Southwest Power Pool

Impact Study for Generation Interconnection Request GEN – 2003 – 005

SPP Coordinated Planning
(#GEN-2003-005)

August 2004

System Impact Study GEN-2003-005

Summary

I2R Technologies (I2R) performed the following study at the request of the Southwest Power Pool (SPP) for SPP Generation Interconnection request Gen-2003-005. 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, I2R 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.

The Customer requested that the study be performed using two different wind turbine machines and two MW levels.

System Impact Study for Generation Interconnection Request For GEN-2003-005

Prepared by I2R Technologies

July 2004

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I. Executive Summary

The Interconnection Customer has requested a generator interconnection study through the Southwest Power Pool Tariff for a 138 kV interconnection of a new wind farm. This wind farm will be connected to a new switching station to be constructed on the Western Farmers Electric Cooperative (WFEC) Anadarko to Paradise 138 kV line near Apache, Oklahoma. The customer asked for studies of 80 and 100 MW output levels. The customer also requested that the study be conducted using both NEG Micon NM72 IEC I (1.65 MW) and GE 1.5 with LVRT (1.5 MW) machines. The projected in-service date for the wind farm is December 2006.

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

SPP provided a basecase load flow model based on the 2005 summer peak forecast. The title is "SPP MDWG 04 STABILITY; 2005 SUMMER PEAK; S05SP-29.CNL; 3-22-04." SPP also defined a comprehensive set of fault scenarios (22) to be evaluated in the dynamic analysis. The wind farm output will displace WFEC generation based on the economic dispatch order provided.

Based on the load flow analysis, no additional capacitor banks were deemed necessary. The new wind turbines packages included sufficient VAR compensation to maintain a power factor near or above 98 percent at the proposed switching station.

The system remained stable for all of the 22 fault scenarios evaluated given the proper operation of the under voltage relays at the Interconnection Customers' substation. No significant differences were observed between the 80 and 100 MW output levels for either the NEG or GE machines. The NEG machines rode through 4 more fault scenarios (6 versus 2) than the GE machines.

The main concern identified in this study was the voltage collapse that occurred when the Anadarko to Gen-2003-005 Wind Farm 138 kV line was removed from service. Even though the voltage recovered after the wind turbines were tripped off-line, the transmission system voltage was dependent on the proper operation of the under-voltage relays at the wind farm substation. This is very undesirable.

Two solutions were evaluated

a. Construction of a second circuit from the Anadarko Substation to the proposed switching station
b. An alternative relaying scheme tripping the Paradise to Customer line when the Customer to Anadarko line is opened

Both solutions proved effective in maintaining the reliability of the transmission system. The second circuit from the Anadarko Substation to the proposed switching station would allow the Interconnection Customer wind turbines to remain on line for all the fault scenarios evaluated. The alternative relaying scheme would result in the Interconnection Customer wind farm being disconnected from the transmission system in Scenarios 1 and 2. In the absence of an operating criteria requiring the wind farm to remain in operation after the Anadarko line segment were lost, the latter solution has a substantial cost advantage over the construction of a second circuit from Anadarko Substation to the proposed switching station.

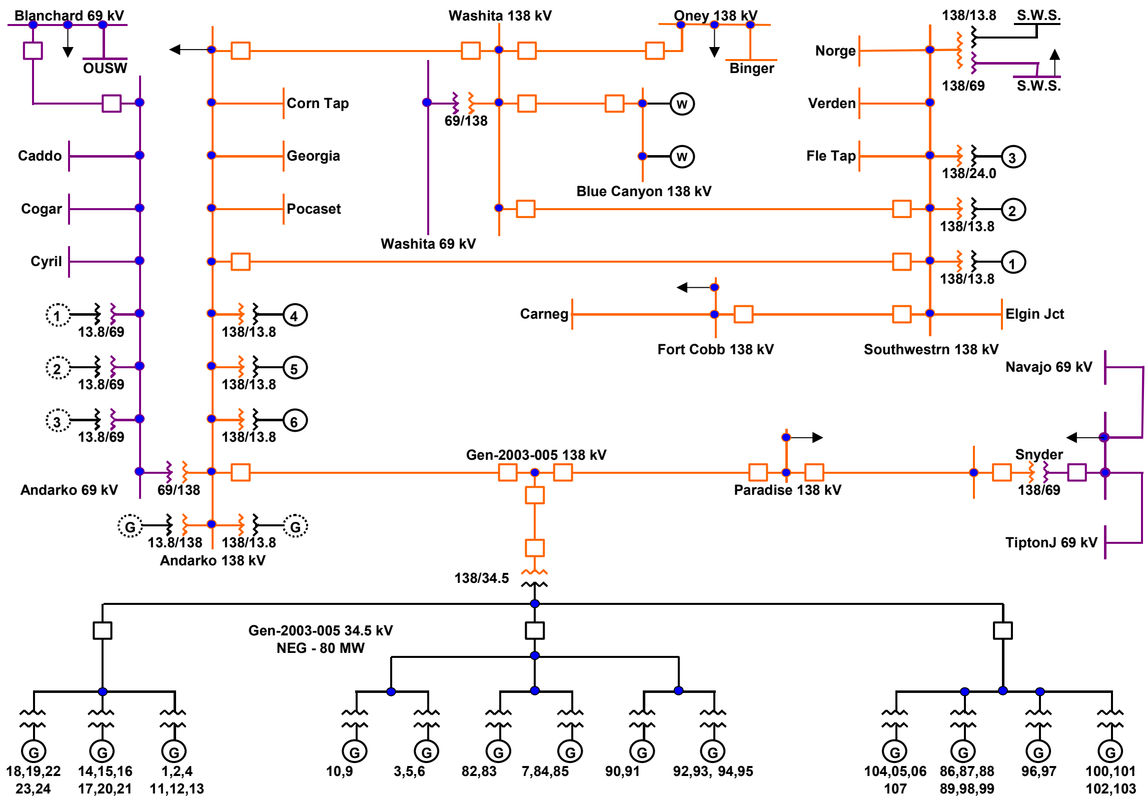
II. Introduction

The Interconnection Customer has requested a generator interconnection study through the Southwest Power Pool Tariff for a 138 kV interconnection of a new wind farm. This wind farm will be connected to a new switching station to be constructed on the Western Farmers Electric Cooperative (WFEC) Anadarko to Paradise 138 kV line near Apache, Oklahoma. The customer asked for studies of 80 and 100 MW output levels. The customer also requested that the study be conducted using both NEG Micon NM72 IEC I (1.65 MW) and GE 1.5 with LVRT (1.5 MW) machines. The projected in-service date for the wind farm is December 2006.

III. Configuration

The proposed wind farm will be connected to a new switching station that will be constructed on the Western Farmers Electric Cooperative (WFEC) Anadarko to Paradise 138 kV line as shown in Figure 1. This switching station will be located approximately 25 miles from the Anadarko Substation and 5 miles from the Paradise Substation. A 5 mile radial 138 kV transmission line will connect the wind farm to the new switching station. It was assumed that the line will be H-frame construction using a 336.4 ACSR 18/1 conductor and an equivalent spacing of 27.72 feet. The line will have a 126.7 MVA rating for 93-degree Celsius operation and a 166.1 MVA rating for 130-degree Celsius operation.

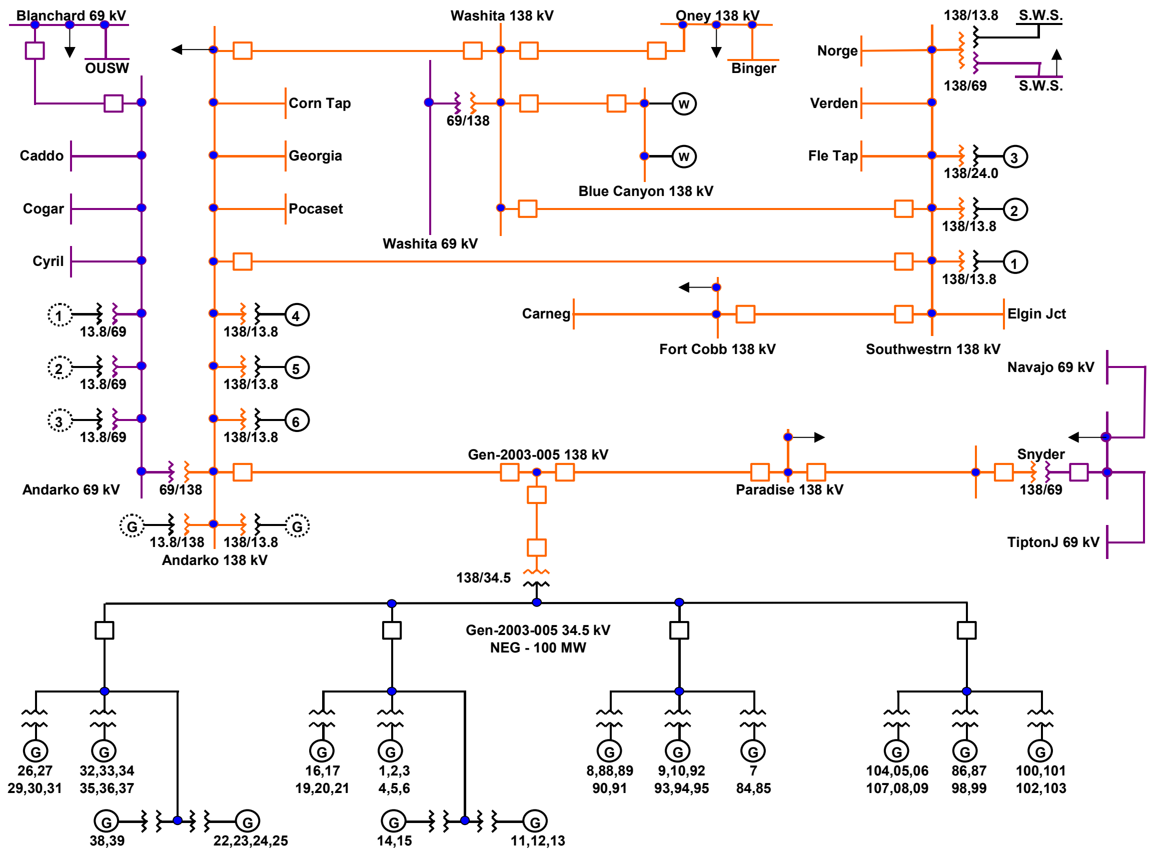
FIGURE 1



The Interconnection Customer substation will contain a 138/34.5 kV transformer connected to the 138 kV bus via a dedicated breaker. A 111.7 MVA rated transformer with 9 percent impedance was used for the 100 MW output level. A 90 MVA rated transformer with 9 percent impedance was used for the 80 MW output level.

The 138/34.5 kV transformer will also be connected to a 34.5 kV bus which will serve three to four 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.

FIGURE 2

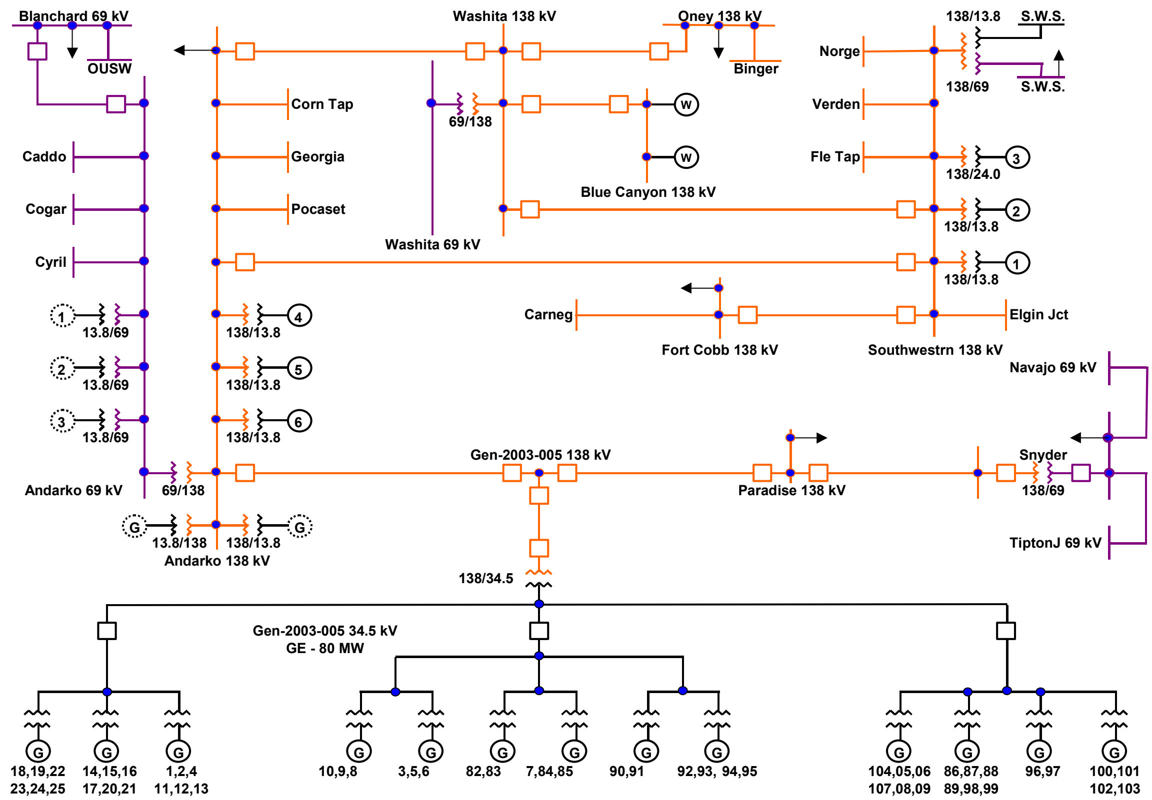


The number and arrangement of wind turbines varies for each MW output level and machine configuration. Wind turbines will be connected to the individual feeders as shown in Figures 1-4 described below:

1. Figure 1 – 80 MW with NEG machines
2. Figure 2 – 100 MW with NEG machines
3. Figure 3 – 80 MW with GE machines
4. Figure 4 – 100 MW with GE machines

Each of the wind turbines is connected to one of the 34.5 kV feeders via its own step-up transformer. A 1.75 MVA rated 34.5/0.6 kV transformer with impedance of 5.75 percent was used with the NEG machines. A 1.75 MVA rated 34.5/0.575 kV transformer with a resistance of 0.77 percent and an inductance of 5.79 percent was used with the GE machines.

