear, >Omitted Text< S. Buffalo	381.5	Stable	-	-
C-10	Mooreland Unstable	>Omitted Text<Wind, >OMITTED TEXT< Wind, >Omitted Text< Sleeping Bear, >Omitted Text< S. Buffalo	381.5	Stable	>Omitted Text<Wind, >OMITTED TEXT< Wind, >Omitted Text< Sleeping Bear, >Omitted Text< S. Buffalo	381.5
C-11	Mooreland Unstable	>Omitted Text<Wind, >OMITTED TEXT< Wind, >Omitted Text< Sleeping Bear, >Omitted Text< S. Buffalo	381.5	Stable	>Omitted Text<Wind, >OMITTED TEXT< Wind, >Omitted Text< Sleeping Bear, >Omitted Text< S. Buffalo	381.5
C-12	Mooreland Unstable	>Omitted Text<Wind, >Omitted Text< Sleeping Bear, >Omitted Text< S. Buffalo	281.5	Stable [2]	>Omitted Text<Wind, >Omitted Text< Sleeping Bear, >Omitted Text< S. Buffalo	281.5
C-13	Stable [2]	>Omitted Text<Wind, >OMITTED TEXT< Wind, >Omitted Text< Sleeping Bear, >Omitted Text< S. Buffalo	381.5	Stable [2]	>Omitted Text<Wind, >OMITTED TEXT< Wind, >Omitted Text< Sleeping Bear, >Omitted Text< S. Buffalo	381.5
C-10-SLG[1]	Stable [2]	>Omitted Text<Wind, >OMITTED TEXT< Wind, >Omitted	381.5	Stable [2]	>Omitted Text<Wind, >OMITTED TEXT< Wind, >Omitted	381.5

		Text< Sleeping Bear, >Omitted Text< S. Buffalo			Text< Sleeping Bear, >Omitted Text< S. Buffalo	
C-11-SLG(1)	Stable	>Omitted Text<Wind, >OMITTED TEXT< Wind, >Omitted Text< Sleeping Bear	356.0	Stable (2)	>Omitted Text<Wind, >OMITTED TEXT< Wind	260.0
C-12-SLG(1)	Stable (2)	>Omitted Text<Wind	160.0	Stable (2)	>Omitted Text<Wind	160.0
C-13-SLG(1)	Stable (2)	>Omitted Text<Wind, >OMITTED TEXT< Wind, >Omitted Text< Sleeping Bear, >Omitted Text< S. Buffalo	381.5	Stable (2)	>Omitted Text<Wind, >OMITTED TEXT< Wind, >Omitted Text< Sleeping Bear, >Omitted Text< S. Buffalo	381.5

Notes:

(1) Contingencies C-10-SLG through C-13-SLG are the same as contingencies C-10 through C-13 respectively with single-line-to-ground faults applied instead of three-phase faults.

(2) Although the system is stable, these contingencies are in violation of voltage criteria listed in the NERC/WECC Planning Standards. (see www.wecc.biz/documents/standards/recently_approved/WSCC_Reliability_Criteria_wsccps_402.pdf). According to these criteria,

- For NERC Category B events (loss of a single component), the transient voltage dip is not to exceed 25% at load buses or 30% at non-load buses. Not to exceed 20% for more than 20 cycles at load buses.
- For NERC Category C events (loss of two or more components), the transient voltage dip is not to exceed 30% at any bus. Not to exceed 20% for more than 40 cycles at load buses.

