Impact Study for Generation Interconnection Request GEN – 2002 – 021

SPP Coordinated Planning
(#GEN-2002-021)

April 2004

Summary

I2R Technologies, Inc (i^2R) performed the following study at the request of the Southwest Power Pool (SPP) for SPP Generation Interconnection request Gen-2002-021. The request for interconnection was placed with SPP in accordance SPP's Open Access Transmission Tariff Attachment V, which covers new generation interconnections on SPP's transmission system.

Pursuant to the tariff, i^2R was asked to perform a detailed stability analysis of the generation interconnection requests to satisfy the System Impact Study Agreement executed by the requesting customer and SPP.

Feasibility Study for Generation Interconnection Request For GEN-2002-021

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I. EXECUTIVE SUMMARY

This study includes both load flow and dynamic analyses for a proposed 230 kV interconnection of a new 160 MW wind farm in Gray County, Texas. This wind farm will be interconnected to the Xcel Energy (SPS) transmission system and will have a nominal 160 MW maximum rating. The wind farm will consist of 160 Mitsubishi MWT-1000a wind turbines rated at 1.0 MW each.

The wind farm will be connected to the transmission system via a simple tap of the 230 kV Grapevine Interchange substation. The tap will consist of a new single breaker feeding the four mile radial 230 kV line to the wind farm and a bus extension of the 230 kV Grapevine Interchange. The radial 230 kV line will terminate on the 230 kV bus in the Interconnection Customer substation.

Interconnection Customer supplied data was used to build load flow and dynamics models using Shaw PTI's PSS/E™ software package. Each of the 160 wind turbines is modeled individually along with its associated step-up transformer. This level of detail allowed an accurate evaluation of the MVAR requirements to support the wind farm operation.

SPP provided a basecase load flow model based on the 2009 summer peak forecast. The title is "SPP MDWG 2003 STABILITY MODEL 2009 SUMMER PEAK (DS09S) (JUNE 25, 2003)." SPP also defined a comprehensive set of fault scenarios (13) to be evaluated in the dynamic analysis. The wind farm output will displace SPS generation based on economic dispatch order.

Based on the load flow analysis, five 15 MVAR capacitor banks were added to ensure that MVARs would not be drawn from the transmission system. Three of these banks were added to one 34.5 kV bus, and two more were added to the other 34.5 kV bus in the Interconnection Customer substation. This arrangement met the interconnection requirements while maintaining an acceptable voltage on the Interconnection Customer bus.

The system remained stable for all 13 fault scenarios evaluated under the operating specifications of the relays that protect the wind turbines. The wind turbines tripped because of low voltage for fault Scenarios 1, 2, 5, 7 and 9. In Scenarios 3 and 4, the wind turbines also tripped because they became isolated from the system when the radial 230 kV was opened.

Four alternatives were studied to determine whether the wind turbines could ride through the faults when they tripped because of low voltage.

- Reducing the wind farm power output level by 50 percent did not mitigate low voltage tripping of the wind turbines. When 80 of the wind turbines were taken out of service along with their reactive support, the remaining wind turbines were still tripped for fault Scenarios 1, 2, 5, 7 and 9.

- Addition of the maximum number of 15 MVAR capacitor banks possible without exceeding the normal voltage operating range kept the wind turbines on-line in Scenarios 7 and 9 through the initial fault but failed to keep the wind turbines from being tripped during the reclosure operation. The normal maximum voltage operating range of 1.1 per unit restricted the number of capacitor banks that could be added without initiating tripping by the over-voltage relays.

- Application of SVCs provided voltage recovery but did not provide it fast enough to keep the under-voltage relays from tripping the turbines. With these devices in service, voltage recovery began immediately after the fault was applied; however, the voltage did not recover before the relays operated and tripped the breakers.

- Relaxing the MHI under-voltage relay control thresholds from 0.9 to 0.85 per unit for the delayed setting and from 0.85 to 0.70 per unit for the instantaneous setting allowed the wind turbines to ride through all the fault scenarios except Scenario 1 (Scenarios 3 and 4 resulted in isolation of the wind farm and thus were excluded). The system remained stable with the wind turbines riding through these faults.

The protection system used by the Mitsubishi MWT-1000a wind turbines limits the effectiveness of the solutions investigated to provide fault ride-through capability. It was found that relaxing these thresholds for the under-voltage relays would allow the wind turbines to ride through all but very close faults. The required changes involved a 5 percent change in the delayed setting and a 15 percent change in the instantaneous setting. This is the only solution investigated that would allow the wind turbines to remain on-line for Scenarios 2, 5, 7 and 9. This solution appears to provide significant value to the transmission system with a small risk to the Interconnection Customer and should be given serious consideration.

Low frequencies were also encountered but the short duration did not present a problem. High frequencies or voltages were not encountered in the dynamic analysis.

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II. INTRODUCTION

The Interconnection Customer requested a generator interconnection study through the Southwest Power Pool Tariff for a 230 kV interconnection of a new 160 MW wind farm in Gray County, Texas. This wind farm will be interconnected to the Xcel Energy (SPS) transmission system and will have a nominal 160 MW maximum rating. The wind farm will use 160 Mitsubishi MWT-1000a wind turbines rated at 1.0 MW each.

III. CONFIGURATION

The wind farm will be connected to the transmission system as shown in Figure 1 via a simple tap of the 230 kV Grapevine Interchange substation. The tap will consist of a new single breaker feeding the four mile radial 230 kV line to the wind farm and a bus extension of the 230 kV Grapevine Interchange. The radial 230 kV line will terminate on the 230 kV bus in the Interconnection Customer substation. Based on the Interconnection Customer data, it was assumed that the four miles of 230 kV line from the tap point to the Interconnection Customer substation would be H-frame construction with equivalent phase spacing of 27.72 feet. A 336.4 ACSR 18/1 conductor gives a normal MVA rating of 211 at 93 degree Celsius and an emergency MVA rating of 269.3 at 125 degree Celsius.

The Interconnection Customer substation will contain two 230/34.5 kV transformers connected to the 230 kV bus via separate breakers. These 230/34.5 kV transformers are Y:Y with a normal rating of 96 MVA and an emergency rating of 128 MVA. They have a load loss of 225 KW and impedance of 10 percent on a 96 MVA base. Each 230/34.5 kV transformer will also be connected to a 34.5 kV bus which will serve three 34.5 kV feeders each with a dedicated breaker. Capacitor banks, sized at 15 MVAR, will be connected directly to the 34.5 kV bus as needed.

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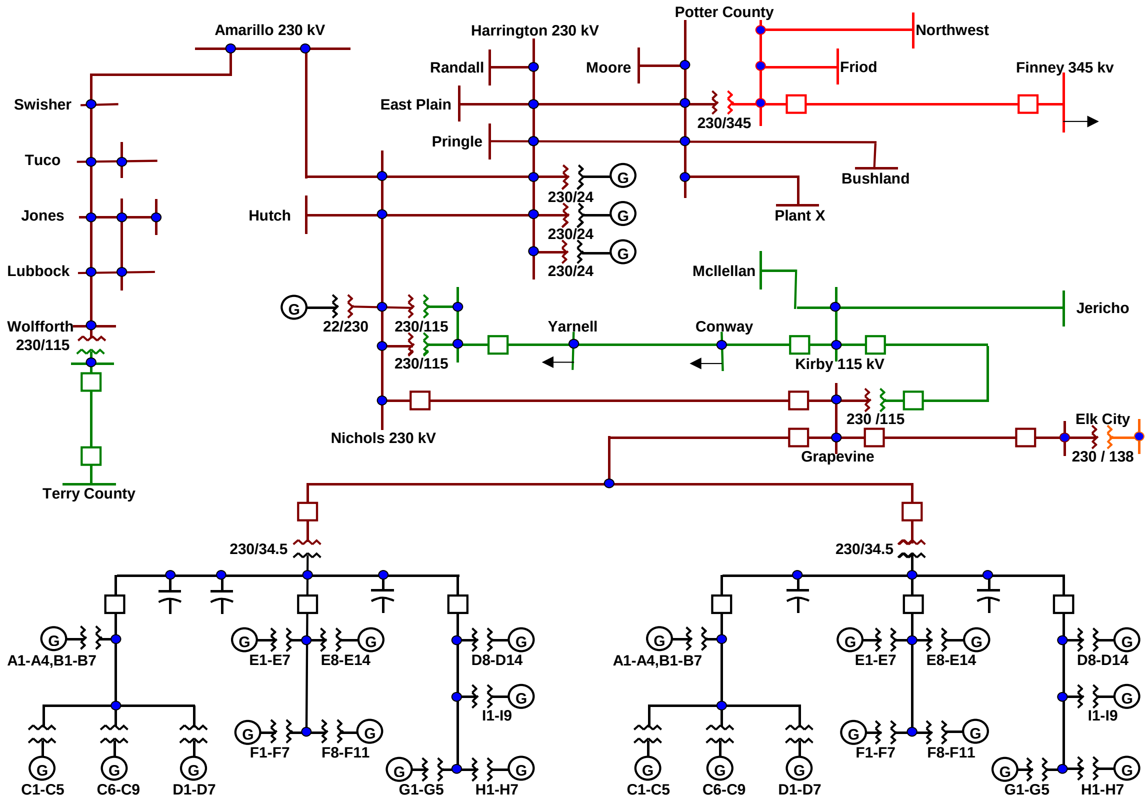
FIGURE 1



The wind turbines will be connected to the individual feeders as follows:

- Feeder 1 - Turbines A1-A4, B1-B7, C1-C9 and D1-D7
- Feeder 2 - Turbines E1-E14 and F1-F11
- Feeder 3 - Turbines D8-D14, G1-G5, H1-H7 and I1-I9

The Interconnection Customer provided the feeder conductor types and lengths. Resistive values provided in their loss table and the inductive values from the Hendrix HQ200 standard tables for the specified conductors are:

- 1/0 AL Resistance 0.1680 ohms/1000ft Inductance 0.0990 ohms/1000ft
- 4/0 AL Resistance 0.0820 ohms/1000ft Inductance 0.0920 ohms/1000ft
- 500 AL Resistance 0.0354 ohms/1000ft Inductance 0.0820 ohms/1000ft
- 1000 AL Resistance 0.0177 ohms/1000ft Inductance 0.0740 ohms/1000ft

Line charging is negligible for these underground cables.

Each of the 160 wind turbines is connected to one of the 34.5 kV feeders via its own 34.5/0.6 kV transformer. These transformers are rated at 1 MVA. These transformers have a load loss of 5.798 kW and impedance of 5.65 percent on a 1 MVA base.

Over/under voltage and frequency relays will monitor the 34.5 kV bus and have the capability to open each 34.5 kV feeder breaker independently.

IV. LOAD FLOW MODELING

SPP provided a basecase load flow model based on the 2009 summer peak forecast. The title is "SPP MDWG 2003 STABILITY MODEL 2009 SUMMER PEAK (DS09S) (JUNE 25,2003)." This model provided the starting point for building a model to evaluate the proposed wind farm.

Each individual wind turbine was modeled along with its step-up transformer. This required the addition of 160 buses for the turbines, 160 buses for the step-up transformers, 14 additional buses for line segments, and 3 buses for the substation. In addition, 160 generators, 162 transformers, 5 capacitor banks and 175 line segments were added to the existing load flow model.

Each wind turbine is rated at 1.111 MVA. For dispatch purposes, the nominal output of each turbine is 1.0 MW at a 97 percent power factor (i.e., absorbing 0.2506 MVAR.) When dispatching the wind turbines, it is assumed that the output of other units in the SPS control area will be reduced to maintain the specified interchange. Table 1 shows the units whose dispatch will be reduced when the wind turbines are brought on-line.

TABLE 1

MW Generation Dispatch			
Generator	Wind Farm 0% Output	Wind Farm 50% Output	Wind Farm 100% Output
Tolk1	422.3	422.3	422.3
Tolk31	100.0	21.0	-
Tolk41	-	-	-
Jones31	243.0	243.0	186.0
Wind Farm	-	80.0	160.0

Table 1 indicates that the phantom unit Tolk31 is turned off and the phantom unit Jones 31 is backed down 57 MW to account for the proposed wind farm generation. Phantom Unit Tolk41 is turned off in the basecase and therefore cannot be backed down. If it were operating, its generation would be reduced before phantom Unit Jones31's output was reduced. Unit Tolk1 is the slack bus for the SPS control area. The fact that its generation is the same in all scenarios verifies that the generation from phantom units Tolk31 and Jones31 has been reduced to exactly match the generation being delivered to the transmission system by the wind farm. It should be noted that the net output to the transmission system is approximately 157 MW due to 3 MW of losses on the wind farm distribution system.

The transmission provider requires the Interconnection Customer to maintain a near unity power factor. Since the wind turbines will operate at 0.97 power factor, additional VARs will be needed to support their generation. A load flow analysis was conducted to determine the optimal level of capacitor banks that would be needed to meet the transmission provider's requirements of unity power factor operation. The Interconnection Customer provided data for a fixed 15 MVAR capacitor bank installation for this analysis. Table 2 shows the results of the load flow analysis.

TABLE 2

	Grapevine			Wind Farm Bus 1		Wind Farm Bus 2	
Scenario	Voltage (PU)	MW (From WF)	MVAR (From WF)	Voltage (PU)	Capacitors MVARS	Voltage (PU)	Capacitors MVARS
Base	0.98137	-	-	-	-	-	
15	0.97115	156.6	(41.7)	0.95585	13.7	0.95585	13.7
30	0.98825	156.8	(7.3)	0.99326	29.6	0.99326	29.6
32.6	0.99134	156.9	(1.0)	1.00000	32.6	1.00000	32.6
30 / 45	0.99727	156.9	11.3	1.02164	47.0	1.00435	30.3
45	1.00620	157.0	30.5	1.03279	48.0	1.03279	48.0

Table 2 shows that adding only one 15 MVAR capacitor bank on each 34.5 kV is bus is insufficient. Under this scenario, the voltage at the Grapevine bus drops to 0.97115 and nearly 42 MVAR are being drawn from the transmission system. The addition of two 15 MVAR capacitor banks results in an improvement in the voltage at the Grapevine bus, but this scenario still requires over 7 MVAR from the transmission system. When three 15 MVAR capacitor banks are added, the voltage at the Grapevine bus increases to 1.0 per unit, and the wind farm supplies over 30 MVAR to the transmission. However, the voltage on the 34.5 kV buses increases to over 1.03 per unit. A better solution appears to be the addition of two 15 MVAR capacitor banks on one 34.5 kV bus and three 15 MVAR capacitor banks on the other 34.5 kV bus. This ensures that the voltage on each 34.5 bus is at least at 1.0 per unit, and no MVARs will be drawn from the transmission system. The value of capacitor banks that would result in exactly a 1.0 per unit voltage on both 34.5 kV buses is 32.6 MVAR. It should be noted that when the voltage is less than 1.0 per unit, the MVAR provided by the capacitor banks fall below the rated value. The MVAR provided by the capacitor banks increases above the rated value for voltages greater than 1.0 per unit voltage.

An additional analysis was performed to determine if the capacitor banks would need to be switched on as the wind turbines were coming on-line. Sets of ten wind turbines were turned off sequentially until all the wind turbines were off line. The voltage on the bus with three 15 MVAR capacitor banks increased to 1.077 per unit while the voltage on the bus with two 15 MVAR capacitor banks increased to 1.059 per unit. Since the normal operating range for the wind turbines is 0.9 to 1.1 per unit, it should not be necessary to switch on the capacitor banks as the wind turbines are being brought on-line, and the capacitor banks can be left on during the peak conditions as represented in the load flow case.

V. DYNAMIC MODELING

The Interconnection Customer supplied dynamic data for the Mitsubishi MWT-1000 wind turbines included tables pertaining to the turbine ratings, machine data, and dynamics data. Dynamics data was developed for the PSS/E™ CIMTR3 library model. The saturation inputs required by this model were developed using the Interconnection Customer supplied no load saturation curve for the wind turbines. The saturation coefficient for 1.0 per unit voltage is equal to the difference between the current at 600 volts based on the saturation curve minus the current at 600 volts based on the air gap curve divided by the current at 600 volts based on the air gap curve. The saturation coefficient for 1.2 per unit voltage is equal to the difference between the current at 720 volts based on the saturation curve minus the current at 720 volts based on the air gap curve divided by the current at 720 volts based on the air gap curve. The values were extracted from the curve and calculated.

The Inertia constant provided by Mitsubishi for the wind turbine generator is atypical. The Inertia constant (H) that was provided is 128.5; however, typical wind turbine generator H values for this size of machine are in the range of 4.0 to 6.0. The equation used to calculate the H constant is shown below:

$$H = \frac{(1.37 * (GD^2) * (rpm^2) * 10^{-6})}{R}$$

where:

H	=	Inertia constant in KW*SEC/KVA
GD^2	=	Moment of inertia in $KG*M^2$ (based on diameter)
rpm	=	Rotational speed of the mass in revolutions per minute
R	=	Machine KVA rating

Using the GD^2 values provided by Mitsubishi, an H constant of 1.1886 was calculated; however, upon further examination of the data, it was determined that the GD^2 values provided by Mitsubishi were in fact the mass moment of inertia (I) of the turbine. The conversion equation for mass moment of inertia to moment of inertia is: $GD^2 = 4 * I$

Thus, the correct H constant for the turbine is 4 * 1.1886 or 4.75 PU on the machine base. This is the H constant used in the dynamic stability analysis.