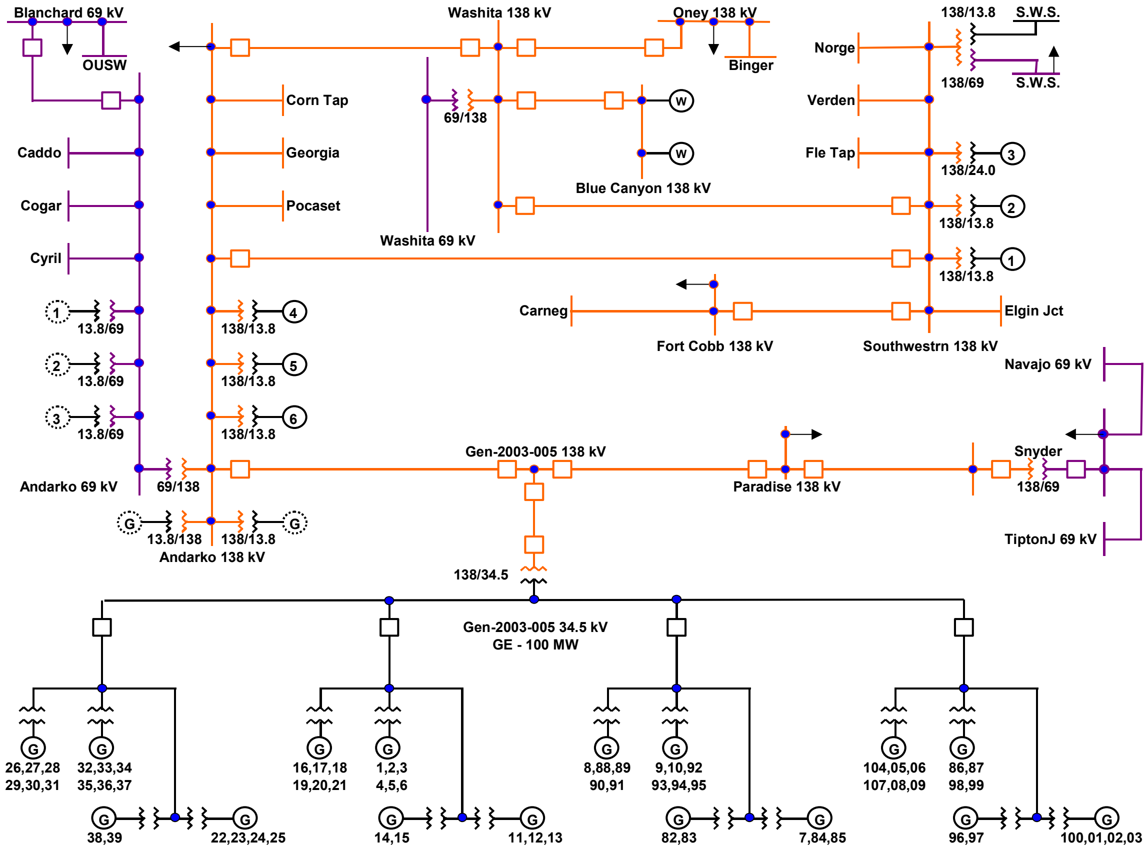
FIGURE 3



The Interconnection Customer provided detailed feeder information including conductor type, resistance, inductance and length for each configuration. Line charging was assumed negligible for underground cables. These values were converted to per unit values using a voltage of 34.5 kV and a 100 MVA base.

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

FIGURE 4



IV. LOAD FLOW MODELING

SPP provided a basecase load flow model based on the 2005 summer peak forecast. The title is “SPP MDWG 04 STABILITY; 2005 SUMMER PEAK; S05SP-29.CNL; 3-22-04.” This model provided the starting point for building a load flow model to evaluate the proposed wind farm. Shaw Group PTI’s PSS/E™ load flow program was used for this analysis

Each individual wind turbine was modeled along with its step-up transformer. This required the addition of several new buses for the turbines, step-up transformers, line segments, and substation. New generator, transformer, capacitor bank, and line segment models were added to the existing load flow model to provide a detailed representation of the wind farm.

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The NEG wind turbines are rated at 1.808 MVA. For dispatch purposes, the nominal output of each turbine is 1.65 MW and -0.74 MVAR. For these machines, the full load compensation package was assumed. This included 0.771 MVAR of multi-staged capacitor banks connected to the generator bus modeled as fixed shunts. When the units were dispatched, other generation units in the WFEC control were redispatched according to the dispatch order provided in Table 1. Generation from MORLND Units 3 and 2 was reduced to compensate for the output of the wind farm. The total wind farm generation for the 80 MW scenario was 80.9 MW (49*1.65 MW wind turbines) while the total dispatch for the 100 MW scenario was 100.7 MW (61*1.65 MW wind turbines).

TABLE 1

MW Generation Dispatch with NEG Machines			
Generator	Wind Farm Off -Line	Wind Farm 80 MW	Wind Farm 100 MW
ANADRK1 13.8	-	-	-
ANADRK2 13.8	-	-	-
GENCO2 413.8	-	-	-
GENCO1 413.8	-	-	-
ANADRK3 13.8	-	-	-
MORLND1 13.8	-	-	-
MORLND3 13.8	34.1	-	-
MORLND2 13.8	112.5	69.0	48.8
ANADRK6 13.8	78.3	78.3	78.3
ANADRK5 13.8	78.3	78.3	78.3
ANADRK4 13.8	63.1	63.1	63.1
HUGO 1 23.4	375.0	375.0	375.0
BLUCAN14 138	74.2	74.2	74.2
BLUCAN14 138	100.0	100.0	100.0
GEN-200234.5	120.0	120.0	120.0
GEN-2003-005	-	80.9	100.7

The GE wind turbines are rated at 1.667 MVA. For dispatch purposes, the nominal output of each turbine is 1.5 MW at unity power factor. A Shaw Group PTI PSS/E™ IPLAN program was used to build the load flow models for the GE machines. This program set the reactive requirements to zero thus representing a fixed unity power factor. When the units were dispatched, other generation units in the WFEC control were redispatched according to the dispatch order provided in Table 2. Generation from MORLND Units 3 and 2 was reduced to compensate for the output of the wind farm. The total wind farm generation for the 80 MW scenario was 79.5 MW (53*1.5 MW wind turbines) while the total dispatch for the 100 MW scenario was 100.5 MW (67*1.5 MW wind turbines).

TABLE 2

MW Generation Dispatch with GE Machines			
Generator	Wind Farm Off-Line	Wind Farm 80 MW	Wind Farm 100 MW
ANADRK1 13.8	-	-	-
ANADRK2 13.8	-	-	-
GENCO2 413.8	-	-	-
GENCO1 413.8	-	-	-
ANADRK3 13.8	-	-	-
MORLND1 13.8	-	-	-
MORLND3 13.8	34.1	-	-
MORLND2 13.8	112.5	69.0	49.4
ANADRK6 13.8	78.3	78.3	78.3
ANADRK5 13.8	78.3	78.3	78.3
ANADRK4 13.8	63.1	63.1	63.1
HUGO 1 23.4	375.0	375.0	375.0
BLUCAN14 138	74.2	74.2	74.2
BLUCAN14 138	100.0	100.0	100.0
GEN-200234.5	120.0	120.0	120.0
GEN-2003-005	-	79.5	100.5

The transmission provider requires the Interconnection Customer to maintain a near unity power factor. Power factors as calculated at the new switching station are provided in Table 3. Since all the power factors were above or very close to 98%, no additional capacitor banks were deemed necessary.

TABLE 3

Scenario	MW	MVAR	MVA	Power Factor
NEG 80	79.9	13.7	81.1	98.6%
NEG 100	99.3	17.6	100.8	98.5%
GE 80	78.1	15.5	79.6	98.1%
GE 100	98.5	20.5	100.6	97.9%

V. Dynamic Modeling

The Interconnection Customer supplied dynamic data for the NEG MICON NM72 wind turbines. This data was used in conjunction with the PSS/E™ CIMTR3 library model to represent the dynamic response of the wind turbines. Several of the parameters fell outside of the acceptable range causing the load flow program to abort. These values were replaced with typical values. The actual data used to build the CIMTR3 model is shown below:

- T’ - 0.201 Seconds **(original value = 0.011)**
- T” - 0.025 Seconds **(original value = 0.0062)**
- H - 4.87 Inertia Constant
- X - 3.65 P.U.
- X’ - 0.089 P.U.
- X” - 0.050 P.U.
- X1 - 0.010 P.U. **(original value = 0.087)**
- E1 - 1.0
- SE1- 0.06
- E2 - 1.2
- SE2- 0.15
- Sw - 0
- SP - 1.0

The NEG MICON NM72 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 with voltage fault ride through was used for this analysis as shown in Attachment 1. These relays have a linear response for voltages between 0.80 and 0.15 per unit. A step-wise function with four steps was used to represent this relationship of voltage versus time. 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 threshold voltage within a preset time. These thresholds and times are listed below:

- Lower Voltage Threshold 0.150 P.U.
- Upper Voltage Threshold 5.000 P.U.
- Relay Pickup Time (delay) 0.080 Seconds
- Breaker Time 0.150 Seconds

- Lower Voltage Threshold 0.300 P.U.
- Upper Voltage Threshold 5.000 P.U.
- Relay Pickup Time (delay) 0.685 Seconds
- Breaker Time 0.150 Seconds

- Lower Voltage Threshold 0.450 P.U.
- Upper Voltage Threshold 5.000 P.U.
- Relay Pickup Time (delay) 1.200 Seconds
- Breaker Time 0.150 Seconds

- Lower Voltage Threshold 0.600 P.U.
- Upper Voltage Threshold 5.000 P.U.
- Relay Pickup Time (delay) 1.800 Seconds
- Breaker Time 0.150 Seconds

- Lower Voltage Threshold 0.750 P.U.
- Upper Voltage Threshold 5.000 P.U.
- Relay Pickup Time (delay) 2.300 Seconds

- Breaker Time 0.150 Seconds

- Lower Voltage Threshold 0.800 P.U.
- Upper Voltage Threshold 5.000 P.U.
- Relay Pickup Time (delay) 2.800 Seconds
- Breaker Time 0.150 Seconds

- Lower Voltage Threshold 0.000 P.U.
- Upper Voltage Threshold 1.135 P.U.
- Relay Pickup Time (delay) 0.200 Seconds
- Breaker Time 0.150 Seconds

- Lower Voltage Threshold 0.000 P.U.
- Upper Voltage Threshold 1.200 P.U.
- Relay Pickup Time (delay) 0.080 Seconds
- Breaker Time 0.150 Seconds

The over/under frequency relay has two settings. Normal operation occurs when the frequency is between 57.0 and 61.8 cycles per second. When frequency exceeds 61.8 or drops below 57.0 cycles per second, a timer is set that will trip the breaker if frequency does not return to the normal range within the preset time. The data for the relay models are shown below:

- Lower Frequency Threshold 57.0 P.U.
- Upper Frequency Threshold 66.0 P.U.
- Relay Pickup Time (delay) 3.0 Seconds
- Breaker Time 0.15 Seconds

- Lower Frequency Threshold 54.0 P.U.
- Upper Frequency Threshold 61.8 P.U.
- Relay Pickup Time (delay) 3.0 Seconds
- Breaker Time 0.15 Seconds

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A Shaw Group PTI PSS/E™ IPLAN program was used to build the dynamic models for the GE machines. This program built user models to represent the dynamic response of wind turbines. It also built over/under voltage relay and over/under frequency relay models. These models were used without modification. They included the DFIGPQ, CGECN2, TWIND1, TSHAFT, GEAERO, TGPTCH, VTGTRP, and FRQTRP user models.

The VTGTRP model represented the under/over voltage relay actions for both the GE and NEG machines in this analysis. For comparison the voltage thresholds, relay times and breaker times for the GE machines are provided below:

- Lower Voltage Threshold 0.300 P.U.
- Upper Voltage Threshold 5.000 P.U.
- Relay Pickup Time (delay) 0.020 Seconds
- Breaker Time 0.150 Seconds

- Lower Voltage Threshold 0.700 P.U.
- Upper Voltage Threshold 5.000 P.U.
- Relay Pickup Time (delay) 0.100 Seconds
- Breaker Time 0.150 Seconds

- Lower Voltage Threshold 0.750 P.U.
- Upper Voltage Threshold 5.000 P.U.
- Relay Pickup Time (delay) 1.000 Seconds
- Breaker Time 0.150 Seconds

- Lower Voltage Threshold 0.850 P.U.
- Upper Voltage Threshold 5.000 P.U.
- Relay Pickup Time (delay) 10.00 Seconds
- Breaker Time 0.150 Seconds

- Lower Voltage Threshold 0.000 P.U.
- Upper Voltage Threshold 1.100 P.U.
- Relay Pickup Time (delay) 1.000 Seconds

- Breaker Time 0.150 Seconds

- Lower Voltage Threshold 0.000 P.U.
- Upper Voltage Threshold 1.150 P.U.
- Relay Pickup Time (delay) 0.100 Seconds
- Breaker Time 0.150 Seconds

- Lower Voltage Threshold 0.000 P.U.
- Upper Voltage Threshold 1.300 P.U.
- Relay Pickup Time (delay) 0.020 Seconds
- Breaker Time 0.150 Seconds

The FRQTRP model represented the under/over frequency relay actions for both the GE and NEG machines in this analysis. For comparison the frequency thresholds, relay times and breaker times for the GE machines are provided below:

- Lower Frequency Threshold 56.5 P.U.
- Upper Frequency Threshold 66.0 P.U.
- Relay Pickup Time (delay) 0.02 Seconds
- Breaker Time 0.15 Seconds

- Lower Frequency Threshold 57.5 P.U.
- Upper Frequency Threshold 66.0 P.U.
- Relay Pickup Time (delay) 10.00 Seconds
- Breaker Time 0.15 Seconds