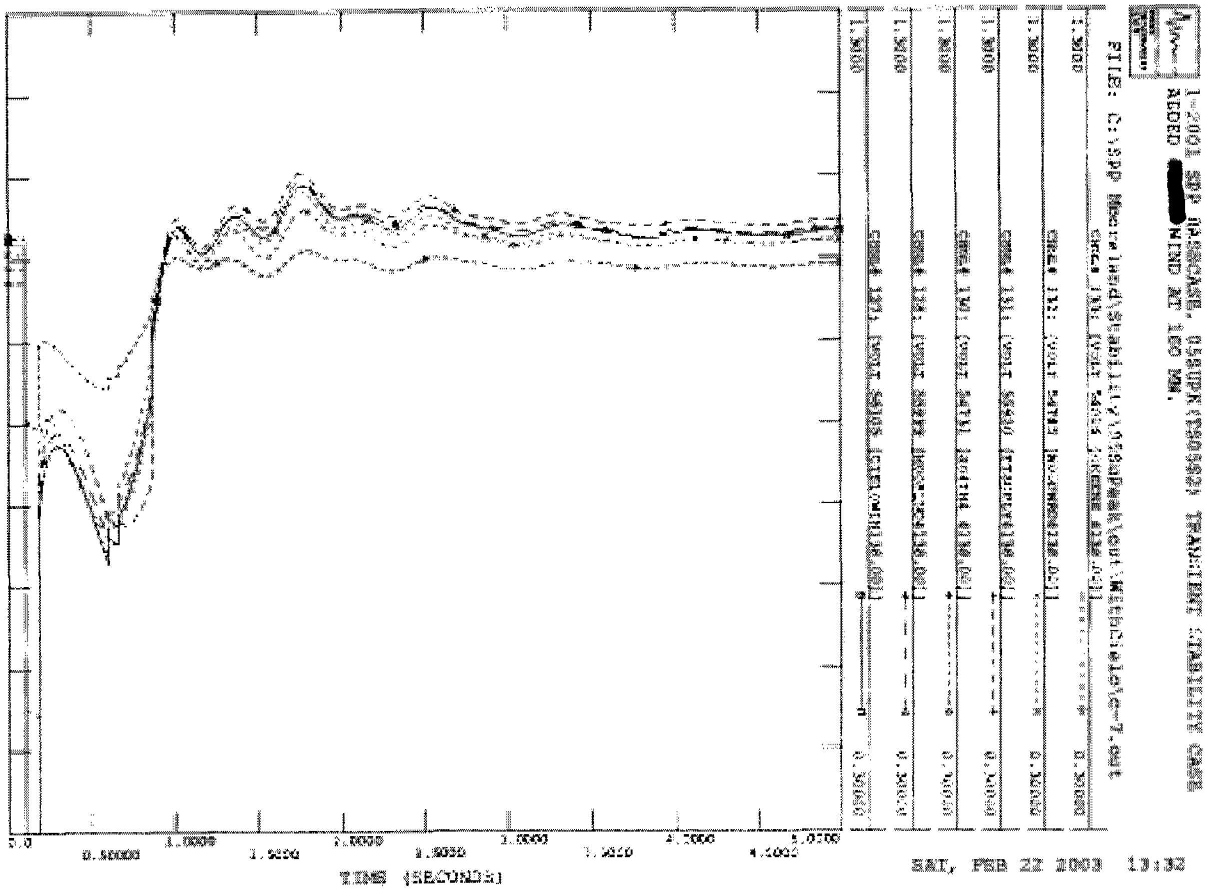

Figure 3.4: 138 kV Bus Voltages Following Contingency C-7 (>Omitted Text<Operating at 160 MW)

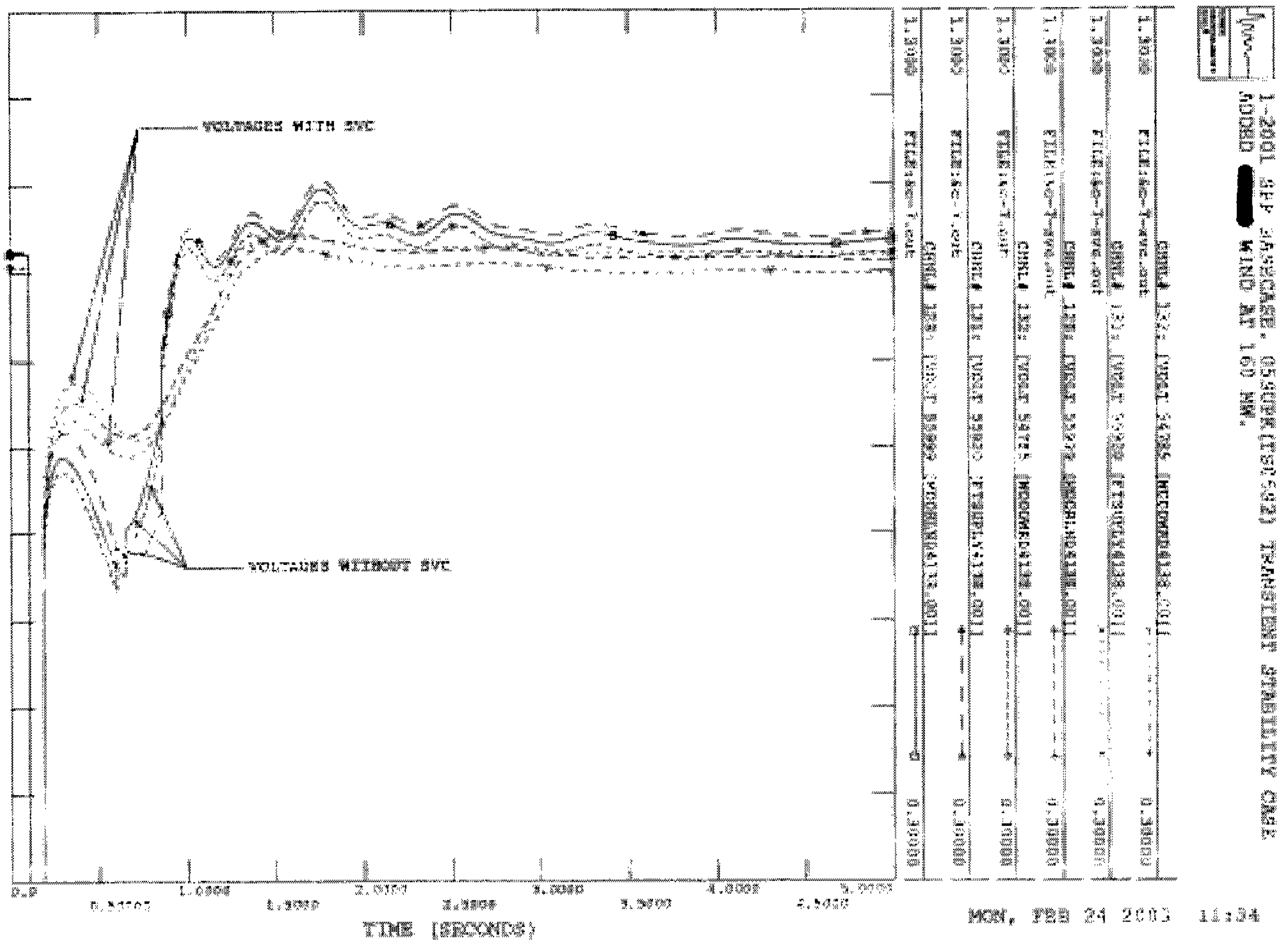

Figure 3.5: Comparison of Voltages at Select 138 kV Buses Following Contingency C-7 With and Without 170 MVAr SVC. >Omitted Text<Operating at 160 MW.

