Submitted to

Southwest Power Pool

SPP Southwest Power Pool

Report On

GEN-2016-045 and GEN-2016-057 Modification Request Impact Study

Revision R1

Date of Submittal
May 6, 2021

anedenconsulting.com

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

APPENDICES

Revision History

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION
05/06/2021	Aneden Consulting	Initial Report Issued.

Executive Summary

Aneden Consulting (Aneden) was retained by the Southwest Power Pool (SPP) to perform a Modification Request Impact Study (Study) for GEN-2016-045 and GEN-2016-057, two active generation interconnection requests with a point of interconnection (POI) at the Mathewson 345 kV Substation.

The GEN-2016-045 and GEN-2016-057 projects are proposed to interconnect in the Oklahoma Gas & Electric (OKGE) control area with a combined capacity of 998.16 MW as shown in Table ES-1 below. This Study has been requested by the Interconnection Customer to evaluate the modification of GEN-2016-045 and GEN-2016-057 from the previously studied 338 x GE 2.82 MW + 18 x GE 2.5 MW to a turbine configuration of 336 x GE 2.82 MW + 20 x GE 2.5 MW wind turbines for total capacity of 997.52 MW. In addition, the modification request included changes to the collection system, generator step-up transformers, main substation transformer, generation interconnection line, and reactive power devices. The existing and modified configurations for GEN-2016-045 and GEN-2016-057 are shown in Table ES-2 and Table ES-3 respectively.

Table ES-1: GEN-2016-045 & GEN-2016-057 Existing Configuration

Request	Capacity (MW)	Existing Generator Configuration	Point of Interconnection
GEN-2016-045 & GEN-2016-057	998.16	338 x GE 2.8 2MW + 18 x GE 2.5 MW	Mathewson 345 kV Substation (515497)

Table ES-2: GEN-2016-045 & GEN-2016-057 Existing Configuration

Facility	Existing GEN-2016-045 & GEN-2016-057					
	Traverse 1		Traverse 2		Traverse 3	
Point of Interconnection	Mathewson 7 345 kV Substation (515497)					
Configuration/Capacity	338 x GE 2.82MW + 18 x GE 2.5MW = 998.16 MW					
Generation Interconnection Line	Length = 51.5 miles R = 0.001334 pu X = 0.024250 pu B = 0.464678 pu		Length = 21.6 miles R = 0.000904 pu X = 0.010462 pu B = 0.189396 pu		Length = 7.78 miles R = 0.000326 pu X = 0.003768 pu B = 0.068218 pu	
Main Substation Transformers[1]	Transformer T1: X12 = 8.997% R12 = 0.18%, X23 = 4.499% R23 = 0.09%, X13 = 17.996% X13 = 0.359%, Winding MVA = 120 MVA, Rating MVA = 200 MVA	Transformer T2: X12 = 8.997% R12 = 0.18%, X23 = 4.499% R23 = 0.09%, X13 = 17.996% X13 = 0.359%, Winding MVA = 120 MVA, Rating MVA = 200 MVA	Transformer T1: X12 = 8.997% R12 = 0.18%, X23 = 4.499% R23 = 0.09%, X13 = 17.996% X13 = 0.359%, Winding MVA = 120 MVA, Rating MVA = 200 MVA	Transformer T2: X12 = 8.997% R12 = 0.18%, X23 = 4.499% R23 = 0.09%, X13 = 17.996% X13 = 0.359%, Winding MVA = 120 MVA, Rating MVA = 200 MVA	Transformer T1: X12 = 8.997% R12 = 0.18%, X23 = 4.499% R23 = 0.09%, X13 = 17.996% X13 = 0.359%, Winding MVA = 120 MVA, Rating MVA = 200 MVA	Transformer T2: X12 = 8.997% R12 = 0.18%, X23 = 4.499% R23 = 0.09%, X13 = 17.996% X13 = 0.359%, Winding MVA = 120 MVA, Rating MVA = 200 MVA
Equivalent GSU Transformer[1]	Gen 1 Equivalent Qty: 54: X = 7.011% R = 0.698%, Rating 168.7 MVA	Gen 2 Equivalent Qty: 58: X = 7.029% R = 0.7%, Winding MVA = 180.6 MVA Rating MVA = 180.6 MVA	Gen 1 Equivalent Qty: 63: X = 7.024% R = 0.699%, Winding MVA = 196.34 MVA Rating MVA[2] = 196.4 MVA	Gen 2 Equivalent Qty: 59: X = 6.976% R = 0.695%, Winding MVA = 180.5 MVA Rating MVA = 180.5 MVA	Gen 1 Equivalent Qty: 59: X = 6.976% R = 0.695%, Winding MVA = 180.5 MVA Rating MVA = 180.5 MVA	Gen 2 Equivalent Qty: 63: X = 6.966% R = 0.694%, Rating 198.45 MVA Winding MVA = 198.45 MVA Rating MVA[2] = 198.5 MVA

Table ES-2 Continued

Facility	Existing GEN-2016-045 & GEN-2016-057					
	Traverse 1		Traverse 2		Traverse 3	
Equivalent Collector Line[3]	R = 0.005955 pu X = 0.006825 pu B = 0.056912 pu	R = 0.005460 pu X = 0.005780 pu B = 0.062699 pu	R = 0.005487 pu X = 0.006091 pu B = 0.069280 pu	R = 0.006251 pu X = 0.006987 pu B = 0.068995 pu	R = 0.007703 pu X = 0.009181 pu B = 0.084861 pu	R = 0.006239 pu X = 0.007707 pu B = 0.078683 pu
Reactive Power Devices	1 x 60 MVAR 34.5 kV Reactor	1 x 45 MVAR 34.5 kV Reactor	N/A		N/A	

1) X/R based on Winding MVA, 2) Rating rounded up in PSS/E, 3) all pu are on 100 MVA Base

Table ES-3: GEN-2016-045 & GEN-2016-057 Modification Request

Facility	Modification GEN-2016-045 & GEN-2016-057					
	Traverse 1		Traverse 2		Traverse 3	
Point of Interconnection	Mathewson 7 345 kV Substation (515497)					
Configuration/Capacity	336 x GE 2.82 MW + 20 x GE 2.5 MW = 997.52 MW					
Generation Interconnection Line	Traverse 1 to Traverse 2: Length = 6.6 miles R = 0.000170 pu X = 0.003250 pu B = 0.014365 pu		Traverse 2 to TRW2-TRW3: Length = 12.09 miles R = 0.000313 pu X = 0.005950 pu B = 0.105260 pu	TRW2-TRW3 to Traverse 3: Length = 9.96 miles R = 0.000257 pu X = 0.004804 pu B = 0.088052 pu	Traverse 3 to Mathewson: Length = 55.05 miles R = 0.001421 pu X = 0.026554 pu B = 0.486676 pu	
Main Substation Transformers[1]	Transformer T1: X12 = 8.997% R12 = 0.25%, X23 = 4.512% R23 = 0.125%, X13 = 13.495% X13 = 0.376%, Winding MVA = 141 MVA, Rating MVA = 235 MVA	Transformer T2: X12 = 8.997% R12 = 0.25%, X23 = 4.512% R23 = 0.125%, X13 = 13.495% X13 = 0.376%, Winding MVA = 141 MVA, Rating MVA = 235 MVA	Transformer T1: X12 = 8.997% R12 = 0.25%, X23 = 4.512% R23 = 0.125%, X13 = 13.495% X13 = 0.376%, Winding MVA = 141 MVA, Rating MVA = 235 MVA	Transformer T2: X12 = 8.997% R12 = 0.25%, X23 = 4.512% R23 = 0.125%, X13 = 13.495% X13 = 0.376%, Winding MVA = 141 MVA, Rating MVA = 235 MVA	Transformer T1: X12 = 8.997% R12 = 0.25%, X23 = 4.512% R23 = 0.125%, X13 = 13.495% X13 = 0.376%, Winding MVA = 141 MVA, Rating MVA = 235 MVA	
Equivalent GSU Transformer[1]	Gen 1 Equivalent Qty: 71: X = 6.985% R = 0.698%, Winding MVA = 222.94 MVA Rating MVA[2] = 222.9 MVA	Gen 2 Equivalent Qty: 71: X = 6.985% R = 0.698%, Winding MVA = 222.94 MVA Rating MVA[2] = 222.9 MVA	Gen 1 Equivalent Qty: 71: X = 6.985% R = 0.698%, Winding MVA = 222.94 MVA Rating MVA[2] = 222.9 MVA	Gen 2 Equivalent Qty: 71: X = 6.985% R = 0.698%, Winding MVA = 222.94 MVA Rating MVA[2] = 222.9 MVA	Gen 1 Equivalent Qty: 52: X = 6.985% R = 0.698%, Winding MVA = 163.28 MVA Rating MVA[2] = 163.3 MVA	Gen 2 Equivalent Qty: 20: X = 6.478% R = 0.648%, Winding MVA = 56 MVA Rating MVA = 56 MVA
Equivalent Collector Line[3]	R = 0.003139 pu X = 0.005572 pu B = 0.095825 pu	R = 0.002539 pu X = 0.004476 pu B = 0.082206 pu	R = 0.004004 pu X = 0.002989 pu B = 0.074732 pu	R = 0.005401 pu X = 0.003966 pu B = 0.092810 pu	R = 0.005454 pu X = 0.005049 pu B = 0.079552 pu	
Reactive Power Devices	N/A		N/A		1 x 15 MVAR 34.5 kV Reactor 1 x 89.1 MVAR 345kV Capacitor Bank	

1) X/R based on Winding MVA, 2) Rating rounded up in PSS/E, 3) all pu are on 100 MVA Base

SPP determined that power flow should not be performed based on the POI MW injection increase of 0.07%. The modification request retained the same GE wind turbine technology and as such, the equivalent impedances from the POI up to and including the step-up transformers for GEN-2016-045 and GEN-2016-057 were calculated before and after the modification request. The modification request resulted in a change in the equivalent impedances of approximately 16.53%. As a result, SPP determined that the change in impedance required short circuit and dynamic stability analyses.

The scope of this modification request study included charging current compensation analysis, short circuit analysis, and dynamic stability analysis.

Aneden performed the analyses using the modification request data based on the post-modification GEN-2016-003 DISIS-2016-002 Group 1 study models:

1. 2017 Winter Peak (2017WP),
2. 2018 Summer Peak (2018SP),
3. 2026 Summer Peak (2026SP)

All analyses were performed using the PTI PSS/E version 33.7 software and the results are summarized below.

The results of the charging current compensation analysis performed using the 2017 Winter Peak, 2018 Summer Peak, and 2026 Summer Peak models showed that the GEN-2016-045 and GEN-2016-057 projects needed 120.02 MVAr of reactor shunts on the 34.5 kV bus of the project substation, an increase from the 115 MVAr found in the previous Modification Request Impact Study[1]. This is necessary to offset the capacitive effect on the transmission network caused by the project's transmission line and collector system during low-wind or no-wind conditions. The information gathered from the charging current compensation analysis is provided as information to the Interconnection Customer and Transmission Owner and/or Transmission Operator. The applicable reactive power requirements will be addressed by the Interconnection Customer and the Transmission Owner and/or Transmission Operator.

The results from the short circuit analysis with the updated topology showed that the maximum GEN-2016-045 and GEN-2016-057 contribution to three-phase fault currents in the immediate systems at or near GEN-2016-045 and GEN-2016-057 was not greater than 2.01 kA for the 2018SP and 2026SP models. All three-phase fault current levels within 5 buses of the POI with the GEN-2016-045 and GEN-2016-057 generators online were below 52 kA for the 2018SP and 2026SP models.

The dynamic stability analysis was performed using the three post-modification GEN-2016-003 DISIS-2016-002 models 2017 Winter Peak, 2018 Summer Peak, and 2026 Summer Peak. Up to 131 events were simulated, which included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground faults with stuck breakers faults.

The results of the dynamic stability analysis showed that there were no damping or voltage recovery violations observed during the simulated faults. Additionally, the project was found to

[1] GEN-2016-045 and GEN-2016-057 Modification Request Impact Study, January 29, 2020

stay connected during the contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements of FERC Order #661A.

The requested modification has been determined by SPP to not be a Material Modification. The requested modification does not have a material adverse impact on the cost or timing of any other Interconnection Request with a later Queue priority date.

In accordance with FERC Order No. 827, the generating facility will be required to provide dynamic reactive power within the range of 0.95 leading to 0.95 lagging at the high-side of the generator substation.

