Generation Interconnection Request # GI-2016-7 Interconnection System Impact Study Cumulative Study Report

240MW Solar Photovoltaic Generating Facility
Boone 230kV Substation
Pueblo County, Colorado

Xcel Energy - Transmission Planning West
Xcel Energy
December 20, 2018

Executive Summary

The GI-2016-7 is a 240MW solar photovoltaic generation facility that will be located in Pueblo County, Colorado. The primary Point of Interconnection (POI) requested is the 230kV bus within PSCo's Boone 230kV Substation. The commercial operation date (COD) requested for the generating facility is November 30, 2019 and the requested back-feed date is October 1, 2019. Based on the 18 months construction timeframe associated with the required transmission system improvements, the proposed November 2019 COD is not achievable.

As per the Interconnection request, GI-2016-7 was studied for both Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS).
For both ERIS and NRIS evaluation, the 240 MW rated output of GI-2016-7 is assumed to be delivered to PSCo native load, so existing PSCo generation is used as its sink.

The results of the single contingency analysis (P1 and P2) are given in Table C6 in "Appendix – Cumulative Study". The following Network Upgrades are assigned to GI-2016-7:

- Fountain Valley – Desert Cove 115kV line loading increased from 87.1% to 101.1% (BHCE facility)
- Fountain Valley – MidwayBR 115kV line loading increased from 89.1% to 103.6% (BHCE facility)
- Midway 230kV Bus Tie line loading increased from 90.9% to 105.4% (WAPA facility)
- Smeltertown – West Canyon 115kV line loading increased from 99.8% to 111.4% (BHCE facility)
- Kelker – RD_Nixon 230kV line loading increased from 98.2% to 101.2% (CSU facility)

PSCo has coordinated with WAPA, CSU and BHCE, and has informed them of the overloads on the one WAPA line, two CSU lines and the two BHCE lines listed above. Mitigation measures for each of these Affected Party overloads must be identified and addressed in order for GI-2016-7 to achieve ERIS or NRIS of 240MW.

The transient stability analysis determined that all generating units are stable (remain in synchronism), display positive damping and the maximum transient voltage dips are within acceptable dynamic performance criteria.

The short-circuit and breaker duty analysis determined that no breaker replacements are needed at the POI station and/or in neighboring PSCo stations.

The total estimated cost of the transmission system improvements required for GI-2016-7 to qualify for:

- **ERIS is $4.083 Million (Tables C2 and C3); and**
- **NRIS is $4.083 Million (Tables C2, C3 and C4)**

This is contingent upon the mitigation of overloads identified in Affected Systems for this Interconnection Request and completion of the Network Upgrades identified for all applicable higher-queued Interconnection Requests (see footnotes to Table C3 and C4).

For GI-2016-7 interconnection:

NRIS (after required transmission system improvements) = 240MW

ERIS (after required transmission system improvements) = 240MW (output delivery assumes the use of existing firm or non-firm capacity of the PSCo Transmission System on as as-available basis)

Note: NRIS or ERIS, in and of itself, does not convey transmission service.