- Lower Frequency Threshold 54.0 P.U.
- Upper Frequency Threshold 61.5 P.U.
- Relay Pickup Time (delay) 30.00 Seconds
- Breaker Time 0.15 Seconds

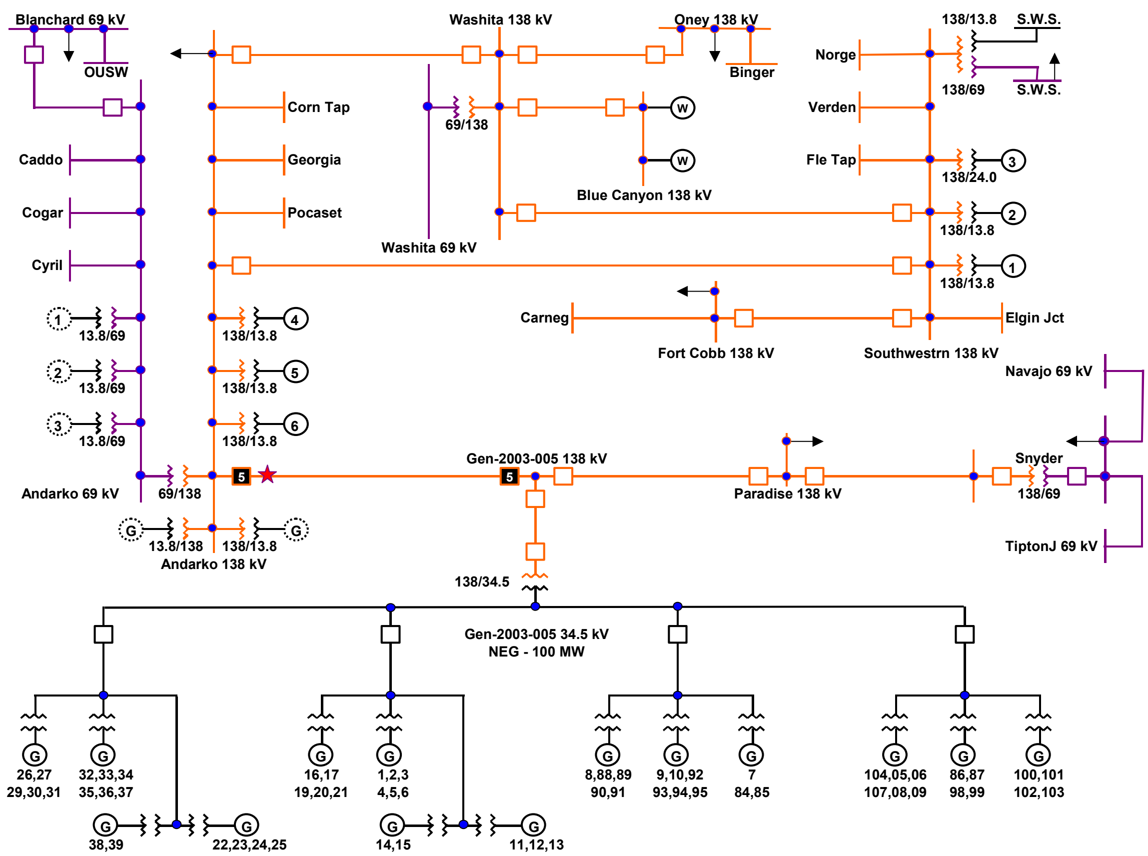
- Lower Frequency Threshold 54.0 P.U.
- Upper Frequency Threshold 62.5 P.U.
- Relay Pickup Time (delay) 0.02 Seconds
- Breaker Time 0.15 Seconds

VI. FAULT SCENARIOS

The SPP defined the following 22 fault scenarios. Each of the GE and NEG machines were evaluated for both the 80 and 100 MW output levels.

1. A three-phase fault on the Anadarko to Gen-2003-005 Wind Farm 138 kV line at Anadarko was evaluated. The fault was applied at Anadarko for 5 cycles. Removing the 138 kV line between the Anadarko Substation and the Gen-2003-005 Wind Farm Switching Station temporarily cleared the fault. After 20 cycles, the 138 kV line was re-closed and the fault was re-applied at Anadarko for 5 cycles. Removing the 138 kV line between the Anadarko Substation and the Gen-2003-005 Wind Farm Switching Station as shown in Figure 5 permanently cleared the fault.

FIGURE 5

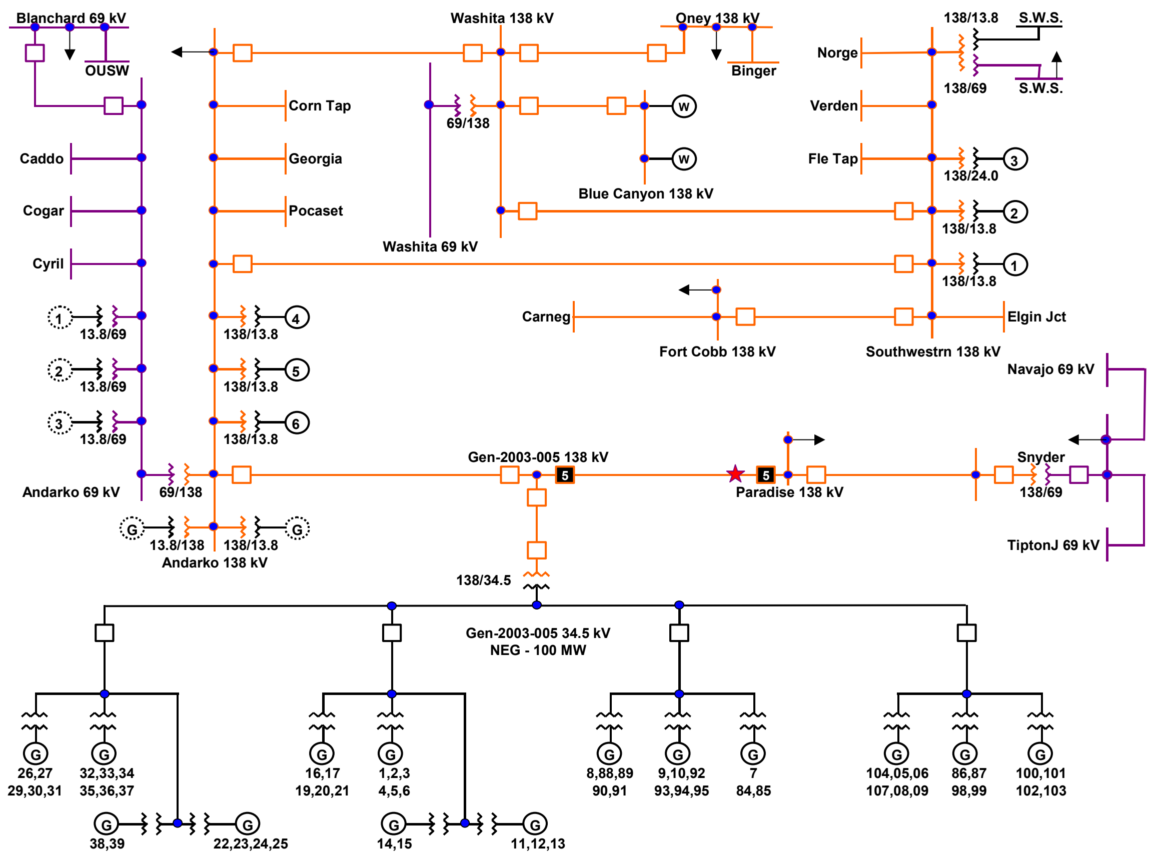


2. A single-phase fault on the Anadarko to Gen-2003-005 Wind Farm 138 kV line near Anadarko was evaluated. The fault was applied at Anadarko for 5 cycles. Removing the 138 kV line between the Anadarko Substation and the Gen-2003-005 Wind Farm Switching Station temporarily cleared the fault. After 20 cycles, the 138 kV line was re-closed and the fault was re-applied at Anadarko for 5 cycles. Removing the 138 kV line between the Anadarko Substation and the Gen-2003-005 Wind Farm Switching Station as shown in Figure 5 permanently cleared the fault.

3. A three-phase fault on the Paradise to Gen-2003-005 Wind Farm 138 kV line near Paradise was evaluated. The fault was applied at Paradise for 5 cycles. Removing the 138 kV line between the Paradise Substation and the Gen-2003-005 Wind Farm Switching Station temporarily cleared the fault. After 20 cycles, the 138 kV line was re-closed and the fault was re-applied at Paradise for 5 cycles. Removing the 138 kV line between the Paradise Substation and the Gen-2003-005 Wind Farm Switching Station as shown in Figure 6 permanently cleared the fault.

4. A single-phase fault on the Paradise to Gen-2003-005 Wind Farm 138 kV line near Paradise was evaluated. The fault was applied at Paradise for 5 cycles. Removing the 138 kV line between the Paradise Substation and the Gen-2003-005 Wind Farm Switching Station temporarily cleared the fault. After 20 cycles, the 138 kV line was re-closed and the fault was re-applied at Paradise for 5 cycles. Removing the 138 kV line between the Paradise Substation and the Gen-2003-005 Wind Farm Switching Station as shown in Figure 6 permanently cleared the fault.

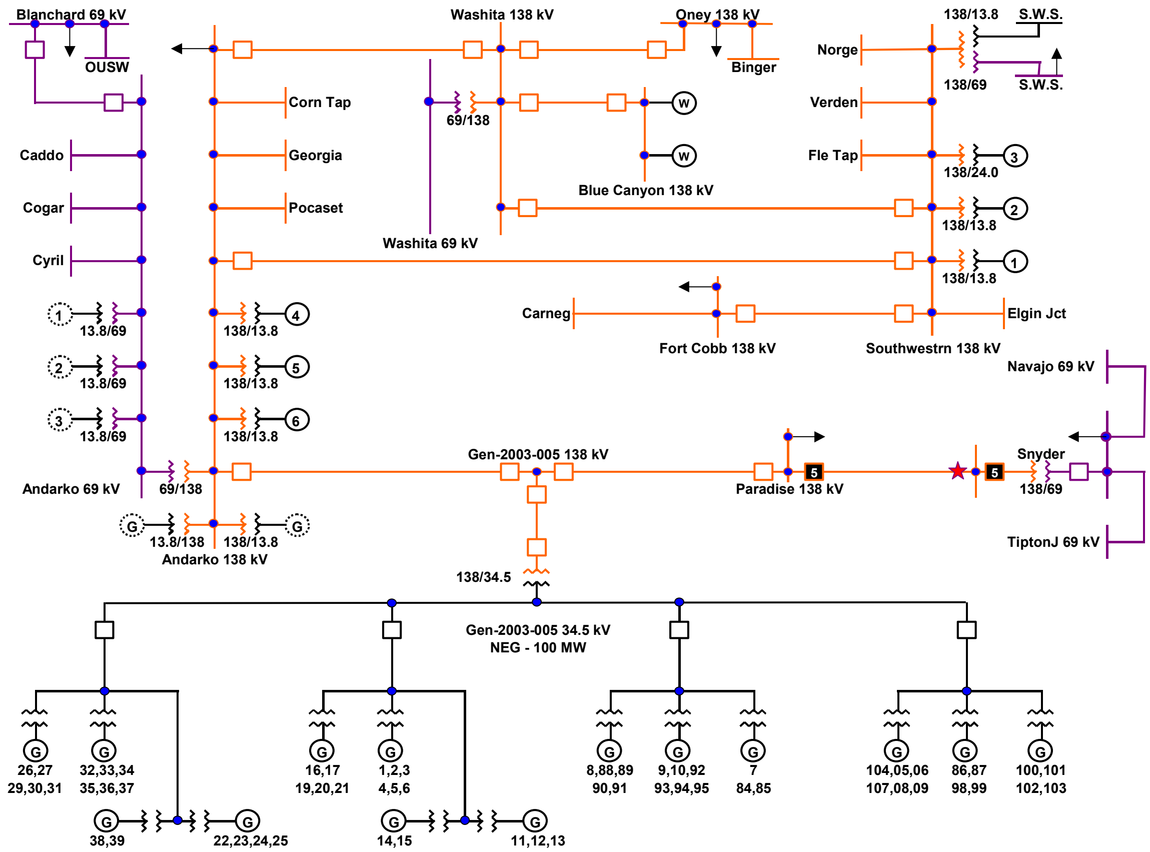
FIGURE 6



5. A three-phase fault on the Snyder to Paradise 138 kV line near Snyder was evaluated. The fault was applied at Snyder for 5 cycles. Removing the 138 kV line between the Snyder and Paradise Substations temporarily cleared the fault. After 20 cycles, the 138 kV line was re-closed and the fault was re-applied at Synder for 5 cycles. Removing the 138 kV line between the Snyder and Paradise Substations as shown in Figure 7 permanently cleared the fault.

6. A single-phase fault on the Snyder to Paradise 138 kV line near Snyder was evaluated. The fault was applied at Snyder for 5 cycles. Removing the 138 kV line between the Snyder and Paradise Substations temporarily cleared the fault. After 20 cycles, the 138 kV line was re-closed and the fault was re-applied at Synder for 5 cycles. Removing the 138 kV line between the Snyder and Paradise Substations as shown in Figure 7 permanently cleared the fault.