It is also important to note that the Interconnection Customer dynamics data showed T' = T" and X' = X" which indicates that the Mitsubishi MWT-100 wind turbines are single cage induction machines. For the single cage induction machines the CIMTR3 requires that T" and X" be set to zero. The actual data used to build the CIMTR3 model is shown below:

- T' - 0.87 Seconds
- T" - 0 Seconds
- H - 4.75 Inertia Constant
- X - 3.97 P.U.
- X' - 0.21 P.U.
- X" - 0 P.U.
- E1 - 1.0
- SE1- 0.0543
- E2 - 1.2
- SE2- 0.4065
- Sw - 0
- SP - 1.0

The Mitsubishi MWT-1000 wind turbines are protected from voltage and frequency excursions via an over/under voltage relay and over/under frequency relay. The over/under voltage relay has two settings. Normal operation occurs when the voltage is between 0.9 and 1.1 per unit. When voltage exceeds 1.1 or drops below 0.9 per unit, a timer is set that will trip the breaker if voltage does not return to the normal range within 0.05 seconds. If the voltage exceeds 1.2 or drops below 0.85 per unit the breaker will be tripped instantaneously. A 0.05 second (3 cycle) relay pick-up time and a 0.5 second (30 cycle) breaker operating time was used. The data for the relay model is shown below:

- Lower Voltage Threshold 0.9 P.U.
- Upper Voltage Threshold 1.1 P.U.
- Relay Pickup Time (delay) 0.1 Seconds
- Breaker Time 0.5 Seconds

- Lower Voltage Threshold 0.85 P.U.
- Upper Voltage Threshold 1.2 P.U.
- Relay Pickup Time (delay) 0.05 Seconds
- Breaker Time 0.5 Seconds

The over/under frequency relay has two settings. Normal operation occurs when the frequency is between 59.0 and 60.5 cycles per second. When frequency exceeds 60.5 or drops below 59.0 cycles per second a timer is set that will trip the breaker if frequency does not return to the normal range within 0.05 seconds. If the voltage exceeds 61.0 cycles per second the breaker will be tripped instantaneously. A 0.5 second breaker operating time was used. The data for the relay model is shown below:

- Lower Frequency Threshold 59.0 P.U.
- Upper Frequency Threshold 60.5 P.U.
- Relay Pickup Time (delay) 0.1 Seconds
- Breaker Time 0.5 Seconds

- Lower Voltage Threshold 0.0 P.U.
- Upper Voltage Threshold 61.0 P.U.
- Relay Pickup Time (delay) 0.05 Seconds
- Breaker Time 0.5 Seconds

The relays monitor each 34.5 kV bus independently and trip the wind turbines by opening the individual 34.5 kV feeder circuit breakers without de-energizing the 34.5 kV bus. Thus, the capacitor banks remain on-line after the turbines are tripped off-line.

VI. FAULT SCENARIOS

The SPP defined the following fault scenarios, and they were evaluated:

1. A three-phase fault on the Nichols to Grapevine 230 kV line near the middle of the line was evaluated. The fault was applied at the midpoint for 5 cycles. Removing the 230 kV line between the Nichols and Grapevine Substations temporarily cleared the fault. After 20 cycles, the 230 kV line was re-closed and fault was re-applied at the midpoint for 5 cycles. Removing the 230 kV line between the Nichols and Grapevine Substations permanently cleared the fault as shown below in Figure 2.

2. A single-phase fault on the Nichols to Grapevine 230 kV line near the middle of the line was evaluated. The fault was applied at the midpoint for 5 cycles. Removing the 230 kV line between the Nichols and Grapevine Substations temporarily cleared the fault. After 20 cycles, the 230 kV line was re-closed and fault was re-applied at the midpoint for 5 cycles. Removing the 230 kV line between the Nichols and Grapevine Substations permanently cleared the fault as shown below in Figure 2.

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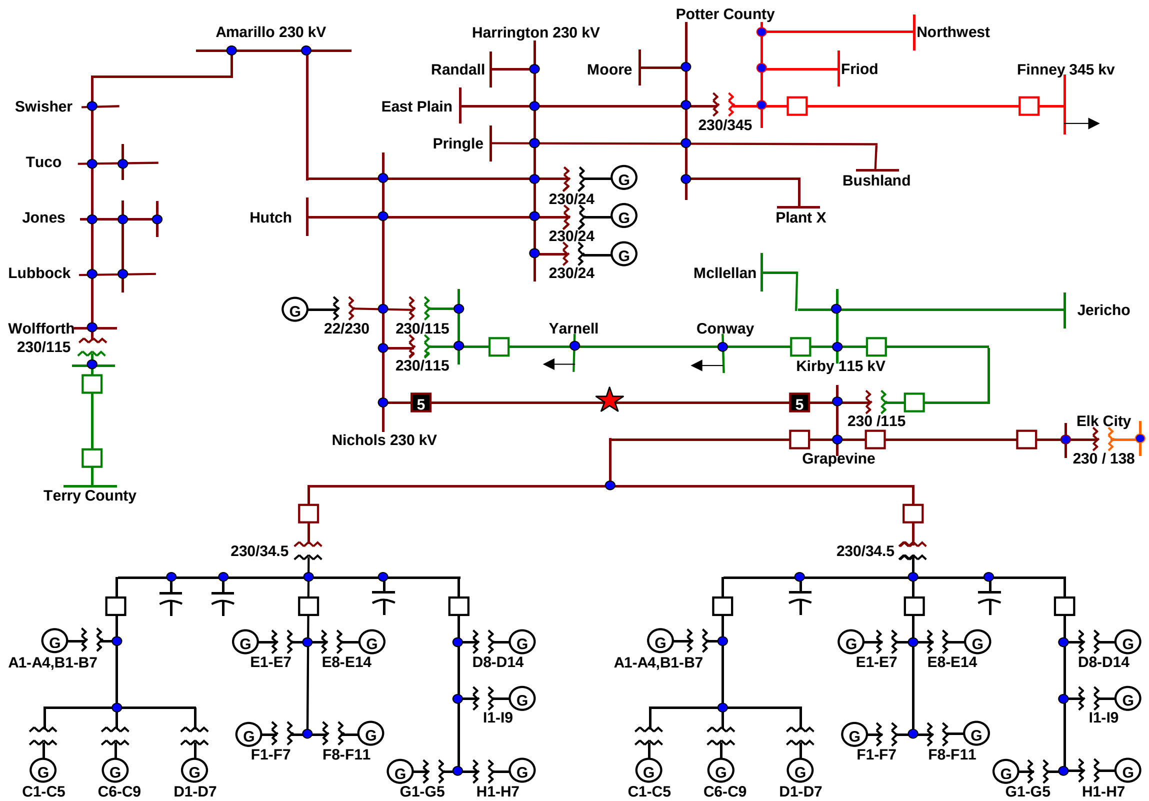
FIGURE 2

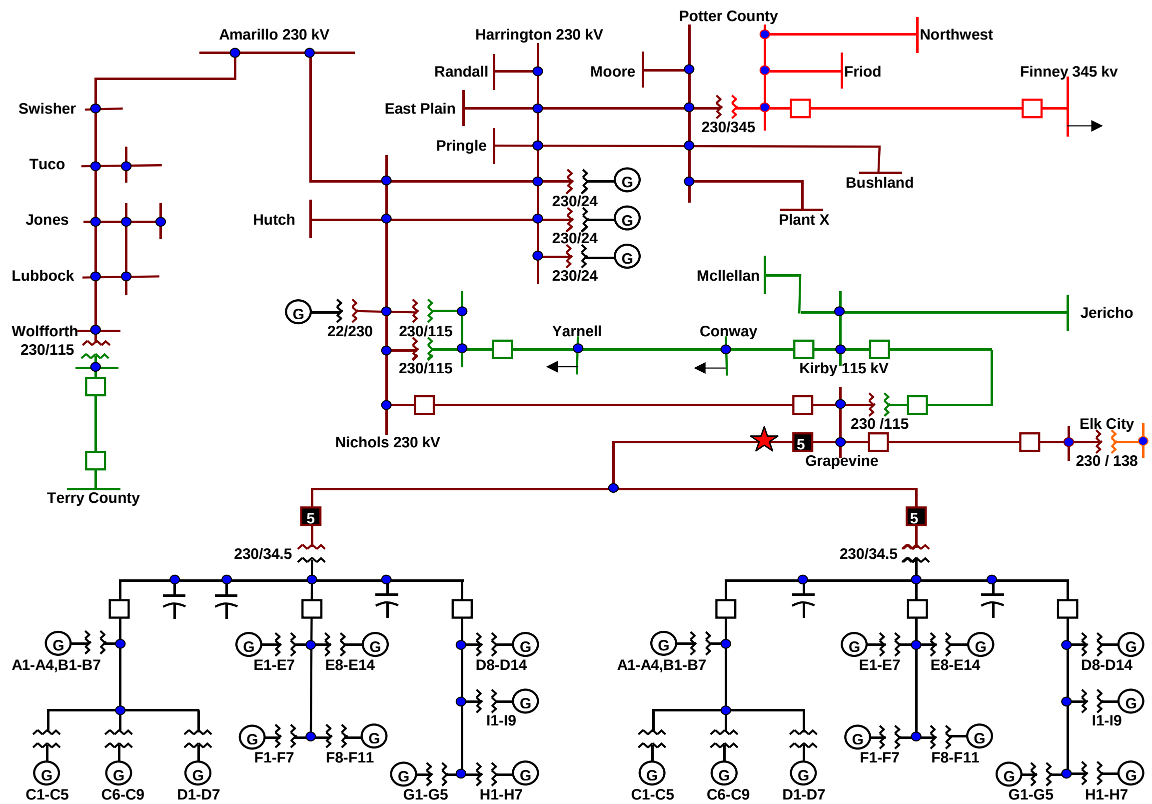


3. A three-phase fault on the Grapevine to Wind Farm radial 230 kV line near the Grapevine Substation was evaluated. The fault was applied at the Grapevine Substation for 5 cycles. Removing the radial 230 kV line between the Grapevine Substation and the Wind Farm Substation temporarily cleared the fault. After 20 cycles, the radial 230 kV line was re-closed and fault was re-applied at the Grapevine Substation for 5 cycles. The fault was permanently cleared by removing the radial 230 kV line between the Grapevine Substation and the Wind Farm Substation as shown below in Figure 3.

4. A single-phase fault on the Grapevine to Wind Farm radial 230 kV line near the Grapevine Substation was evaluated. The fault was applied at the Grapevine Substation for 5 cycles. Removing the radial 230 kV line between the Grapevine Substation and the Wind Farm Substation temporarily cleared the fault. After 20 cycles, the radial 230 kV line was re-closed and fault was

re-applied at the Grapevine Substation for 5 cycles. The fault was permanently cleared by removing the radial 230 kV line between the Grapevine Substation and the Wind Farm Substation as shown below in Figure 3.

FIGURE 3

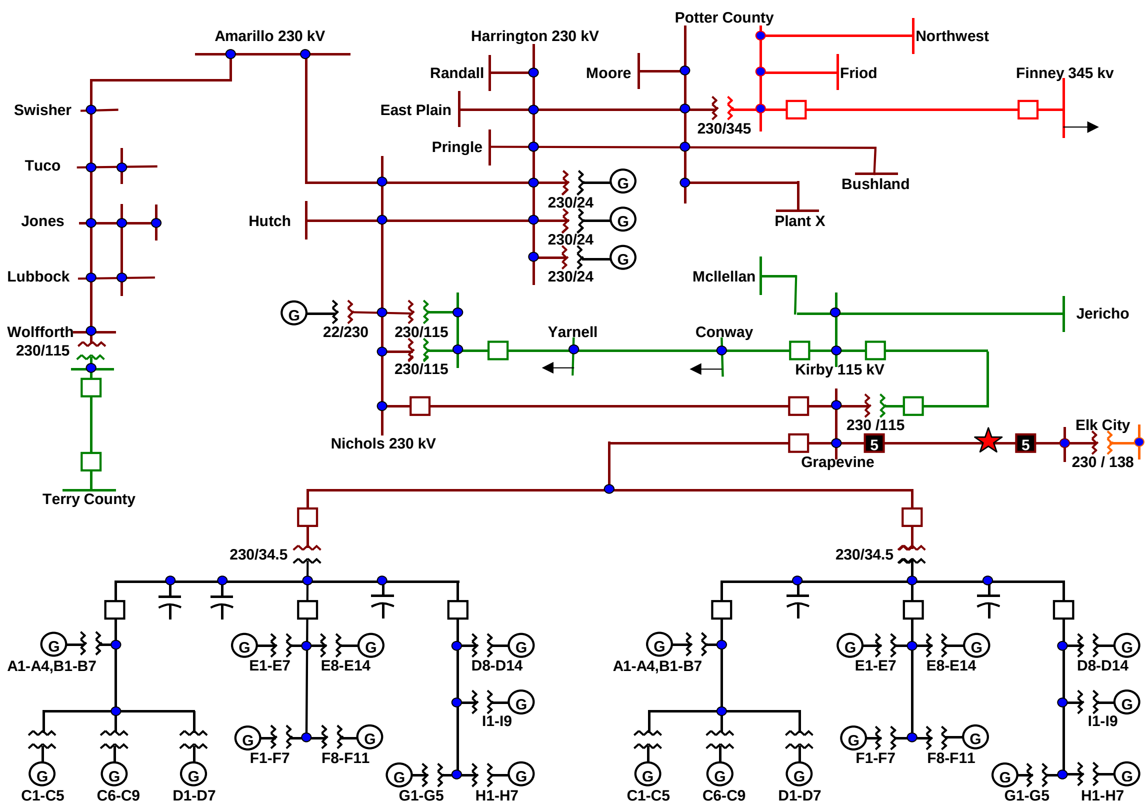


5. A three-phase fault on the Elk City to Grapevine 230 kV line near the Elk City Substation was evaluated. The fault was applied at the Elk City Substation for 5 cycles. Removing the 230 kV line between the Elk City and Grapevine Substations temporarily cleared the fault. After 20 cycles, the 230 kV line was re-closed and fault was re-applied at the Elk City Substation for 5 cycles. Removing the 230 kV line between the Elk City and Grapevine Substations as shown below in Figure 4 permanently cleared the fault.

6. A single-phase fault on the Elk City to Grapevine 230 kV line near the Elk City Substation was evaluated. The fault was applied at the Elk City Substation for 5 cycles. Removing the 230 kV line between the Elk City and

Grapevine Substations temporarily cleared the fault. After 20 cycles, the 230 kV line was re-closed and fault was re-applied at the Elk City Substation for 5 cycles. Removing the 230 kV line between the Elk City and Grapevine Substations permanently cleared the fault as shown below in Figure 4.

FIGURE 4

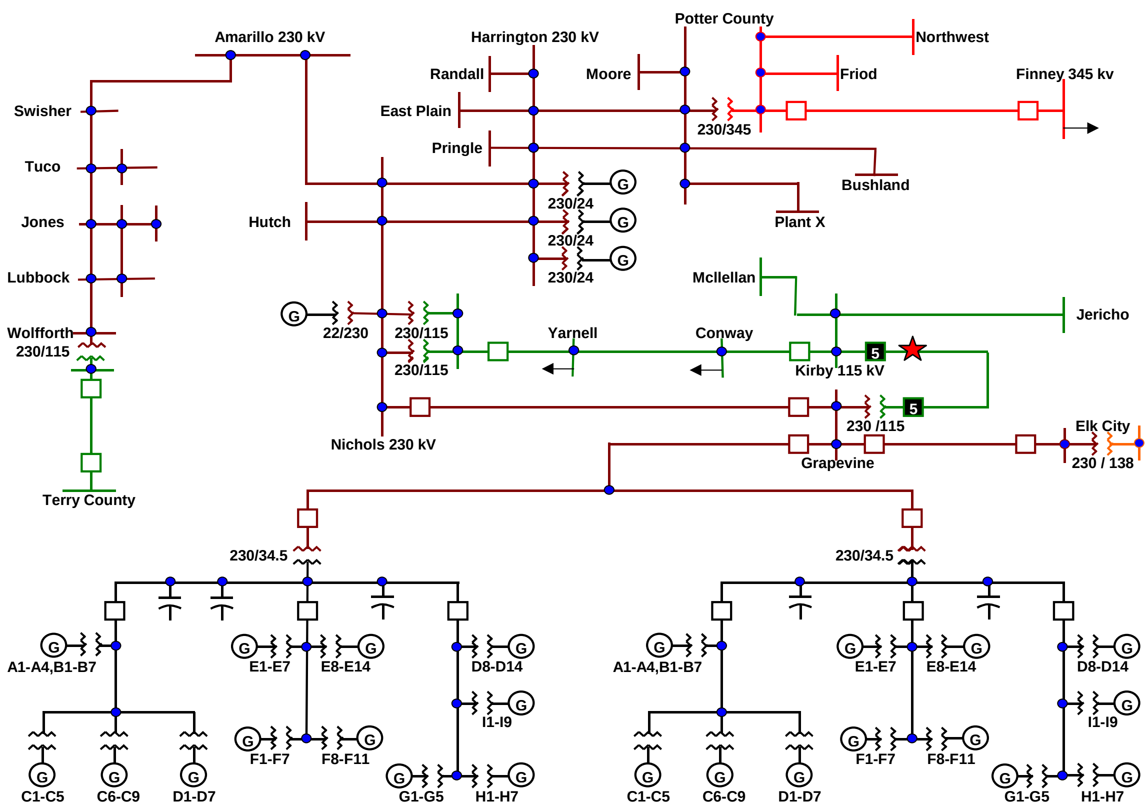


7. A three-phase fault on the Kirby to Grapevine 115 kV line near the Kirby Substation was evaluated. The fault was applied at the Kirby Substation for 5 cycles. Removing the 115 kV line between the Kirby and Grapevine Substations temporarily cleared the fault. After 20 cycles, the 115 kV line was re-closed and fault was re-applied at the Kirby Substation for 5 cycles. Removing the 115 kV line between the Kirby and Grapevine Substations permanently cleared the fault as shown below in Figure 5.

8. A single-phase fault on the Kirby to Grapevine 115 kV line near the Kirby Substation was evaluated. The fault was applied at the Kirby Substation for 5

cycles. Removing the 115 kV line between the Kirby and Grapevine Substations temporarily cleared the fault. After 20 cycles, the 115 kV line was re-closed and fault was re-applied at the Kirby Substation for 5 cycles. Removing the 115 kV line between the Kirby and Grapevine Substations permanently cleared the fault as shown below in Figure 5.

FIGURE 5



9. A three-phase fault on the Kirby to Conway 115 kV line near the Kirby Substation was evaluated. The fault was applied at the Kirby Substation for 5 cycles. Opening the path between the Kirby and Nichols Substations and dropping load at Yarnell and Conway temporarily cleared the fault. After 20 cycles, the 115 kV path was re-closed, the loads were reconnected and fault was re-applied at the Kirby Substation for 5 cycles. Removing the 115 kV lines between the Kirby, Conway, Yarnell and Nichols Substations permanently cleared the fault as shown below in Figure 6.