It is likely that the customer may be required to reduce its generation output to 0 MW in real-time, also known as curtailment, under certain system conditions to allow system operators to maintain the reliability of the transmission network.

Nothing in this study should be construed as a guarantee of transmission service or delivery rights. If the customer wishes to obtain deliverability to final customers, a separate request for transmission service must be requested on Southwest Power Pool's OASIS by the customer.

1.0 Scope of Study

Aneden Consulting (Aneden) was retained by the Southwest Power Pool (SPP) to perform a Modification Request Impact Study (Study) for GEN-2016-045 and GEN-2016-057. A Modification Request Impact Study is a generation interconnection study performed to evaluate the impacts of modifying the DISIS study assumptions. The determination of the required scope of the study is dependent upon the specific modification requested and how it may impact the results of the DISIS study. Impacting the DISIS results could potentially affect the cost or timing of any Interconnection Request with a later Queue priority date, deeming the requested modification a Material Modification. The criteria sections below include reasoning as to why an analysis was either included or excluded from the scope of study.

All analyses were performed using the PTI PSS/E version 33.7 software. The post-modification GEN-2016-003 DISIS-2016-002 Group 1 models were used as the base models for this study. The results of each analysis are presented in the following sections.

1.1 Power Flow

To determine whether power flow analysis is required, SPP evaluates the difference in the real power output at the POI between the existing configuration and the requested modification. Power flow analysis is included if the difference has a significant impact on the results of DISIS study.

1.2 Stability Analysis, Short Circuit Analysis

To determine whether stability and short circuit analyses are required, SPP evaluates the difference between the turbine parameters and, if needed, the collector system impedance between the existing configuration and the requested modification. Dynamic stability analysis and short circuit analysis would be required if the differences listed above were determined to have a significant impact on the most recently performed DISIS stability analysis.

1.3 Charging Current Compensation Analysis

SPP requires that a charging current compensation analysis be performed on the requested modification configuration as it is a non-synchronous resource. The charging current compensation analysis determines the capacitive effect at the POI caused by the project's collector system and transmission line's capacitance. A shunt reactor size is determined in order to offset the capacitive effect and maintain zero (0) MVAr flow at the POI while the plant's generators and capacitors are offline.

1.4 Study Limitations

The assessments and conclusions provided in this report are based on assumptions and information provided to Aneden by others. While the assumptions and information provided may be appropriate for the purposes of this report, Aneden does not guarantee that those conditions assumed will occur. In addition, Aneden did not independently verify the accuracy or completeness of the information provided. As such, the conclusions and results presented in this report may vary depending on the extent to which actual future conditions differ from the assumptions made or information used herein.

2.0 Project and Modification Request

The GEN-2016-045 and GEN-2016-057 Interconnection Customer has requested a modification to its Interconnection Request (IR) with a point of interconnection (POI) at the Mathewson 345 kV Substation. At the time of the posting of this report, GEN-2016-045 and GEN-2016-057 are active Interconnection Requests with queue statuses of "IA FULLY EXECUTED/ON SCHEDULE." Both GEN-2016-045 and GEN-2016-057 are wind farms, and have a combined maximum summer and winter queue capacity of 998.16 MW with Energy Resource Interconnection Service (ERIS).

The GEN-2016-045 and GEN-2016-057 projects were previously studied in a Modification Request Impact Study[2]. Figure 2-1 shows the power flow model single line diagram for the existing GEN-2016-045 and GEN-2016-057 configurations.

The GEN-2016-045 and GEN-2016-057 projects are proposed to interconnect in the Oklahoma Gas & Electric (OKGE) control area with a combined nameplate capacity of 998.16 MW as shown in Table 2-1 below.

Table 2-1: GEN-2016-045 & GEN-2016-057 Existing Configuration

Request	Capacity (MW)	Existing Generator Configuration	Point of Interconnection
GEN-2016-045 & GEN-2016-057	998.16	338 x GE 2.8 2MW + 18 x GE 2.5 MW	Mathewson 345 kV Substation (515497)

This Study has been requested by the Interconnection Customer to evaluate the modification of GEN-2016-045 and GEN-2016-057 from the previously studied 338 x GE 2.82 MW + 18 x GE 2.5 MW to a turbine configuration of 336 x GE 2.82 MW + 20 x GE 2.5 MW wind turbines for total capacity of 997.52 MW. In addition, the modification request included changes to the collection system, generator step-up transformers, main substation transformer, generation interconnection line, and reactive power devices. The existing and modified configurations for GEN 2016-045 and GEN-2016-057 are shown in Table 2-2 and Table 2-3 respectively. Figure 2-2 shows the power flow model single line diagram for the GEN-2016-045 and GEN-2016-057 modification.

[2] GEN-2016-045 and GEN-2016-057 Modification Request Impact Study, January 29, 2020

Figure 2-1: GEN-2016-045 & GEN-2016-057 Single Line Diagram (Existing Configuration)

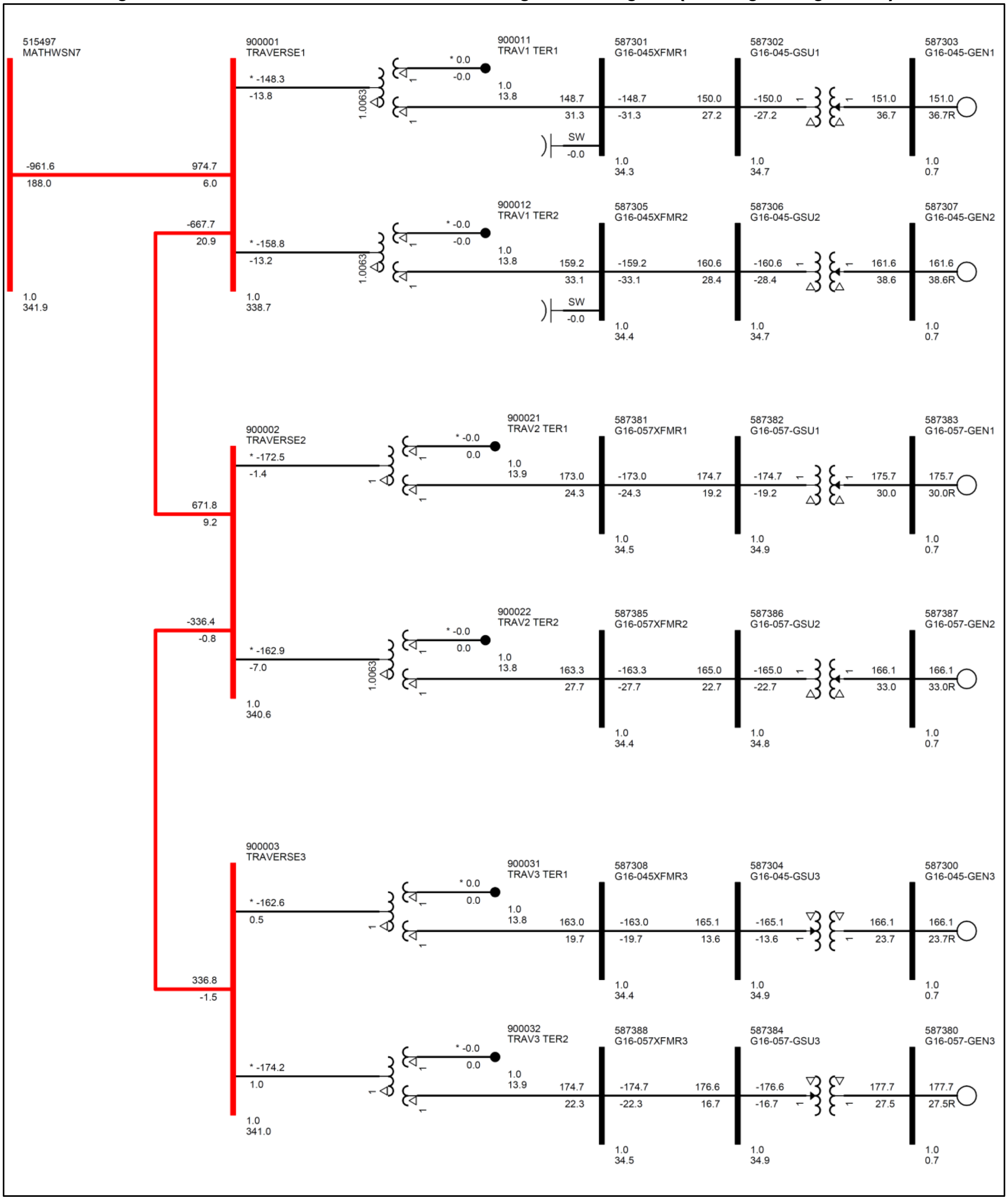


Figure 2-2: GEN-2016-045 & GEN-2016-057 Single Line Diagram (Modification Configuration)