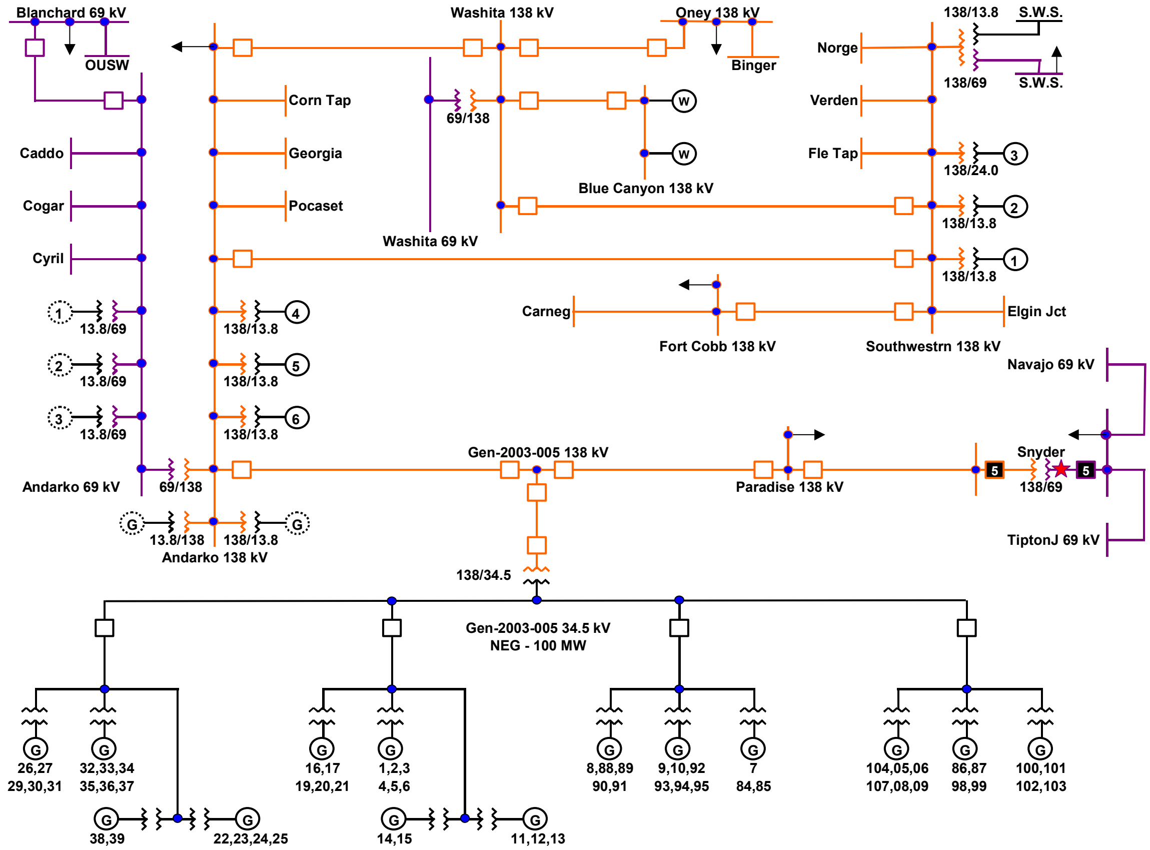
FIGURE 7



7. A three-phase fault on the Snyder 138/69 kV transformer was evaluated. The fault was applied on the Snyder 69 kV bus for 5 cycles. Removing the Snyder 138/69 kV transformer temporarily cleared the fault. After 20 cycles, the 138/69 kV transformer was re-energized and the fault was re-applied on the Synder 69 kV bus for 5 cycles. Removing the Synder 138/69 kV transformer as shown in Figure 8 permanently cleared the fault.

8. A single-phase fault on the Snyder 138/69 kV transformer was evaluated. The fault was applied on the Snyder 69 kV bus for 5 cycles. Removing the Snyder 138/69 kV transformer temporarily cleared the fault. After 20 cycles, the 138/69 kV transformer was re-energized and the fault was re-applied on the Synder 69 kV bus for 5 cycles. Removing the Synder 138/69 kV transformer as shown in Figure 8 permanently cleared the fault.

FIGURE 8

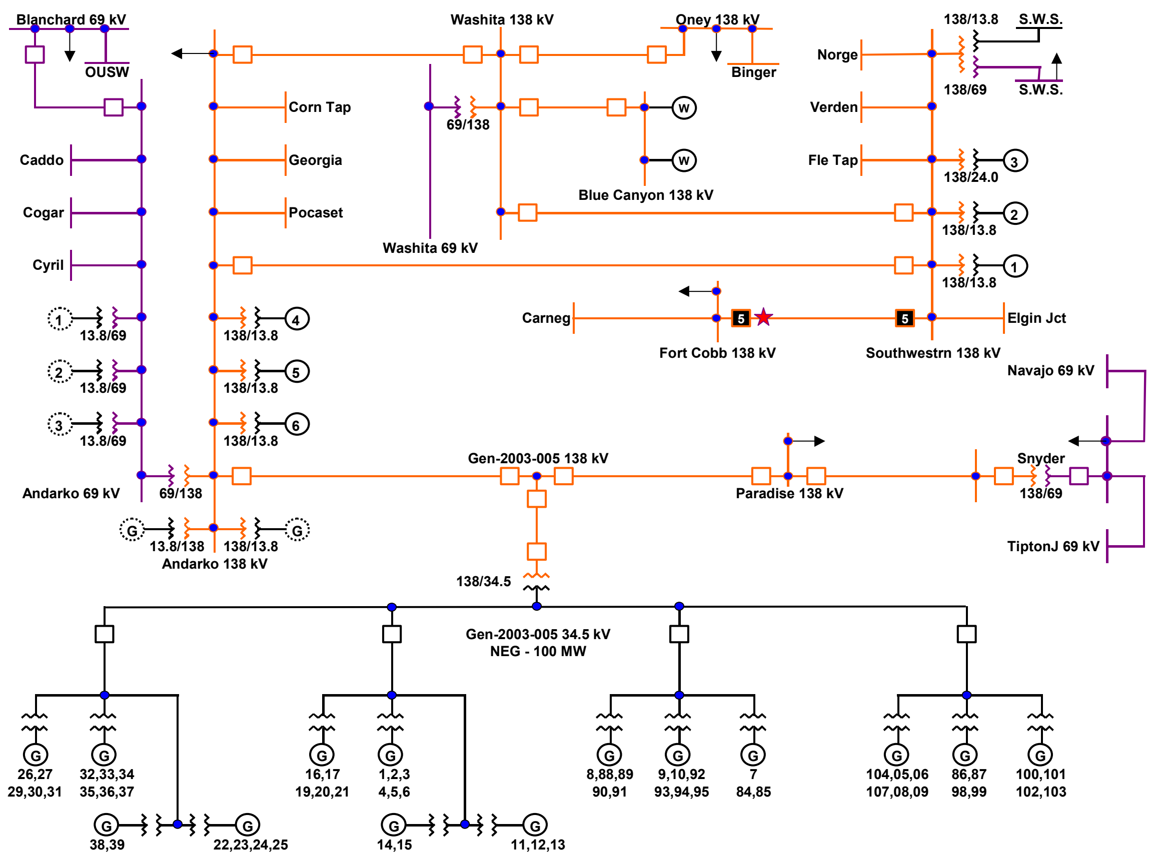


9. A three-phase fault on the Fort Cobb to Southwestern Station 138 kV line near Fort Cobb was evaluated. The fault was applied at Fort Cobb for 5 cycles. Removing the 138 kV line between the Fort Cobb Substation and the Southwestern Station temporarily cleared the fault. After 20 cycles, the 138 kV line was re-closed and the fault was re-applied at Fort Cobb for 5 cycles. Removing the 138 kV line between the Fort Cobb Substation and the Southwestern Station as shown in Figure 9 permanently cleared the fault.

10. A single-phase fault on the Fort Cobb to Southwestern Station 138 kV line near Fort Cobb was evaluated. The fault was applied at Fort Cobb for 5 cycles. Removing the 138 kV line between the Fort Cobb Substation and the Southwestern Station temporarily cleared the fault. After 20 cycles, the 138 kV line was re-closed and the fault was re-applied at Fort Cobb for 5 cycles.

Removing the 138 kV line between the Fort Cobb Substation and the Southwestern Station as shown in Figure 9 permanently cleared the fault.

FIGURE 9

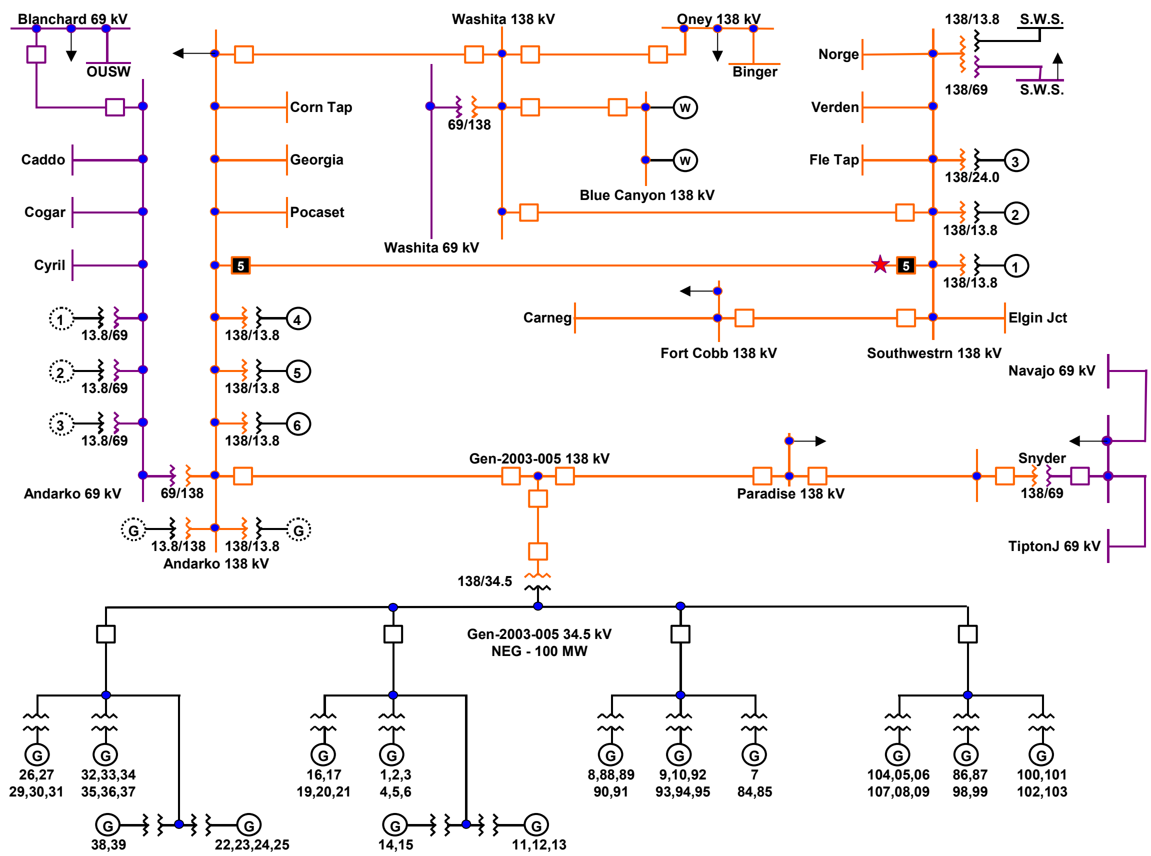


11. A three-phase fault on the Anadarko to Southwestern Station 138 kV line near Southwestern Station was evaluated. The fault was applied at Southwestern Station for 5 cycles. Removing the 138 kV line between the Anadarko Substation and the Southwestern Station temporarily cleared the fault. After 20 cycles, the 138 kV line was re-closed and the fault was re-applied at Southwestern Station for 5 cycles. Removing the 138 kV line between the Anadarko Substation and the Southwestern Station as shown in Figure 10 permanently cleared the fault.

12. A single-phase fault on the Anadarko to Southwestern Station 138 kV line near Southwestern Station was evaluated. The fault was applied at

Southwestern Station for 5 cycles. Removing the 138 kV line between the Anadarko Substation and the Southwestern Station temporarily cleared the fault. After 20 cycles, the 138 kV line was re-closed and the fault was re-applied at Southwestern Station for 5 cycles. Removing the 138 kV line between the Anadarko Substation and the Southwestern Station as shown in Figure 10 permanently cleared the fault.

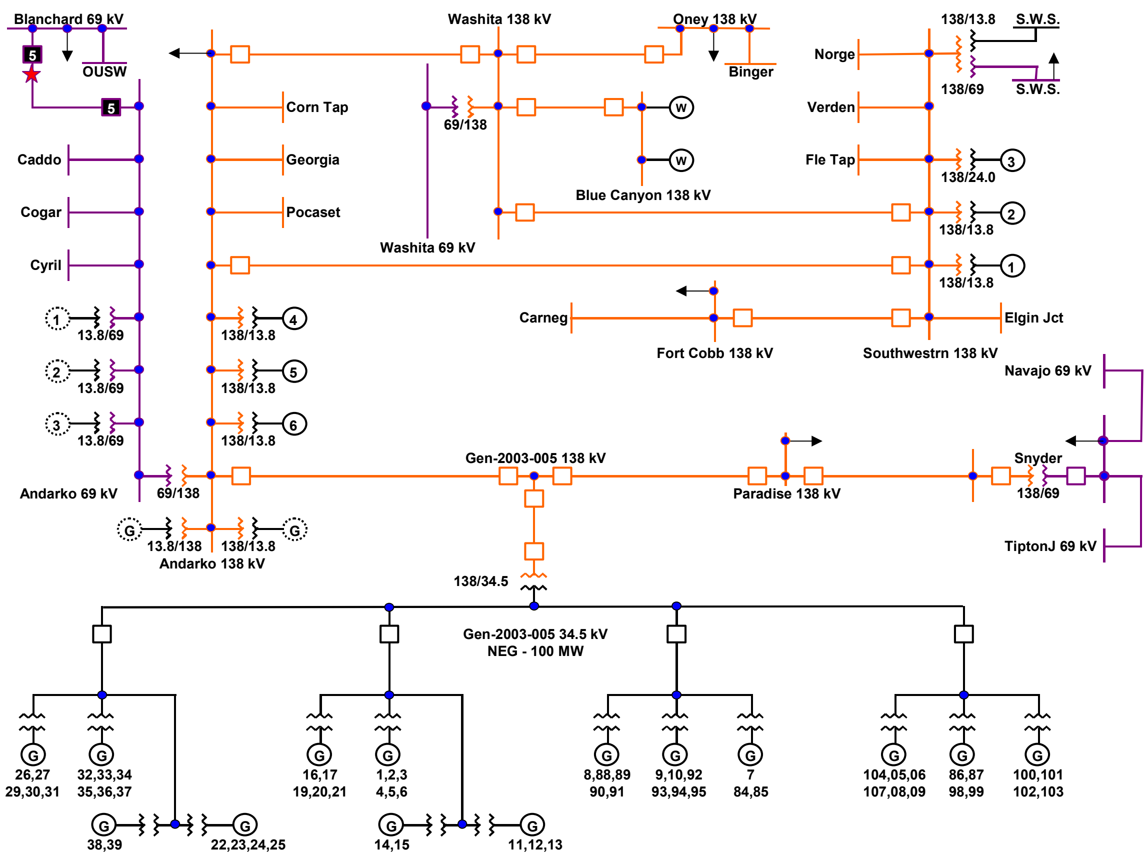
FIGURE 10



13. A three-phase fault on the Anadarko to Blanchard 69 kV line near Blanchard was evaluated. The fault was applied at Blanchard for 5 cycles. Removing the 69 kV line between the Anadarko and Blanchard Substations temporarily cleared the fault. After 20 cycles, the 69 kV line was re-closed and the fault was re-applied at Blanchard for 5 cycles. Removing the 69 kV line between the Anadarko and Blanchard Substations as shown in Figure 11 permanently cleared the fault.