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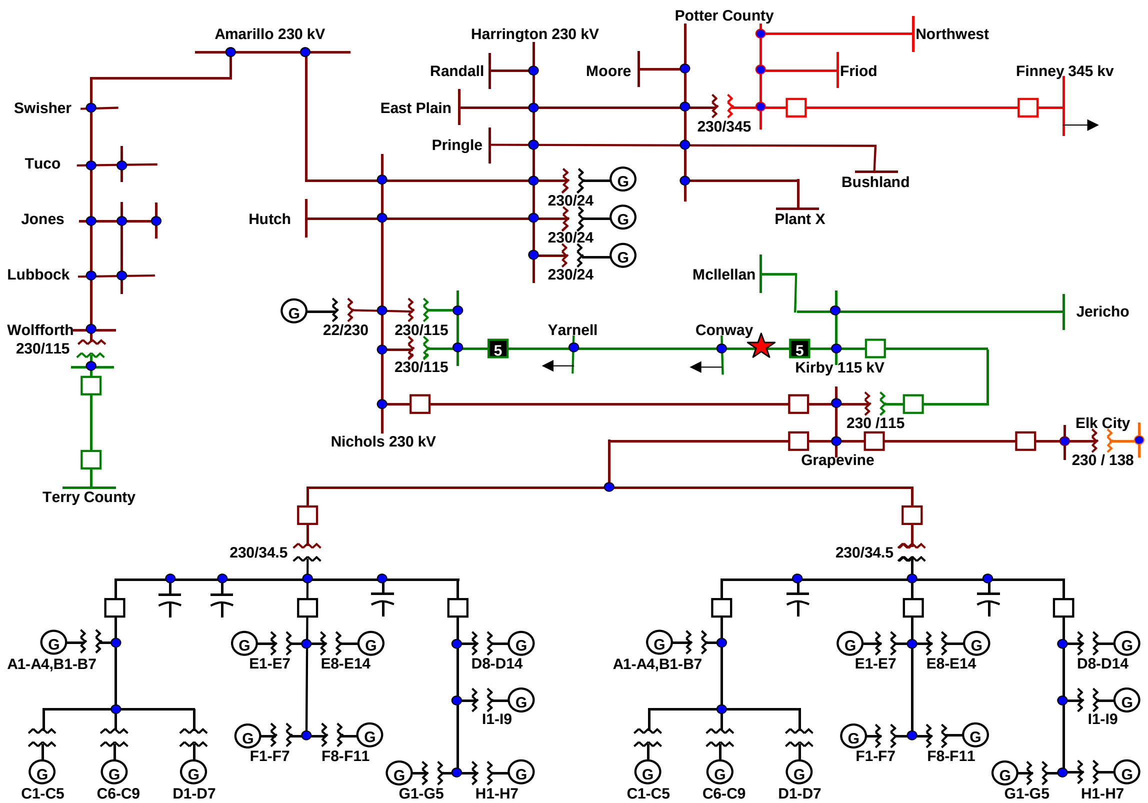
10. A single-phase fault on the Kirby to Conway 115 kV line near the Kirby Substation was evaluated. The fault was applied at the Kirby Substation for 5 cycles. Opening the path between the Kirby and Nichols Substations and dropping load at Yarnell and Conway temporarily cleared the fault. After 20 cycles, the 115 kV path was re-closed, the loads were reconnected and the fault was re-applied at the Kirby Substation for 5 cycles. Removing the 115 kV lines between the Kirby, Conway, Yarnell and Nichols Substations permanently cleared the fault as shown below in Figure 6.

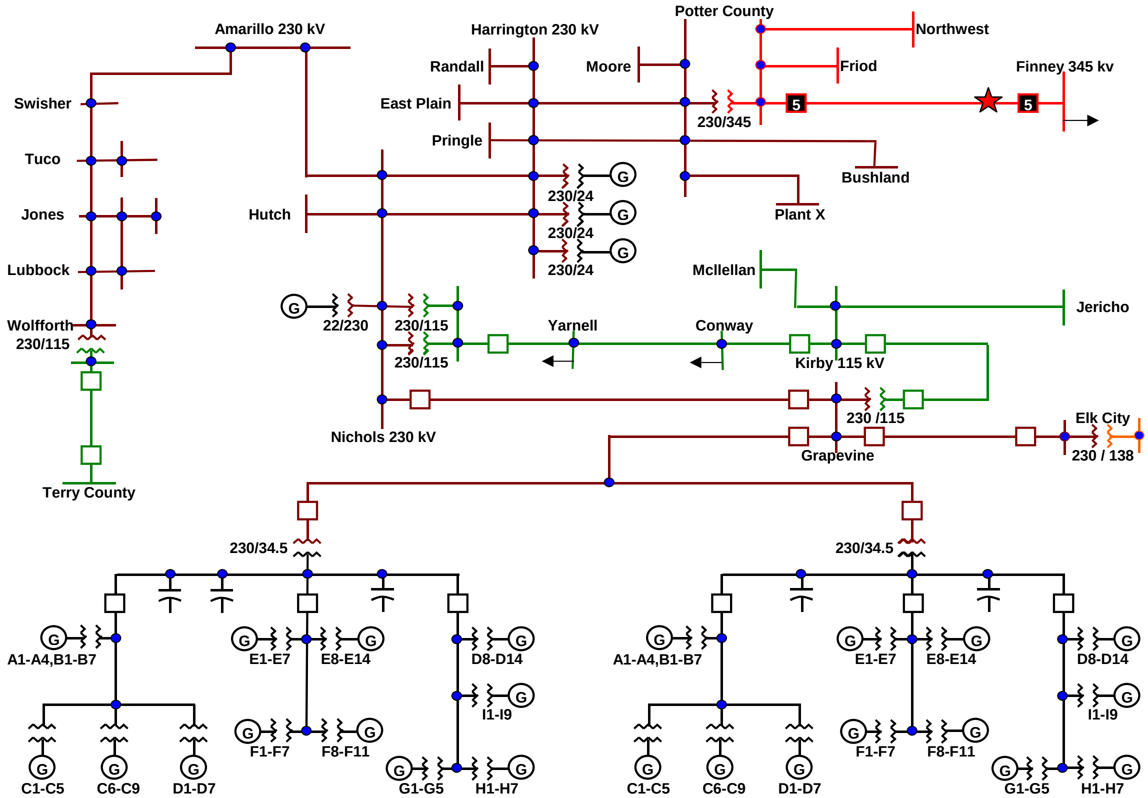
FIGURE 6



11. A three-phase fault on the Finney to Potter County 345 kV line near the Finney Substation was evaluated. The fault was applied at the Finney Substation for 5 cycles. Removing the 345 kV line between the Finney and Potter County Substations temporarily cleared the fault. After 30 cycles, the 345 kV line was re-closed and fault was re-applied at the Finney Substation

for 5 cycles. Removing the 345 kV line between the Finney and Potter County Substations permanently cleared the fault as shown below in Figure 7.

FIGURE 7

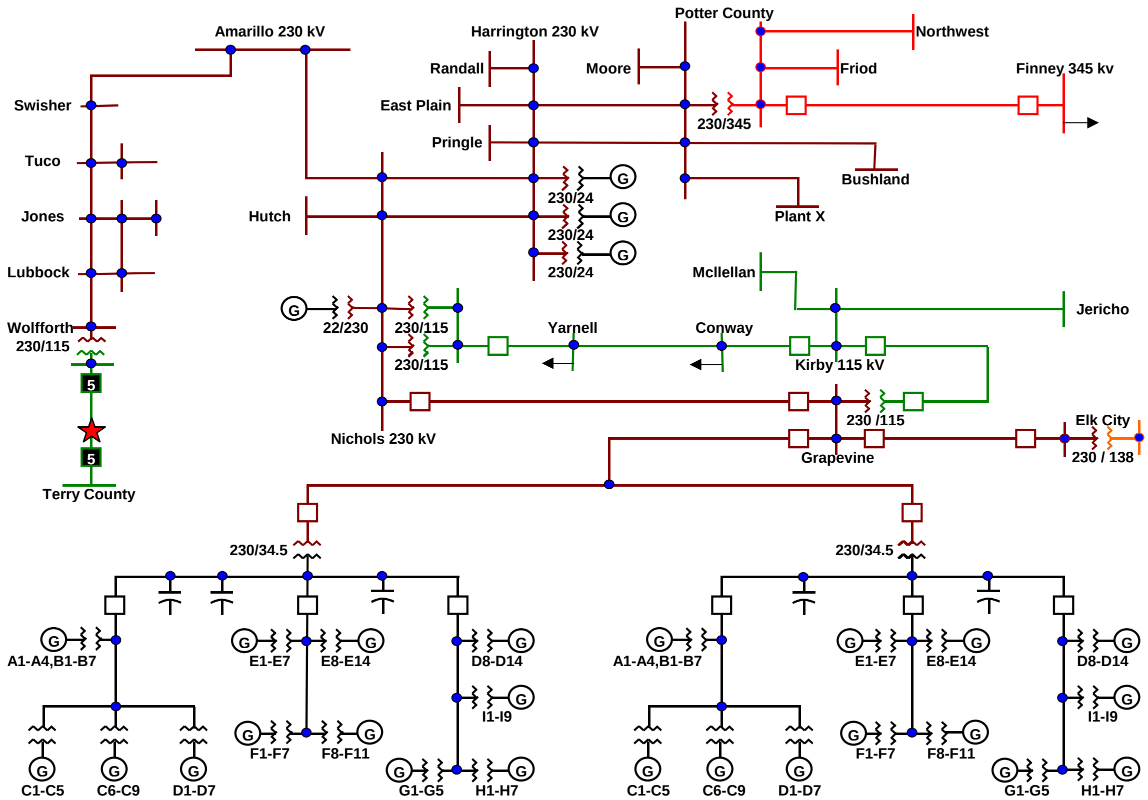


12. A three-phase fault on the Terry County to Wolfforth Interchange 115 kV line near the Terry County Substation was evaluated. The fault was applied at the Terry County Substation for 5 cycles. Removing the 115 kV line between the Terry County and Wolfforth Substations temporarily cleared the fault. After 20 cycles, the 115 kV line was re-closed and fault was re-applied at the Terry County Substation for 5 cycles. Removing the 115 kV line between the Terry County and Wolfforth Substations permanently cleared the fault as shown below in Figure 8.

13. A single-phase fault on the Terry County to Wolfforth Interchange 115 kV line near the Terry County Substation was evaluated. The fault was applied at

the Terry County Substation for 5 cycles. Removing the 115 kV line between the Terry County and Wolfforth Substations temporarily cleared the fault. After 20 cycles, the 115 kV line was re-closed and fault was re-applied at the Terry County Substation for 5 cycles. Removing the 115 kV line between the Terry County and Wolfforth Substations permanently cleared the fault as shown below in Figure 8.

FIGURE 8



VII. RESULTS

The results of the dynamic simulations are shown in Table 3 below:

TABLE 3

Scenario	System Stable	Turbines Tripped	Relay
1	Yes	Yes	Under-Voltage
2	Yes	Yes	Under-Voltage
3	Yes	Yes	Under-Voltage
4	Yes	Yes	Under-Voltage
5	Yes	Yes	Under-Voltage
6	Yes	No	
7	Yes	Yes	Under-Voltage
8	Yes	No	
9	Yes	Yes	Under-Voltage
10	Yes	No	
11	Yes	No	
12	Yes	No	
13	Yes	No	

Table 3 shows that the system remains stable for all the faults evaluated; however, the wind turbines tripped off-line in Scenarios 1, 2, 3, 4, 5, 7, 9 by the under-voltage relays. In Scenarios 3 and 4, the wind farm is isolated from the system when the fault is cleared. The relay monitors the voltage on the 34.5 kV bus and trips each breaker. It is assumed that relays will open the 34.5 kV breakers to trip the turbines. Thus the capacitor banks will remain on-line after the wind turbines are tripped.

Figures 9-12 show the angle swings of Nichols Unit 1 and Harrington Unit 1 for the faults simulated. These units are located close to the proposed wind farm. Figures 9 and 10 show the angle swings for Nichols Unit 1 and Harrington Unit 1 respectively for Scenarios 6, 8, 10, 11, 12 and 13 where the wind turbines remain on-line after the fault is cleared. Figures 11 and 12 show the angle swings for Nichols Unit 1 and Harrington Unit 1 respectively for Scenarios 1, 2, 3, 4, 5, 7, and 9 where the wind turbines are tripped off-line.

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The pre-fault angle of the Nichols Unit 1 and Harrington Unit 1 decreased approximately 7 degrees to post-fault values that were within a few degrees for all the scenarios where the wind turbines are tripped off-line. In the scenarios where the wind turbines remained on-line, the angles for these two machines tended to return to their pre-fault values with one scenario slightly higher and one scenario slightly lower. The variance was less than 5 degrees. For all fault scenarios investigated, units remain in synchronism with the system, and swings dampened out significantly by the end of the simulation period. There is no indication of angular instability.