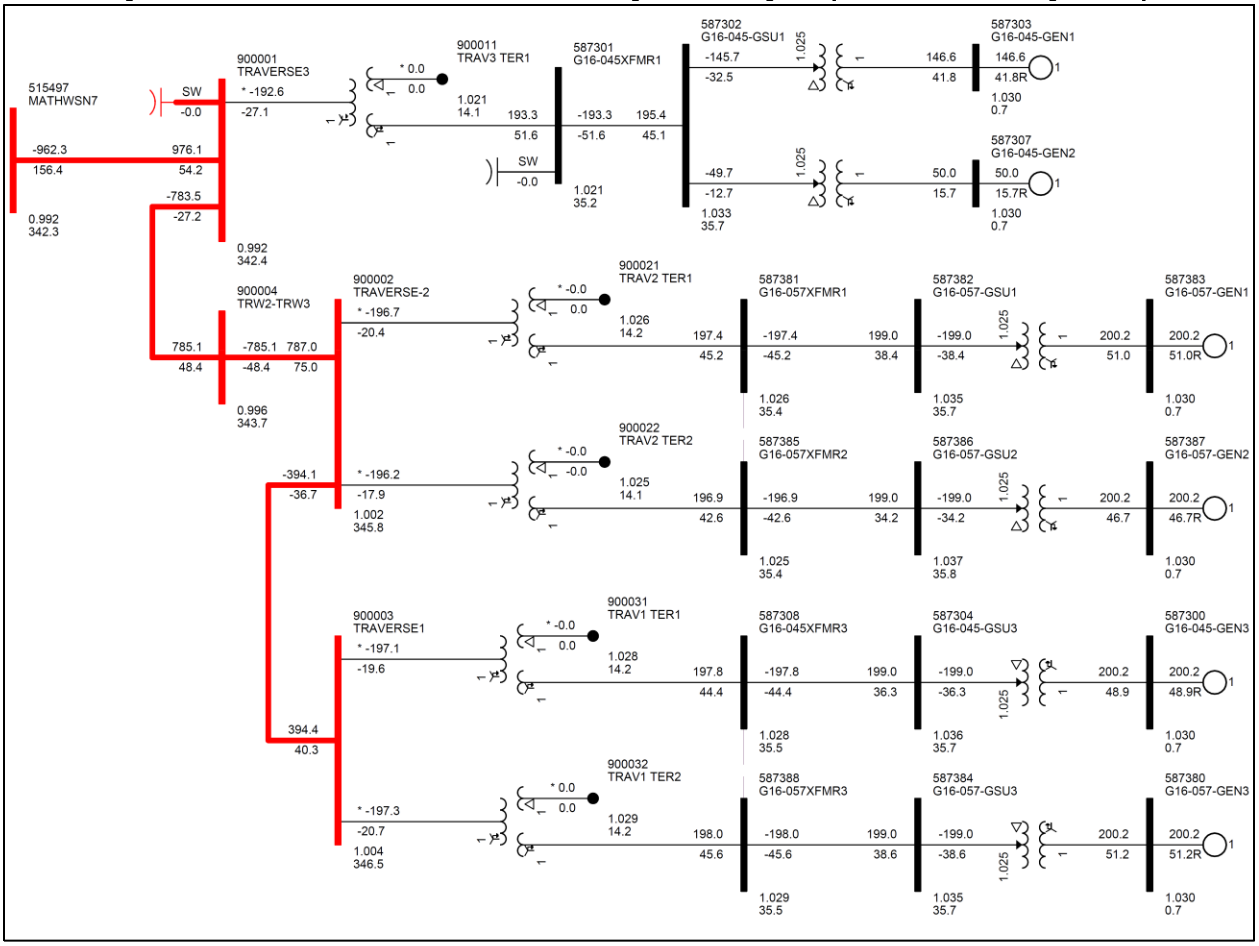


Table 2-2: GEN-2016-045 & GEN-2016-057 Existing Configuration

Facility	Existing GEN-2016-045 & GEN-2016-057					
	Traverse 1		Traverse 2		Traverse 3	
Point of Interconnection	Mathewson 7 345 kV Substation (515497)					
Configuration/Capacity	338 x GE 2.82MW + 18 x GE 2.5MW = 998.16 MW					
Generation Interconnection Line	Length = 51.5 miles R = 0.001334 pu X = 0.024250 pu B = 0.464678 pu		Length = 21.6 miles R = 0.000904 pu X = 0.010462 pu B = 0.189396 pu		Length = 7.78 miles R = 0.000326 pu X = 0.003768 pu B = 0.068218 pu	
Main Substation Transformers[1]	<u>Transformer T1:</u> X12 = 8.997% R12 = 0.18%, X23 = 4.499% R23 = 0.09%, X13 = 17.996% X13 = 0.359%, Winding MVA = 120 MVA, Rating MVA = 200 MVA	<u>Transformer T2:</u> X12 = 8.997% R12 = 0.18%, X23 = 4.499% R23 = 0.09%, X13 = 17.996% X13 = 0.359%, Winding MVA = 120 MVA, Rating MVA = 200 MVA	<u>Transformer T1:</u> X12 = 8.997% R12 = 0.18%, X23 = 4.499% R23 = 0.09%, X13 = 17.996% X13 = 0.359%, Winding MVA = 120 MVA, Rating MVA = 200 MVA	<u>Transformer T2:</u> X12 = 8.997% R12 = 0.18%, X23 = 4.499% R23 = 0.09%, X13 = 17.996% X13 = 0.359%, Winding MVA = 120 MVA, Rating MVA = 200 MVA	<u>Transformer T1:</u> X12 = 8.997% R12 = 0.18%, X23 = 4.499% R23 = 0.09%, X13 = 17.996% X13 = 0.359%, Winding MVA = 120 MVA, Rating MVA = 200 MVA	<u>Transformer T2:</u> X12 = 8.997% R12 = 0.18%, X23 = 4.499% R23 = 0.09%, X13 = 17.996% X13 = 0.359%, Winding MVA = 120 MVA, Rating MVA = 200 MVA
Equivalent GSU Transformer[1]	Gen 1 Equivalent Qty: 54: X = 7.011% R = 0.698%, Rating 168.7 MVA	Gen 2 Equivalent Qty: 58: X = 7.029% R = 0.7%, Winding MVA = 180.6 MVA Rating MVA = 180.6 MVA	Gen 1 Equivalent Qty: 63: X = 7.024% R = 0.699%, Winding MVA = 196.34 MVA Rating MVA[2] = 196.4 MVA	Gen 2 Equivalent Qty: 59: X = 6.976% R = 0.695%, Winding MVA = 180.5 MVA Rating MVA = 180.5 MVA	Gen 1 Equivalent Qty: 59: X = 6.976% R = 0.695%, Winding MVA = 180.5 MVA Rating MVA = 180.5 MVA	Gen 2 Equivalent Qty: 63: X = 6.966% R = 0.694%, Rating 198.45 MVA Winding MVA = 198.45 MVA Rating MVA[2] = 198.5 MVA
Equivalent Collector Line[3]	R = 0.005955 pu X = 0.006825 pu B = 0.056912 pu	R = 0.005460 pu X = 0.005780 pu B = 0.062699 pu	R = 0.005487 pu X = 0.006091 pu B = 0.069280 pu	R = 0.006251 pu X = 0.006987 pu B = 0.068995 pu	R = 0.007703 pu X = 0.009181 pu B = 0.084861 pu	R = 0.006239 pu X = 0.007707 pu B = 0.078683 pu
Reactive Power Devices	1 x 60 MVAR 34.5 kV Reactor	1 x 45 MVAR 34.5 kV Reactor	N/A		N/A	

1) X/R based on Winding MVA, 2) Rating rounded up in PSS/E, 3) all pu are on 100 MVA Base

Table 2-3: GEN-2016-045 & GEN-2016-057 Modification Request

<table>
<tr><th rowspan="2">Facility</th><th colspan="6">Modification GEN-2016-045 & GEN-2016-057</th></tr>
<tr><th colspan="2">Traverse 1</th><th colspan="2">Traverse 2</th><th colspan="2">Traverse 3</th></tr>
<tr><td>Point of Interconnection</td><td colspan="6">Mathewson 7 345 kV Substation (515497)</td></tr>
<tr><td>Configuration/Capacity</td><td colspan="6">336 x GE 2.82 MW + 20 x GE 2.5 MW = 997.52 MW</td></tr>
<tr><td>Generation Interconnection Line</td><td colspan="2"><u>Traverse 1 to Traverse 2:</u>
Length = 6.6 miles
R = 0.000170 pu
X = 0.003250 pu
B = 0.014365 pu</td><td><u>Traverse 2 to TRW2-TRW3:</u>
Length = 12.09 miles
R = 0.000313 pu
X = 0.005950 pu
B = 0.105260 pu</td><td><u>TRW2-TRW3 to Traverse 3:</u>
Length = 9.96 miles
R = 0.000257 pu
X = 0.004804 pu
B = 0.088052 pu</td><td colspan="2"><u>Traverse 3 to Mathewson:</u>
Length = 55.05 miles
R = 0.001421 pu
X = 0.026554 pu
B = 0.486676 pu</td></tr>
<tr><td>Main Substation Transformers[1]</td><td><u>Transformer T1:</u>
X12 = 8.997% R12 = 0.25%, X23 = 4.512% R23 = 0.125%, X13 = 13.495% X13 = 0.376%, Winding MVA = 141 MVA, Rating MVA = 235 MVA</td><td><u>Transformer T2:</u>
X12 = 8.997% R12 = 0.25%, X23 = 4.512% R23 = 0.125%, X13 = 13.495% X13 = 0.376%, Winding MVA = 141 MVA, Rating MVA = 235 MVA</td><td><u>Transformer T1:</u>
X12 = 8.997% R12 = 0.25%, X23 = 4.512% R23 = 0.125%, X13 = 13.495% X13 = 0.376%, Winding MVA = 141 MVA, Rating MVA = 235 MVA</td><td><u>Transformer T2:</u>
X12 = 8.997% R12 = 0.25%, X23 = 4.512% R23 = 0.125%, X13 = 13.495% X13 = 0.376%, Winding MVA = 141 MVA, Rating MVA = 235 MVA</td><td colspan="2"><u>Transformer T1:</u>
X12 = 8.997% R12 = 0.25%, X23 = 4.512% R23 = 0.125%, X13 = 13.495% X13 = 0.376%, Winding MVA = 141 MVA, Rating MVA = 235 MVA</td></tr>
<tr><td>Equivalent GSU Transformer[1]</td><td>Gen 1 Equivalent Qty: 71:
X = 6.985% R = 0.698%, Winding MVA = 222.94 MVA
Rating MVA[2] = 222.9 MVA</td><td>Gen 2 Equivalent Qty: 71:
X = 6.985% R = 0.698%, Winding MVA = 222.94 MVA
Rating MVA[2] = 222.9 MVA</td><td>Gen 1 Equivalent Qty: 71:
X = 6.985% R = 0.698%, Winding MVA = 222.94 MVA
Rating MVA[2] = 222.9 MVA</td><td>Gen 2 Equivalent Qty: 71:
X = 6.985% R = 0.698%, Winding MVA = 222.94 MVA
Rating MVA[2] = 222.9 MVA</td><td>Gen 1 Equivalent Qty: 52:
X = 6.985% R = 0.698%, Winding MVA = 163.28 MVA
Rating MVA[2] = 163.3 MVA</td><td>Gen 2 Equivalent Qty: 20:
X = 6.478% R = 0.648%, Winding MVA = 56 MVA
Rating MVA = 56 MVA</td></tr>
<tr><td>Equivalent Collector Line[3]</td><td>R = 0.003139 pu
X = 0.005572 pu
B = 0.095825 pu</td><td>R = 0.002539 pu
X = 0.004476 pu
B = 0.082206 pu</td><td>R = 0.004004 pu
X = 0.002989 pu
B = 0.074732 pu</td><td>R = 0.005401 pu
X = 0.003966 pu
B = 0.092810 pu</td><td colspan="2">R = 0.005454 pu
X = 0.005049 pu
B = 0.079552 pu</td></tr>
<tr><td>Reactive Power Devices</td><td colspan="2">N/A</td><td colspan="2">N/A</td><td colspan="2">1 x 15 MVAR 34.5 kV Reactor
1 x 89.1 MVAR 345kV Capacitor Bank</td></tr>
</table>

1) X/R based on Winding MVA, 2) Rating rounded up in PSS/E, 3) all pu are on 100 MVA Base

3.0 Existing vs Modification Comparison

To determine which analyses are required for the Study, the differences between the existing configuration and the requested modification were evaluated.

Aneden performed this comparison and the resulting analyses using a set of modified study models developed based on the modification request data and the post-modification GEN-2016-003 DISIS-2016-002 Group 1 study models.

The methodology and results of the comparisons are described below. The analysis was completed using PSS/E version 33.7 software.

3.1 POI Injection Comparison

The real power injection at the POI was determined using PSS/E to compare the existing configuration and the requested modifications for GEN-2016-045 and GEN-2016-057. The percentage change in the POI injection before and after the modification request was then compared. If the MW difference was determined to be significant, power flow analysis would be performed to assess the impact of the modification request.

SPP determined that power flow analysis was not required due to the insignificant change (increase of 0.07%) in the real power output at the POI between the existing configuration and requested modification shown in Table 3-1.

Table 3-1: GEN-2016-045 & GEN-2016-057 POI Injection Comparison

Interconnection Request	Existing POI Injection from Project (MW)	Modification POI Injection from Project (MW)	POI Injection Difference from Project %
GEN-2016-045 & GEN-2016-057	961.6	962.3	0.07%

3.2 Equivalent Impedance Comparison Calculation

The impedances from all the components of the transmission lines, substation and step-up transformers, and equivalent collector line impedances were added in series for GEN-2016-045 and GEN-2016-057 before and after the modification request. The percentage increase in the impedances before and after the modification request were then compared. If the percentage increase was greater than 10%, additional dynamic stability analysis and short circuit analysis would be performed to determine the impact of the requested modification. Table 3-2 shows the impedance differences before and after the modification request. Table 3-3 shows the increases in impedances from the original impedances to the modification request impedances.

Table 3-2: GEN-2016-045 & GEN-2016-057 Impedance Comparisons

System Component	Existing Model Impedances (p.u.)			Modification Request Impedances (p.u.)		
	R	***X***		***R***	***X***	
Gen Tie Line from POI to GEN-2016-045/057	0.00113	0.01863		0.00074	0.01388	
GEN-2016-045/057 collector system equivalent	0.00618	0.00711		0.00410	0.00441	
	R	***X***	***MVA Base***	***R***	***X***	***MVA Base***
GEN-2016-045/057 Main Transformer @ 100 MVA	0.00025	0.01250	100	0.00035	0.01276	100
GEN-2016-045/057 Unit GSU @ 100 MVA Base	0.0006	0.0063	100	0.00063	0.00628	100
	R	***X***	***Z***	***R***	***X***	***Z***
Total Impedance from POI to Generator terminal	0.008189	0.044514	0.045261	0.005822	0.037328	0.037779

Table 3-3: GEN-2016-045 & GEN-2016-057 Combined Impedance Comparison

Interconnection Request	Existing Impedance Z (p.u.)	Modification Impedance Z (p.u.)	Impedance Z Absolute Difference %
GEN-2016-045 & GEN-2016-057 Impedance Change	0.045261	0.037779	16.53%

SPP determined that the change in impedance (16.53%) has the potential to alter the project impact and would require dynamic stability analysis and short circuit analysis to be performed to determine the impact of the requested modification.

3.3 Turbine Parameters Comparison

The turbine changes were from GE turbines to GE turbines. The generator dynamic model for the modification can be found in Appendix A.

As short circuit and dynamic stability analyses were required due to the equivalent impedance comparison, a turbine parameters comparison was not needed for the determination of the scope of the study.