14. A single-phase fault on the Anadarko to Blanchard 69 kV line near Blanchard was evaluated. The fault was applied at Blanchard for 5 cycles. Removing the 69 kV line between the Anadarko and Blanchard Substations temporarily cleared the fault. After 20 cycles, the 69 kV line was re-closed and the fault was re-applied at Blanchard for 5 cycles. Removing the 69 kV line between the Anadarko and Blanchard Substations as shown in Figure 11 permanently cleared the fault.

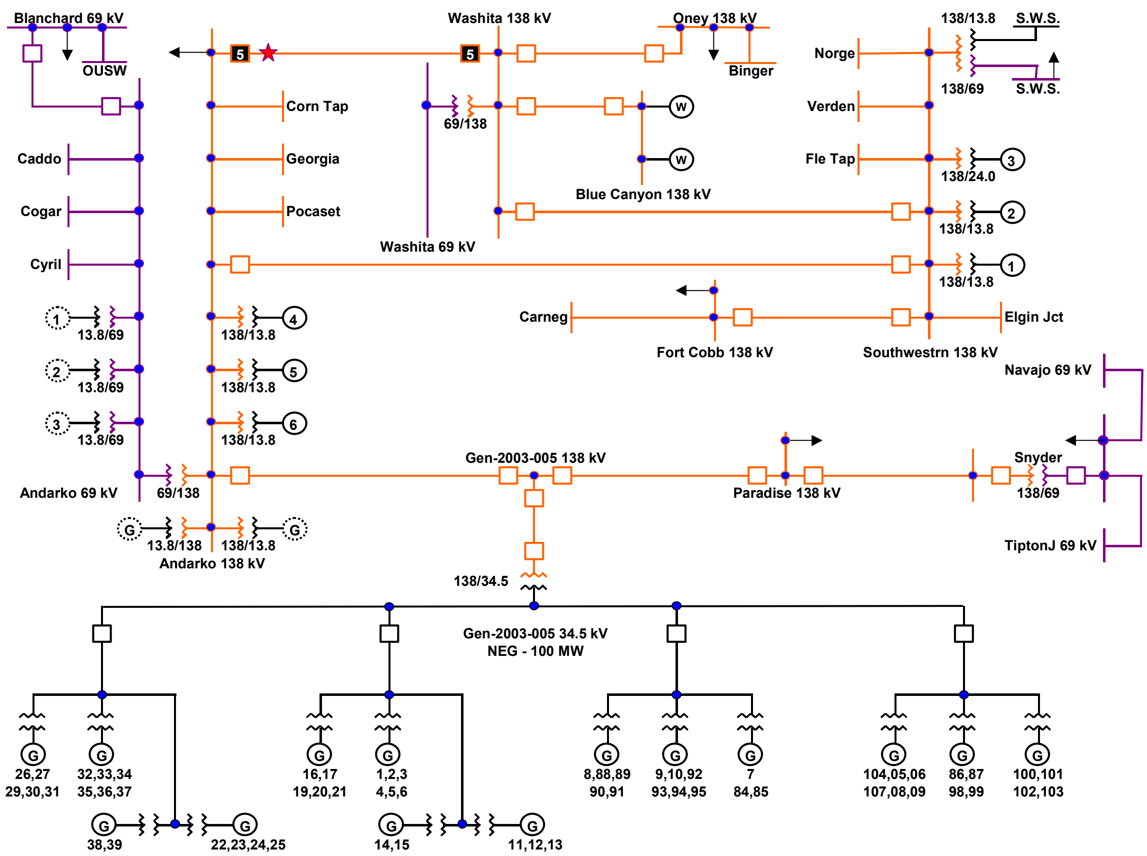
FIGURE 11



15. A three-phase fault on the Washita to Anadarko 138 kV line near Anadarko was evaluated. The fault was applied at Anadarko for 5 cycles. Removing the 138 kV line between the Washita and Anadarko Substations temporarily cleared the fault. After 20 cycles, the 138 kV line was re-closed and the fault

was re-applied at Anadarko for 5 cycles. Removing the 138 kV line between the Washita and Anadarko Substations as shown in Figure 12 permanently cleared the fault.

FIGURE 12

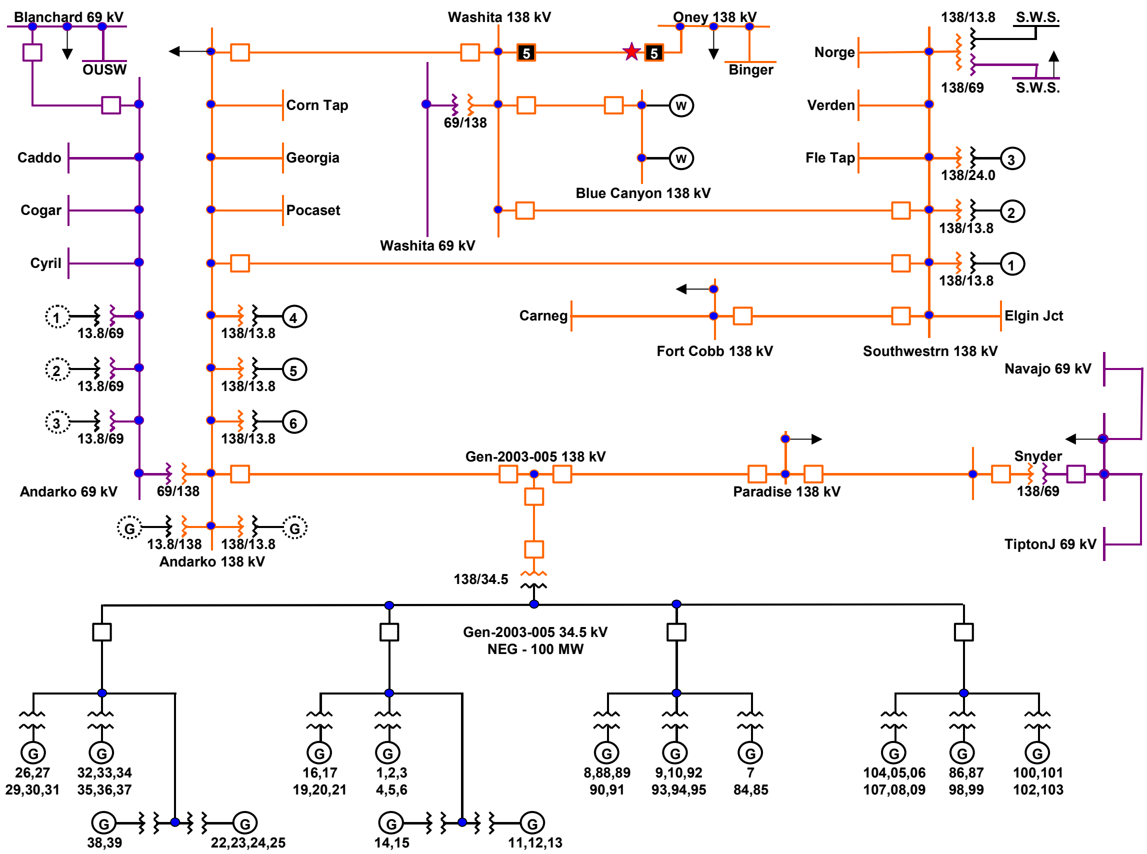


16. A single-phase fault on the Washita to Anadarko 138 kV line near Anadarko was evaluated. The fault was applied at Anadarko for 5 cycles. Removing the 138 kV line between the Washita and Anadarko Substations temporarily cleared the fault. After 20 cycles, the 138 kV line was re-closed and the fault was re-applied at Anadarko for 5 cycles. Removing the 138 kV line between the Washita and Anadarko Substations as shown in Figure 12 permanently cleared the fault.

17. A three-phase fault on the Washita to Oney 138 kV line near Oney was evaluated. The fault was applied at Oney for 5 cycles. Removing the 138 kV line between the Washita and Oney Substations temporarily cleared the fault.

After 20 cycles, the 138 kV line was re-closed and the fault was re-applied at Oney for 5 cycles. Removing the 138 kV line between the Washita and Oney Substations as shown in Figure 13 permanently cleared the fault.

FIGURE 13

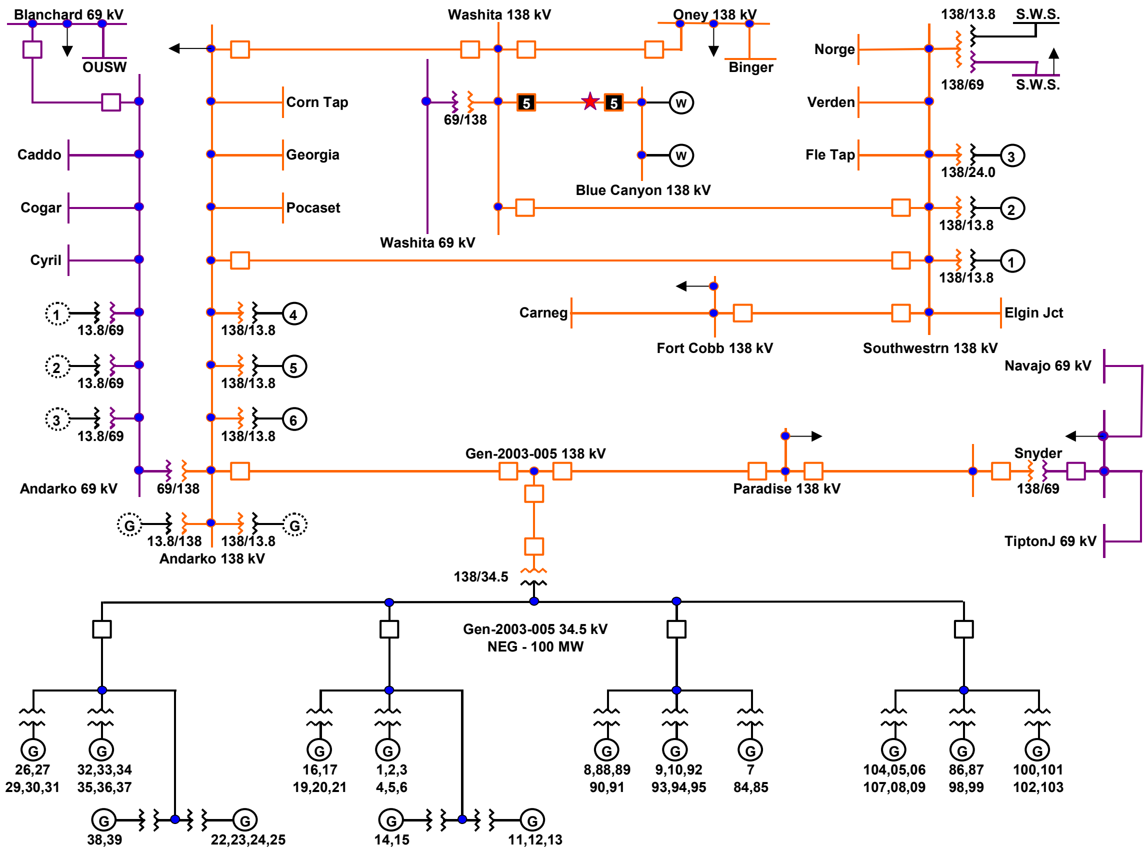


18. A single-phase fault on the Washita to Oney 138 kV line near Oney was evaluated. The fault was applied at Oney for 5 cycles. Removing the 138 kV line between the Washita and Oney Substations temporarily cleared the fault. After 20 cycles, the 138 kV line was re-closed and fault was re-applied at Oney for 5 cycles. Removing the 138 kV line between the Washita and Oney Substations as shown in Figure 13 permanently cleared the fault.

19. A three-phase fault on the Washita to Gen-2003-004 Wind Farm 138 kV line near the Wind Farm was evaluated. The fault was applied at the Wind Farm for 5 cycles. Removing the 138 kV line between the Washita and Gen-2003-

004 Wind Farm Substations temporarily cleared the fault. After 20 cycles, the 138 kV line was re-closed and the fault was re-applied at the Wind Farm for 5 cycles. Removing the 138 kV line between the Washita and Gen-2003-004 Wind Farm Substations as shown in Figure 14 permanently cleared the fault.