FIGURE 9

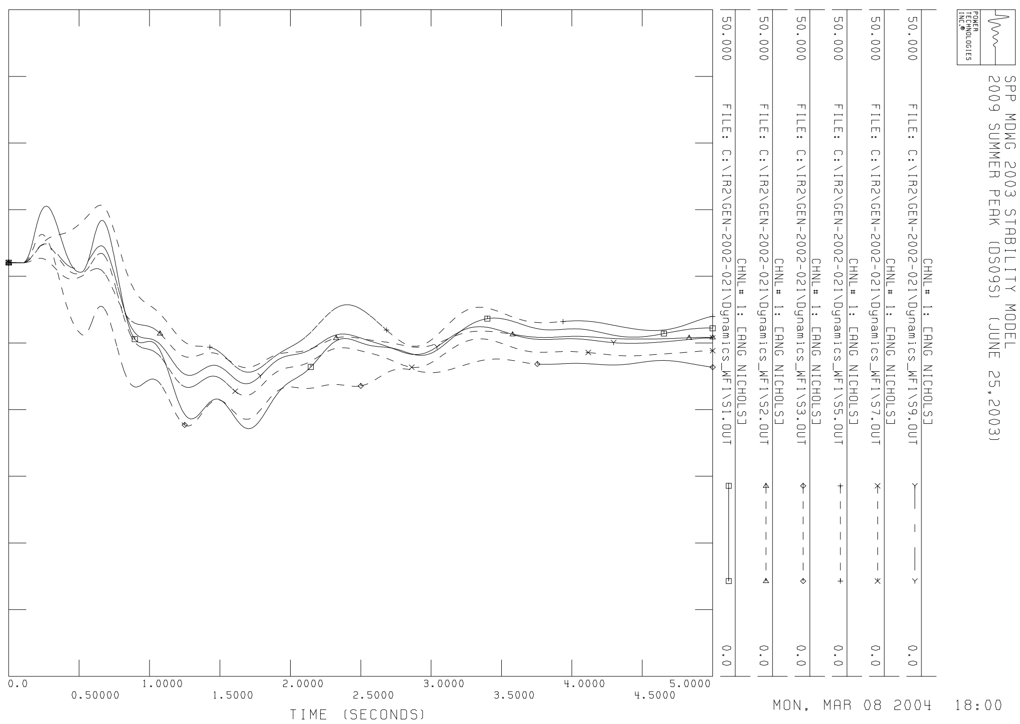

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FIGURE 10

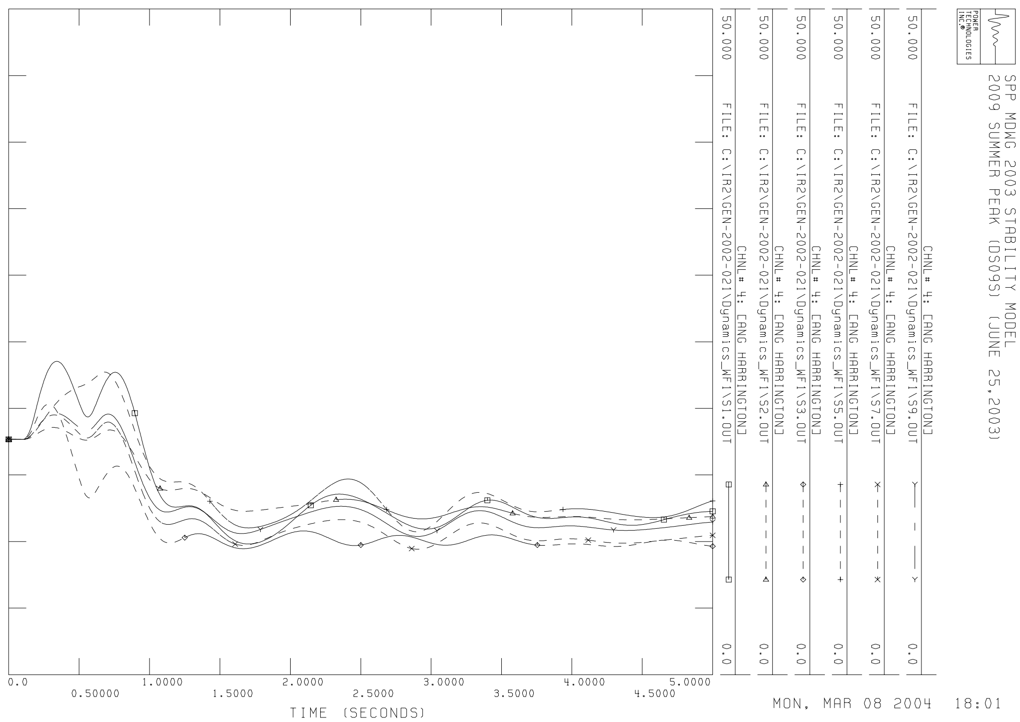


FIGURE 11

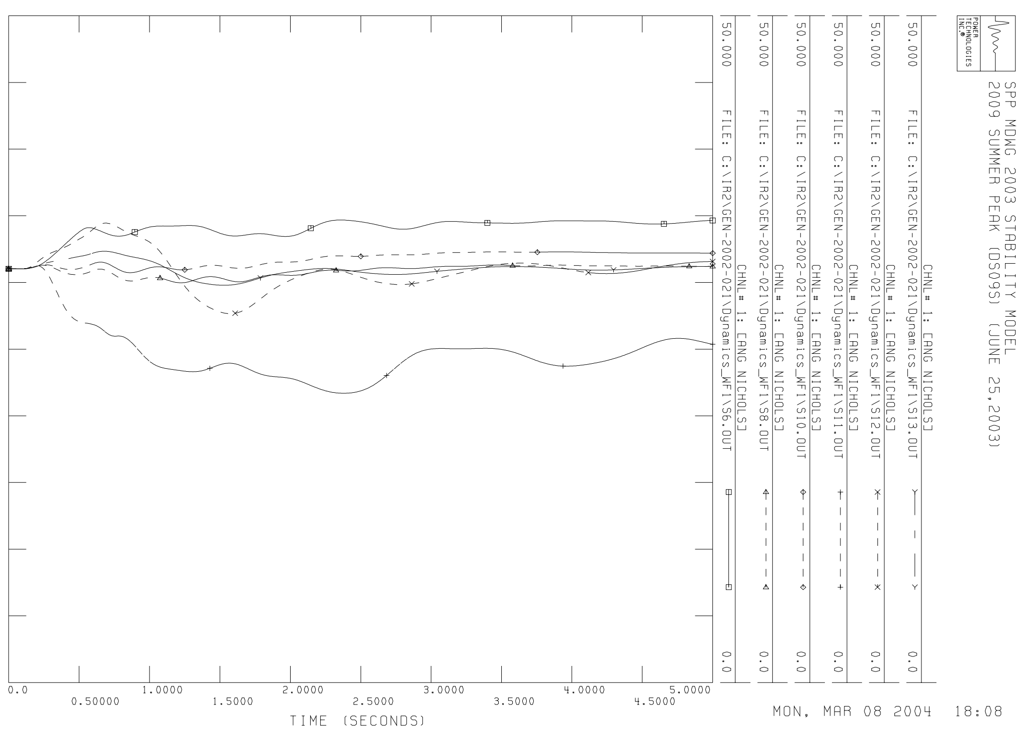
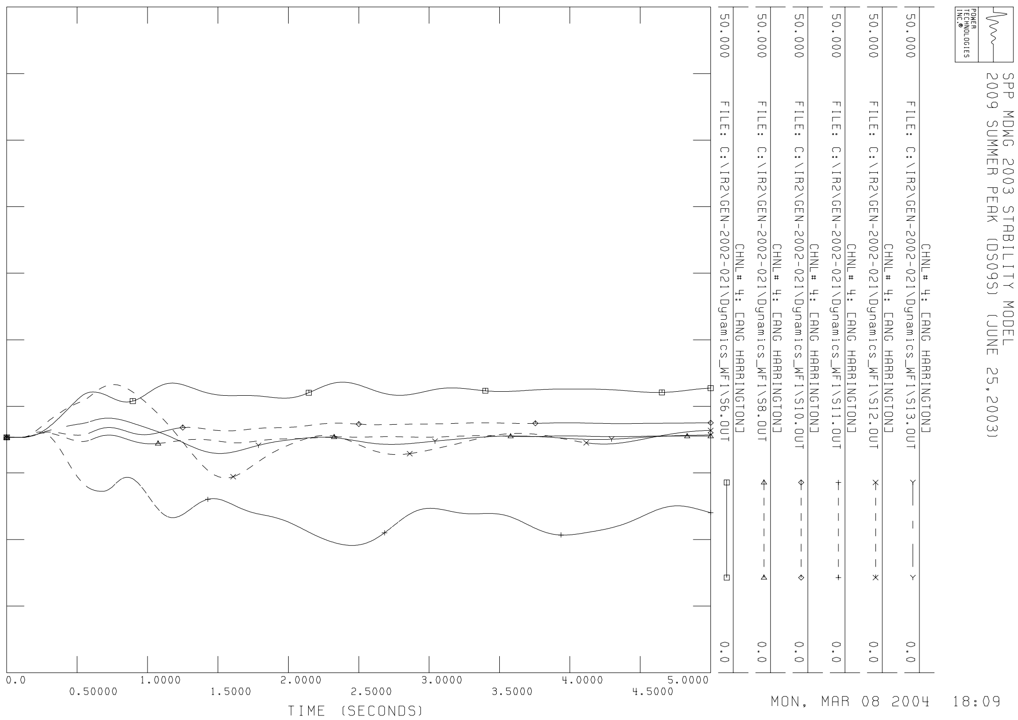


FIGURE 12



Figures 13-16 contain the speed deviations of Nichols Unit 1 and Harrington Unit 1 for the faults simulated. The range varies from a positive 0.5 to a negative 0.5 percent. Figures 13 and 14 show the speed deviations for Nichols Unit 1 and Harrington Unit 1 respectively for Scenarios 6, 8, 10, 11, 12 and 13 when the wind turbines remain on-line after the fault is cleared. Figures 15 and 16 show the speed deviations for Nichols Unit 1 and Harrington Unit 1 respectively for Scenarios 1, 2, 3, 4, 5, 7, and 9 where the wind turbines are tripped off-line.

The speed deviations shown in Figures 13 and 14 are more severe than those shown in Figures 15 and 16 but they appear to be well damped and barely observable by the end of the simulation period. Loss of the wind turbines created a deceleration in other nearby units as they picked up the demand in the area. This can be seen in Figure 15 after the first two swings. The oscillations dampen sooner when the wind turbines remain on-line. One exception is Scenario 11 that involves the loss a major 345 kV line. This scenario was simulated for a longer period to ensure that the speed deviations were indeed damping out. Based on a longer simulation period, the speed deviations appear to be well damped for Scenario 11 as well.

FIGURE 13

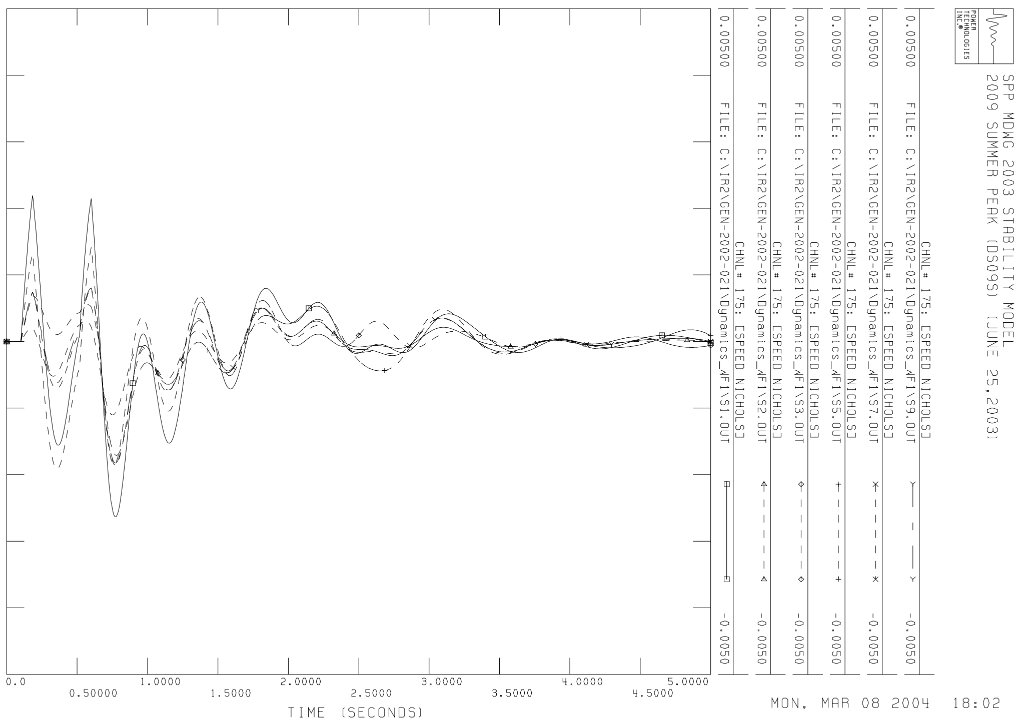


FIGURE 14

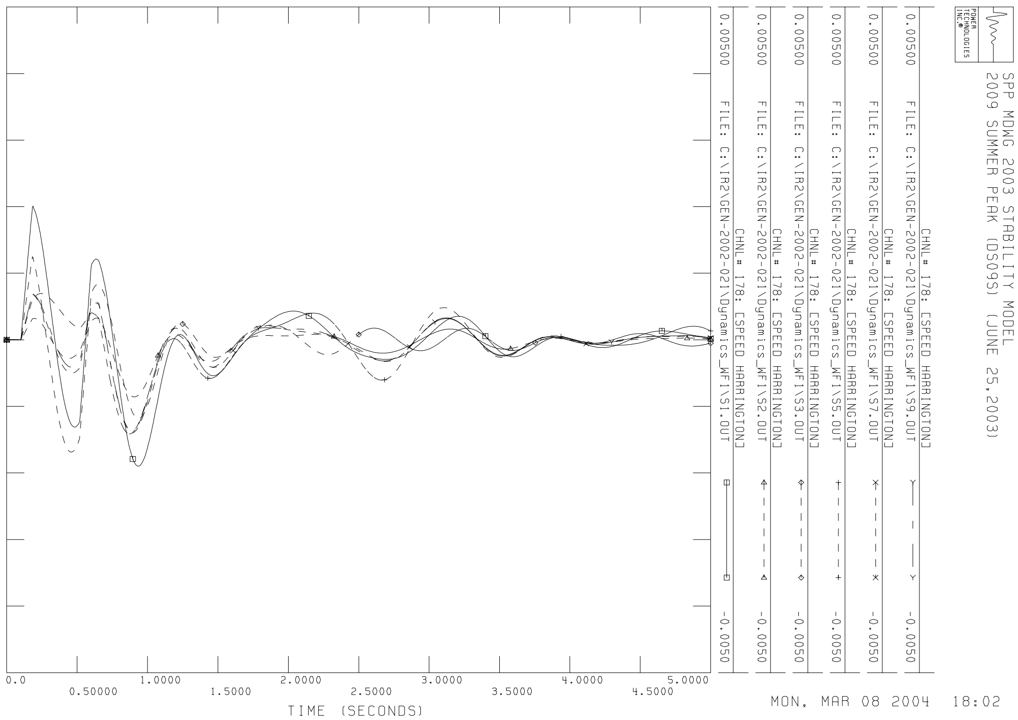


FIGURE 15

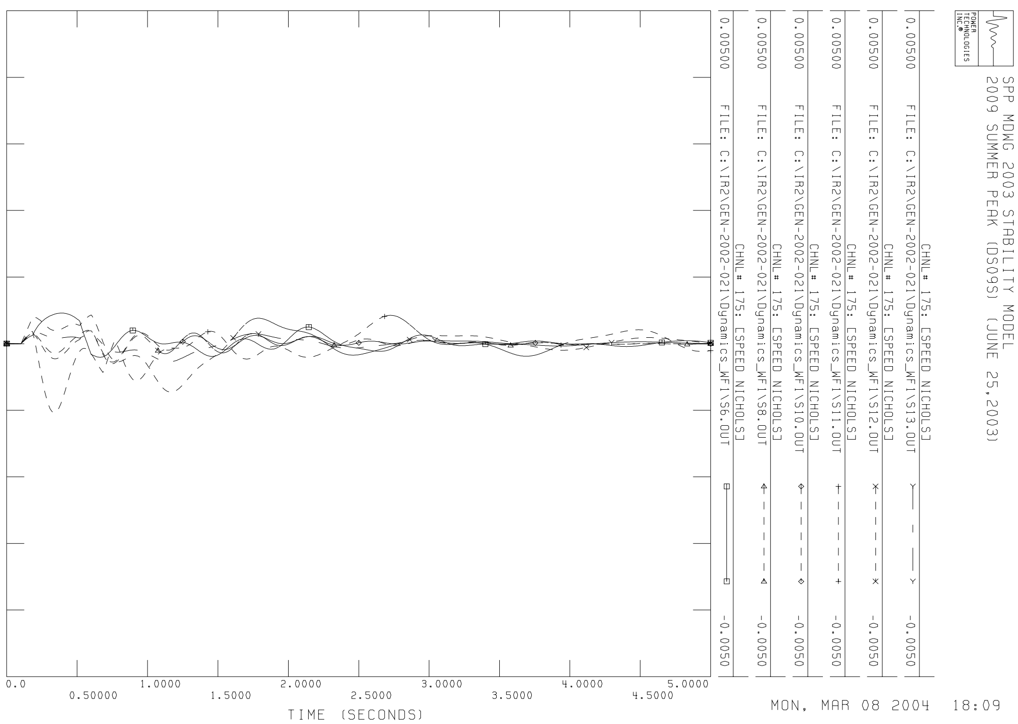
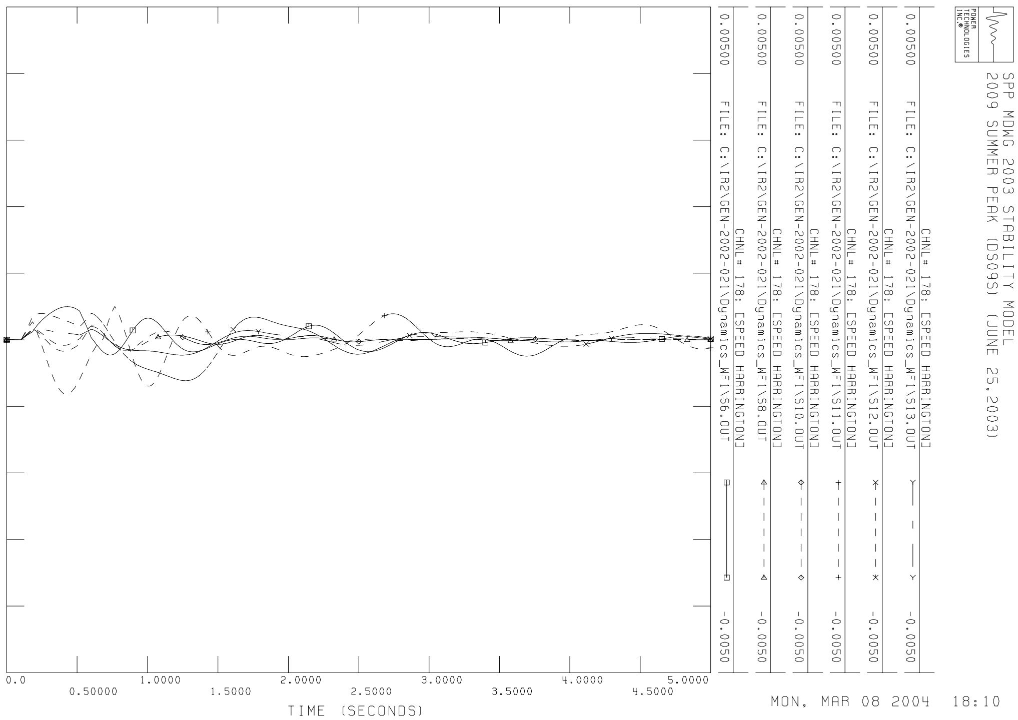


FIGURE 16



Figures 17-20 depict the electrical output of a selected wind turbine for each 34.5 kV bus. The plot range is from .002 to .012 per unit based on a 100 MVA base. Figures 17 and 18 demonstrate that units are tripped off-line in Scenarios 1, 2, 3, 5, 7, and 9 while Figures 19 and 20 illustrate that the wind turbines ride through the fault for Scenarios 6, 8, 10, 11, 12 and 13. A shorter time is plotted for Scenarios 1, 2, 3, 5, 7 and 9 to magnify the period when the turbines are tripped by the under-voltage relays.

Figures 17 and 18 clearly show the impact of the initial fault and reclosure into the fault. The severity of the various faults can be compared by the decrease in the electrical output of the wind turbines. For the cases where the wind turbines are eventually tripped off-line, the output decreases to as low as 0.002 per unit. The least severe in this group drops to 0.0075 compared a low of 0.008 per unit for the scenarios where the wind turbines remained on-line. In Scenario 3, the wind turbines are isolated from the system by the fault, and their output drops to zero when the fault is applied. In most cases, the electrical output of the wind turbines returned to their rated output before the reclosure.

At 0.65 seconds, the under-voltage relays tripped the wind turbines in Scenarios 1, 2, 3, 5, 7 and 9.   This corresponds to the 0.05-second relay pickup time plus the 0.5-second breaker time given the fault was applied at 0.1 seconds. This means that the voltage fell below the 0.85 instantaneous trip value for over 0.05 seconds after the initial fault was applied.

Figures 19 and 20 indicate that the electrical output will return to the rated value once the fault is cleared. For Scenarios 6, 8, 10, 11, 12 and 13, the electrical output of the wind turbines reached the rated values within a second of the permanent fault clearing and remained steady for the duration of the simulation period.