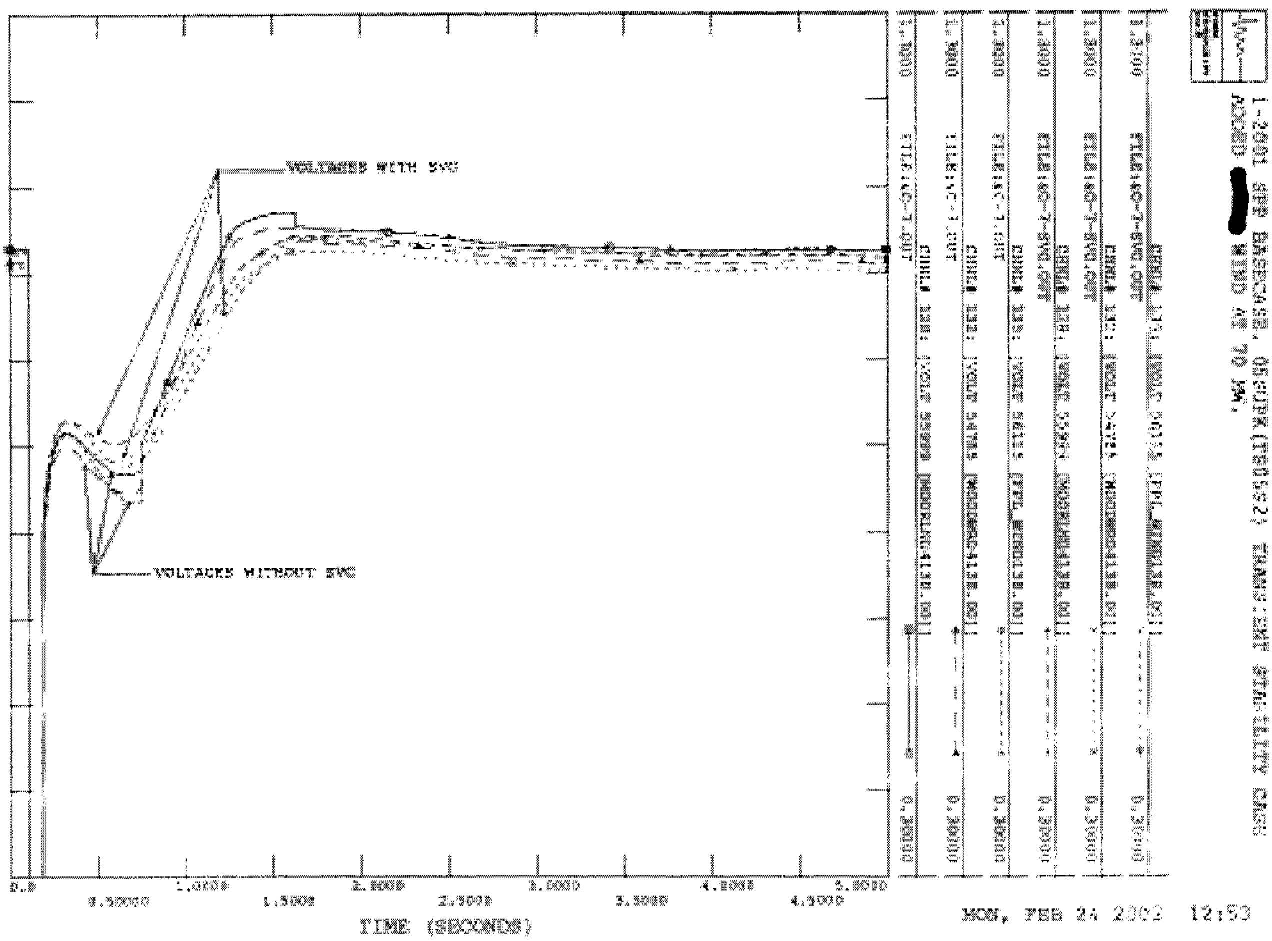

Figure 3.6: Comparison of Voltages at Select 138 kV Buses Following Contingency C-7 With and Without 35 MVAr SVC. >Omitted Text<Operating at 70 MW.