4.0 Charging Current Compensation Analysis

The charging current compensation analysis was performed for GEN-2016-045 and GEN-2016-057 to determine the capacitive charging effects during reduced generation conditions (unsuitable wind speeds, unsuitable solar irradiance, insufficient state of charge, idle conditions, curtailment, etc.) at the generation site and to size shunt reactors that would reduce the project reactive power contribution to the POI to approximately zero.

4.1 Methodology and Criteria

The GEN-2016-045 and GEN-2016-057 generators and capacitors (if any) were switched out of service while other collection system elements remained in-service. A shunt reactor was tested at the project's collection substation 34.5 kV bus to set the MVAr flow into the POI to approximately zero. The size of the shunt reactor is equivalent to the charging current value at unity voltage and the compensation provided is proportional to the voltage effects on the charging current (i.e. for voltages above unity, reactive compensation is greater than the size of the reactor).

4.2 Results

The results from the analysis showed that the GEN-2016-045 and GEN-2016-057 project needed an approximately 120.02 MVAr shunt reactor at the project substation, to reduce the POI MVAr to zero. This is an increase from the 115 MVAr found in the previous Modification Request Impact Study[3]. Figure 4-1 illustrates the shunt reactor size needed to reduce the POI MVAr to approximately zero with the updated topology. The final shunt reactor requirement for GEN-2016-045 and GEN-2016-057 is shown in Table 4-1.

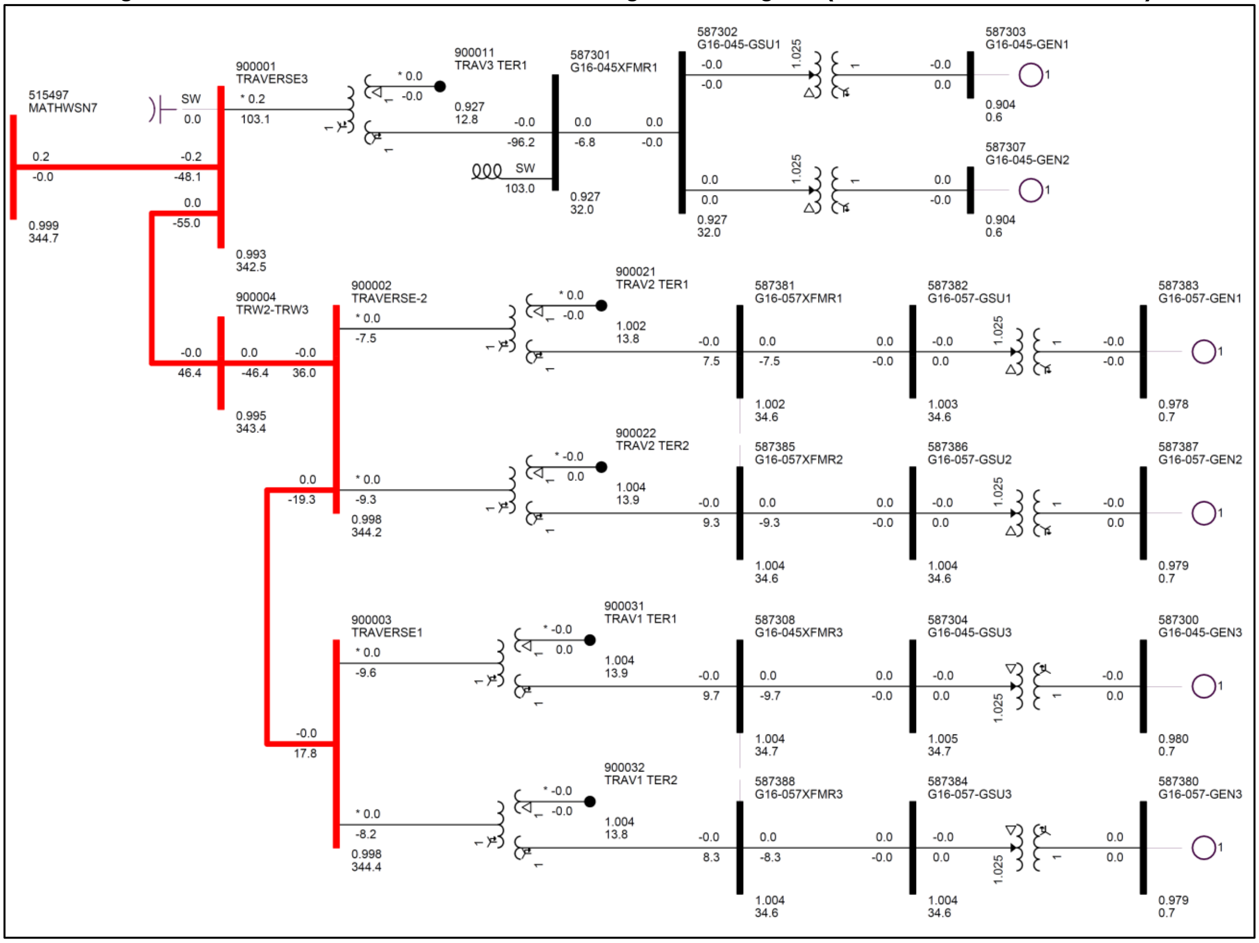
The information gathered from the charging current compensation analysis is provided as information to the Interconnection Customer and Transmission Owner and/or Transmission Operator. The applicable reactive power requirements will be addressed by the Interconnection Customer and the Transmission Owner and/or Transmission Operator.

Table 4-1: Shunt Reactor Size for Low Wind Study (Modification)

Machine	POI Bus Number	POI Bus Name	Reactor Size (MVAr)		
			17WP	18SP	26SP
GEN-2016-045 & GEN-2016-057	515497	Mathewson 345 kV	120.02	120.02	120.02

[3] GEN-2016-045 and GEN-2016-057 Modification Request Impact Study, January 29, 2020

Figure 4-1: GEN-2016-045 & GEN-2016-057 Single Line Diagram (Modification Shunt Reactor)



5.0 Short Circuit Analysis

A short circuit study was performed using the 2018SP and 2026SP models for GEN-2016-045 and GEN-2016-057. The detailed results of the short circuit analysis are provided in Appendix B.

5.1 Methodology

The short circuit analysis included applying a 3-phase fault on buses up to 5 levels away from the 345 kV POI bus. The PSS/E "Automatic Sequence Fault Calculation (ASCC)" fault analysis module was used to calculate the fault current levels with and without GEN-2016-045 and GEN-2016-057 online.

5.2 Results

The results of the short circuit analysis for the 2018SP and 2026SP models are summarized in Table 5-1 through Table 5-3 respectively. The GEN-2016-045 and GEN-2016-057 POI bus fault current magnitudes are provided in Table 5-1 showing a maximum fault current of 32.52 kA.

The maximum fault current calculated within 5 buses of the GEN-2016-045 and GEN-2016-057 POI was less than 52 kA for the 2018SP and 2026SP models respectively. The maximum GEN-2016-045 and GEN-2016-057 contribution to three-phase fault current was about 6.6% and 2.01 kA.

Table 5-1: POI Short Circuit Results

Case	GEN-OFF Current (kA)	GEN-ON Current (kA)	Max kA Change	Max %Change
2018SP	30.52	32.52	2.00	6.6%
2026SP	30.49	32.50	2.01	6.6%

Table 5-2: 2018SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	10.6	0.00	0.0%
138	49.9	0.39	0.9%
345	33.3	2.00	6.6%
Max	**49.9**	**2.00**	**6.6%**

Table 5-3: 2026SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	10.8	0.00	0.0%
138	51.2	0.40	0.9%
345	33.2	2.01	6.6%
Max	**51.2**	**2.01**	**6.6%**

6.0 Dynamic Stability Analysis

Aneden performed a dynamic stability analysis to identify the impact of the turbine configuration change and other modifications to the GEN-2016-045 and GEN-2016-057 project. The analysis was performed according to SPP's Disturbance Performance Requirements shown in Appendix C. The modification details are described in Section 2.0 above and the dynamic modeling data is provided in Appendix A. The simulation plots can be found in Appendix D.

6.1 Methodology and Criteria

The dynamic stability analysis was performed using models developed with the requested 336 x GE 2.82 MW (REGCAU1) + 20 x GE 2.5 MW (REGCAU1) configuration for the GEN-2016-045 and GEN-2016-057 generating facilities. This stability analysis was performed using PTI's PSS/E version 33.7 software.

The stability models were developed using the post-modification GEN-2016-003 DISIS-2016-002 Group 1 models. The modifications requested for the GEN-2016-045 and GEN-2016-057 projects were used to create modified stability models for this impact study. In addition, the following system adjustments were made to address existing base case issues:

1. Disabled tripping for withdrawn project GEN-2015-084
2. Adjusted the GEN-2015-048 Qgen from 0 MVAR to 20 MVAR in the 17WP case to be consistent with the 18Sp and 26 SP cases

The modified dynamics model data for the DISIS-2016-001 Group 1 request, GEN-2016-045 and GEN-2016-057, is provided in Appendix A. The modified power flow models and associated dynamics database were initialized (no-fault test) to confirm that there were no errors in the initial conditions of the system and the dynamic data.

During the fault simulations, the active power (PELEC), reactive power (QELEC), and terminal voltage (ETERM) were monitored for GEN-2016-045 and GEN-2016-057 and other equally and prior queued projects in Group 1. In addition, voltages of five (5) buses away from the POI of GEN-2016-045 and GEN-2016-057 were monitored and plotted. The machine rotor angle for synchronous machines and speed for asynchronous machines within this study area including 520 (AEPW), 524 (OKGE), 525 (WFEC), 526 (SPS), 531 (MIDW), 534 (SUNC), 536 (WERE) were monitored. In addition, the voltages of all 100 kV and above buses within the study area were monitored.

6.2 Fault Definitions

Aneden simulated the faults previously simulated for GEN-2016-045 and GEN-2016-057 and selected additional fault events for GEN-2016-045 and GEN-2016-057 as required. The new set of faults were simulated using the modified study models. The fault events included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground faults with stuck breakers. The simulated faults are listed and described in Table 6-1 below. These contingencies were applied to the modified 2017 Winter Peak, 2018 Summer Peak, and the 2026 Summer Peak models.