FIGURE 17

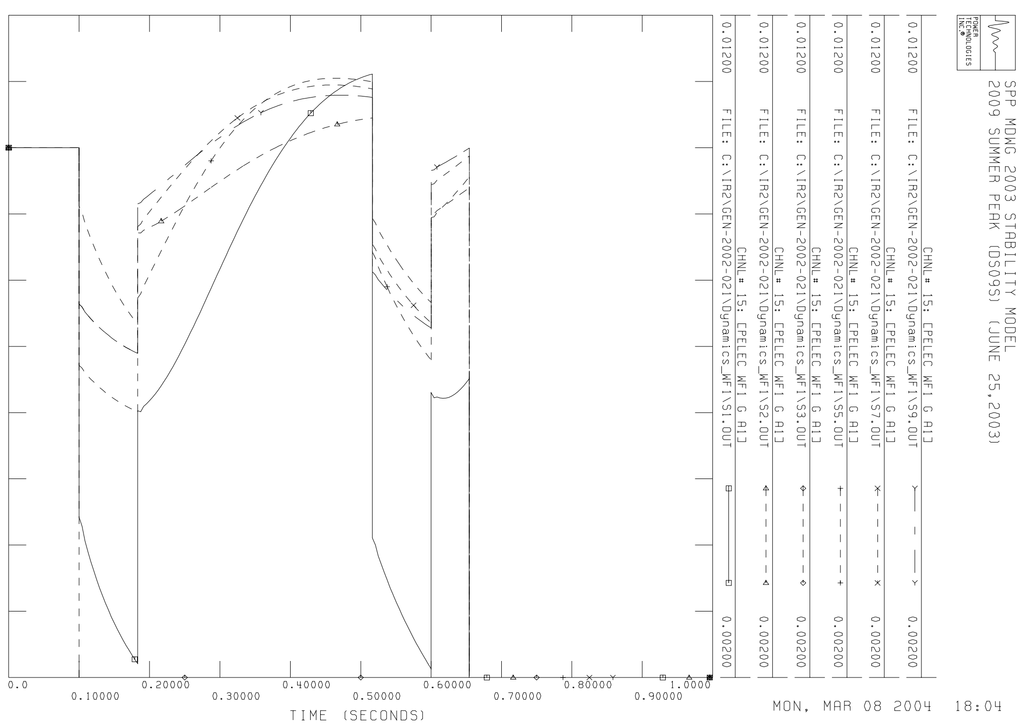


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FIGURE 18

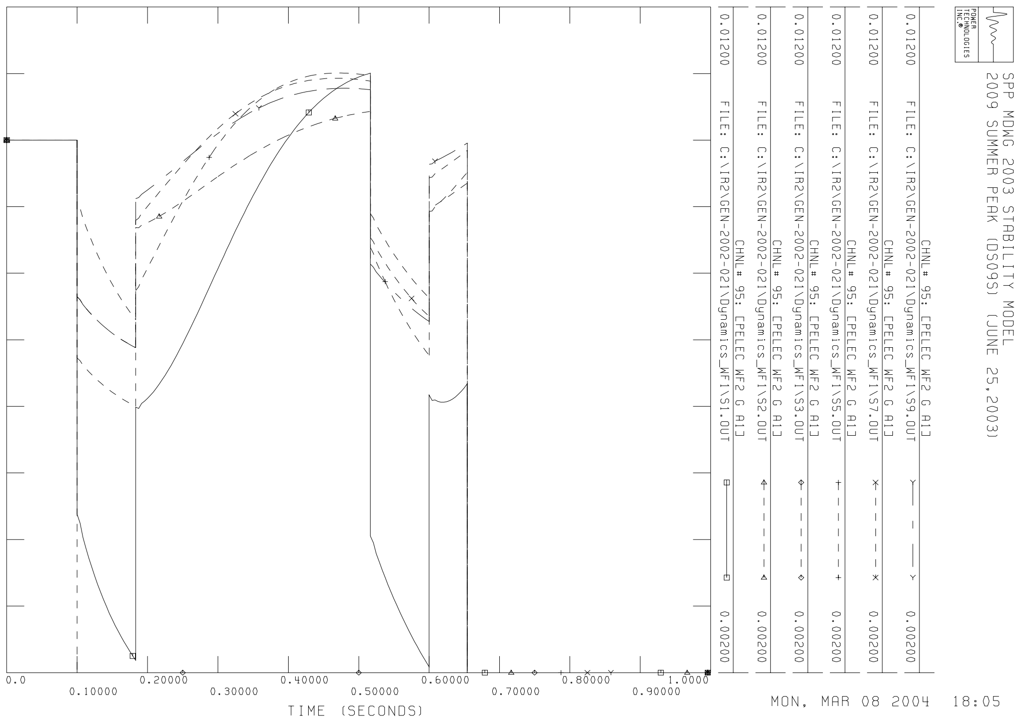

FIGURE 19

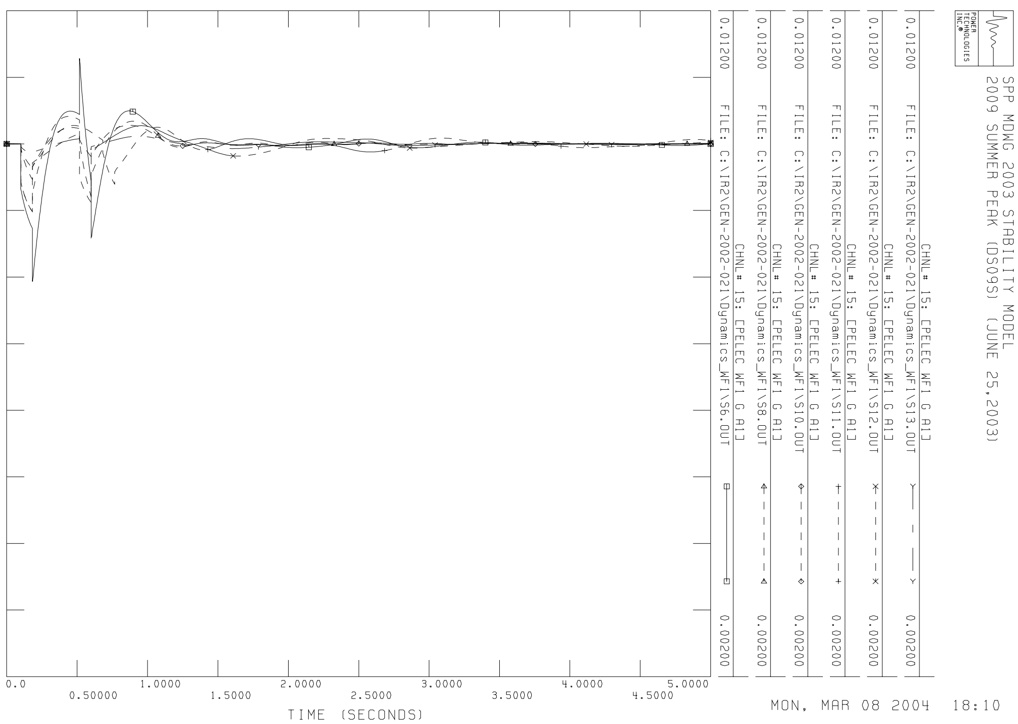

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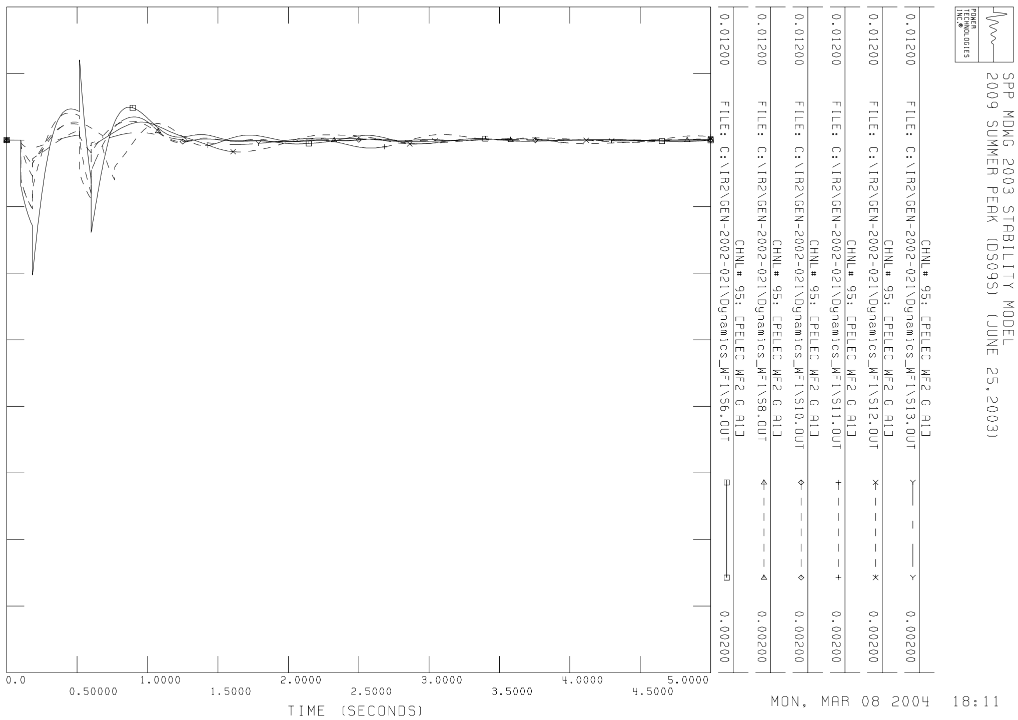
FIGURE 20



Figures 21-24 provide the voltage on the two 34.5 kV buses. The plot range is from 0.2 to 1.2 per unit. Figures 21 and 22 correspond to Scenarios 1, 2, 3, 5, 7, and 9 where the wind turbines are tripped off-line. Figures 23 and 24 correspond to Scenarios 6, 8, 10, 11, 12 and 13 where the wind turbines ride through the fault. A shorter period is plotted for Scenarios 1, 2, 3, 5, 7 and 9 in order to magnify the response during the time when the turbines are tripped by the under-voltage relays.

Figures 21 and 22 demonstrate that not only did the voltage drop during the initial fault occurrence but also continued to decline until the fault was cleared. In all these scenarios, the voltage dropped below 0.8 per unit. For the closer faults, the voltage dropped below 0.3 per. Based on the relay settings, the breaker timer will be initiated 0.05 seconds after the voltage drops below 0.85 per unit. The figures show that voltage at time 0.15 seconds remained below this value for

Scenarios 1, 2, 3, 5, 7 and 9. Therefore the breaker timer was set to open in 0.5 seconds or at time 0.65 seconds as shown in the Figures17 and 18.

Figures 23 and 24 indicate that the voltage remained above the 0.90 per unit threshold for all but one scenario among Scenarios 6, 8, 10, 11, 12 and 13. The lowest voltage for these scenarios occurred during the reclosure. In the case where the voltage dropped below 0.90 per unit, it recovered before the 0.1-second delay that preceded setting of the breaker timer. Once the faults were permanently cleared, the voltage recovered to its prefault value and remained steady for the duration of the simulation period.

FIGURE 21

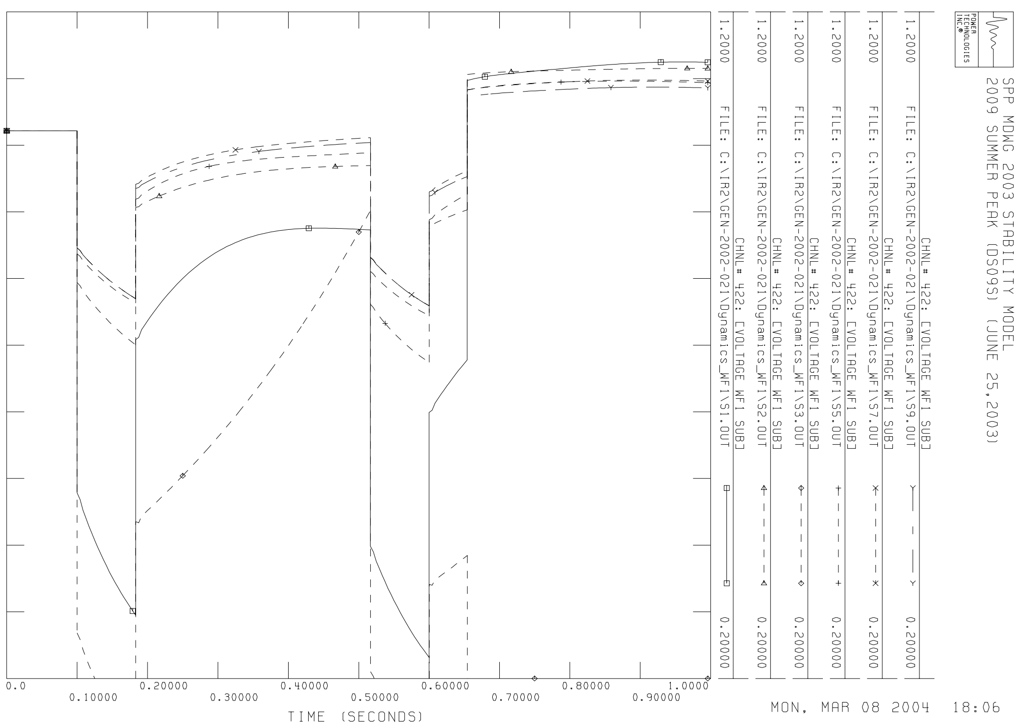


FIGURE 22

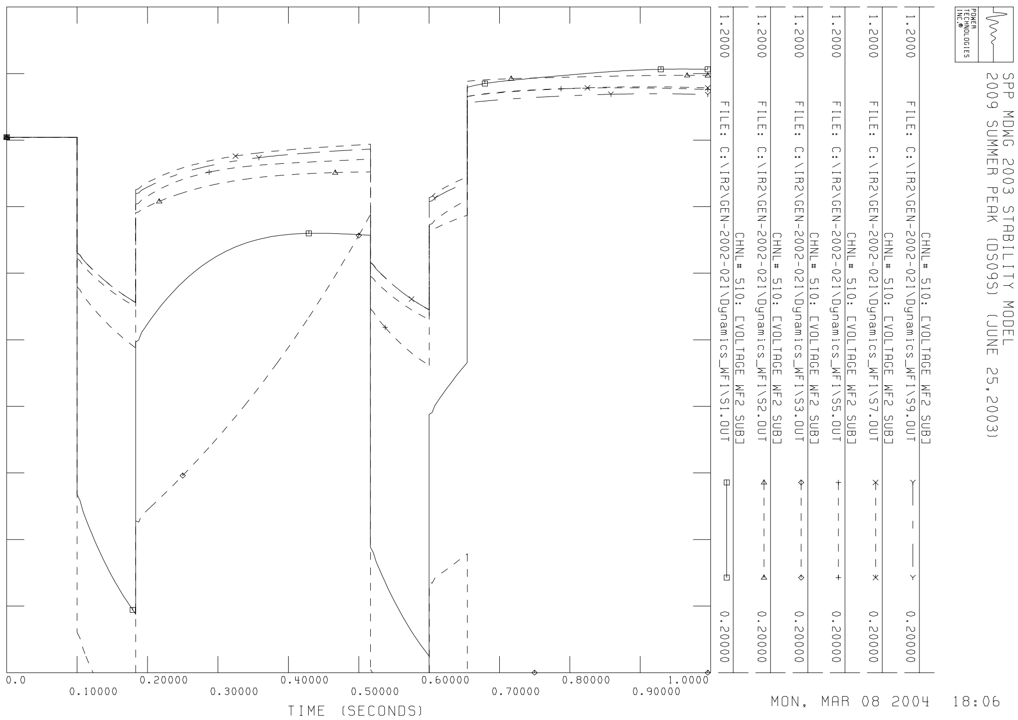


FIGURE 23

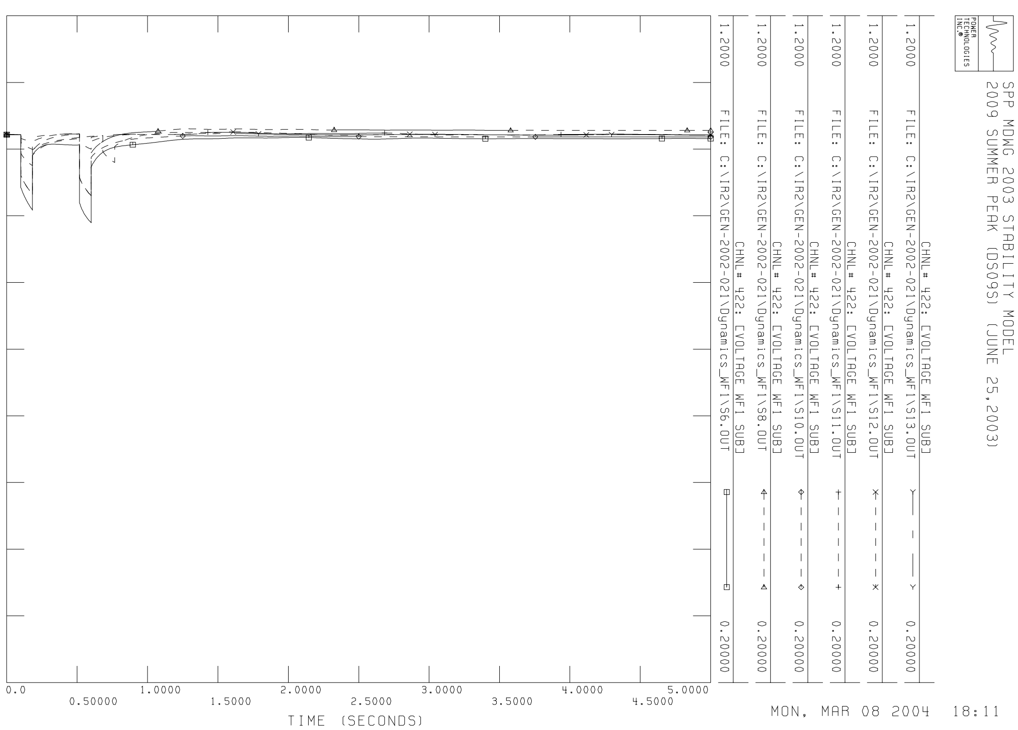
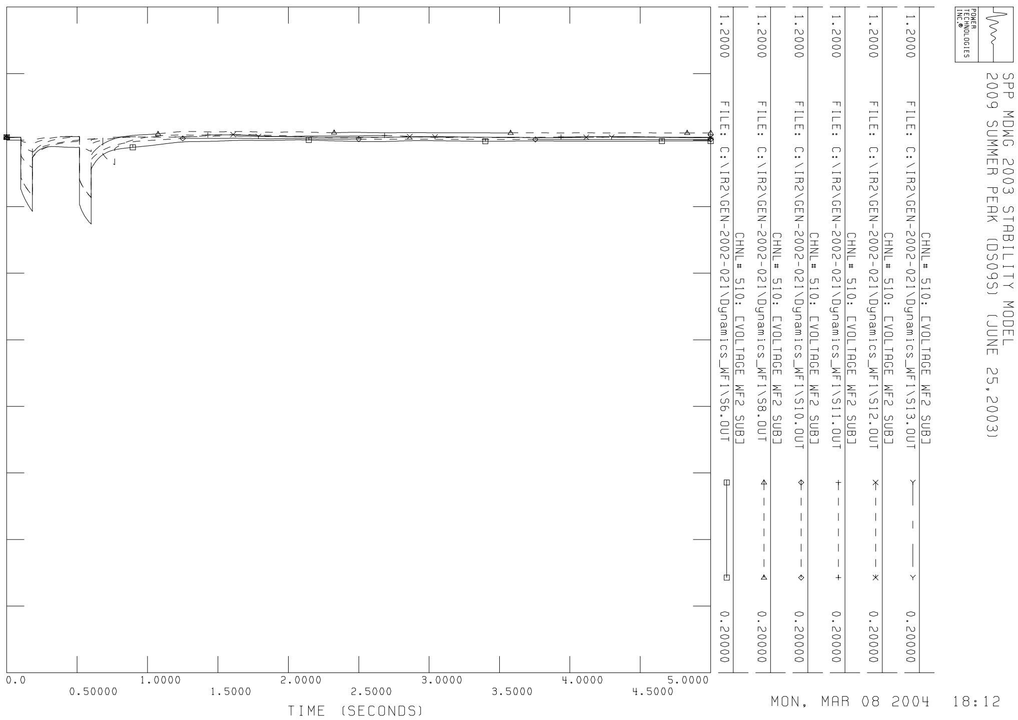


FIGURE 24



VIII. SENSITIVITIES

The scenarios that resulted in the wind turbines tripping were re-examined under several alternative design configurations. Scenarios 3 and 4 were not reexamined since the wind farm is isolated from the system in these scenarios and thus variations in the base assumptions would not kept the wind turbines on-line. Scenarios 1, 2, 5, 7 and 9 were simulated with:

- a 50 percent lower level of output from the wind farm,
- additional capacitor banks on-line,
- implementation of a SVC device in lieu of the capacitor banks, and
- relaxed thresholds for the under-voltage relay settings.