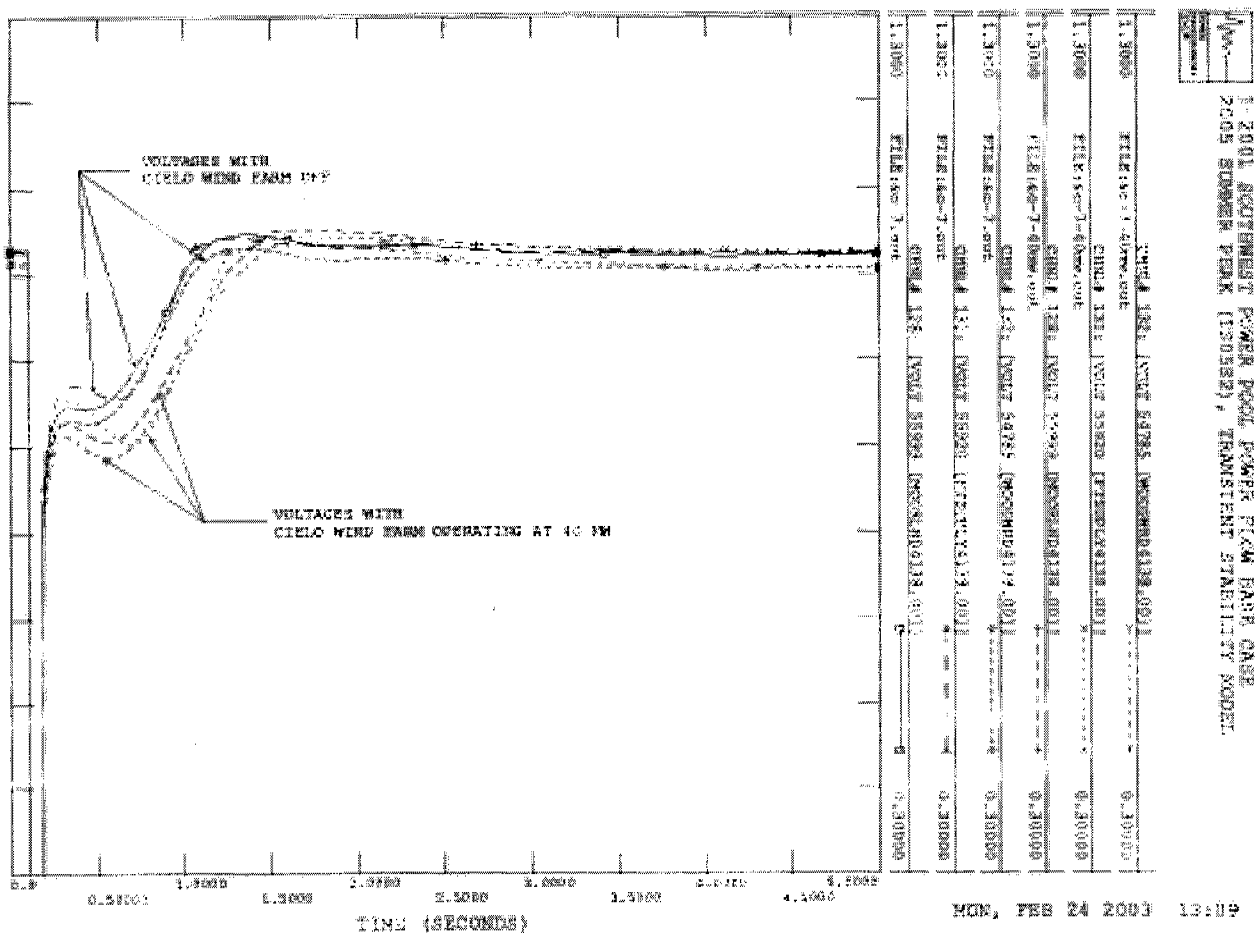

Figure 3.7: Comparison of Voltages at Select 138 kV Buses Following Contingency C-7 Without >Omitted Text<and With >Omitted Text<Operating at 40 MW.

4. STUDY CONCLUSIONS

Based on the results of the loadflow and stability analysis, the following conclusions are drawn:

- Operating >Omitted Text<at 160 MW would lead to operational (i.e., generation restrictions) and capital costs (i.e., transmission system reinforcements and dynamic reactive support). Simulation results suggest that without adequate dynamic reactive support (170 MVAr), post-fault voltage recovery is poor. This causes >Omitted Text<and other nearby wind farms to trip on undervoltages.

- Limiting the output of >Omitted Text<to 70 MW alleviates most of the thermal overloads that are attributable to the proposed plant. However, the post-contingency overload on the Morewood 138/69 kV transformer would still need to be addressed. >Omitted Text<will need to provide at least 35 MVAr of dynamic reactive support to keep itself and another nearby wind farm (>OMITTED TEXT< Wind) from tripping on undervoltages following normally cleared faults.

- >Omitted Text< could consider other solutions for dynamic reactive support, for instance using doubly-fed induction generators (DFIGs) in their wind farm instead of squirrel-cage induction generators. Unlike squirrel-cage units that consume reactive power (thereby depressing system voltages), DFIGs can exchange reactive power with the grid to regulate terminal voltages (similar to SVC function). It is to be noted that if >Omitted Text<decides to use doubly-fed induction generators in their wind farm, another system impact study would be required.

- Limiting the output of >Omitted Text<to 40 MW eliminates the need for system reinforcements and dynamic reactive compensation. Results show that there is no loss of generation for normally cleared faults and voltage recovery is comparable to the pre->Omitted Text<case. Overvoltages at the >Omitted Text<138 kV bus resulting from the loss of the 138 kV line between Mooreland and >Omitted Text<can be prevented by tripping the fixed shunt at >Omitted Text<.