Table 6-1: Fault Definitions

Fault ID	Planning Event	Fault Descriptions
FLT02-3PH	P1	3 phase fault on CIMARON7 345 kV (514901) to NORTWST7 345 kV (514880) line CRT 1, near CIMARON7. a. Apply fault at the CIMARON7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT03-3PH	P1	3 phase fault on CIMARON7 345 kV (514901) to MINCO 7 345 kV (514801) line CRT 1, near CIMARON7. a. Apply fault at the CIMARON7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT04-3PH	P1	3 phase fault on CIMARON7 345 kV (514901) to DRAPER 7 345 kV (514934) line CRT 1, near CIMARON7. a. Apply fault at the CIMARON7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT05-3PH	P1	3 phase fault on the CIMARON7 345 kV (514901) to CIMARON4 138 kV (514898) to CIMARO11 13.8 kV (515714) XFMR CRT 1, near CIMARON7 345 kV. a. Apply fault at the CIMARON7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT20-SB	P4	**Stuck Breaker at CIMARON7 (514901)** a. Apply single phase fault at CIMARON7 bus. b. Clear fault after 16 cycles and trip the following elements c. CIMARON7 (514901) - MATHWSN7 (515497) 345kV line CKT 1 d. CIMARON7 345 kV (514901) / CIMARON4 138 kV (514898) / CIMARON11 13.8 kV (515714) transformer CKT 1.
FLT43-3PH	P1	3 phase fault on WWRDEHV7 345 kV (515375) to THISTLE7 345 kV (539801) line CKT1, near WWRDEHV7. a. Apply fault at the WWRDEHV7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT44-3PH	P1	3 phase fault on WWRDEHV7 345 kV (515375) to BORDER 7 345 kV (515458) line CKT1, near WWRDEHV7. a. Apply fault at the WWRDEHV7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT45-3PH	P1	3 phase fault on WWRDEHV7 345 kV (515375) to WWRDEHV4 138 kV (515376) to WWDEHV31 13.8 kV (515795) XFMR CKT1, near WWRDEHV7 345 kV. a. Apply fault at the WWRDEHV7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT65-3PH	P1	3 phase fault on MATHWSN7 345 kV (515497) to TATONGA7 345 kV (515407) line CKT1, near MATHWSN7. a. Apply fault at the MATHWSN7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT67-3PH	P1	3 phase fault on MATHWSN7 345 kV (515497) to NORTWST7 345 kV (514880) line CKT1, near MATHWSN7. a. Apply fault at the MATHWSN7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT68-3PH	P1	3 phase fault on NORTWST7 345 kV (514880) to NORTWST4 138 kV (514879) to NORTWS41 13.8 kV (514885) XFMR CKT1, near NORTWST7 345 kV. a. Apply fault at the NORTWST7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT69-3PH	P1	3 phase fault on NORTWST7 345 kV (514880) to ARCADIA7 345 kV (514908) line CKT1, near NORTWST7. a. Apply fault at the NORTWST7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT70-3PH	P1	3 phase fault on NORTWST7 345 kV (514880) to SPRNGCK7 345 kV (514881) line CKT1, near NORTWST7. a. Apply fault at the NORTWST7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT75-3PH	P1	3 phase fault on MATHWSN7 345 kV (515497) to CIMARON7 345 kV (514901) line CKT 1, near MATHWSN7. a. Apply fault at the MATHWSN7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT04-PO1	P6	**Prior Outage of CIMARON7 345 kV (514901) to NORTWST7 345 kV (514880) line;** 3 phase fault on CIMARON7 345 kV (514901) to DRAPER 7 345 kV (514934) line CKT 1, near CIMARON7. a. Apply fault at the CIMARON7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT05-PO2	P6	**Prior Outage of CIMARON7 345 kV (514901) to MINCO 7 345 kV (514801) line;** 3 phase fault on the CIMARON7 345 kV (514901) to CIMARON4 138 kV (514898) to CIMARO11 13.8 kV (515714) XFMR CKT 1, near CIMARON7 345 kV. a. Apply fault at the CIMARON7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT45-PO3	P6	**Prior Outage of WWRDEHV7 345 kV (515375) to THISTLE7 345 kV (539801) CKT1 line;** 3 phase fault on WWRDEHV7 345 kV (515375) to WWRDEHV4 138 kV (515376) to WWDEHV31 13.8 kV (515795) XFMR CKT 1, near WWRDEHV7 345 kV. a. Apply fault at the WWRDEHV7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT75-PO4	P6	**Prior Outage of MATHWSN7 345 kV (515497) to NORTWST7 345 kV (514880) line;** 3 phase fault on CIMARON7 345 kV (514901) to MATHWSN7 345 kV (515497) line CKT 1, near MATHWSN7. a. Apply fault at the MATHWSN7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9001-3PH	P1	3 phase fault on TATONGA7 345 kV (515407) to SLNGWND7 345 kV (515582) line CKT 1, near TATONGA7. a. Apply fault at the TATONGA7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. **Trip generator SELIG WTG1 (599059), generator SILNGWG1 (515587).** c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9002-3PH	P1	3 phase fault on TATONGA7 345 kV (515407) to CRSRDSW7 345 kV (515448) line CKT 1, near TATONGA7. a. Apply fault at the TATONGA7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. **Trip generator CRSRD-WTG1 (599099) generator CRSRD-WTG2 (599101) and CRSRDX-WTG2 (599103).** c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9003-3PH	P1	3 phase fault on TATONGA7 345 kV (515407) to WWRDEHV 345 kV (515375) line CRT 1, near TATONGA7. a. Apply fault at the TATONGA7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT9004-3PH	P1	3 phase fault on TATONGA7 345 kV (515407) to GEN-2015-029 345 kV (584700) line CRT 1, near TATONGA7. a. Apply fault at the TATONGA7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. **Trip generator G15-029-GEN1 (584703).** c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9005-3PH	P1	3 phase fault on TATONGA7 345 kV (515407) to MAMTHPW7 345 kV (515585) line CRT 1, near TATONGA7. a. Apply fault at the TATONGA7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. **Trip generator MMTHPLN_GEN (599136).** c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9006-3PH	P1	3 phase fault on WWRDEHV7 345 kV (515375) to G07621119-20 345 kV (515599) line CRT 1, near WWRDEHV7. a. Apply fault at the WWRDEHV7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. **Trip generators GW_WTG11 (585413), GW_WTG12 (585414), GW_WTG22 (585418), GW_WTG21 (585417), CB_WTG1 (585423), CB_WTG2 (585426), PC1_WTG2 (585436), PC1_WTG1 (585433), PC2_WTG1 (585443) and PC2_WTG2 (585446).** c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9007-3PH	P1	3 phase fault on WWRDEHV7 345 kV (515375) to G16-003-TAP 345 kV (560071) line CRT 1, near WWRDEHV7. a. Apply fault at the WWRDEHV7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9008-3PH	P1	3 phase fault on WWRDEHV4 138 kV (515376) to IODINE-4 138 kV (514796) line CRT 1, near WWRDEHV4. a. Apply fault at the WWRDEHV4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9009-3PH	P1	3 phase fault on WWRDEHV4 138 kV (515376) to WWDPST 4 138 kV (515425) line CRT 1, near WWRDEHV4. a. Apply fault at the WWRDEHV4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9010-3PH	P1	3 phase fault on WWRDEHV4 138 kV (515376) to KEENAN 4 138 kV (515394) line CRT 1, near WWRDEHV4. a. Apply fault at the WWRDEHV4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. **Trip generators KEENAN-WTG1 (599064) and KEENAN-WTG2 (599065)** c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9011-3PH	P1	3 phase fault on WWRDEHV4 138 kV (515376) to OUSPRT 4 138 kV (515398) line CRT 1, near WWRDEHV4. a. Apply fault at the WWRDEHV4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. **Trip generator OUSPRT-WTG1 (599081).** c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9017-3PH	P1	3 phase fault on MATHWSN7 345 kV (515497) to REDNGTN7 345 kV (515875) line CRT 1, near MATHWSN7. a. Apply fault at the MATHWSN7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT9018-3PH	P1	3 phase fault on REDNGTN7 345 kV (515875) to WOODRNG7 345 kV (514715) line CRT 1, near REDNGTN7. a. Apply fault at the REDNGTN7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9019-3PH	P1	3 phase fault on REDNGTN7 345 kV (515875) to REDDIRT7 345 kV (515877) line CRT 1, near REDNGTN7. a. Apply fault at the REDNGTN7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. **Trip generator RDDRTG11 (515882), RDDRTG21 (515883).** c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9020-3PH	P1	3 phase fault on WOODRNG7 345 kV (514715) to HUNTERS7 345 kV (515476) line CRT 1, near WOODRNG7. a. Apply fault at the WOODRNG7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9021-3PH	P1	3 phase fault on the WOODRNG7 345 kV (514715) to WOODRNG4 138 kV (514714) to WOODRNG1 13.8 kV (515770) XFMR CRT 1, near WOODRNG7 345 kV. a. Apply fault at the WOODRNG7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT9022-3PH	P1	3 phase fault on WOODRNG7 345 kV (514715) to G16-061-TAP 345 kV (560084) line CRT 1, near WOODRNG7. a. Apply fault at the WOODRNG7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9023-3PH	P1	3 phase fault on WOODRNG7 345 kV (514715) to GEN-2016-068 345 kV (587460) line CRT 1, near WOODRNG7. a. Apply fault at the WOODRNG7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. **Trip generators G16-068-GEN1 (587463) and G16-068-GEN1 (587466).** c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9024-3PH	P1	3 phase fault on WOODRNG7 345 kV (514715) to GEN-2016-128 345 kV (588190), near WOODRNG7. a. Apply fault at the WOODRNG7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. **Trip generator G16-128-GEN1 (588193).** c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9025-3PH	P1	3 phase fault on CIMARON7 345 kV (514901) to FSHRTAP7 345 kV (515610) line CRT 1, near CIMARON7. a. Apply fault at the CIMARON7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. **Trip generators KNGFSHR-GEN1 (599122), KNGFSHR-GEN2 (599124), CANDIAN_WTG1 (599114) and CANDIAN_WTG2 (599116).** c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9026-3PH	P1	3 phase fault on FSHRTAP7 345 kV (515610) to CANADN7 345 kV (515605) line CRT 1, near FSHRTAP7. a. Apply fault at the FSHRTAP7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. **Trip generators CANDIAN_WTG1 (599114) and CANDIAN_WTG2 (599116).** c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9027-3PH	P1	3 phase fault on FSHRTAP7 345 kV (515610) to KNGFSHR7 345 kV (515600) line CRT 1, near FSHRTAP7. a. Apply fault at the FSHRTAP7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. **Trip generators KNGFSHR-GEN1 (599122) and KNGFSHR-GEN2 (599124).** c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT9028-3PH	P1	3 phase fault on MINCO 7 345 kV (514801) to GRACMNT7 345 kV (515800) line CRT 1, near MINCO 7. a. Apply fault at the MINCO 7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9029-3PH	P1	3 phase fault on MINCO 7 345 kV (514801) to MNCWND37 345 kV (515549) line CRT 1, near MINCO 7. a. Apply fault at the MINCO 7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. **Trip generators MINCO-WTG3 (599117), G14-056-GEN2 (584064), MNCO4G11 (515943), G15-057-GEN2 (584954), G15-057-GEN1 (584953) and G15-057-GEN3 (584955).** c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9030-3PH	P1	3 phase fault on MINCO 7 345 kV (514801) to MCNOWND7 345 kV (515444) line CRT 1, near MINCO 7. a. Apply fault at the MINCO 7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. **Trip generator MINCO-WTG1 (599062).