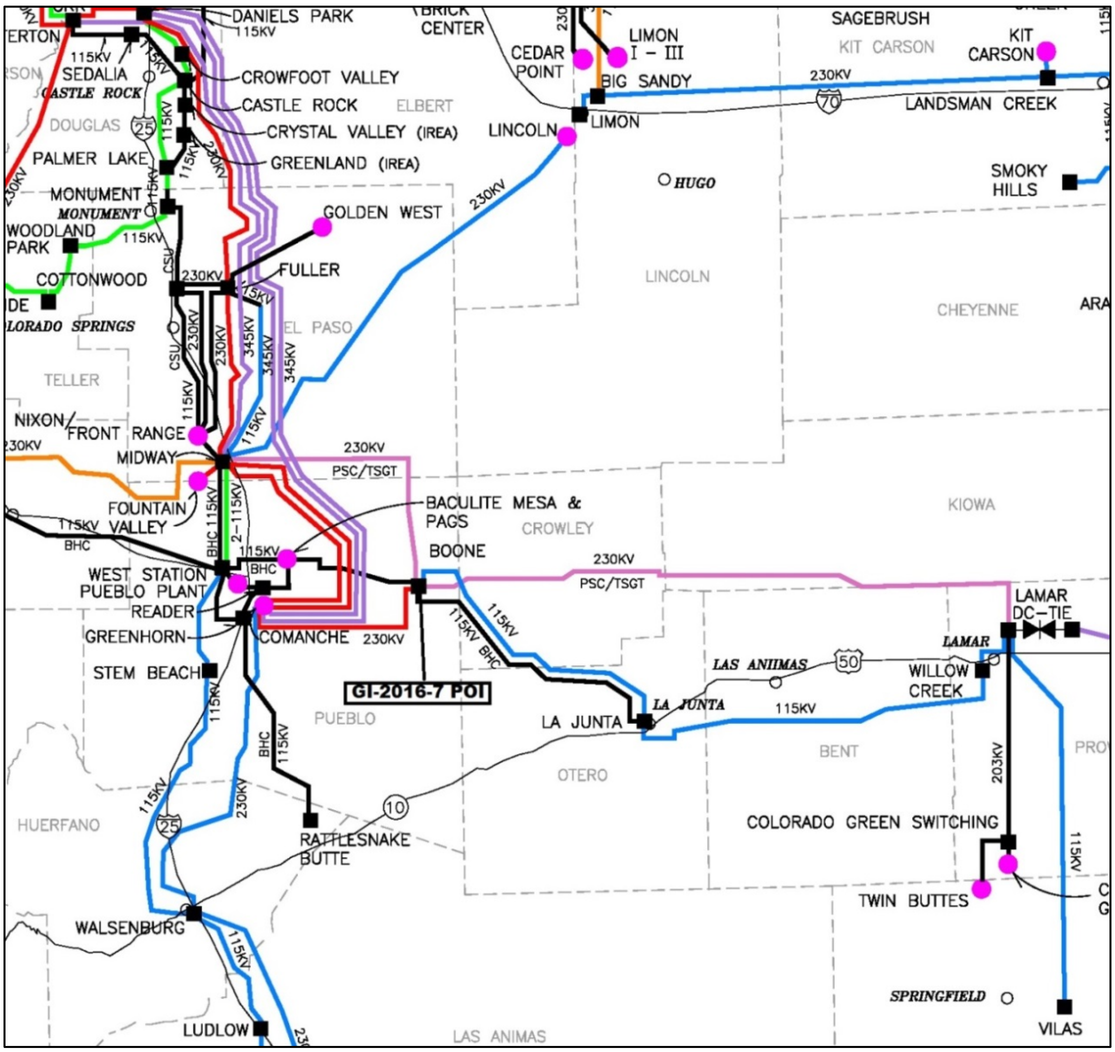

Figure C1 - GI-2016-7 Point of Interconnection and Study Area – Cumulative Study

Introduction

The GI-2016-7 is a 240MW solar photovoltaic generation facility that will be located in Pueblo County, Colorado. The Generating Facility (GF) will be made up of one hundred and twenty (120) SMA Sunny Central 2200-US inverters equally distributed over three groups and each group will consist of twenty 4MVA generator step-up transformers. The three groups will connect to a 240MVA main step-up transformer which will connect to the Boone 230kV Primary Point of Interconnection (POI) using a Generator Interconnection Customer owned 230kV tie-line.

The main purpose of this Interconnection System Impact Study is to determine the system impact of interconnecting 240 MW of generation at the Boone 230kV POI. As per the Interconnection Study Request, GI-2016-7 was studied for both Energy Resource Interconnection Service (ERIS)[1] and Network Resource Interconnection Service (NRIS)[2]. For both ERIS and NRIS evaluation, the 240 MW rated output of GI-2016-7 is assumed to be delivered to PSCo network load, so existing PSCo generation is used as its sink.

The Affected Systems for this GI are: Black Hills Colorado Electric (BHCE), Colorado Springs Utilities (CSU), Tri-State Generation and Transmission Inc. (TSGT), Intermountain Rural Electric Association (IREA), and Western Area Power Administration (WAPA).