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

APPENDIX A - PSS/E ONE-LINE DIAGRAMS

A.1 One-line Diagrams for Steady-State Analysis

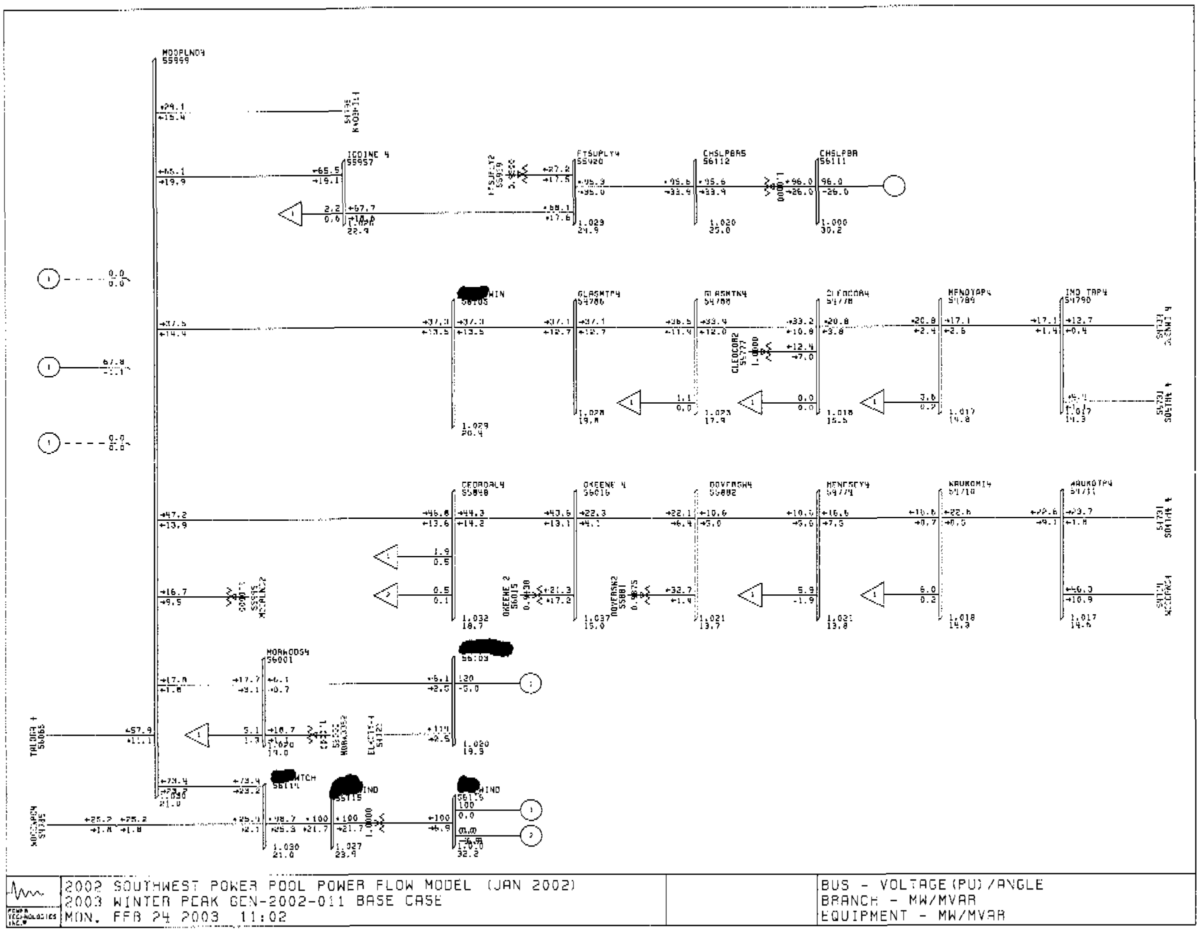

Figure A.1.1: System Conditions Without the >Omitted Text<Plant