** c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9031-3PH	P1	3 phase fault on the DRAPER 7 345 kV (514934) to DRAPER 4 138 kV (514933) to DRAPER21 13.8 kV (515792) XFMR CRT 1, near DRAPER 7 345 kV. a. Apply fault at the DRAPER 7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT9032-3PH	P1	3 phase fault on DRAPER 7 345 kV (514934) to SEMINOL7 345 kV (515045) line CRT 1, near DRAPER 7. a. Apply fault at the DRAPER 7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9033-3PH	P1	3 phase fault on DRAPER 4 138 kV (514933) to GM 4 138 kV (514961) line CRT 1, near DRAPER 4. a. Apply fault at the DRAPER 4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9034-3PH	P1	3 phase fault on DRAPER 4 138 kV (514933) to BARNES 4 138 kV (515003) line CRT 1, near DRAPER 4. a. Apply fault at the DRAPER 4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9035-3PH	P1	3 phase fault on DRAPER 4 138 kV (514933) to SOONRTP4 138 kV (514949) line CRT 1, near DRAPER 4. a. Apply fault at the DRAPER 4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9036-3PH	P1	3 phase fault on DRAPER 4 138 kV (514933) to MIDWEST4 138 kV (514946) line CRT 1, near DRAPER 4. a. Apply fault at the DRAPER 4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9037-3PH	P1	3 phase fault on NORTWST4 138 kV (514879) to BRADEN 4 138 kV (514854) line CRT 1, near NORTWST4. a. Apply fault at the NORTWST4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT9038-3PH	P1	3 phase fault on NORTWST4 138 kV (514879) to LNEOAK 4 138 kV (514873) line CRT 1, near NORTWST4. a. Apply fault at the NORTWST4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9039-3PH	P1	3 phase fault on NORTWST4 138 kV (514879) to PIEDMNT4 138 kV (514864) line CRT 1, near NORTWST4. a. Apply fault at the NORTWST4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9040-3PH	P1	3 phase fault on NORTWST4 138 kV (514879) to KETCHTP4 138 kV (514828) line CRT 1, near NORTWST4. a. Apply fault at the NORTWST4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9041-3PH	P1	3 phase fault on SPRNGCK7 345 kV (514881) to G16-100-TAP 345 kV (587804) line CRT 1, near SPRNGCK7. a. Apply fault at the SPRNGCK7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9042-3PH	P1	3 phase fault on SPRNGCK7 345 kV (514881) to SPGCK1&2 13.8 kV (514882) XFMR CRT 1, near SPRNGCK7 345 kV. a. Apply fault at the SPRNGCK7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer. **Trip generator SPGCK1&2 (514882)**
FLT9043-3PH	P1	3 phase fault on WOODRNG4 138 kV (514714) to WAUKOTP4 138 kV (514711) line CRT 1, near WOODRNG4. a. Apply fault at the WOODRNG4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9044-3PH	P1	3 phase fault on WOODRNG4 138 kV (514714) to OTTER 138 kV (514708) line CRT 1, near WOODRNG4. a. Apply fault at the WOODRNG4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9045-3PH	P1	3 phase fault on WOODRNG4 138 kV (514714) to MARSHL 4 138 kV (514733) line CRT 1, near WOODRNG4. a. Apply fault at the WOODRNG4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9046-3PH	P1	3 phase fault on WOODRNG4 138 kV (514714) to FRMNTAP4 138 kV (514709) line CRT 1, near WOODRNG4. a. Apply fault at the WOODRNG4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9047-3PH	P1	3 phase fault on CIMARON4 138 kV (514898) to CZECHAL4 138 kV (514894) line CRT 1, near CIMARON4. a. Apply fault at the CIMARON4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9048-3PH	P1	3 phase fault on CIMARON4 138 kV (514898) to SARA 4 138 kV (514895) line CRT 1, near CIMARON4. a. Apply fault at the CIMARON4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT9049-3PH	P1	3 phase fault on CIMARON4 138 kV (514898) to TUTCONT4 138 kV (511425) line CRT 1, near CIMARON4. a. Apply fault at the CIMARON4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9050-3PH	P1	3 phase fault on CIMARON4 138 kV (514898) to HAYMAKR4 138 kV (514863) line CRT 1, near CIMARON4. a. Apply fault at the CIMARON4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9051-3PH	P1	3 phase fault on CIMARON4 138 kV (514898) to EL-RENO4 138 kV (514819) line CRT 1, near CIMARON4. a. Apply fault at the CIMARON4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9052-3PH	P1	3 phase fault on CIMARON4 138 kV (514898) to JENSENT4 138 kV (514820) line CRT 1, near CIMARON4. a. Apply fault at the CIMARON4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9053-3PH	P1	3 phase fault on CZECHAL4 138 kV (514894) to XEROX 4 138 kV (514893) line CRT 1, near CZECHAL4. a. Apply fault at the CZECHAL4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9054-3PH	P1	3 phase fault on JENSENT4 138 kV (514820) to JENSEN4 138 kV (514821) line CRT 1, near JENSENT4. a. Apply fault at the JENSENT4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9055-3PH	P1	3 phase fault on TUTCONT4 138 kV (511425) to T-CONCO4 138 kV (511424) line CRT 1, near TUTCONT4. a. Apply fault at the TUTCONT4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9056-3PH	P1	3 phase fault on TUTCONT4 138 kV (511425) to TUTTLE4 138 kV (511501) line CRT 1, near TUTCONT4. a. Apply fault at the TUTCONT4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9057-3PH	P1	3 phase fault on HAYMAKR4 138 kV (514863) to DVISION4 138 kV (514853) line CRT 1, near HAYMAKR4. a. Apply fault at the HAYMAKR4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9058-3PH	P1	3 phase fault on EL-RENO4 138 kV (514819) to ELRENO2 69 kV (514818) to EL RENO1 13.2 kV (515722) XFMR CRT 1, near EL-RENO4 138 kV. a. Apply fault at the EL-RENO4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT9059-3PH	P1	3 phase fault on JENSENT4 138 kV (514820) to EL-RENO4 138 kV (514819) line CRT 1, near JENSENT4. a. Apply fault at the JENSENT4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT9060-3PH (18SP and 26SP)	P1	3 phase fault on SARA 4 138 kV (514895) to STHLAKE4 138 kV (515481) line CRT 1, near SARA 4. a. Apply fault at the SARA 4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9061-3PH (17WP)	P1	3 phase fault on SARA 4 138 kV (514895) to MCCLAIN4 138 kV (514902) line CRT 1, near SARA 4. a. Apply fault at the SARA 4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT02-PO4	P6	**Prior Outage of MATHWSN7 345 kV (515497) to NORTWST7 345 kV (514880) line CRT 1;** 3 phase fault on CIMARON7 345 kV (514901) to NORTWST7 345 kV (514880) line CRT 1, near CIMARON7. a. Apply fault at the CIMARON7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT03-PO4	P6	**Prior Outage of MATHWSN7 345 kV (515497) to NORTWST7 345 kV (514880) line CRT 1;** 3 phase fault on CIMARON7 345 kV (514901) to MINCO 7 345 kV (514801) line CRT 1, near CIMARON7. a. Apply fault at the CIMARON7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT04-PO4	P6	**Prior Outage of MATHWSN7 345 kV (515497) to NORTWST7 345 kV (514880) line CRT 1;** 3 phase fault on CIMARON7 345 kV (514901) to DRAPER 7 345 kV (514934) line CRT 1, near CIMARON7. a. Apply fault at the CIMARON7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT05-PO4	P6	**Prior Outage of MATHWSN7 345 kV (515497) to NORTWST7 345 kV (514880) line CRT 1;** 3 phase fault on the CIMARON7 345 kV (514901) to CIMARON4 138 kV (514898) to CIMARO11 13.8 kV (515714) XFMR CRT 1, near CIMARON7 345 kV. a. Apply fault at the CIMARON7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT9025-PO4	P6	**Prior Outage of MATHWSN7 345 kV (515497) to NORTWST7 345 kV (514880) line CRT 1;** 3 phase fault on CIMARON7 345 kV (514901) to FSHRTAP7 345 kV (515610) line CRT 1, near CIMARON7. a. Apply fault at the CIMARON7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. **Trip generators KNGFSHR-GEN1 (599122), KNGFSHR-GEN2 (599124), CANDIAN_WTG1 (599114) and CANDIAN_WTG2 (599116).** c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9001-PO4	P6	**Prior Outage of MATHWSN7 345 kV (515497) to NORTWST7 345 kV (514880) line CRT 1;** 3 phase fault on TATONGA7 345 kV (515407) to SLNGWND7 345 kV (515582) line CRT 1, near TATONGA7. a. Apply fault at the TATONGA7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT9003-PO4	P6	**Prior Outage of MATHWSN7 345 kV (515497) to NORTWST7 345 kV (514880) line CRT 1;** 3 phase fault on TATONGA7 345 kV (515407) to WWRDEHV 345 kV (515375) line CRT 1, near TATONGA7. a. Apply fault at the TATONGA7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9004-PO4	P6	**Prior Outage of MATHWSN7 345 kV (515497) to NORTWST7 345 kV (514880) line CRT 1;** 3 phase fault on TATONGA7 345 kV (515407) to GEN-2015-029 345 kV (584700) line CRT 1, near TATONGA7. a. Apply fault at the TATONGA7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9005-PO4	P6	**Prior Outage of MATHWSN7 345 kV (515497) to NORTWST7 345 kV (514880) line CRT 1;** 3 phase fault on TATONGA7 345 kV (515407) to MAMTHPW7 345 kV (515585) line CRT 1, near TATONGA7. a. Apply fault at the TATONGA7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9018-PO4	P6	**Prior Outage of MATHWSN7 345 kV (515497) to NORTWST7 345 kV (514880) line CRT 1;** 3 phase fault on REDNGTN7 345 kV (514875) to WOODRNG7 345 kV (514715) line CRT 1, near REDNGTN7. a. Apply fault at the REDNGTN7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9019-PO4	P6	**Prior Outage of MATHWSN7 345 kV (515497) to NORTWST7 345 kV (514880) line CRT 1;** 3 phase fault on REDNGTN7 345 kV (514875) to REDDIRT7 345 kV (515877) line CRT 1, near REDNGTN7. a. Apply fault at the REDNGTN7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. Trip generator RDDRTG11 (515882), RDDRTG21 (515883). c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT02-PO5	P6	**Prior Outage of MATHWSN7 345 kV (515497) to TATONGA7 345 kV (515407) line CRT 1;** 3 phase fault on CIMARON7 345 kV (514901) to NORTWST7 345 kV (514880) line CRT 1, near CIMARON7. a. Apply fault at the CIMARON7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT03-PO5	P6	**Prior Outage of MATHWSN7 345 kV (515497) to TATONGA7 345 kV (515407) line CRT 1;** 3 phase fault on CIMARON7 345 kV (514901) to MINCO 7 345 kV (514801) line CRT 1, near CIMARON7. a. Apply fault at the CIMARON7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT04-PO5	P6	**Prior Outage of MATHWSN7 345 kV (515497) to TATONGA7 345 kV (515407) line CRT 1;** 3 phase fault on CIMARON7 345 kV (514901) to DRAPER 7 345 kV (514934) line CRT 1, near CIMARON7. a. Apply fault at the CIMARON7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT05-PO5	P6	**Prior Outage of MATHWSN7 345 kV (515497) to TATONGA7 345 kV (515407) line CRT 1;** 3 phase fault on the CIMARON7 345 kV (514901) to CIMARON4 138 kV (514898) to CIMARO11 13.8 kV (515714) XFMR CRT 1, near CIMARON7 345 kV. a. Apply fault at the CIMARON7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT9025-PO5	P6	**Prior Outage of MATHWSN7 345 kV (515497) to TATONGA7 345 kV (515407) line CRT 1;** 3 phase fault on CIMARON7 345 kV (514901) to FSHRTAP7 345 kV (515610) line CRT 1, near CIMARON7. a. Apply fault at the CIMARON7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. **Trip generators KNGFSHR-GEN1 (599122), KNGFSHR-GEN2 (599124), CANDIAN_WTG1 (599114) and CANDIAN_WTG2 (599116).