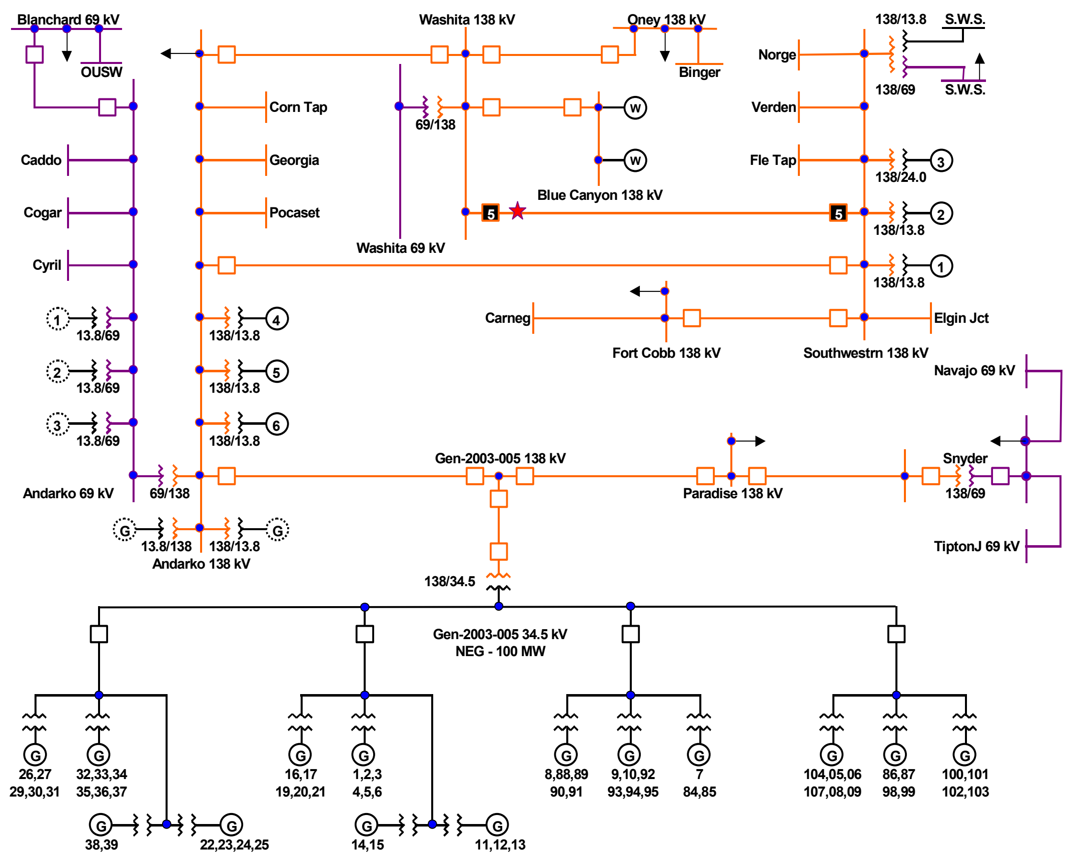
FIGURE 14



20. A single-phase fault on the Washita to Gen-2003-004 Wind Farm 138 kV line near the Wind Farm was evaluated. The fault was applied at the Wind Farm for 5 cycles. Removing the 138 kV line between the Washita and Gen-2003-004 Wind Farm Substations temporarily cleared the fault. After 20 cycles, the 138 kV line was re-closed and fault was re-applied at the Wind Farm for 5 cycles. Removing the 138 kV line between the Washita and Gen-2003-004 Wind Farm Substations as shown in Figure 14 permanently cleared the fault.
21. A three-phase fault on the Washita to Southwestern Station 138 kV line near Washita was evaluated. The fault was applied at Washita for 5 cycles.

Removing the 138 kV line between the Washita Substation and Southwestern Station temporarily cleared the fault. After 20 cycles, the 138 kV line was re-closed and the fault was re-applied at Washita for 5 cycles. Removing the 138 kV line between the Washita Substation and Southwestern Station as shown in Figure 15 permanently cleared the fault.

FIGURE 15



22. A single-phase fault on the Washita to Southwestern Station 138 kV line near Washita was evaluated. The fault was applied at Washita for 5 cycles. Removing the 138 kV line between the Washita Substation and Southwestern Station temporarily cleared the fault. After 20 cycles, the 138 kV line was re-closed and the fault was re-applied at Washita for 5 cycles. Removing the 138 kV line between the Washita Substation and Southwestern Station as shown in Figure 15 permanently cleared the fault.

VII. Results

The results of the dynamic simulations are shown below in Table 4 for the 80 MW NEG machine configuration:

TABLE 4

Scenario	Angle		Speed		Relay	Stable	Comments
	Initial	Final	Initial	Final	Tripped		
1	(94.7)	-	0.011	(1.000)	Yes		Voltage Collapse
2	(94.7)	-	0.011	(1.000)	Yes		Voltage Collapse
3	(94.7)	(109.0)	0.011	0.011		Yes	
4	(94.7)	(94.6)	0.011	0.011		Yes	
5	(94.7)	(95.2)	0.011	0.011		Yes	
6	(94.7)	(94.2)	0.011	0.011		Yes	
7	(94.7)	(95.0)	0.011	0.011		Yes	
8	(94.7)	(94.3)	0.011	0.011		Yes	
9	(94.7)	(95.0)	0.011	0.011		Yes	Blue Canyon 1 Tripped
10	(94.7)	(94.7)	0.011	0.011		Yes	
11	(94.7)	(99.1)	0.011	0.011		Yes	Blue Canyon 1 Tripped
12	(94.7)	(95.0)	0.011	0.011		Yes	
13	(94.7)	(94.7)	0.011	0.011		Yes	
14	(94.7)	(94.7)	0.011	0.011		Yes	
15	(94.7)	(109.1)	0.011	0.011		Yes	Blue Canyon 1 Tripped
16	(94.7)	(95.2)	0.011	0.011		Yes	
17	(94.7)	(95.0)	0.011	0.011		Yes	Blue Canyon 1 Tripped
18	(94.7)	(94.4)	0.011	0.011		Yes	
19	(94.7)	(95.0)	0.011	0.011		Yes	Blue Canyon 1 Tripped Gen 2003-004 Tripped
20	(94.7)	(95.1)	0.011	0.011		Yes	Blue Canyon 1 Tripped Gen 2003-004 Tripped
21	(94.7)	(96.8)	0.011	0.011		Yes	Blue Canyon 1 Tripped
22	(94.7)	(94.9)	0.011	0.011		Yes	Blue Canyon 1 Tripped

Table 4 illustrates that the voltage relays tripped the wind turbines in Scenarios 1 and 2. For the remaining twenty scenarios the wind turbines rode through the fault and remained on-line. For induction machines, stability is best measured by the speed deviations (i.e., whether the machine continues to accelerate or stalls.) In the scenarios where the wind turbines units remain on-line, they remained stable as indicated by the final speed, which settled close to the initial value once the fault was cleared and the transients subsided. It should also be noted that Blue Canyon I wind farm tripped in Scenarios 1, 9, 11, 15, 17, 21 and 22 due to low voltage. In Scenarios 19 and 20, Blue Canyon I wind farm and Gen-2003-004 were isolated from the system.

The results of the dynamic simulations are shown below in Table 5 for the 100 MW NEG machine configuration:

TABLE 5

Scenario	Angle Initial	Angle Final	Speed Initial	Speed Final	Relay Tripped	Stable	Comments
1	(93.2)	-	0.011	(1.000)	Yes		Voltage Collapse
2	(93.2)	-	0.011	(1.000)	Yes		Voltage Collapse
3	(93.2)	(106.6)	0.011	0.011		Yes	
4	(93.2)	(93.1)	0.011	0.011		Yes	
5	(93.2)	(93.5)	0.011	0.011		Yes	
6	(93.2)	(92.7)	0.011	0.011		Yes	
7	(93.2)	(93.3)	0.011	0.011		Yes	
8	(93.2)	(92.7)	0.011	0.011		Yes	
9	(93.2)	(93.5)	0.011	0.011		Yes	Blue Canyon 1 Tripped
10	(93.2)	(93.1)	0.011	0.011		Yes	
11	(93.2)	(97.3)	0.011	0.011		Yes	Blue Canyon 1 Tripped
12	(93.2)	(93.4)	0.011	0.011		Yes	
13	(93.2)	(93.1)	0.011	0.011		Yes	
14	(93.2)	(93.1)	0.011	0.011		Yes	
15	(93.2)	(106.3)	0.011	0.011		Yes	Blue Canyon 1 Tripped
16	(93.2)	(93.6)	0.011	0.011		Yes	
17	(93.2)	(93.4)	0.011	0.011		Yes	Blue Canyon 1 Tripped
18	(93.2)	(93.1)	0.011	0.011		Yes	
19	(93.2)	(93.4)	0.011	0.011		Yes	Blue Canyon 1 Tripped Gen 2003-004 Tripped
20	(93.2)	(93.6)	0.011	0.011		Yes	Blue Canyon 1 Tripped Gen 2003-004 Tripped
21	(93.2)	(95.0)	0.011	0.011		Yes	Blue Canyon 1 Tripped
22	(93.2)	(93.3)	0.011	0.011		Yes	Blue Canyon 1 Tripped

Table 5 demonstrates that the voltage relays tripped the wind turbines in Scenarios 1 and 2. For the remaining twenty scenarios the wind turbines rode through the fault and remained on-line. For induction machines, stability is best measured by the speed deviations (i.e., whether the machine continues to accelerate or stalls.) In the scenarios where the wind turbines units remain on-line, they remained stable as indicated by the final speed, which settled close to the initial value once the fault was cleared and the transients subsided. It should also be noted that Blue Canyon I wind farm tripped in Scenarios 1, 9, 11, 15, 17, 21 and 22 due to low voltage. In Scenarios 19 and 20, Blue Canyon I wind farm and Gen-2003-004 were isolated from the system.

The results of the dynamic simulations are shown below in Table 6 for the 80 MW GE machine configuration:

TABLE 6

Scenario	Angle		Speed		Relay	Stable	Comments
	Initial	Final	Initial	Final	Tripped		
1	66.2	-	0.200	(1.000)	Yes		Voltage Collapse
2	66.2	-	0.200	(1.000)	Yes		Voltage Collapse
3	66.2	-	0.200	(1.000)	Yes		
4	66.2	305.3	0.200	0.202		Yes	
5	66.2	505.9	0.200	0.203		Yes	
6	66.2	65.3	0.200	0.200		Yes	
7	66.2	331.0	0.200	0.202		Yes	
8	66.2	65.4	0.200	0.200		Yes	
9	66.2	542.3	0.200	0.200		Yes	Blue Canyon 1 Tripped
10	66.2	65.1	0.200	0.200		Yes	
11	66.2	-	0.200	(1.000)	Yes		Blue Canyon 1 Tripped
12	66.2	236.4	0.200	0.201		Yes	
13	66.2	65.4	0.200	0.200		Yes	
14	66.2	65.4	0.200	0.200		Yes	
15	66.2	-	0.200	(1.000)	Yes		Blue Canyon 1 Tripped
16	66.2	385.6	0.200	0.202		Yes	
17	66.2	372.8	0.200	0.200		Yes	Blue Canyon 1 Tripped
18	66.2	65.2	0.200	0.200		Yes	
19	66.2	65.5	0.200	0.200		Yes	Blue Canyon 1 Tripped Gen 2003-004 Tripped
20	66.2	65.7	0.200	0.200		Yes	Blue Canyon 1 Tripped Gen 2003-004 Tripped
21	66.2	-	0.200	(1.000)	Yes		Blue Canyon 1 Tripped
22	66.2	138.8	0.200	0.201		Yes	Blue Canyon 1 Tripped

Table 6 demonstrates that the voltage relays tripped the wind turbines in Scenarios 1, 2, 3, 11, 15 and 21. With the exception of Scenario 2 the faults are 3-phase faults. For the remaining sixteen scenarios the wind turbines rode through the fault and remained on-line. For induction machines, stability is best measured by the speed deviations (i.e., whether the machine continues to accelerate or stalls.) In the scenarios where the wind turbines units remained on-line, they remained stable as indicated by the final speed, which settled close to the initial value once the fault was cleared and the transients subsided. The GE machines will normally operate at 120 percent of rated speed or –20 percent slip at rated power as shown in Table 6. It should also be noted that Blue Canyon I wind farm tripped in Scenarios 1, 9, 11, 15, 17, 21 and 22 due to low voltage. In Scenarios 19 and 20, Blue Canyon I wind farm and Gen-2003-004 were isolated from the system.

The results of the dynamic simulations are shown below in Table 7 for the 100 MW GE machine configuration:

TABLE 7

Scenario	Angle Initial	Angle Final	Speed Initial	Speed Final	Relay Tripped	Stable	Comments
1	66.2	-	0.200	(1.000)	Yes		Voltage Collapse
2	66.2	-	0.200	(1.000)	Yes		Voltage Collapse
3	66.2	-	0.200	(1.000)	Yes		
4	66.2	330.4	0.200	0.202		Yes	
5	66.2	522.6	0.200	0.203		Yes	
6	66.2	65.3	0.200	0.200		Yes	
7	66.2	345.3	0.200	0.202		Yes	
8	66.2	65.4	0.200	0.200		Yes	
9	66.2	570.6	0.200	0.204		Yes	Blue Canyon 1 Tripped
10	66.2	65.1	0.200	0.200		Yes	
11	66.2	-	0.200	(1.000)	Yes		Blue Canyon 1 Tripped
12	66.2	253.2	0.200	0.201		Yes	
13	66.2	65.4	0.200	0.200		Yes	
14	66.2	65.4	0.200	0.200		Yes	
15	66.2	-	0.200	(1.000)	Yes		Blue Canyon 1 Tripped
16	66.2	407.6	0.200	0.203		Yes	
17	66.2	392.8	0.200	0.202		Yes	Blue Canyon 1 Tripped
18	66.2	65.3	0.200	0.200		Yes	
19	66.2	65.6	0.200	0.200		Yes	Blue Canyon 1 Tripped Gen 2003-004 Tripped
20	66.2	65.7	0.200	0.200		Yes	Blue Canyon 1 Tripped Gen 2003-004 Tripped
21	66.2	-	0.200	(1.000)	Yes		Blue Canyon 1 Tripped
22	66.2	152.6	0.200	0.201		Yes	Blue Canyon 1 Tripped

Table 7 illustrates that the voltage relays tripped the wind turbines in Scenarios 1, 2, 3, 11, 15 and 21. With the exception of Scenario 2 the faults are 3-phase faults. For the remaining sixteen scenarios the wind turbines rode through the fault and remained on-line. For induction machines, stability is best measured by the speed deviations (i.e., whether the machine continues to accelerate or stalls.) In the scenarios where the wind turbines units remained on-line, they remained stable as indicated by the final speed, which settled close to the initial value once the fault was cleared and the transients subsided. The GE machines will normally operate at 120 percent of rated speed or –20 percent slip at rated power as shown in Table 7. It should also be noted that Blue Canyon I wind farm tripped in Scenarios 1, 9, 11, 15, 17, 21 and 22 due to low voltage. In Scenarios 19 and 20, Blue Canyon I wind farm and Gen-2003-004 were isolated from the system.