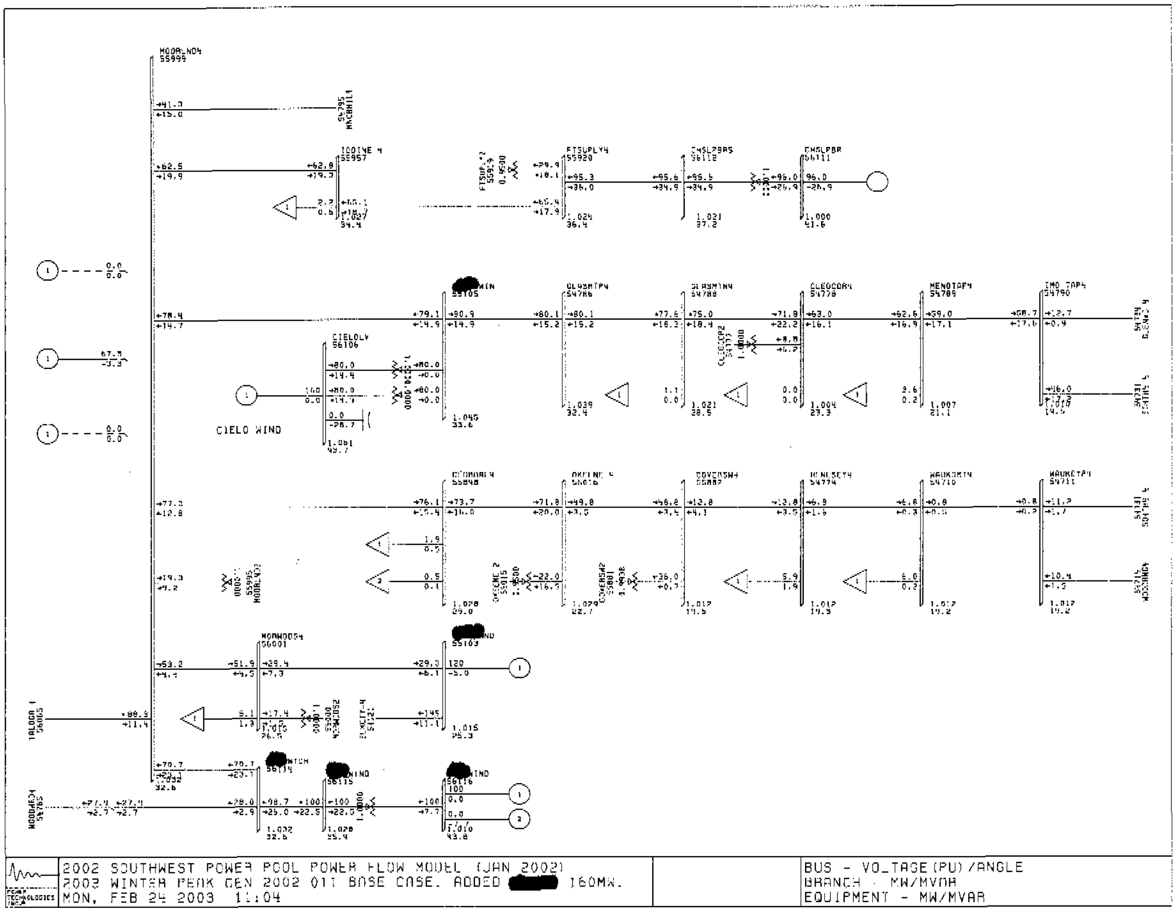

Figure A.1.2: System Conditions With the >Omitted Text<Plant

A.2 One-line Diagrams for Stability Analysis

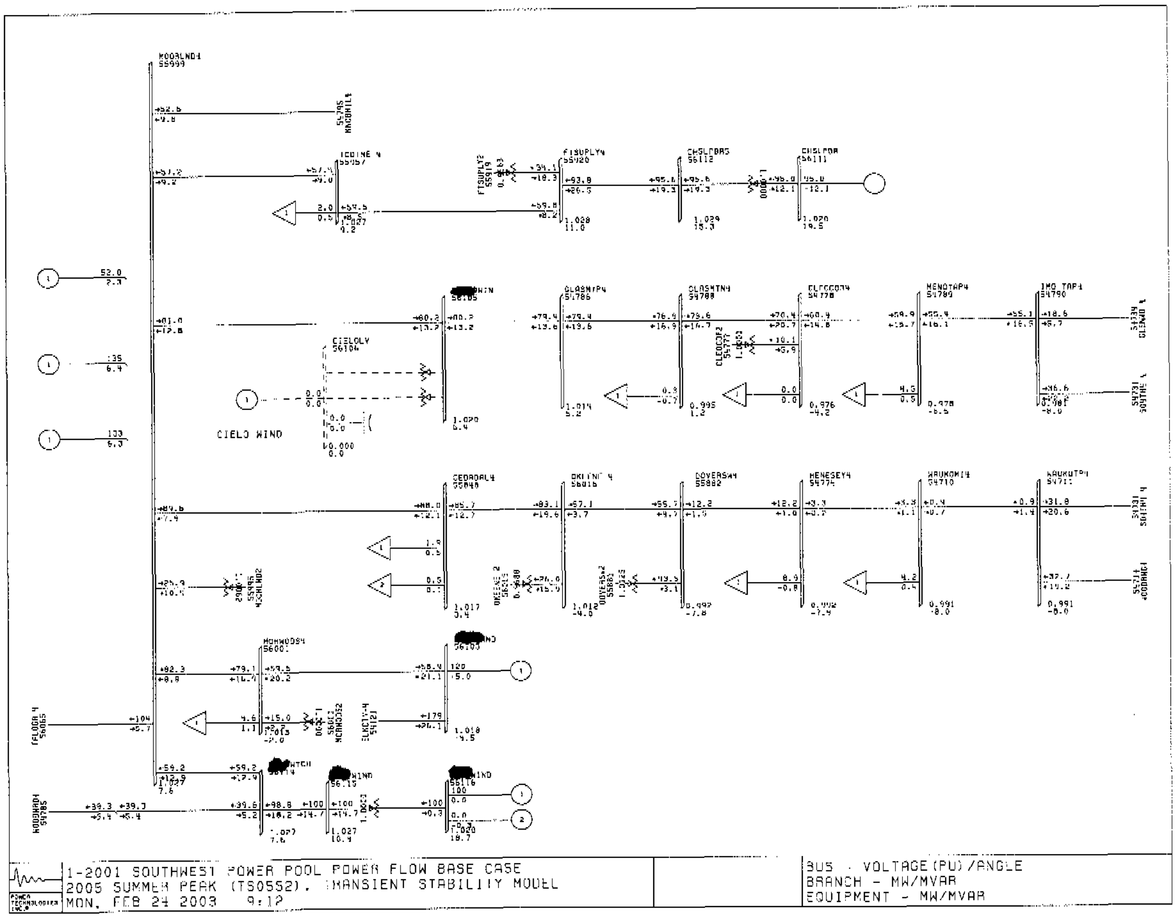

Figure A.2.1: System Conditions Without the >Omitted Text<Plant (2005 Summer Peak Case)