Study Scope and Analysis Criteria

The scope of this report includes steady state (power flow) analysis, transient stability analysis, short circuit analysis and scoping level cost estimates. The power flow analysis identifies thermal and voltage violations in the PSCo system and the Affected Systems as a result of the interconnection of the GI. Several single contingencies were studied. The transient stability analysis verifies that all generating units within the PSCo transmission system and the Affected Systems remain stable (in synchronism), have positive damping and satisfy acceptable dynamic performance criteria. The short circuit analysis determines the maximum available fault current at the POI and identifies if any circuit breaker(s) within the PSCo station(s) exceed their breaker duty ratings and need to be replaced.

PSCo adheres to applicable NERC Reliability Standards and Western Electricity Coordinating Council (WECC) Reliability Criteria, as well as its internal transmission planning criteria for studies. The steady state analysis criteria are as follows:

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[1] Energy Resource Interconnection Service shall mean an Interconnection Service that allows the Interconnection Customer to connect its Generating Facility to the Transmission Provider's Transmission System to be eligible to deliver the Generating Facility's electric output using the existing firm or non-firm capacity of the Transmission Provider's Transmission System on an as available basis. Energy Resource Interconnection Service in and of itself does not convey transmission service.

[2] Network Resource Interconnection Service shall mean an Interconnection Service that allows the Interconnection Customer to integrate its Large Generating Facility with the Transmission Provider's Transmission system (1) in a manner comparable to that in which the Transmission Provider integrates its generating facilities to serve native load customers; or (2) in an RTO or ISO with market based congestion management, in the same manner as all other Network Resources. Network Resource Interconnection Service in and of itself does not convey transmission service.

P0 - System Intact conditions:
Thermal Loading: <=100% of the normal facility rating
Voltage range: 0.95 to 1.05 per unit

P1-P2 – Single Contingencies:
Thermal Loading: <=100% Normal facility rating
Voltage range: 0.90 to 1.10 per unit
Voltage deviation: <=8% of pre-contingency voltage

The study area is the electrical system consisting of PSCo's transmission system and the Affected Party's transmission system that is impacted or that will impact interconnection of GI-2016-7. The study area for GI-2016-7 includes WECC designated zones 121, 700, 703, 704, 705, 709, 710, 712, 752 and 757.

Transient stability criteria require that all generating machines remain in synchronism and all power swings should be well damped following a contingency event. Also, transient voltage performance should meet the following WECC Disturbance-Performance criteria:

- Following fault clearing, the voltage shall recover to 80% of the pre-contingency voltage within 20 seconds for all contingencies
- For all contingencies, following fault clearing and voltage recovery above 80%, voltage at each applicable BES bus serving load shall neither dip below 70% of pre-contingency voltage for more than 30 cycles nor remain below 80% of pre-contingency voltage for more than two seconds.
- For contingencies without a fault, voltage dips at each applicable BES bus serving load shall neither dip below 70% of pre-contingency voltage for more than 30 cycles nor remain below 80% of pre-contingency voltage for more than two seconds

Cumulative Power Flow Analysis (including all higher-queued generation)

The power flow analysis was performed using the Western Electricity Coordinating Council (WECC) 2023HS (heavy summer) base case.

The generation dispatch in the WECC base case was adjusted to create a heavy south to north flow on the Comanche – Midway – Jackson Fuller – Daniels Park transmission system. This was accomplished by adopting the generation dispatch given in Table C5 in "Appendix – Cumulative Study". All the relevant generation changes approved per the Colorado Energy Plan were modeled.

In addition, the following lines for which PSCo has plans to increase the ratings, have been modeled at their future ratings:

- Waterton – Martin2 tap 115kV line was modeled at 189MVA
- Daniels Park – Prairie1 230kV line was modeled at 576MVA
- Greenwood – Monaco 230kV line was modeled at 503MVA
- Leetsdale – Monaco 230kV line was modeled at 470MVA
- Poncha – Smelter town 115kV line was modeled at 114MVA

Transient stability analysis was performed using General Electric's PSLF Ver.21.0_02 program. A study case was created by modeling GI-2016-7 in the 2023HS case. Three phase faults were simulated for selected single and multiple contingencies using standard clearing times. The voltage and frequency of transmission busses in the study area, and the relative rotor angle of generators in the study area were recorded and analyzed. PSLF's DYTOOLS EPCL program was used to simulate the disturbances.

The steady state analysis was performed using PTI's PSSE Ver. 33.6.0 program and the ACCC contingency analysis tool.