The first sensitivity that was examined involved a lower level of output from the proposed wind farm. A 50 percent reduction in the original level of output was modeled by removing one half of the wind turbines along with their associated 34.5 kV feeders and 230/34.5 kV transformer. The dispatch is shown in Table 1 for this level of output. Fault Scenarios 1, 2, 5, 7 and 9 were simulated with this lower level of output.

Figure 25 provides the electrical output of a selected wind turbine for Scenarios 1, 2, 5, 7 and 9. The plot range varies from 0.002 to 0.012 per unit on a 100 MVA base. Figure 26 contains the voltage plotted for the 34.5 kV bus. It ranges from 0.2 to 1.2 per unit. Only a fraction of the simulations are shown in Figures 25 and 26 in order to expand the view of the critical switching time frame.

FIGURE 25

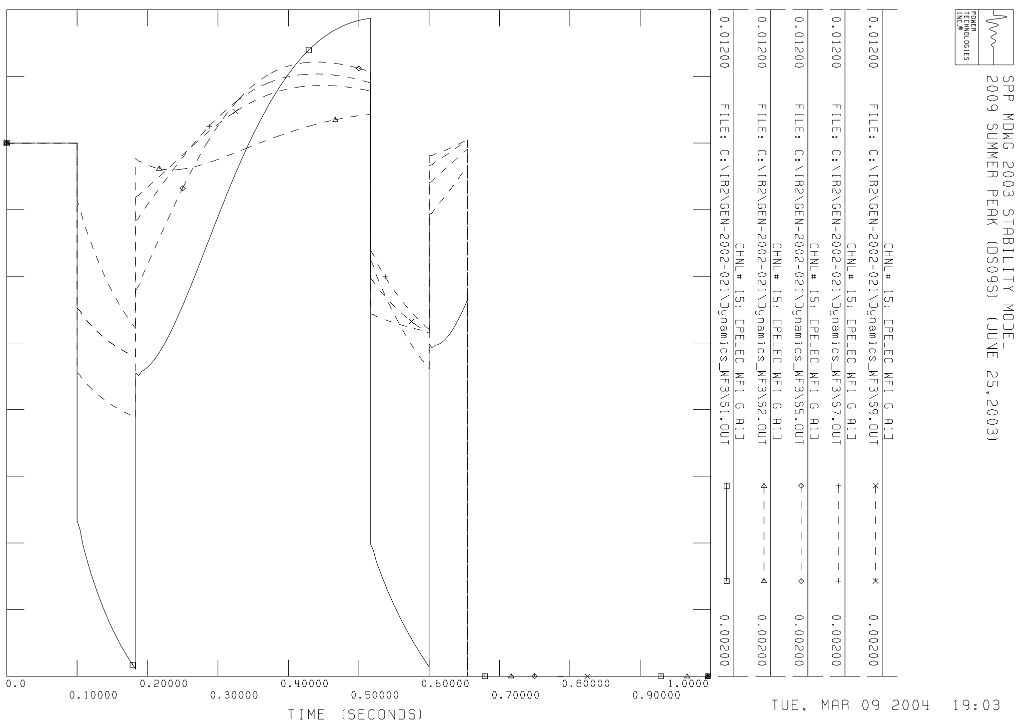


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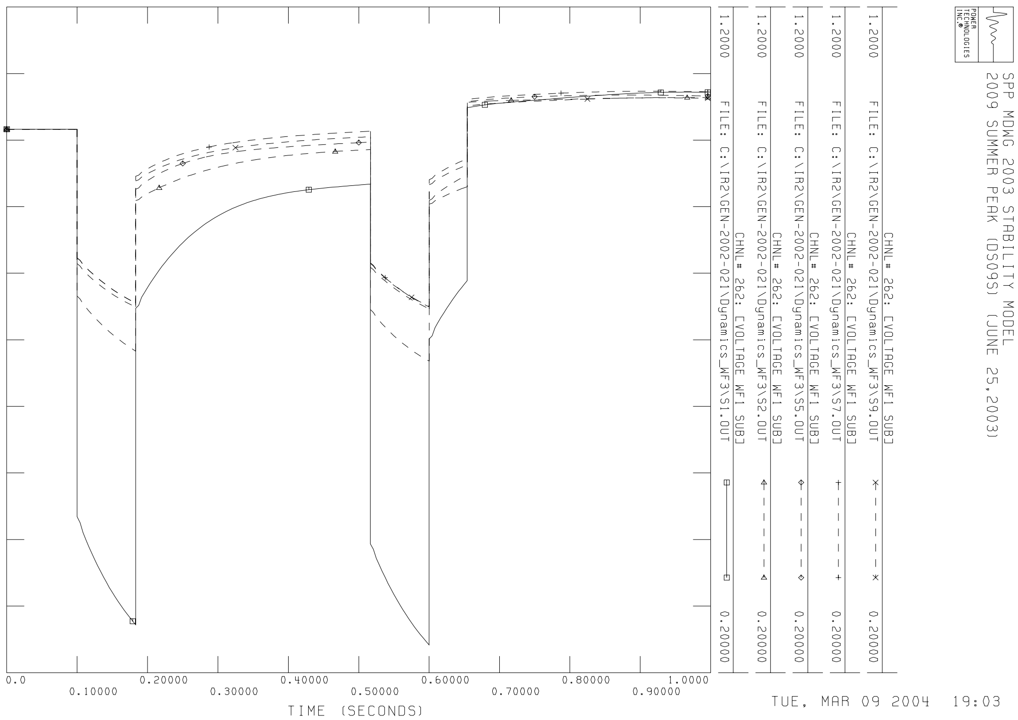
FIGURE 26



As shown earlier in Figures 17 and 18, the impact of the initial fault and reclosure into the fault are very clear. Once again, the voltage continued to decline after the initial fault was applied. During this time, the voltage for each of the examined scenarios dropped below the instantaneous threshold voltage of 0.85 per unit. The recovery did not begin until the fault was cleared. Before the voltage could recover, the 0.05-second (3 cycle) delay expired and the breaker timer was set. At time 0.65 seconds or 0.5 seconds later, the units tripped when the breaker opened. For at least four scenarios, the voltage appeared to recover to the normal operating range even after the fault is permanently cleared. However, the breaker opened and tripped all the wind turbines since the relays had already initiated the breaker timer.

The second sensitivity investigated the impact of additional capacitor banks connected to the 34.5 kV buses in the Interconnection Customer substation. Capacitor banks were added in 15 MVAR increments until the voltage increased above the normal operating range of 1.1 per unit. Using this approach, it was possible to add four 15 MVAR capacitor banks on each 34.5 kV bus. The voltage increased to approximately 1.08 per unit on each 34.5 kV bus. Fault Scenarios 1, 2, 5, 7 and 9 were then simulated with these additional capacitor banks on-line.

Electrical output for a selected wind turbine on each 34.5 bus is plotted in Figures 27 and 28 for Scenarios 1, 2, 5, 7 and 9. The plot range varies from 0.002 to 0.012 per unit on a 100 MVA base. Voltage on the 34.5 kV buses is provided in Figures 29 and 30. It ranges from 0.2 to 1.2 per unit. The initial voltage for this sensitivity is clearly above 1.0 as shown in these two figures. Only a fraction of the total simulation is shown in these figures in order to focus on critical switching times.

FIGURE 27

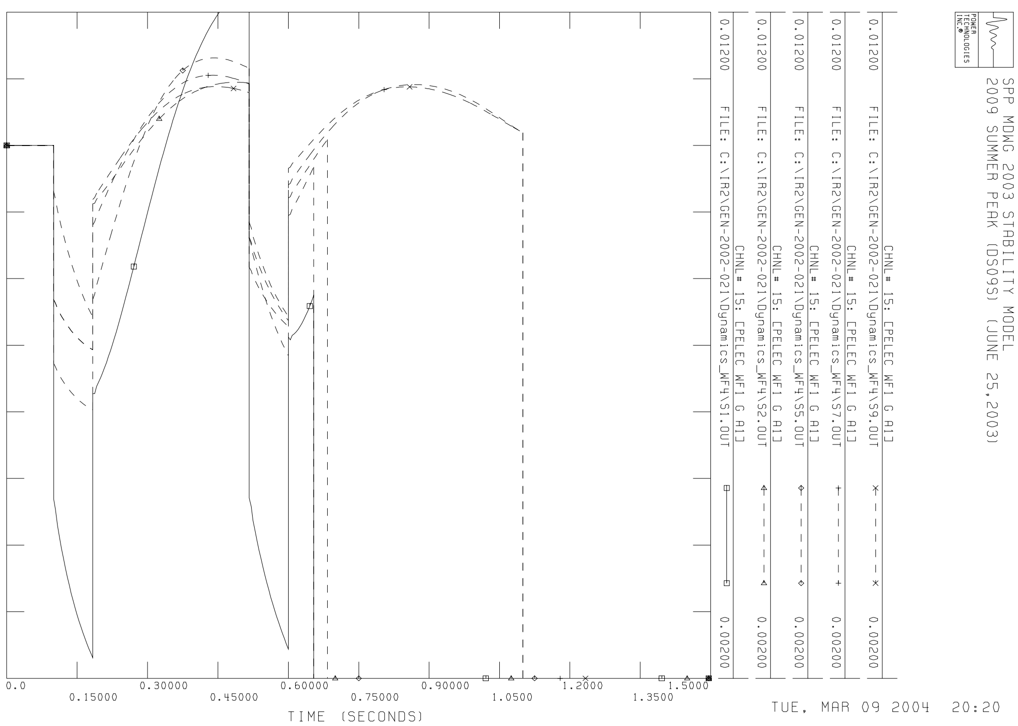


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FIGURE 28

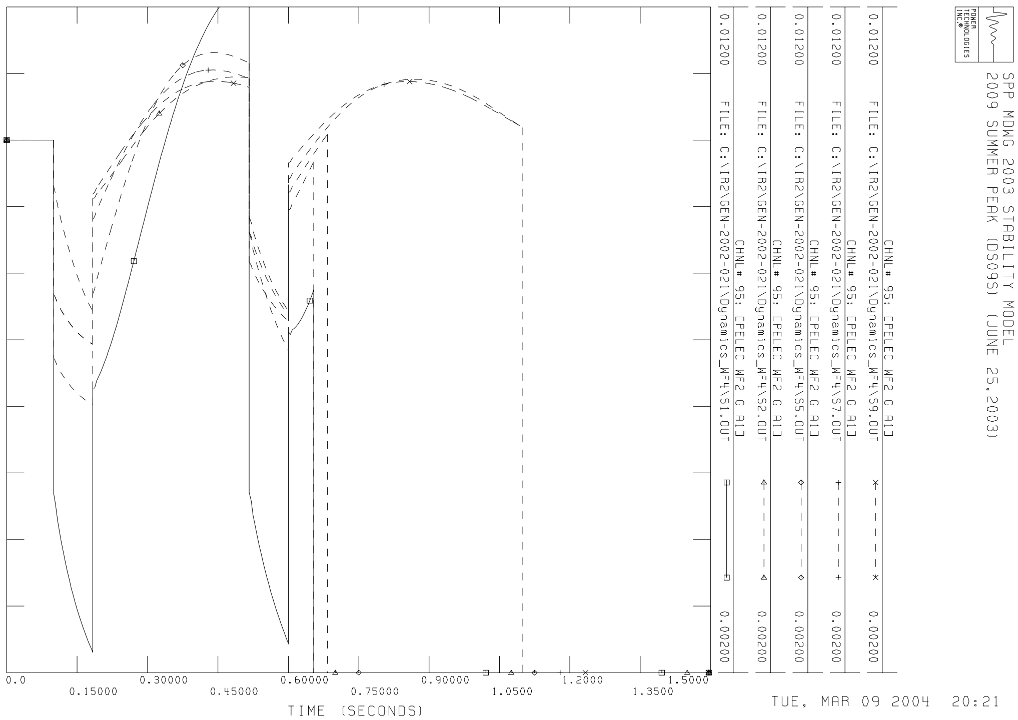


FIGURE 29

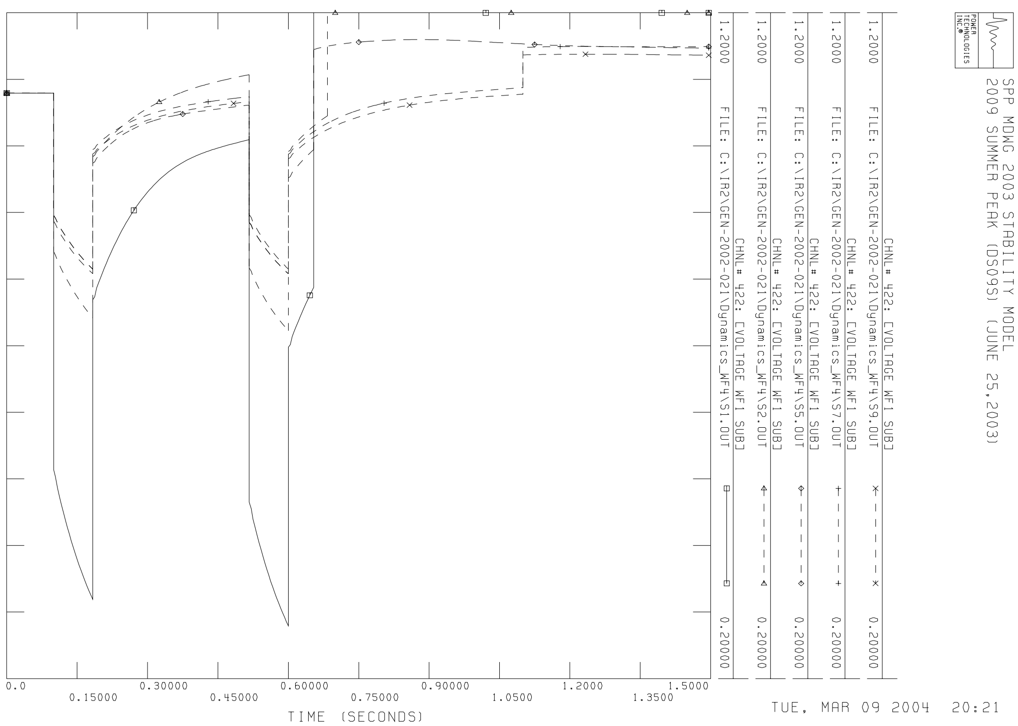
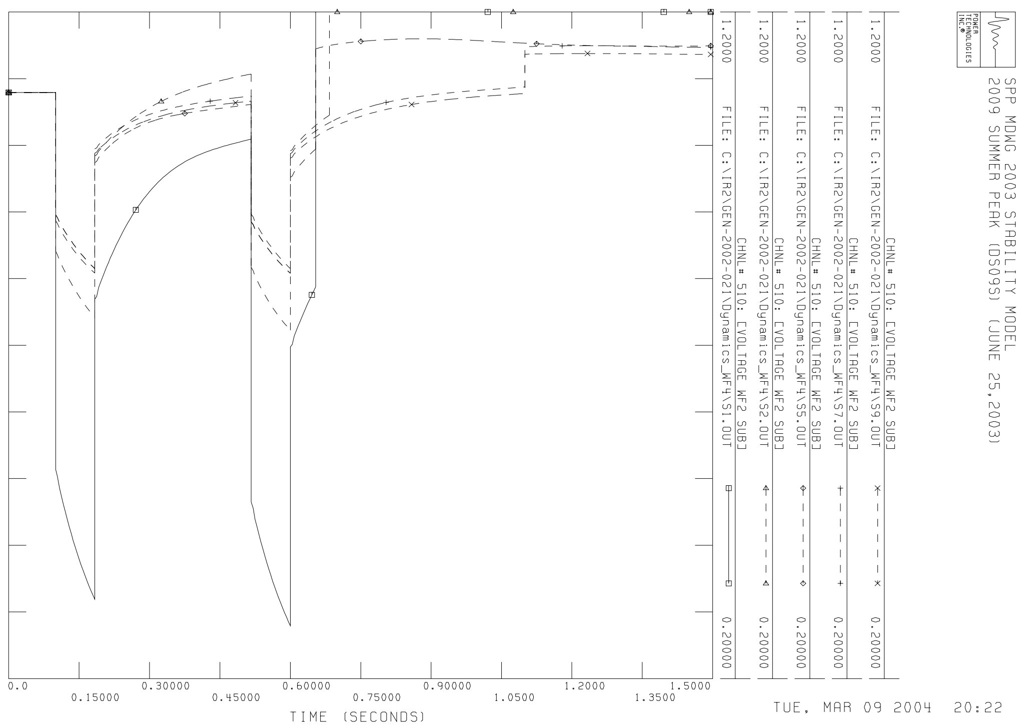


FIGURE 30



Based on Figures 27 and 28, the wind turbines stayed on-line longer in three of the five scenarios. In Scenarios 1 and 5, the wind turbines tripped off-line at time 0.65 seconds because the voltage fell below the instantaneous threshold of 0.85 per unit and remained there for at least 0.05 seconds as in the base case. In Scenario 2, the wind turbines remained on-line until time 0.7 seconds. This indicates that voltage in this scenario dropped below the delayed threshold of 0.90 per unit and remained there for at least 0.1 seconds. For Scenarios 7 and 9, the wind turbines rode through the initial fault but the voltage fell below the instantaneous threshold of 0.85 per unit on the reclosure and remained there for at least 0.05 seconds. This resulted in the wind turbines being tripped around time 1.1 seconds. The additional capacitor banks provided some ride-through capability in several of the scenarios but could not sustain the voltage in order to prevent the under-voltage relays from operating. It appears that additional capacitor banks could possibly sustain the voltage; however additional capacitor banks could not be added without exceeding the normal operating upper limit of 1.1 per unit.

The third sensitivity investigated the installation of static var compensators (SVC) on the 34.5 kV buses in the Interconnection Customer substation. A SVC rated at 150 MVA was added to each 34.5 kV bus. The control voltage was set to ensure that no MVAR would be drawn from the transmission system in the load flow. PSS/E™ model CSVGN1 was used to model the dynamic response of the SVC. Fault Scenarios 1, 2, 5, 7 and 9 were then simulated with these devices in service. The results are depicted graphically in Figures 31 through 34.