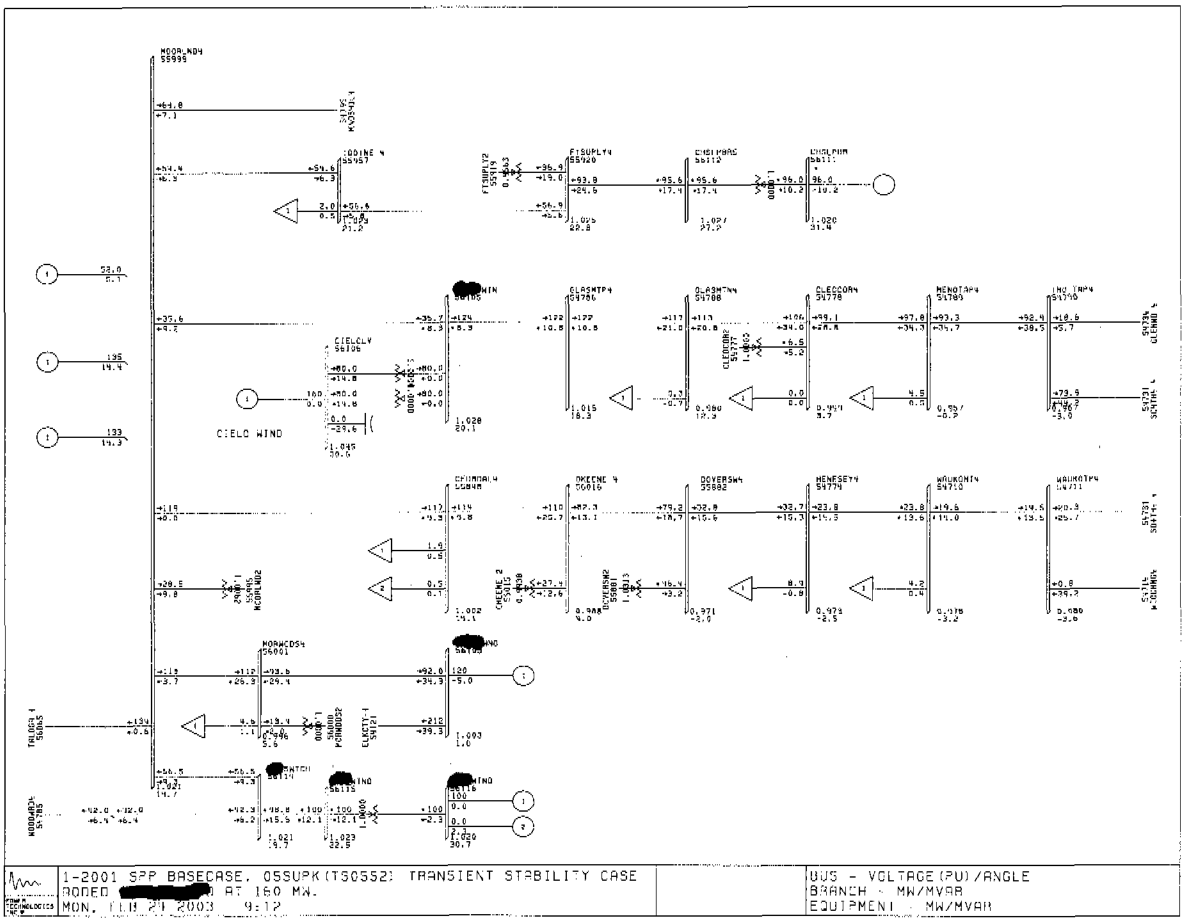

Figure A.2.2: System Conditions With the >Omitted Text<Plant (2005 Summer Peak Case)