** c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT68-PO5	P6	**Prior Outage of MATHWSN7 345 kV (515497) to TATONGA7 345 kV (515407) line CRT 1;** 3 phase fault on NORTWST7 345 kV (514880) to NORTWST4 138 kV (514879) to NORTWS41 13.8 kV (514885) XFMR CRT 1, near NORTWST7 345 kV. a. Apply fault at the NORTWST7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT69-PO5	P6	**Prior Outage of MATHWSN7 345 kV (515497) to TATONGA7 345 kV (515407) line CRT 1;** 3 phase fault on NORTWST7 345 kV (514880) to ARCADIA7 345 kV (514908) line CRT 1, near NORTWST7. a. Apply fault at the NORTWST7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT70-PO5	P6	**Prior Outage of MATHWSN7 345 kV (515497) to TATONGA7 345 kV (515407) line CRT 1;** 3 phase fault on NORTWST7 345 kV (514880) to SPRNGCK7 345 kV (514881) line CRT 1, near NORTWST7. a. Apply fault at the NORTWST7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9018-PO5	P6	**Prior Outage of MATHWSN7 345 kV (515497) to TATONGA7 345 kV (515407) line CRT 1;** 3 phase fault on REDNGTN7 345 kV (514875) to WOODRNG7 345 kV (514715) line CRT 1, near REDNGTN7. a. Apply fault at the REDNGTN7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9019-PO5	P6	**Prior Outage of MATHWSN7 345 kV (515497) to TATONGA7 345 kV (515407) line CRT 1;** 3 phase fault on REDNGTN7 345 kV (514875) to REDDIRT7 345 kV (515877) line CRT 1, near REDNGTN7. a. Apply fault at the REDNGTN7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. Trip generator RDDRTG11 (515882), RDDRTG21 (515883). c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT02-PO6	P6	**Prior Outage of MATHWSN7 345 kV (515497) to REDNGTN7 345 kV (515875) line CRT 1;** 3 phase fault on CIMARON7 345 kV (514901) to NORTWST7 345 kV (514880) line CRT 1, near CIMARON7. a. Apply fault at the CIMARON7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT03-PO6	P6	**Prior Outage of MATHWSN7 345 kV (515497) to REDNGTN7 345 kV (515875) line CRT 1;** 3 phase fault on CIMARON7 345 kV (514901) to MINCO 7 345 kV (514801) line CRT 1, near CIMARON7. a. Apply fault at the CIMARON7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT04-PO6	P6	**Prior Outage of MATHWSN7 345 kV (515497) to REDNGTN7 345 kV (515875) line CRT 1;** 3 phase fault on CIMARON7 345 kV (514901) to DRAPER 7 345 kV (514934) line CRT 1, near CIMARON7. a. Apply fault at the CIMARON7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT05-PO6	P6	**Prior Outage of MATHWSN7 345 kV (515497) to REDNGTN7 345 kV (515875) line CRT 1;** 3 phase fault on the CIMARON7 345 kV (514901) to CIMARON4 138 kV (514898) to CIMARO11 13.8 kV (515714) XFMR CRT 1, near CIMARON7 345 kV. a. Apply fault at the CIMARON7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT9025-PO6	P6	**Prior Outage of MATHWSN7 345 kV (515497) to REDNGTN7 345 kV (515875) line CRT 1;** 3 phase fault on CIMARON7 345 kV (514901) to FSHRTAP7 345 kV (515610) line CRT 1, near CIMARON7. a. Apply fault at the CIMARON7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. **Trip generators KNGFSHR-GEN1 (599122), KNGFSHR-GEN2 (599124), CANDIAN_WTG1 (599114) and CANDIAN_WTG2 (599116).** c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT68-PO6	P6	**Prior Outage of MATHWSN7 345 kV (515497) to REDNGTN7 345 kV (515875) line CRT 1;** 3 phase fault on NORTWST7 345 kV (514880) to NORTWST4 138 kV (514879) to NORTWS41 13.8 kV (514885) XFMR CRT 1, near NORTWST7 345 kV. a. Apply fault at the NORTWST7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT69-PO6	P6	**Prior Outage of MATHWSN7 345 kV (515497) to REDNGTN7 345 kV (515875) line CRT 1;** 3 phase fault on NORTWST7 345 kV (514880) to ARCADIA7 345 kV (514908) line CRT 1, near NORTWST7. a. Apply fault at the NORTWST7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT70-PO6	P6	**Prior Outage of MATHWSN7 345 kV (515497) to REDNGTN7 345 kV (515875) line CRT 1;** 3 phase fault on NORTWST7 345 kV (514880) to SPRNGCK7 345 kV (514881) line CRT 1, near NORTWST7. a. Apply fault at the NORTWST7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9001-PO6	P6	**Prior Outage of MATHWSN7 345 kV (515497) to REDNGTN7 345 kV (515875) line CRT 1;** 3 phase fault on TATONGA7 345 kV (515407) to SLNGWND7 345 kV (515582) line CRT 1, near TATONGA7. a. Apply fault at the TATONGA7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT9002-PO6	P6	**Prior Outage of MATHWSN7 345 kV (515497) to REDNGTN7 345 kV (515875) line CRT 1;** 3 phase fault on TATONGA7 345 kV (515407) to CRSRDSW7 345 kV (515448) line CRT 1, near TATONGA7. a. Apply fault at the TATONGA7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9003-PO6	P6	**Prior Outage of MATHWSN7 345 kV (515497) to REDNGTN7 345 kV (515875) line CRT 1;** 3 phase fault on TATONGA7 345 kV (515407) to WWRDEHV 345 kV (515375) line CRT 1, near TATONGA7. a. Apply fault at the TATONGA7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9004-PO6	P6	**Prior Outage of MATHWSN7 345 kV (515497) to REDNGTN7 345 kV (515875) line CRT 1;** 3 phase fault on TATONGA7 345 kV (515407) to GEN-2015-029 345 kV (584700) line CRT 1, near TATONGA7. a. Apply fault at the TATONGA7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9005-PO6	P6	**Prior Outage of MATHWSN7 345 kV (515497) to REDNGTN7 345 kV (515875) line CRT 1;** 3 phase fault on TATONGA7 345 kV (515407) to MAMTHPW7 345 kV (515585) line CRT 1, near TATONGA7. a. Apply fault at the TATONGA7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT68-PO7	P6	**Prior Outage of MATHWSN7 345 kV (515497) to CIMARON7 345 kV (514901) line CRT 1;** 3 phase fault on NORTWST7 345 kV (514880) to NORTWST4 138 kV (514879) to NORTWS41 13.8 kV (514885) XFMR CRT 1, near NORTWST7 345 kV. a. Apply fault at the NORTWST7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT69-PO7	P6	**Prior Outage of MATHWSN7 345 kV (515497) to CIMARON7 345 kV (514901) line CRT 1;** 3 phase fault on NORTWST7 345 kV (514880) to ARCADIA7 345 kV (514908) line CRT 1, near NORTWST7. a. Apply fault at the NORTWST7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT70-PO7	P6	**Prior Outage of MATHWSN7 345 kV (515497) to CIMARON7 345 kV (514901) CRT 1 line;** 3 phase fault on NORTWST7 345 kV (514880) to SPRNGCK7 345 kV (514881) line CRT 1, near NORTWST7. a. Apply fault at the NORTWST7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9001-PO7	P6	**Prior Outage of MATHWSN7 345 kV (515497) to CIMARON7 345 kV (514901) line CRT 1;** 3 phase fault on TATONGA7 345 kV (515407) to SLNGWND7 345 kV (515582) line CRT 1, near TATONGA7. a. Apply fault at the TATONGA7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT9002-PO7	P6	**Prior Outage of MATHWSN7 345 kV (515497) to CIMARON7 345 kV (514901) line CRT 1;** 3 phase fault on TATONGA7 345 kV (515407) to CRSRDSW7 345 kV (515448) line CRT 1, near TATONGA7. a. Apply fault at the TATONGA7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9003-PO7	P6	**Prior Outage of MATHWSN7 345 kV (515497) to CIMARON7 345 kV (514901) line CRT 1;** 3 phase fault on TATONGA7 345 kV (515407) to WWRDEHV 345 kV (515375) line CRT 1, near TATONGA7. a. Apply fault at the TATONGA7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9004-PO7	P6	**Prior Outage of MATHWSN7 345 kV (515497) to CIMARON7 345 kV (514901) line CRT 1;** 3 phase fault on TATONGA7 345 kV (515407) to GEN-2015-029 345 kV (584700) line CRT 1, near TATONGA7. a. Apply fault at the TATONGA7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9005-PO7	P6	**Prior Outage of MATHWSN7 345 kV (515497) to CIMARON7 345 kV (514901) line CRT 1;** 3 phase fault on TATONGA7 345 kV (515407) to MAMTHPW7 345 kV (515585) line CRT 1, near TATONGA7. a. Apply fault at the TATONGA7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9018-PO7	P6	**Prior Outage of MATHWSN7 345 kV (515497) to CIMARON7 345 kV (514901) line CRT 1;** 3 phase fault on REDNGTN7 345 kV (514875) to WOODRNG7 345 kV (514715) line CRT 1, near REDNGTN7. a. Apply fault at the REDNGTN7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9019-PO7	P6	**Prior Outage of MATHWSN7 345 kV (515497) to CIMARON7 345 kV (514901) line CRT 1;** 3 phase fault on REDNGTN7 345 kV (514875) to REDDIRT7 345 kV (515877) line CRT 1, near REDNGTN7. a. Apply fault at the REDNGTN7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. **Trip generator RDDRTG11 (515882), RDDRTG21 (515883).** c. Wait 20 cycles, and then reclose the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT1001-SB	P4	**Stuck Breaker at NORTWST7 (514880)** a. Apply single phase fault at NORTWST7 bus. b. Clear fault after 16 cycles and trip the following elements c. NORTWST7 (514880) - SPRNGCK7 (514881) 345kV line CKT 1. d. NORTWST7 (514880) / NORTWST4 138 kV (514879) / NORTWS21 13.8 kV (515742) transformer CKT 1.
FLT1002-SB	P4	**Stuck Breaker at NORTWST7 (514880)** a. Apply single phase fault at NORTWST7 bus. b. Clear fault after 16 cycles and trip the following elements c. NORTWST7 (514880) - CIMARON7 (514901) 345kV line CKT 1. d. NORTWST7 (514880) / NORTWST4 138 kV (514879) / NORTWS31 13.8 kV (515743) transformer CKT 1.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT1003-SB	P4	**Stuck Breaker at NORTWST7 (514880)** a. Apply single phase fault at NORTWST7 bus. b. Clear fault after 16 cycles and trip the following elements c. NORTWST7 (514880) - MATHWSN7 (515497) 345kV line CKT 1. d. NORTWST7 (514880) / NORTWST4 138 kV (514879) / NORTWS41 13.8 kV (514885) transformer CKT 1.
FLT1004-SB	P4	**Stuck Breaker at CIMARON7 (514901)** a. Apply single phase fault at CIMARON7 bus. b. Clear fault after 16 cycles and trip the following elements c. CIMARON7 (514901) - MATHWSN7 (515497) 345kV line CKT 2. d. CIMARON7 (514901) - NORTWST7 (514880) 345kV line CKT 1.
FLT1005-SB	P4	**Stuck Breaker at CIMARON7 (514901)** a. Apply single phase fault at CIMARON7 bus. b. Clear fault after 16 cycles and trip the following elements c. CIMARON7 (514901) - FSHRTAP7 (515610) 345kV line CKT 1. **Trip generators connected to this POI bus KNGFSHR-GEN1 (599122), KNGFSHR-GEN2 (599124), CANDIAN_WTG1 (599114), CANDIAN_WTG2 (599116).** d. CIMARON7 (514901) - MINCO (514801) 345kV line CKT 1.
FLT1006-SB	P4	**Stuck Breaker at CIMARON7 (514901)** a. Apply single phase fault at CIMARON7 bus. b. Clear fault after 16 cycles and trip the following elements c. CIMARON7 (514901) - DRAPER (514934) 345kV line CKT 1 d. CIMARON7 345 kV (514901) / CIMARON4 138 kV (514898) / CIMARON21 13.8 kV (515715) transformer CKT 1.
FLT1007-SB	P4	**Stuck Breaker at WWRDEHV7 (515375)** a. Apply single phase fault at WWRDEHV7 bus. b. Clear fault after 16 cycles and trip the following elements c. WWRDEHV7 (515375) - G07621119-20 (515599) 345kV line CKT 1.Trip generators connected to this POI bus d. WWRDEHV7 (515375) - G16-003-TAP (560071) 345kV line CKT 2.
FLT1008-SB	P4	**Stuck Breaker at WWRDEHV7 (515375)** a. Apply single phase fault at WWRDEHV7 bus. b. Clear fault after 16 cycles and trip the following elements c. WWRDEHV7 (515375) - TATONGA (515407) 345kV line CKT 2. d. WWRDEHV7 345kV (515375) / WWRDEHV4 138 kV (515376) / WWDEHV31 13.8 kV (515795) transformer CKT 1.
FLT1009-SB	P4	**Stuck Breaker at WWRDEHV7 (515375)** a. Apply single phase fault at WWRDEHV7 bus. b. Clear fault after 16 cycles and trip the following elements c. WWRDEHV7 (515375) - TATONGA (515407) 345kV line CKT 1. d. WWRDEHV7 345kV (515375) / WWRDEHV4 138 kV (515376) / WWDEHV21 13.8 kV (515799) transformer CKT 2.
FLT1010-SB	P4	**Stuck Breaker at REDNGTN7 (515875)** a. Apply single phase fault at REDNGTN7 bus. b. Clear fault after 16 cycles and trip the following elements c. Trip the whole bus REDNGTN7 (515875).
FLT1011-SB	P4	**Stuck Breaker at TATONGA7 (515407)** a. Apply single phase fault at TATONGA7 bus. b. Clear fault after 16 cycles and trip the following elements c. TATONGA7 (515407) - MATHWSN7 (515497) line CKT 1. d. TATONGA7 (515407) - MAMTHPW7 345 kV (515585) line CKT 1.
FLT1012-SB	P4	**Stuck Breaker at TATONGA7 (515407)** a. Apply single phase fault at TATONGA7 bus. b. Clear fault after 16 cycles and trip the following elements c. TATONGA7 (515407) - WWRDEHV7 (515375) line CKT 2. d. TATONGA7 (515407) - SLNGWND7 345 kV (515582) line CKT 1. Trip generators (599059) and (515587).