Electrical output for selected wind turbines is plotted in Figures 31 and 32 for Scenarios 1, 2, 5, 7 and 9. The plot range varies from 0.002 to 0.012 per unit on a 100 MVA base. Voltage on the 34.5 kV buses is provided in Figures 33 and 34. It ranges from 0.2 to 1.2 per unit. The initial voltage for this sensitivity is very

FIGURE 31

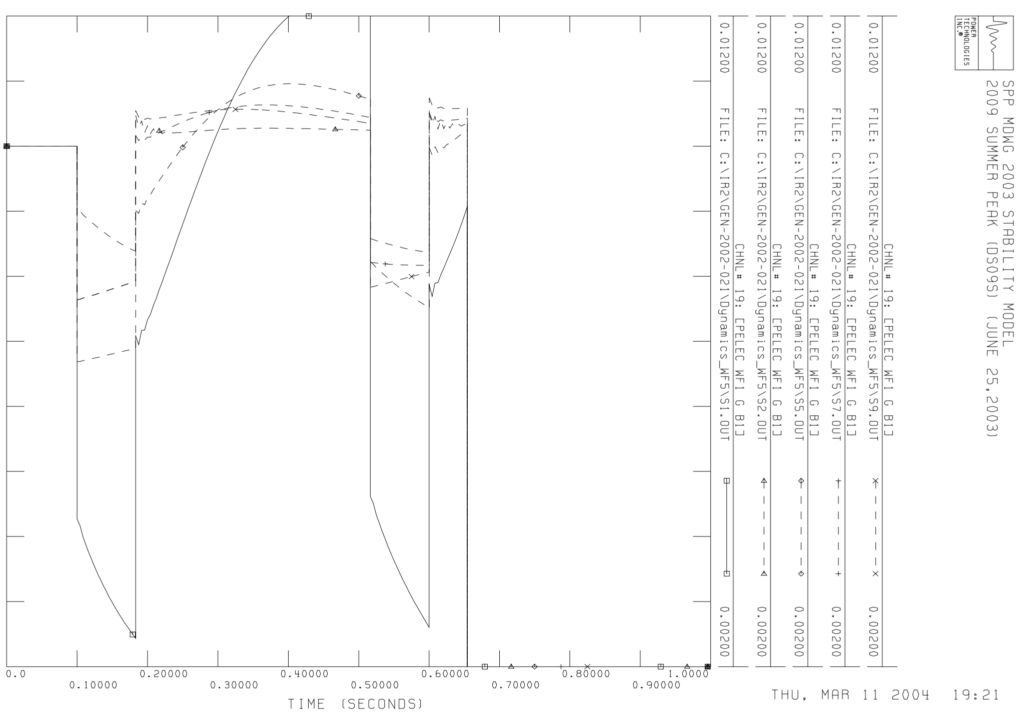


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FIGURE 32

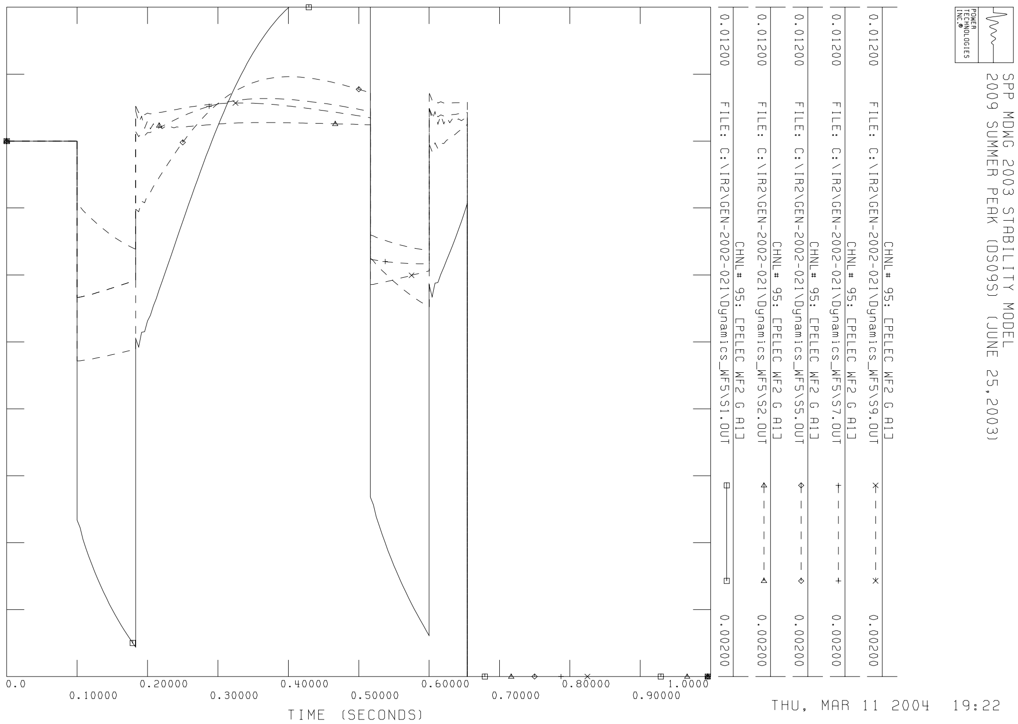


FIGURE 33

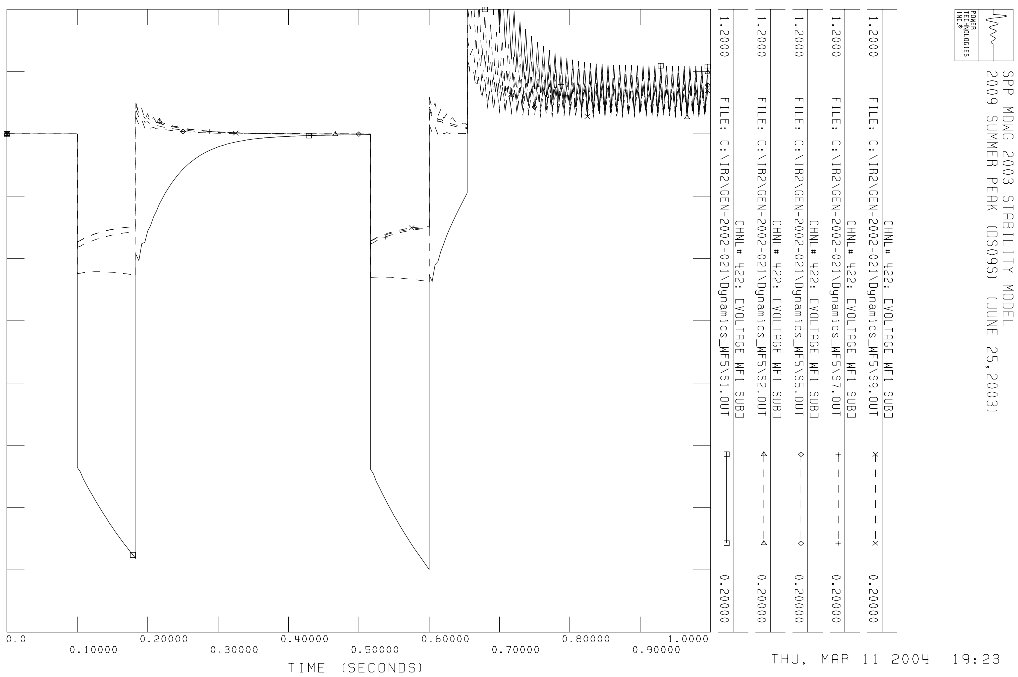
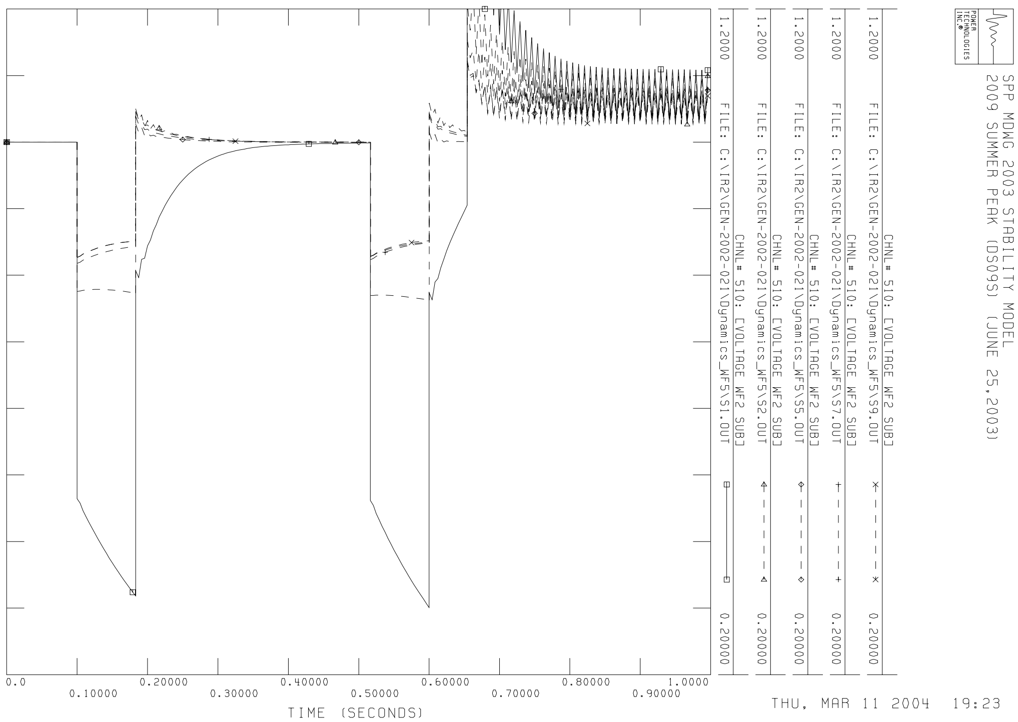


FIGURE 34



close to 1.0 per unit as shown in these two figures. Only a fraction of the total simulation is shown in these figures in order to focus on critical switching times.

The figures shown above are distinctly different from those shown earlier in Figures 17 through 20. It can be observed from the plots that the voltage did not continue to decline after the fault was applied but began a slow recovery. Once the fault was removed, the voltage returned instantaneously to the prefault levels. The initial voltage drop for these scenarios fell below the instantaneous threshold voltage of 0.85 per unit. Although the voltage began to recover immediately, it did not recover before the relay pickup time expired. At time 0.65 seconds or 0.5 seconds after the delay expired, the units tripped when the breaker opened. The SVC models applied in this approach did not allow the wind turbines to ride through the faults simulated in Scenarios 1, 2, 5, 7 and 9.

The final sensitivity involved relaxing the voltage thresholds for the under-voltage relays. The delay voltage threshold of 0.9 was reduced to 0.85 per unit and the instantaneous voltage threshold of 0.85 was reduced to 0.70 per unit. Scenarios 1, 2, 5, 7 and 9 were re-evaluated with these new assumptions. As the figures below show, the units remained on-line in all but Scenario 1.

Angle swings of Nichols Unit 1 and Harrington Unit 1 for Scenarios 1, 2, 5, 7, and 9 are shown in Figures 35 and 36. For all the scenarios, the final angle was within 5 degrees of the prefault angle for both the Nichols Unit 1 and Harrington Unit 1. The final angle was higher than the prefault angle when the wind turbines remained on-line. The units remained in synchronism with the system, and there was no indication of angular instability.

FIGURE 35

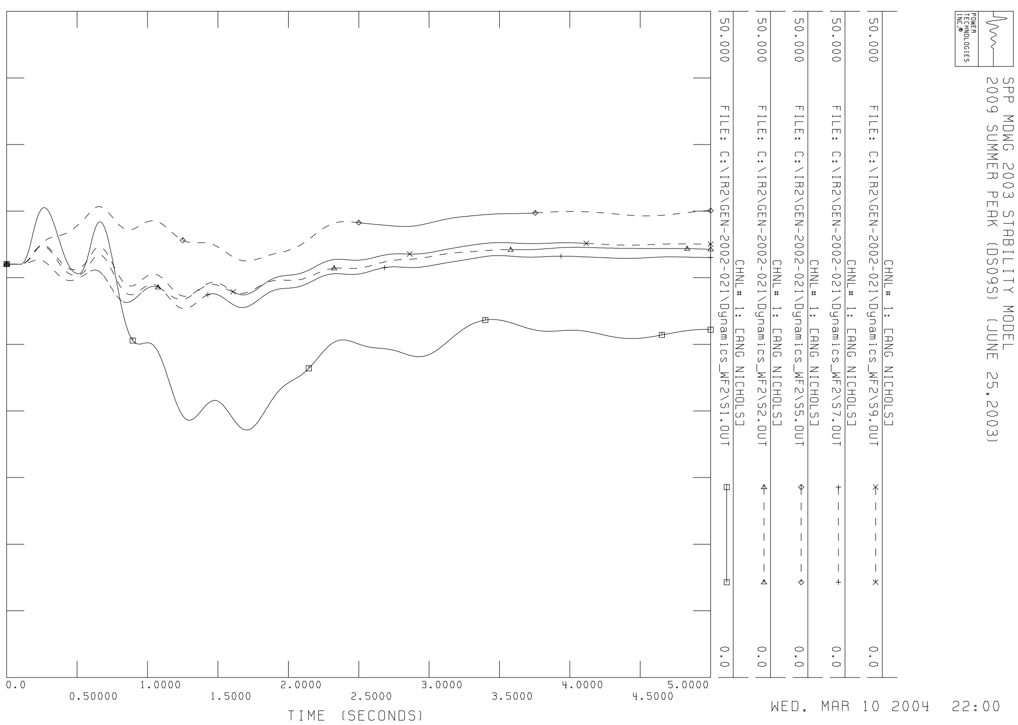
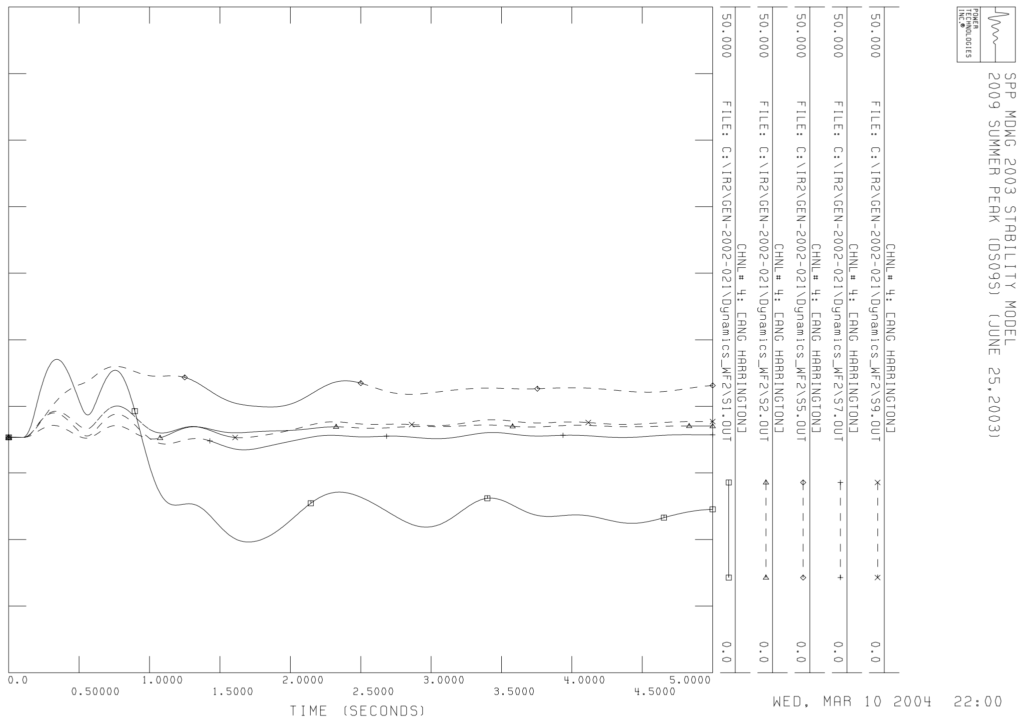


FIGURE 36



Speed deviations of Nichols Unit 1 and Harrington Unit 1 for Scenarios 1, 2, 5, 7, and 9 are illustrated in Figures 37 and 38. The range shown varies from a positive 0.5 to a negative 0.5 percent. The swings shown in the figures appear to be well damped and barely observable by the end of the simulation period. Scenario 1 resulted in the largest swing as would be expected since the fault simulated is closer to the units. Although the speed deviations for this scenario are slightly observable at the end of the simulation period, they appear to be damping out.