The cumulative study benchmark case for GI-2016-7 was developed starting from the 2023HS base case by using a top down (sequential) cumulative approach to add all higher-queued generation in the PSCo GIR queue that have an NRIS request, along with associated network upgrades. The benchmark case for the analysis of GI-2016-7 was created by modeling the following higher-queued NRIS Generation Interconnection request: GI-2014-6, GI-2014-8, GI-2014-9 and GI-2014-12.

The cumulative study case was created from the cumulative study benchmark case by adding GI-2016-7 model to the cumulative study benchmark case. The results from cumulative study benchmark case and the cumulative study case were compared to determine the thermal constraints attributable to GI-2016-7, and identify the network upgrades required for GI-2016-7 to qualify as NRIS. This determination is contingent upon all network upgrades identified for the higher-queued requests being placed in-service.

Power Flow Analysis Results

The results of the single contingency analysis (P1 and P2) are given in Table C6 in "Appendix – Cumulative Study". The following Network Upgrades are assigned to GI-2016-7:

- Fountain Valley – Desert Cove 115kV line loading increased from 87.1% to 101.1% (BHCE facility)
- Fountain Valley – MidwayBR 115kV line loading increased from 89.1% to 103.6% (BHCE facility)
- Midway 230kV Bus Tie line loading increased from 90.9% to 105.4% (WAPA facility)

- Smeltertown – West Canyon 115kV line loading increased from 99.8% to 111.4% (BHCE facility)
- Kelker – RD_Nixon 230kV line loading increased from 98.2% to 101.2% (CSU facility)

PSCo has coordinated with WAPA, CSU and BHCE, and has informed them of the overloads on the one WAPA line, two CSU lines and the two BHCE lines listed above. Mitigation measures for each of these Affected Party overloads must be identified and addressed in order for GI-2016-7 to achieve ERIS or NRIS of 240MW.

Voltage Regulation and Reactive Power Capability

Interconnection Customer is required to interconnect its Large Generating Facility with Public Service of Colorado's (PSCo) Transmission System in accordance with the *Xcel Energy Interconnection Guidelines for Transmission Interconnected Producer-Owned Generation Greater Than 20 MW* (available at:

http://www.transmission.xcelenergy.com/staticfiles/microsites/Transmission/Files/PDF/Interconnection/Interconnections-POL-TransmissionInterconnectionGuidelineGreat20MW.pdf).

In addition, any wind generating plant interconnections must also fulfill the performance requirements specified in FERC Order 661-A. Accordingly, the following voltage regulation and reactive power capability requirements at the POI are applicable to this interconnection request:

- To ensure reliable operation, all Generating Facilities interconnected to the PSCo transmission system are expected to adhere to the *Rocky Mountain Area Voltage Coordination Guidelines (RMAVCG)*. Accordingly, since the POI for this interconnection request is located within Southeast Colorado - Region 4 defined in the *RMAVCG*; the applicable ideal transmission system voltage profile range is 1.02 – 1.03 per unit at regulated buses and 1.0 – 1.03 per unit at non-regulated buses.
- Xcel Energy's OATT (Attachment N effective 10/14/2016) requires all non-synchronous Generator Interconnection (GI) Customers to provide dynamic reactive power within the power factor range of 0.95 leading to 0.95 lagging at the high side of the generator substation. Furthermore, Xcel Energy requires every Generating Facility to have dynamic voltage control capability to assist in maintaining the POI voltage schedule specified by the Transmission Operator as long as the Generating Facility does not have to operate outside its 0.95 lag – 0.95 lead dynamic power factor range capability.
- It is the responsibility of the Interconnection Customer to determine the type (switched shunt capacitors and/or switched shunt reactors, etc.), the size (MVAR), and the locations (34.5kV or 230kV bus) of any additional static reactive power compensation needed within the generating plant in order to have adequate reactive capability to meet the +/- 0.95 power factor and the 1.02 – 1.03 per unit voltage range standards at the POI. Further, for wind generating plants to meet the LVRT (Low Voltage Ride Through) performance requirements specified in FERC Order 661-A, an appropriately sized and located dynamic

reactive power device (DVAR, SVC, etc.) may also need to be installed within the generating plant. Finally, it is the responsibility of the Interconnection Customer to compensate their generation tie-line to ensure minimal reactive power flow under no load conditions.