6.3 Results

Table 6-2 shows the results of the fault events simulated for each of the three modified cases. The associated stability plots are provided in Appendix D.

Table 6-2: GEN-2016-045 & GEN-2016-057 Dynamic Stability Results

Fault ID	17WP			18SP			26SP		
	Voltage Recovery	Voltage Violation	Stable	Voltage Recovery	Voltage Violation	Stable	Voltage Recovery	Voltage Violation	Stable
FLT02-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT03-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT04-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT05-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT43-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT44-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT45-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT65-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT67-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT68-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT69-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT70-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT75-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9006-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9007-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9008-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9009-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9010-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9011-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9017-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9018-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9019-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9020-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9021-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9022-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9023-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9024-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9025-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9026-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9027-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9028-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9029-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9030-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9031-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9032-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9033-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9034-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

Table 6-2 continued

Fault ID	17WP			18SP			26SP		
	Voltage Recovery	Voltage Violation	Stable	Voltage Recovery	Voltage Violation	Stable	Voltage Recovery	Voltage Violation	Stable
FLT9035-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9036-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9037-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9038-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9039-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9040-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9041-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9042-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9043-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9044-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9045-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9046-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9047-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9048-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9049-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9050-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9051-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9052-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9053-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9054-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9055-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9056-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9057-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9058-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9059-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9060-3PH (18SP and 26SP)	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9061-3PH (17WP)	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT20-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1001-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1002-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1003-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1004-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1005-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1006-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1007-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1008-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1009-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1010-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1011-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1012-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT04-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT05-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT45-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT75-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT02-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

Table 6-2 continued

Fault ID	17WP			18SP			26SP		
	Voltage Recovery	Voltage Violation	Stable	Voltage Recovery	Voltage Violation	Stable	Voltage Recovery	Voltage Violation	Stable
FLT03-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT04-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT05-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9025-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9018-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9019-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT02-PO5	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT03-PO5	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT04-PO5	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT05-PO5	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9025-PO5	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT68-PO5	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT69-PO5	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT70-PO5	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9018-PO5	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9019-PO5	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT02-PO6	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT03-PO6	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT04-PO6	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT05-PO6	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9025-PO6	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT68-PO6	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT69-PO6	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT70-PO6	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-PO6	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-PO6	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-PO6	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-PO6	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-PO6	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT68-PO7	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT69-PO7	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT70-PO7	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-PO7	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-PO7	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-PO7	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-PO7	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-PO7	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9018-PO7	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9019-PO7	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

The results of the dynamic stability analysis showed that the loss of the Mathewson to Tatonga 345 kV line caused the Spring Creek Units at buses 514882 and 514883 to show sustained EFD oscillations in response to a fault event on this circuit. Figure 6-1 shows that the Spring Creek generators showed oscillations after the fault in the 26SP case. This problem also occured for the generators in the existing base case models as shown in Figure 6-2. As the oscillations are present in both the base and modification cases, it is not caused by the GEN-2016-045 and GEN-2016-057 modification request. SPP is further investigating this stability issue.

Figure 6-1: FLT65-3PH Spring Creek (514882 & 514883) EFD Response (26SP Modification Case)

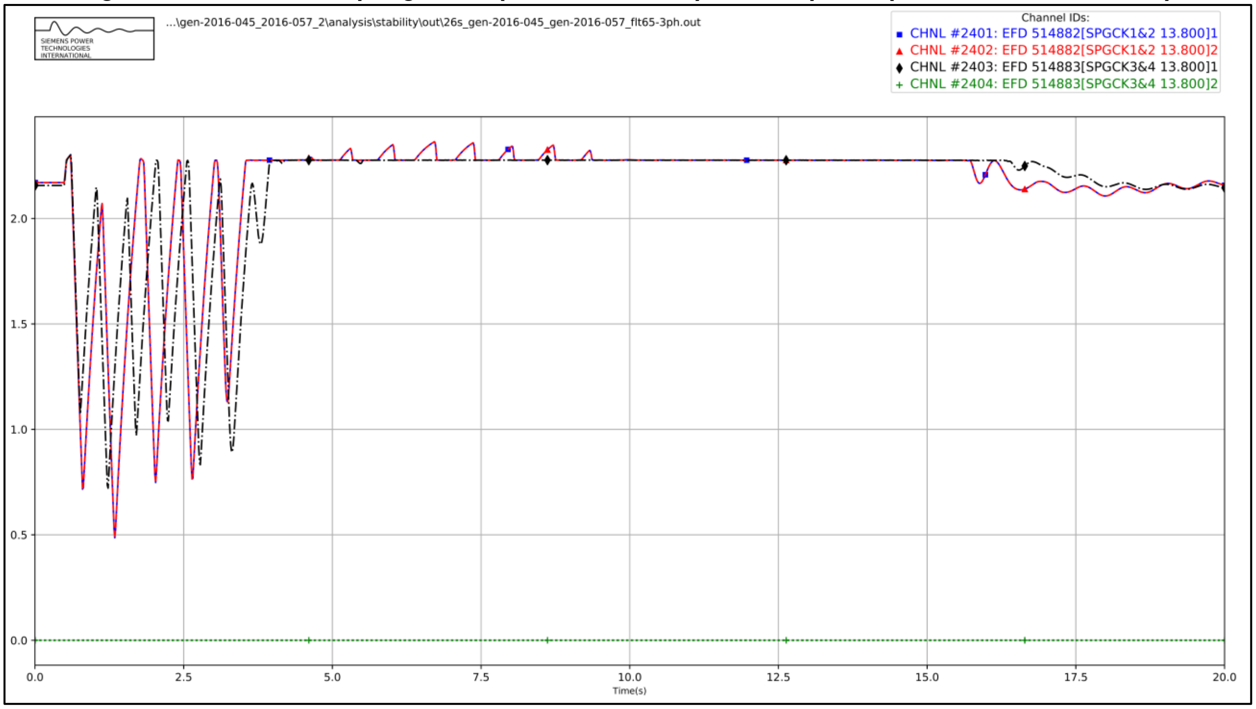
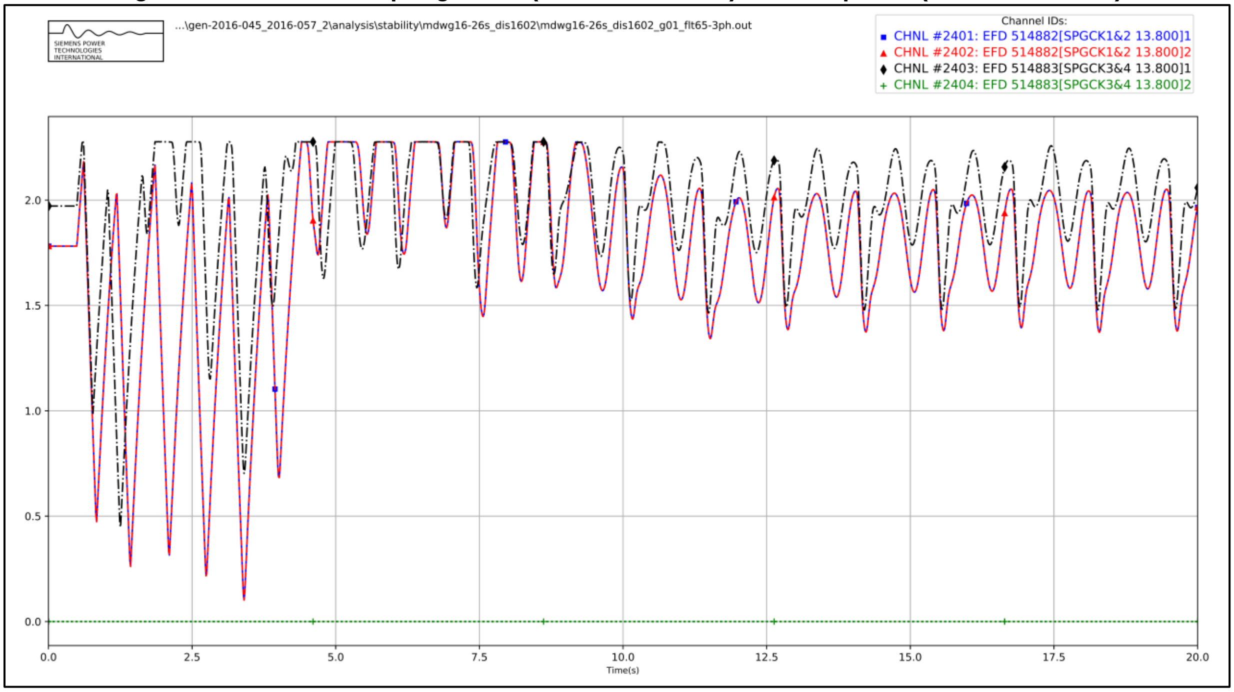


Figure 6-2: FLT65-3PH Spring Creek (514882 & 514883) EFD Response (26SP Base Case)



There were no damping or voltage recovery violations observed during the simulated faults. Additionally, the project was found to stay connected during the contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements of FERC Order #661A.

7.0 Material Modification Determination

In accordance with Attachment V of SPP's Open Access Transmission Tariff, for modifications other than those specifically permitted by Attachment V, SPP shall evaluate the proposed modifications prior to making them and inform the Interconnection Customer in writing of whether the modifications would constitute a Material Modification. Material Modification shall mean (1) modification to an Interconnection Request in the queue that has a material adverse impact on the cost or timing of any other Interconnection Request with a later Queue priority date; or (2) planned modification to an Existing Generating Facility that is undergoing evaluation for a Generating Facility Modification or Generating Facility Replacement, and has a material adverse impact on the Transmission System with respect to: i) steady-state thermal or voltage limits, ii) dynamic system stability and response, or iii) short-circuit capability limit; compared to the impacts of the Existing Generating Facility prior to the modification or replacement.

7.1 Results

SPP determined the requested modification is not a Material Modification based on the results of this Modification Request Impact Study performed by Aneden. Aneden evaluated the impact of the requested modification on the prior study results. Aneden determined that the requested modification resulted in similar dynamic stability and short circuit analyses and that the prior study power flow results are not negatively impacted.

This determination implies that any network upgrades already required by GEN-2016-045 and GEN-2016-057 would not be negatively impacted and that no new upgrades are required due to the requested modification, thus not resulting in a material adverse impact on the cost or timing of any other Interconnection Request with a later Queue priority date.

8.0 Conclusions

The Interconnection Customer for GEN-2016-045 and GEN-2016-057 requested a Modification Request Impact Study to assess the impact of the turbine and facility changes to a configuration with a total of 336 x GE 2.82 MW + 20 x GE 2.5 MW wind turbines for total capacity of 997.52 MW. In addition, the modification request included changes to the collection system, generator step-up transformers, main substation transformer, generation interconnection line, and reactive power devices.

SPP determined that power flow should not be performed based on the POI MW injection increase of 0.07%. The modification request retained the same GE wind turbine technology and as such, the equivalent impedances from the POI up to and including the step-up transformers for GEN-2016-045 and GEN-2016-057 were calculated before and after the modification request. The modification request resulted in a change in the equivalent impedances of approximately 16.53%. As a result, SPP determined that the change in impedance required short circuit and dynamic stability analyses.

The scope of this modification request study included charging current compensation analysis, short circuit analysis, and dynamic stability analysis.

The results of the charging current compensation analysis performed using the 2017 Winter Peak, 2018 Summer Peak, and 2026 Summer Peak models showed that the GEN-2016-045 and GEN-2016-057 projects needed 120.02 MVAr of reactor shunts on the 34.5 kV bus of the project substation, an increase from the 115 MVAr found in the previous Modification Request Impact Study[4]. This is necessary to offset the capacitive effect on the transmission network caused by the project's transmission line and collector system during low-wind or no-wind conditions. The information gathered from the charging current compensation analysis is provided as information to the Interconnection Customer and Transmission Owner and/or Transmission Operator. The applicable reactive power requirements will be addressed by the Interconnection Customer and the Transmission Owner and/or Transmission Operator.

The results from the short circuit analysis with the updated topology showed that the maximum GEN-2016-045 and GEN-2016-057 contribution to three-phase fault currents in the immediate systems at or near GEN-2016-045 and GEN-2016-057 was not greater than 2.01 kA for the 2018SP and 2026SP models. All three-phase fault current levels within 5 buses of the POI with the GEN-2016-045 and GEN-2016-057 generators online were below 52 kA for the 2018SP and 2026SP models.

The dynamic stability analysis was performed using the three post-modification GEN-2016-003 DISIS-2016-002 models 2017 Winter Peak, 2018 Summer Peak, and 2026 Summer Peak. Up to 131 events were simulated, which included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground faults with stuck breakers faults.

[4] GEN-2016-045 and GEN-2016-057 Modification Request Impact Study, January 29, 2020

The results of the dynamic stability analysis showed that there were no damping or voltage recovery violations observed during the simulated faults. Additionally, the project was found to stay connected during the contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements of FERC Order #661A.

The requested modification has been determined by SPP to not be a Material Modification. The requested modification does not have a material adverse impact on the cost or timing of any other Interconnection Request with a later Queue priority date.

It is likely that the customer may be required to reduce its generation output to 0 MW in real-time, also known as curtailment, under certain system conditions to allow system operators to maintain the reliability of the transmission network.

Nothing in this study should be construed as a guarantee of transmission service or delivery rights. If the customer wishes to obtain deliverability to final customers, a separate request for transmission service must be requested on Southwest Power Pool's OASIS by the customer.