A comparison of Tables 4 and 5 indicate no significant differences between the 80 and 100 MW output levels for the NEG machines. The only observable differences are the angle swings. Likewise a comparison of Tables 6 and 7 indicate no significant differences between the 80 and 100 MW output levels for the GE machines. Once again the only observable differences are the angle swings.

A comparison of Tables 4 and 6 as well as Tables 5 and 7 indicates that the under voltage relays are more sensitive for the GE machines. The NEG wind turbines were tripped in only two scenarios compared to six for the GE machines. Based on the initial data the NEG wind turbines can tolerate a voltage as low as 0.15 per unit compared to 0.30 per unit for the GE machines.

The most significant finding of this analysis pertains to Scenario 1 and 2. The electrical output of Wind Turbine #1 is shown in Figure 16. This figure indicates that the wind turbine tripped at time 1.721. A review of the voltage at the collector bus as illustrated in Figure 17 indicates that the voltage did not recover after the fault was permanently removed. The NEG units appeared to have been tripped due to a sustained low voltage as opposed to the initial dip. Only after the wind turbines were tripped did the voltage recover. Thus, a voltage collapse occurred due to the inability of the system to support the wind farm with the Anadarko to Gen-2003-005 Wind Farm 138 kV line out of service.

System Impact Study GEN-2003-005

FIGURE 16

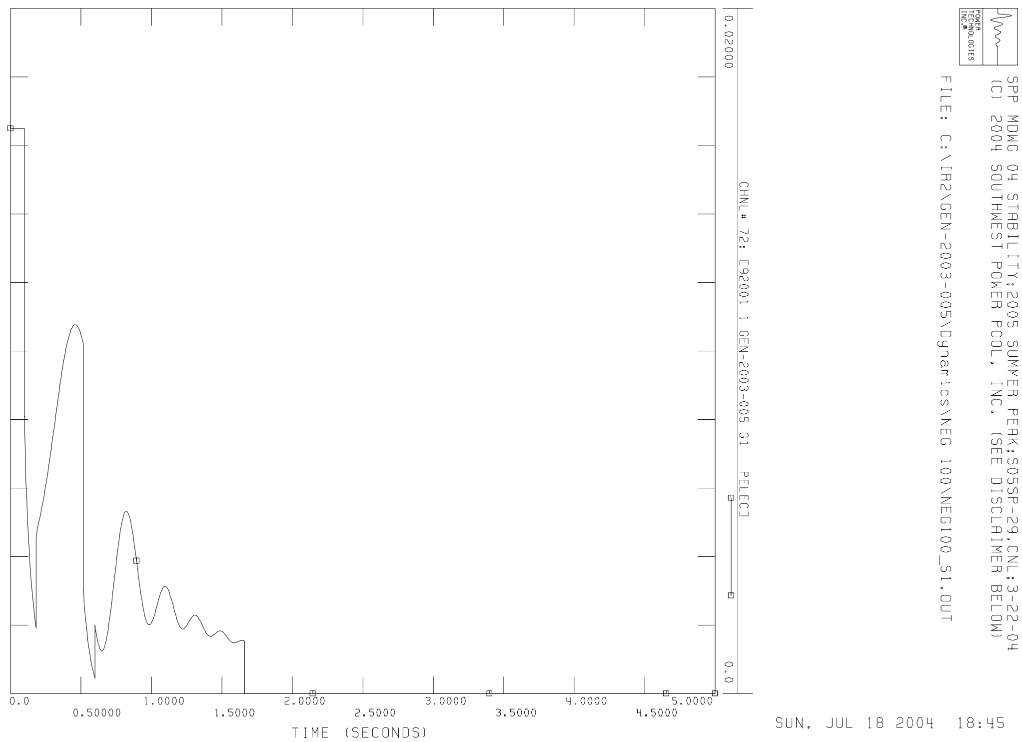
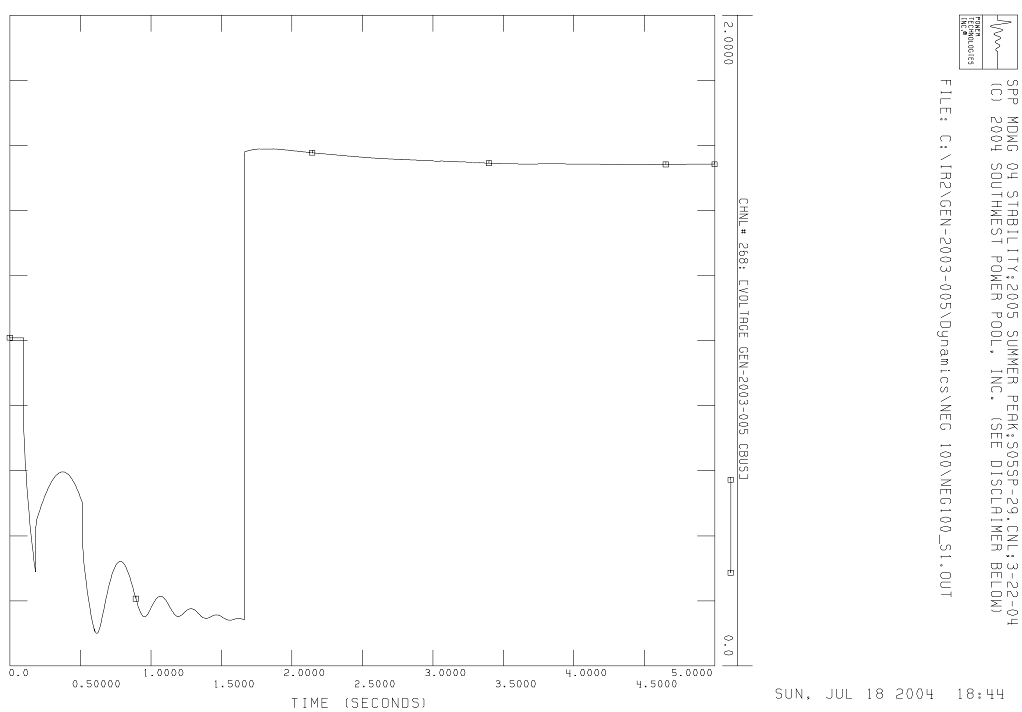


FIGURE 17



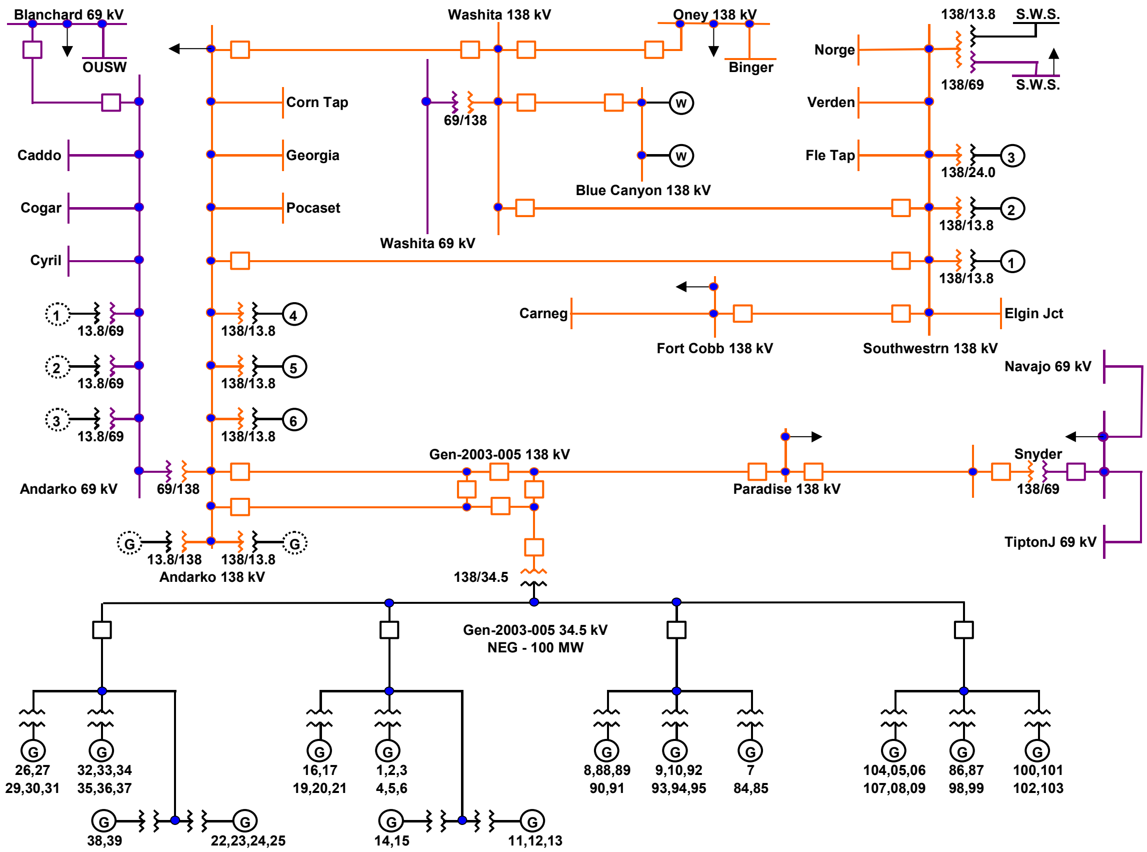
VIII. Sensitivities

Evaluation of different output levels and machines as requested by the Interconnection Customer provided key insight to the stability impacts of the proposed wind farm interconnection. The new machines are for the most part compensated for MVAR consumption and designed to ride through most voltage dips. Additional reactive sources if fixed could result in over voltages and cause unnecessary trips by the over voltage relays. Therefore, additional capacitor banks were not evaluated.

The main concern is the voltage collapse that occurred when the Anadarko to Gen-2003-005 Wind Farm 138 kV line was removed from service. Even though the voltage recovered after the wind turbines were tripped off-line, this makes the transmission system voltage dependent on the proper operation of the under-voltage relays at a customer substation in order to maintain integrity. A potential solution to this problem would be a second 138 kV circuit from the Anadarko Substation to the new switching station.

A new load flow case was created that included a second 138 kV circuit from the Anadarko Substation to the new switching station as shown in Figure 18. Scenarios 1 and 2 were re-evaluated under this basecase. The results are presented in Figures 19 and 20. Figure 19 shows the electrical output with the second circuit in service. Figure 20 illustrates that voltage recovered allowing the wind turbines to remain on-line.

FIGURE 18


Blanchard 69 kV
OUSW
Washita 138 kV
Oney 138 kV
Binger
138/13.8
S.W.S.
Norge
138/69
S.W.S.
Corn Tap
69/138
Verden
Caddo
Georgia
Fle Tap
138/24.0
Blue Canyon 138 kV
Cogar
Pocaset
138/13.8
Washita 69 kV
Cyril
138/13.8
13.8/69
138/13.8
Carneg
Fort Cobb 138 kV
Southwestrn 138 kV
Elgin Jct
Navajo 69 kV
Gen-2003-005 138 kV
Snyder
Andarko 69 kV
69/138
Paradise 138 kV
138/69
TiptonJ 69 kV
13.8/138
Andarko 138 kV
138/34.5
Gen-2003-005 34.5 kV
NEG - 100 MW
26,27
29,30,31
32,33,34
35,36,37
38,39
22,23,24,25
16,17
19,20,21
1,2,3
4,5,6
14,15
11,12,13
8,88,89
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9,10,92
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7
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107,08,09
86,87
98,99
100,101
102,103

FIGURE 19

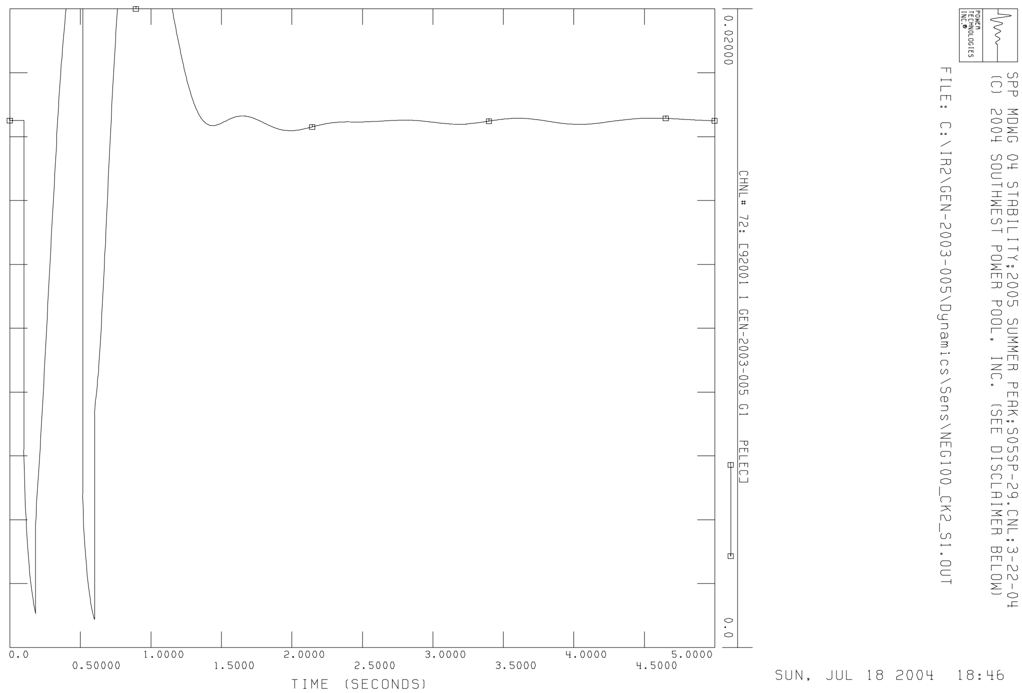
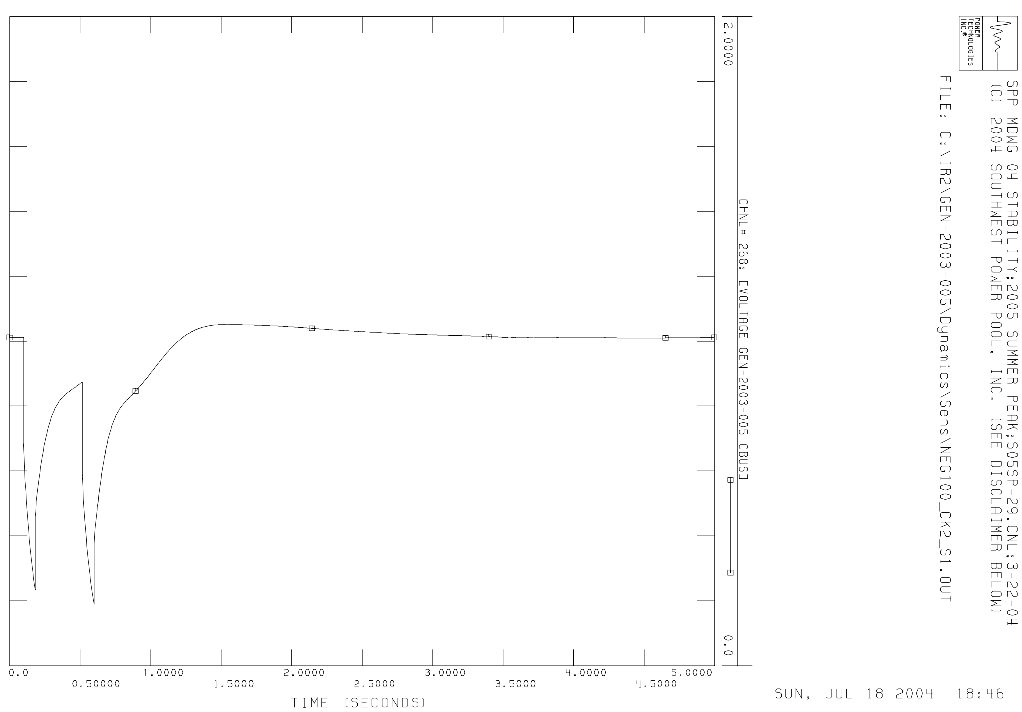