The Interconnection Customer is required to demonstrate to the satisfaction of PSCo Transmission Operations prior to the commercial in-service date of the generating plant that it can safely and reliably operate within the required power factor and voltage ranges (noted above).

Transient Stability Study Results

The transient stability analysis for GI-2016-7 System Impact Study simulated nine disturbances for the study case (power flow case with GI-2016-7 modeled).

It is determined that GI-2016-7 produced no adverse system stability impact. The following results were obtained for every case and disturbance analyzed:

- ✓ No machines lost synchronism with the system
- ✓ No transient voltage drop violations were observed
- ✓ Machine rotor angles displayed positive damping

Transient stability plots showing surrounding bus voltages, bus frequencies, generator terminal voltages, generator relative angles, generator speeds, and generator power output for each of the disturbances run for each study scenario have been created and documented in "Appendix - Cumulative Study". Furthermore, it is the responsibility of the Interconnection Customer to ensure that its generating facility is capable of meeting the voltage ride-through and frequency ride-through (VRT and FRT) performance specified in the NERC Reliability Standard PRC-024.

Short Circuit and Breaker Duty Analysis

The calculated short circuit levels and Thevenin system equivalent impedances at the Boone 230kV POI are tabulated below.

Table C1 – Short Circuit Parameters at (GI-2016-7) Boone 230kV bus POI – Cumulative Study

	Before GI-2016-7 Interconnection	After GI-2016-7 Interconnection
Three Phase Current	11708.4A	11924.9A
Single Line to Ground Current	10347.1A	10556.6A
Positive Sequence Impedance	1.34022+j11.4891ohms	1.34022+j11.4891ohms
Negative Sequence Impedance	1.36627+j11.4859ohms	1.36627+j11.4859ohms
Zero Sequence Impedance	2.65812+j16.1031ohms	2.65802+j15.8805ohms

A preliminary breaker duty study did not identify any circuit breakers that became over-dutied”[3] as a result of adding this generation.

Costs Estimates and Assumptions

The Transmission Provider has specified and estimated the cost of the equipment, engineering, procurement and construction work needed to interconnect GI-2016-7. The results of the engineering analysis for facilities owned by the Transmission Provider are estimates and are summarized in Table C2 and Table C3.

> Table C2: “Transmission Provider’s Interconnection Facilities” includes the nature and estimated cost of the Transmission Provider's Interconnection Facilities and an estimate of the time required to complete the construction and installation of such facilities.
>
> Table C3: “Network Upgrades required for Interconnection (applicable for either ERIS or NRIS)” includes the nature and estimated cost of the Transmission Provider's Network Upgrades necessary to accomplish the interconnection and an estimate of the time required to complete the construction and installation of such facilities.

Upgrades identified in Table C2 and Table C3 are illustrated in Figure C2 in the “Appendix – Cumulative Study” which shows the physical and electrical connection of the Interconnection Customer’s Generating Facility to the Transmission Provider’s Transmission System. The one-line diagram also identifies the electrical switching configuration of the interconnection equipment, including, without limitation: the transformer, switchgear, meters, and other station equipment.

Transmission Provider has also specified and estimated the cost of the equipment, engineering, procurement and construction work of additional Network Upgrades required for NRIS. The results of the engineering analysis for facilities owned by the Transmission Provider are estimates and are summarized in Table C4.

> Table C4: “Additional Network Upgrades required for NRIS” includes the nature and estimated cost of the Transmission Provider's additional Network Upgrades required for NRIS and an estimate of the time required to complete the construction and installation of such facilities.

[3] Over-dutied” circuit breaker: A circuit breaker whose short circuit current (SCC) rating is less than the available SCC at the bus.

<u>**Conclusion:**</u>

The total estimated cost of the transmission system improvements required for GI-2016-7 to qualify for:

- **ERIS is $4.083 Million (Tables C2 and C3); and**
- **NRIS is $4.083 Million (Tables C2, C3 and C4)**

This is contingent upon the mitigation of overloads identified in Affected Systems for this Interconnection Request and completion of the Network Upgrades identified for all applicable higher-queued Interconnection Requests (see footnotes to Table C3 and Table C4).