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FIGURE 37

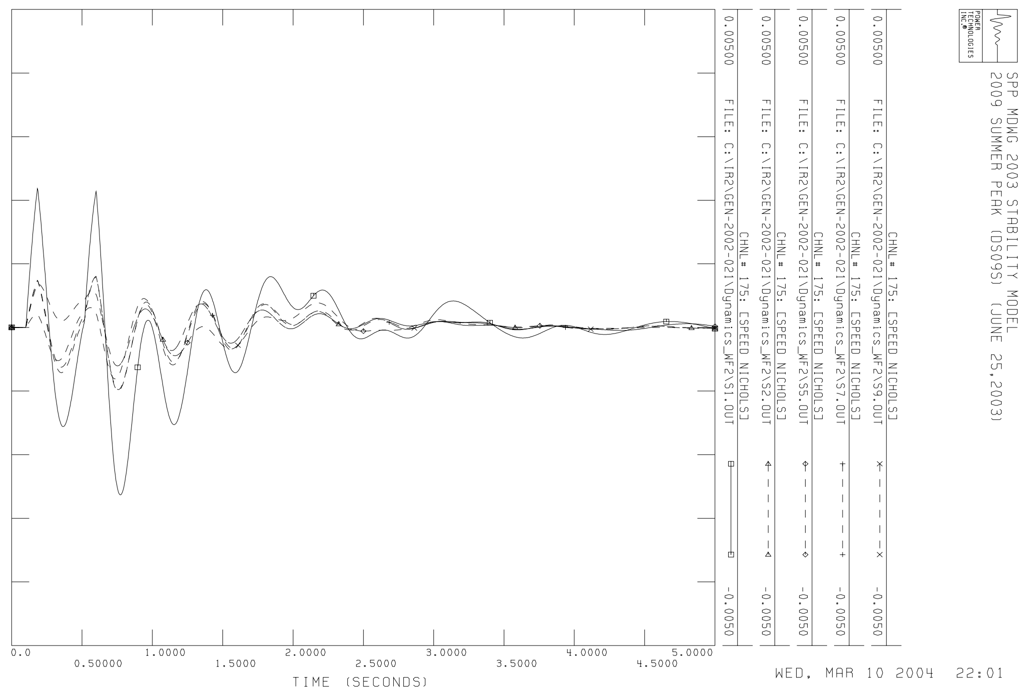
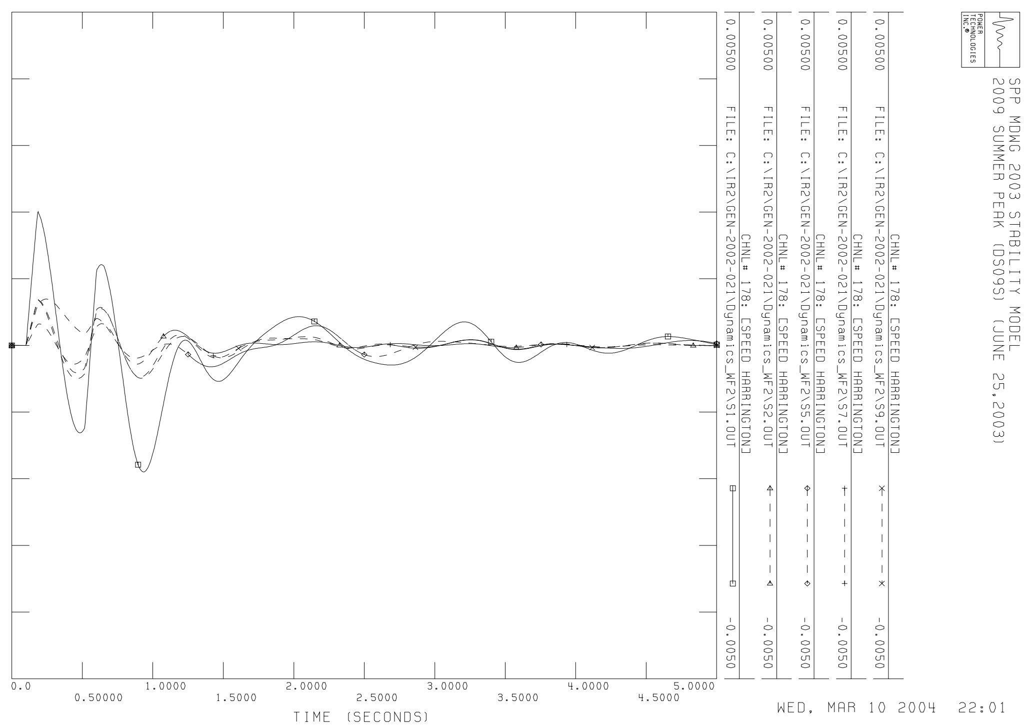


FIGURE 38



Electrical output for a selected wind turbine for each 34.5 kV bus is plotted in Figures 39 and 40. The plot range is from .002 to .012 per unit based on a 100 MVA base. Based on Figures 39 and 40, the wind turbine electrical output returned to the rated value once the fault was cleared. For Scenarios 2, 5, 7, and 9, the electrical output of the wind turbines reached its rated value within a second of the permanent fault clearing and remained steady for the duration of the simulation period. The wind turbines still tripped off-line at time 0.65 seconds in Scenario 1. Because of the proximity of the fault, the voltage dropped to nearly 0.2 per unit during the fault. Since the fault duration was longer than the relay pickup time of 0.05 seconds, the breaker timer was initiated and the wind turbines tripped.

FIGURE 39

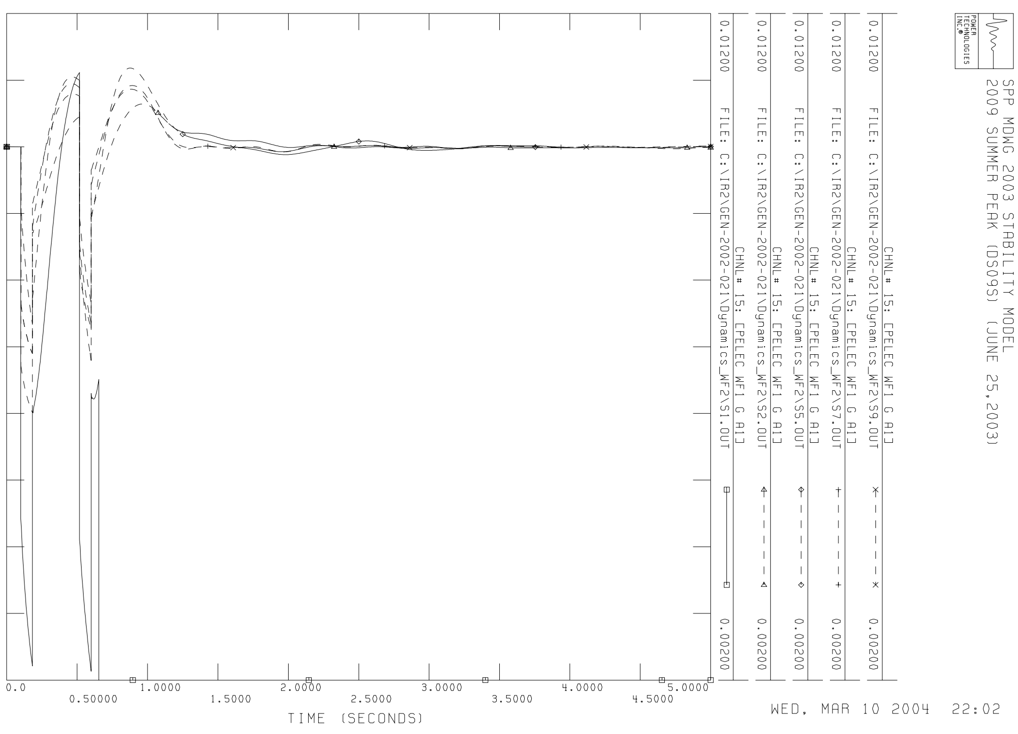
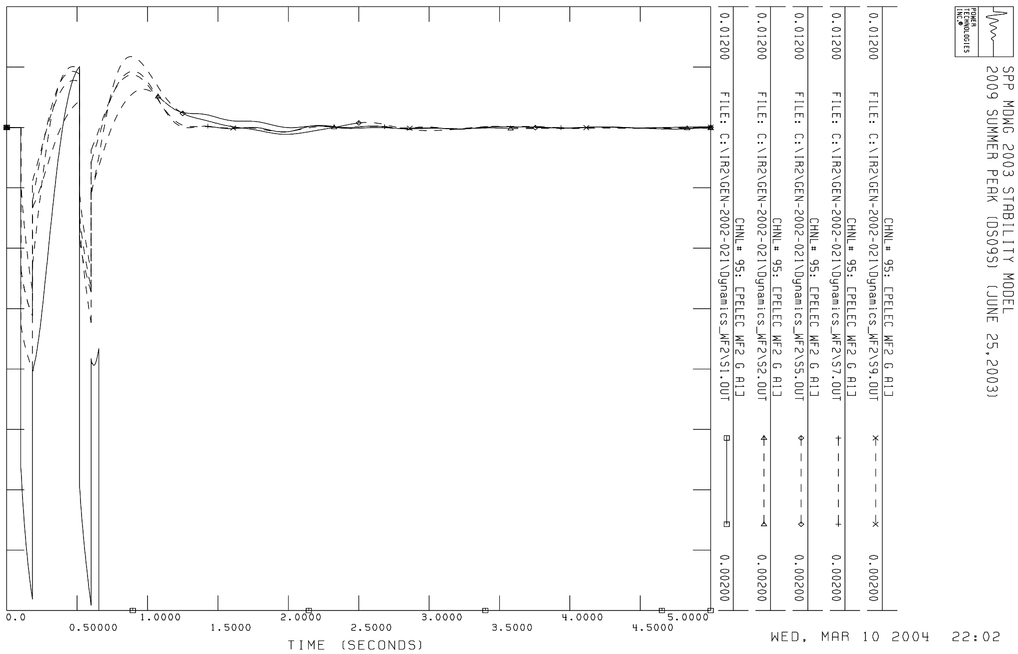


FIGURE 40



Voltage on the two 34.5 kV buses is provided in Figures 41 and 42. The plot range is from 0.2 to 1.2 per unit. Figures 41 and 42 show that the voltage remained above 0.70 per unit during the initial fault for Scenarios 2, 5, 7 and 9. For at least one of these scenarios, the voltage dropped below this value on the reclosure but recovered before the relay pickup time expired. The figures also show that the voltage dropped to nearly 0.2 per unit in Scenario 1. In Scenario 1, the voltage dropped below 0.70 per unit when the fault was applied and then continued to drop until the fault was cleared. Since the fault lasted for 5 cycles and the relay pickup time is 3 cycles, the wind turbines cannot remain on-line when the voltage drops below the instantaneous threshold at the fault inception and continues to decline.

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FIGURE 41

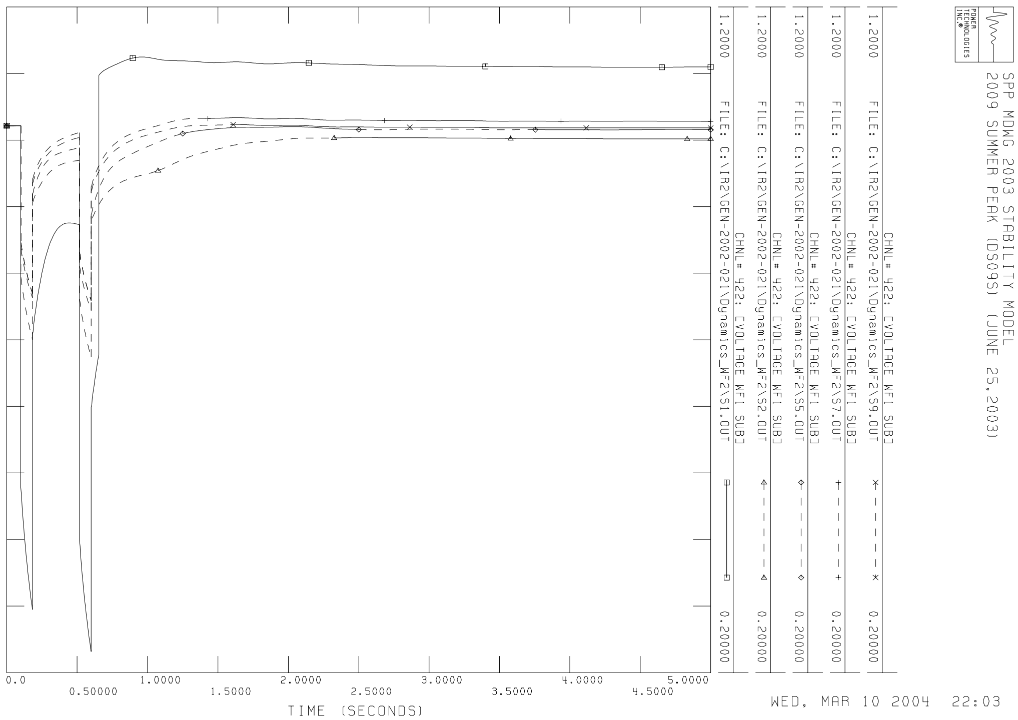
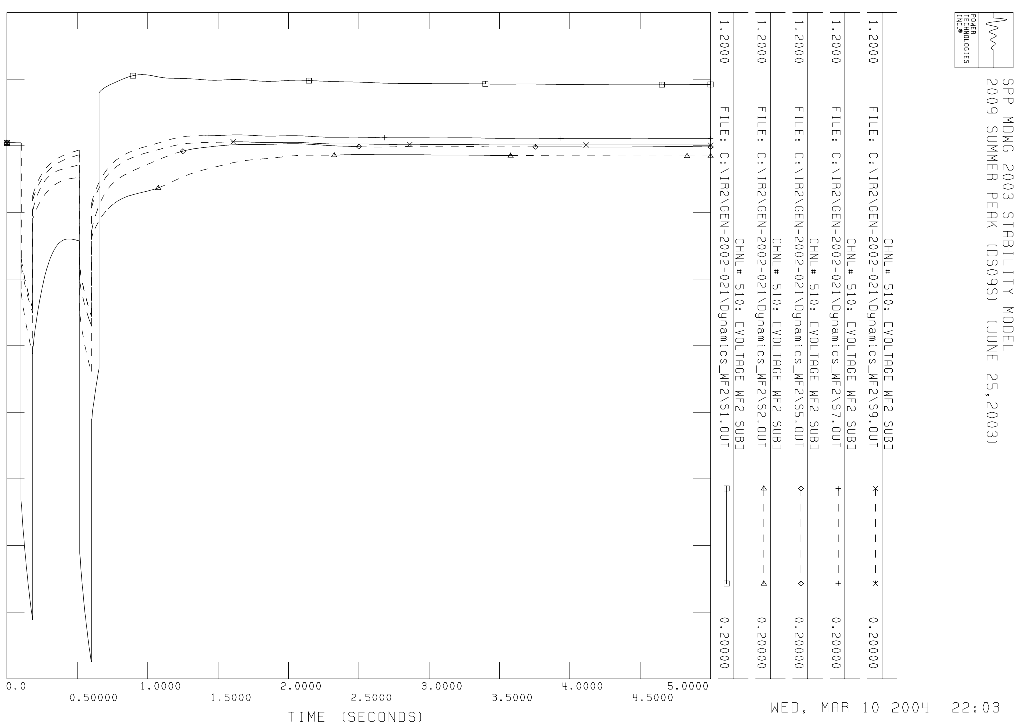


FIGURE 42



IX. Cost Estimate

The following components comprise the project's cost estimate:

1) Extension of Grapevine Interchange 230kV bus, and addition of a 230 kV GCB.
2) Extension of a new 230kV transmission line, approximately 4 miles.
3) Addition of a 230kV/34.5kV substation, per single line diagram entitled "Single Line Meter and Relay Diagram", dated 7/27/02.
4) Addition of five (5)15 MVAR capacitor banks on the 34.5 kV bus.

This cost estimate is based upon recent data related to similar utility installations, and installation in the Midwest in general. Information on Right-of-Way and land costs are not included since these costs can be extremely variable, depending on exact location, urban or rural area and factors related to present and future land use. Finally, the cost estimates will be improved and finalized during the Facility Study if the customer elects to proceed.

The attached Table A below itemizes the cost installed, less Right-of-Way and land, for the items listed above. In the case of items 1) and 3), a further breakdown is included as described in the Table 4.

TABLE 4

ITEM	DESCRIPTION	ESTIMATE
	NETWORK UPGRADES	
1a)	Extension of Grapevine 230kV bus	$360,000
1b)	Addition of 230 kV GCB at Grapevine	$245,000
	NETWORK UPGRADES SUBTOTAL	**$605,000**
	DIRECT ASSIGNMENT FACILITIES	
2)	Extension of 230kV line, approx. 4 miles	$1,320,000
3a)	230/34.5kV Substation, relay & metering	$75,000
3b)	230/34.5kV 3-winding transformer, 100mva	$945,000
3c)	Circuit Switcher, Breakers, Switches for	$540,000
3d)	Substation buswork & misc.	$250,000
4)	5-15MVAR, 34.5 Capacitor Banks	$950,000
	DIRECT ASSIGNMENT FACILITIES SUBTOTAL	$4,080,000
	TOTAL	$4,685,000

X. CONCLUSIONS

The following conclusions are reached from the load flow and dynamic analyses performed in this study:

- Based on the evaluation of a comprehensive set of 13 fault scenarios provided by the SPP, the system remains stable given the operating specifications of the relays that protect the wind turbines. Dynamic responses of both the wind turbines and nearby generating units dampened out once the faults were permanently cleared.

- Wind turbine occurred for faults near the wind farm tripping because of the operation of the under-voltage relays. Fault Scenarios 1, 2, 3, 4, 5, 7 and 9 resulted in the tripping of the wind farm turbines by the under-voltage relays. In Scenarios 3 and 4, the wind farm was isolated from the transmission system when the radial 230 kV transmission line was opened to clear the fault.

- Reducing the wind farm power output level by 50 percent did not mitigate low voltage tripping of the wind turbines. When 80 of the wind turbines were taken out of service along with their reactive support, the remaining wind turbines were still tripped for fault Scenarios 1, 2, 5, 7 and 9.

- In Scenarios 7 and 9, addition of the maximum number of 15 MVAR capacitor banks possible without exceeding the normal voltage operating range kept the wind turbines on-line through the initial fault but failed to keep the wind turbines from being tripped during the reclosure operation. The normal maximum voltage operating range of

1.1 per unit restricted the number of capacitor banks that could be added without initiating tripping by the over-voltage relays.

- Application of SVCs provided voltage recovery but did not provide it fast enough to keep the under-voltage relays from tripping the turbines. With these devices in service, voltage recovery began immediately after the fault was applied; however, the voltage did not recover before the relays operated and tripped the breakers.

- Relaxing the MHI under-voltage relay control thresholds from 0.9 to 0.85 per unit for the delayed setting and from 0.85 to 0.70 per unit for the instantaneous setting allowed the wind turbines to ride through all the fault scenarios except Scenario 1 (Scenarios 3 and 4 resulted in isolation of the wind farm and thus were excluded). This is only solution that was found that would allow the wind turbines to remain on-line for Scenarios 2, 5, 7 and 9. This solution appears to provide a significant value to the transmission system with a small risk to the Interconnection Customer and should be given serious consideration.

No stability concerns presently exist for the wind farm based on this study. At this time there are no stability recommendations for further facilities that would be required for interconnection. To maintain a unity power factor, the Interconnection Customer shall add a minimum of five 15 MVAR capacitor banks at an estimated cost of $990,000, as shown on the one-lines. The total, estimated cost to the Interconnection Customer for interconnection is $4,685,000. This includes costs for the Grapevine upgrade, the radial transmission line, and the capacitor banks.

Based on the under-voltage tripping identified in Scenarios 2, 5, 7 and 9, the Interconnection Customer should discuss the possibility of revising the under-voltage relay settings from 0.90 to 0.85 per unit for the delayed operation and from 0.85 to 0.70 per unit for the instantaneous operation with MHI, the wind turbine manufacturer. If MHI is not willing to modify the controls accordingly, the Interconnection Customer should consider the additional risk implications of wind farm outages that this wind turbine manufacturer's under-voltage relay scheme may cause to the wind farm.

If any previously queued projects that were included in this study drop out then this System Impact Study may have to be revised to determine the impacts of this Interconnection Customer's project on SPS transmission facilities. Since this is also a preliminary System Impact Study, not all previously queued projects were assumed to be in service in this System Impact Study. If any of those projects are constructed, then this System Impact Study may have to be revised to determine the impacts of this Interconnection Customer's project on SPS transmission facilities. In accordance with FERC and SPP procedures the study cost for restudy shall be borne by the Interconnection Customer.