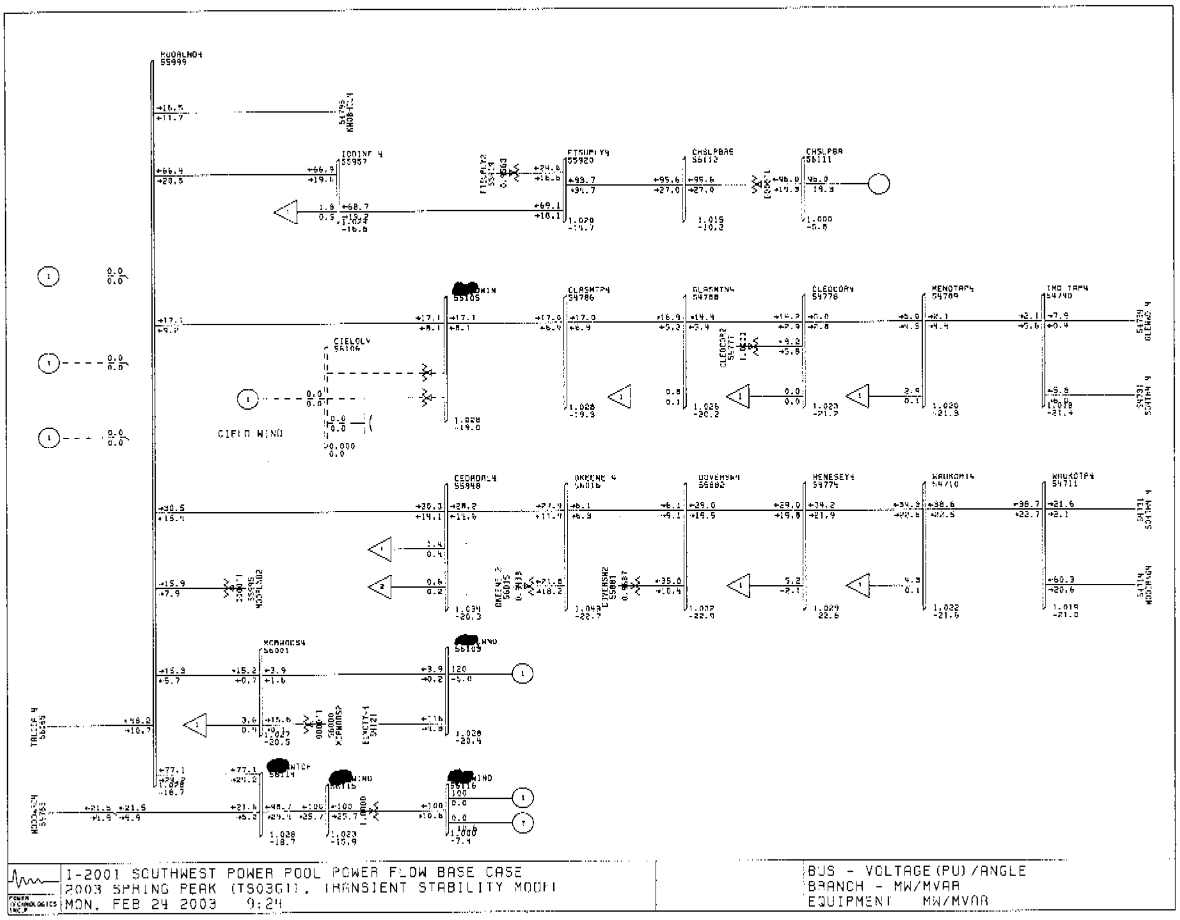

Figure A.2.3: System Conditions Without the >Omitted Text<Plant (2003 Spring Peak Case)

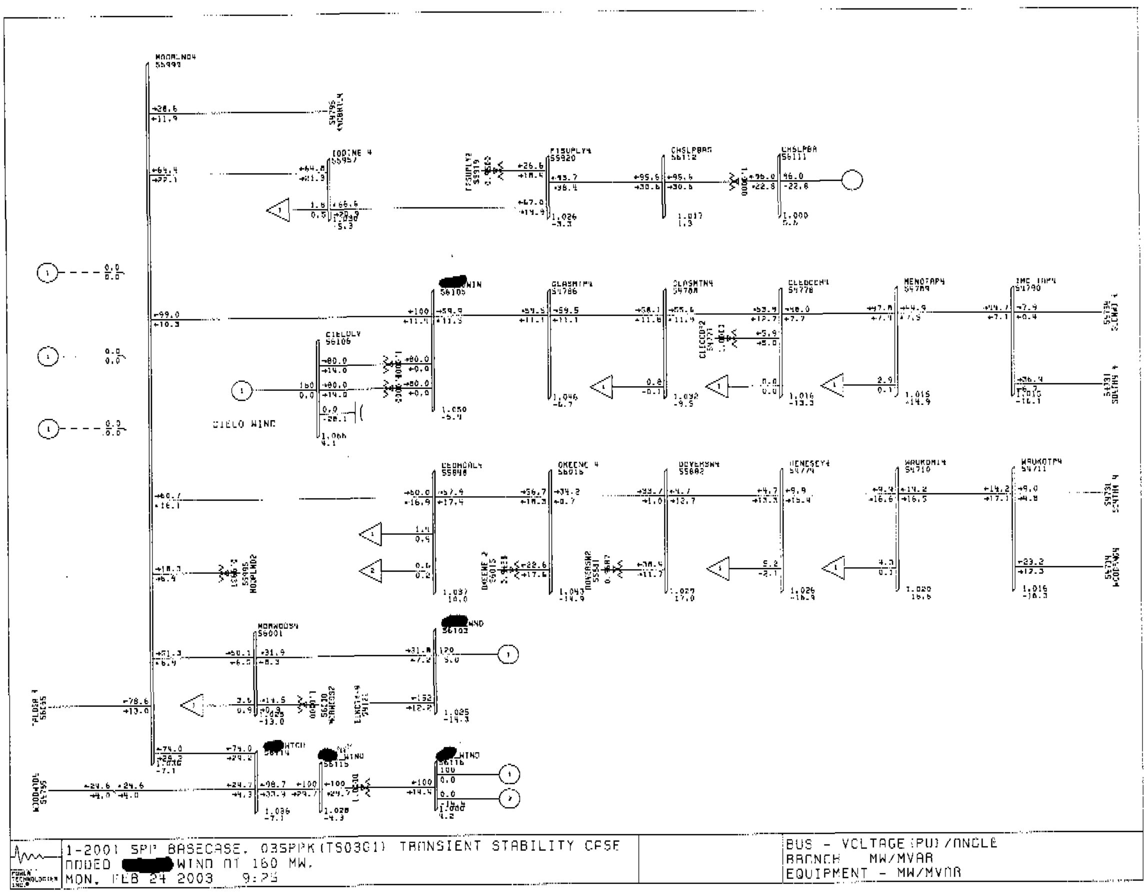

Figure A.2.4: System Conditions With the >Omitted Text<Plant (2003 Spring Peak Case)

APPENDIX B - STABILITY MODEL PARAMETERS FOR >OMITTED TEXT<160 MW PLANT

```
    ** CIMTR3 **  BUS X-- NAME --X BASEKV MC    C O N S      S T A T E S     V A R S       ICON
                56106     >OMITTED TEXT<LV  34.500 1  141010-141022  53166-53171    6895-6897
1466

            MBASE      Z S O R C E          X T R A N       GENTAP
           179.78  0.00000+J 0.23000  0.00000+J 0.00000  1.00000

               T'     T''       H       X       X'       X''      XL
            0.910  0.000    5.20  4.1800  0.2300  0.0000  0.1400

            E1       S(E1)     E2      S(E2)          D     SYN-POW
            1.0000    0.1700   1.2000   0.4400        0.00    0.0000
```

Note: Model parameters are expressed in per unit on an MBASE of 179.78 MVA (0.89 pf assumed). Time constants are expressed in seconds.