FIGURE 20



An alternative solution to the construction of a second circuit is to design the relaying scheme such that the Interconnection Customer Substation would disconnect from the system at the switching station whenever the Anadarko to Gen-2003-005 Wind Farm 138 kV line was permanently removed from service. With this relaying scheme in place, the transmission system would no longer be dependent on the Interconnection Customer's equipment to operate properly.

Scenarios 1 and 2 were re-evaluated to ensure there would be no problems under this relaying scheme when Anadarko to Gen-2003-005 Wind Farm 138 kV recloses for a temporary fault. The results of this analysis are presented in Figures 21 through 23. Figure 21 shows that the wind turbines remained on line. Figure 22 illustrates that voltage recovered and remained stable at the collector bus in the Interconnection Customer Substation. Figure 23 demonstrates that frequency at the proposed switching station remained stable after the switching was completed. Thus, the alternative relaying scheme maintains transmission system integrity under Scenarios 1 and 2, and it is a viable alternative to the construction of a second circuit from Anadarko to the new switching station.

FIGURE 21

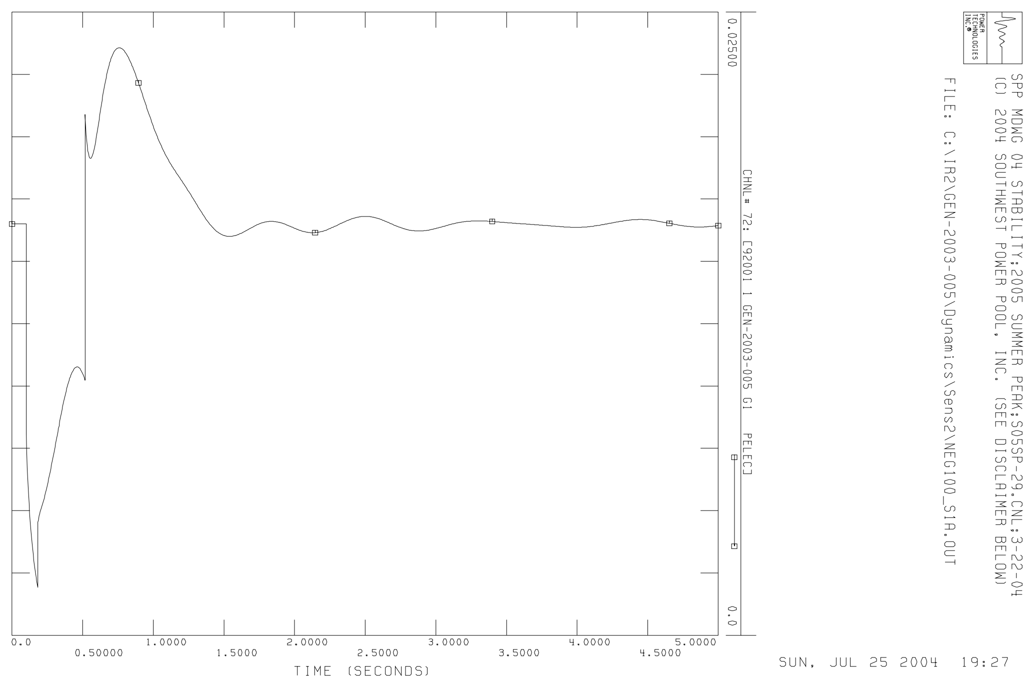


FIGURE 22

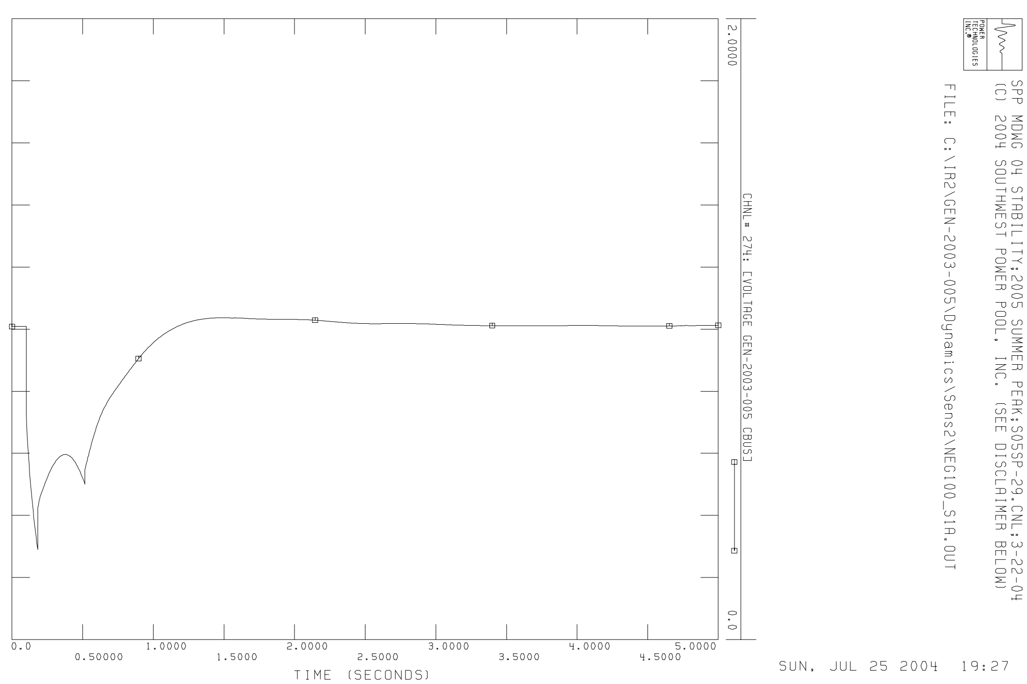
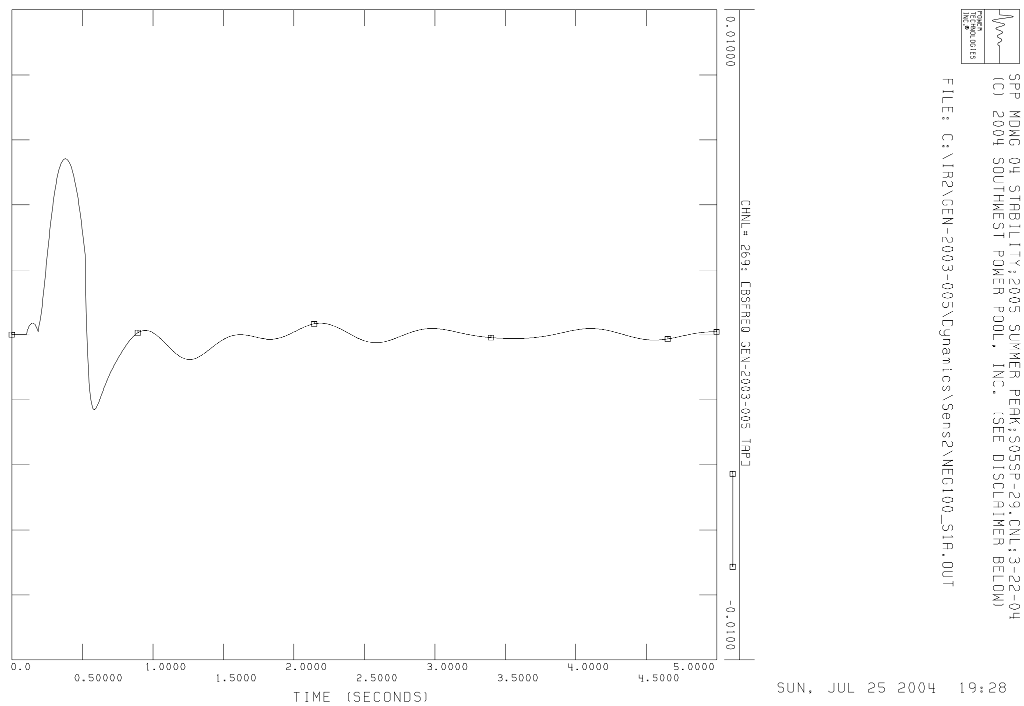


FIGURE 23



IX. Cost Estimate

The estimated cost for building a new switching station with three breakers is $ 1,500,000.00.

The estimated cost for building a 5 mile radial 138 kV line with H-frame construction and 336.4 ACSR 18/1 conductor is $ 1,000,000.00.

The estimated cost for building a 25 mile 138 kV line with H-frame construction parallel to the existing line between the Anadarko Substation and the new switching station with breakers at both terminals is $ 6,000,000.00

See Table 8 below to determine the Network Upgrade and the Direct Assignment cost breakdowns.

TABLE 8

ITEM	DESCRIPTION	ESTIMATE
	NETWORK UPGRADES	
1	New Three breaker switching station	$1,500,000
2a	Optional addition of 25 mile line between Anadarko Substation and new switching station including terminals at both ends.	$6,000,000
2b	Optional relaying scheme	$100,000
	OPTION "A" NETWORK UPGRADE SUBTOTAL	**$7,500,000**
	OPTION "B" NETWORK UPGRADE SUBTOTAL	**$1,600,000**
	DIRECT ASSIGNMENT FACILITIES	
1	Extension of 138 kV line, to wind farm, approx. 5 miles	$1,000,000
2	138/34.5kV Substation, relay & metering systems	*
3	138/34.5kV 3-winding transformer, 130MVA	*
	DIRECT ASSIGNMENT FACILITIES SUBTOTAL	**$1,000,000**
	TOTAL OPTION "A"	**$8,500,000**
	TOTAL OPTION "B"	**$2,600,000**

* TO BE ESTIMATED BY CUSTOMER

X. CONCLUSIONS

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

- The wind turbines are available with adequate VAR compensation to maintain power factors at the interconnection point near or above 98 percent.
- No significant differences were noted between the 80 and 100 MW output levels for either the NEG or GE machines.
- The most significant differences between the GE and NEG machines was the ability of the NEG machines to ride through more low voltages caused by

faults. The GE machines tripped for six of the fault scenarios simulated versus on only two for the NEG machines.

- Loss of the Anadarko to Gen-2003-005 Wind Farm 138 kV resulted in voltage collapse at the switching station as identified in Scenarios 1 and 2.

- A second 138 kV circuit between the Anadarko Substation and the new switching station (see Figure 18) provided sufficient voltage support to allow the wind turbines to remain on-line for the outage of the first circuit.

- A relaying scheme that disconnected the Interconnection Customer Substation from the system at the switching station whenever the Anadarko to Gen-2003-005 Wind Farm 138 kV line was permanently removed from service also proved to be an acceptable solution.

The main concern identified in this study was the voltage collapse that occurred when the Anadarko to Gen-2003-005 Wind Farm 138 kV was removed from service. Even though the voltage recovered after the wind turbines were tripped off-line, the transmission system becomes dependent on the proper operation of the under-voltage relays at the wind farm substation in order to remain whole. This is very undesirable.

Two solutions were evaluated

a. Construction of a second circuit from the Anadarko Substation to the proposed switching station
b. An alternative relaying scheme tripping the Paradise to Customer line when the Customer to Anadarko line is opened

Both solutions proved effective in maintaining the reliability of the transmission system. The second circuit from the Anadarko Substation to the proposed switching station would allow the Interconnection Customer wind turbines to remain on line for all the fault scenarios evaluated. The alternative relaying scheme would result in the Interconnection Customer wind farm being disconnected from the transmission system in Scenarios 1 and 2. In the absence of an operating criteria requiring the wind farm to remain in operation after the Anadarko line segment were lost, the latter solution has a substantial cost advantage over the construction of a second circuit from Anadarko Substation to the proposed switching station.

If any previously queued projects that were included in this study are not constructed, then this System Impact Study may have to be revised to determine the impacts of this Interconnection Customer's project on WFEC transmission facilities. In accordance with FERC and SPP procedures, the study cost for restudy shall be borne by the Interconnection Customer. **The costs do not include any costs associated with the deliverability of the energy to final customers. These costs are determined by separate studies if the Customer requests transmission service through Southwest Power Pool's OASIS.**