For GI-2016-7 interconnection:

NRIS (after required transmission system improvements) = 240MW

ERIS (after required transmission system improvements) = 240MW (output delivery assumes the use of existing firm or non-firm capacity of the PSCo Transmission System on as as-available basis).

<u>**Note: NRIS or ERIS, in and of itself, does not convey transmission service.**</u>

Table C2 –Transmission Provider's Interconnection Facilities – Cumulative Study

Element	Description	Cost Est. (Millions)
PSCo's Boone 230kV Bus	Interconnect Customer to tap at the Boone 230kV Bus The new equipment includes: • One 230kV gang switch with MOD • Three 230kV Arrestors • Three 230kV metering CTs • Three 230kV metering PTs • Station controls • Associated electrical equipment, bus, wiring and grounding • Associated foundations and structures • Associated transmission line communications, fiber, relaying and testing	**$1.305**
	Transmission line tap into substation.	**$0.055**
	Siting and Land Rights support for siting studies, land and ROW acquisition and construction	**$0.03**
	Total Cost Estimate for Transmission Provider's Interconnection Facilities	**$1.390**
Time Frame	**Site, design, procure and construct**	**18 Months**

Table C3 - Network Upgrades for Interconnection (applicable for either ERIS or NRIS) – Cumulative Study*

Element	Description	Cost Estimate (Millions)
PSCo's Boone 230kV Bus	Interconnect Customer to tap at the Boone 230kV Bus The new equipment includes: Three 230kV breakers Six 230kV gang switches • Station controls • Associated electrical equipment, bus, wiring and grounding • Associated foundations and structures • Associated transmission line communications, fiber, relaying and testing.	**$2.693**
	Siting and Land Rights support for Substation Construction:	**N/A**
	Total Cost Estimate for Network Upgrades for Interconnection	**$2.693**
Time Frame	**Site, design, procure and construct**	**18 Months**

*** Not contingent on completion of Network Upgrades for Interconnection identified for any higher queued Interconnection Requests.**

Table C4 – Additional Network Upgrades for NRIS – Cumulative Study *

Element	Description	Cost Est. (Millions)
N/A	None identified	**$0.00**
	Total Cost Estimate for Network Upgrades for Delivery (NRIS)	**$0.000**
Time Frame	**Site, design, procure and construct**	**N/A**
	Total Project Estimate	**$4.083**

*** Contingent on completion of the Network Upgrades for NRIS and the mitigation of overloads identified in Affected Systems for higher-queued Interconnection Requests GI-2014-6, GI-2014-8, GI-2014-9 and GI-2014-12. For details, refer to their respective System Impact Study reports.**

Cost Estimate Assumptions

- Scoping level cost estimates for Interconnection Facilities and Network Upgrades have a specified accuracy of +/- 30%.
- Estimates are based on 2018 dollars (appropriate contingency and escalation applied, AFUDC is not included).
- Labor is estimated for straight time only – no overtime included.
- Lead times for materials were considered for the schedule.
- Estimates are developed assuming typical construction costs for previous completed projects. These estimates include all applicable labor and overheads associated with the siting support, engineering, design, material/equipment procurement, construction, testing and commissioning of these new substation and transmission line facilities.
- The Generation Facility is not in PSCo's retail service territory. Therefore, no costs for retail load metering are included in these estimates.

- PSCo (or it's Contractor) crews will perform all construction, wiring, and testing and commissioning for PSC owned and maintained facilities.
- The estimated time to site, design, procure and construct the Transmission Provider's Interconnection Facilities and Network Upgrades required for Interconnection is approximately 18 months after authorization to proceed has been obtained.
- A CPCN will not be required for the interconnection facilities construction.
- Line and substation bus outages will be necessary during the construction period. Outage availability could potentially be problematic and necessitate extending the back-feed date.
- Estimates do not include the cost for any Customer owned equipment and associated design and engineering.
- The Customer will be required to design, procure, install, own, operate and maintain a Load Frequency/Automated Generation Control (LF/AGC) RTU at the Customer Substation. PSCo / Xcel will need indications, readings and data from the LFAGC RTU.
- Power Quality Metering (PQM) will be required on the Customer's 230 kV line terminating into the Boone Substation.
- Customer will string optical ground wire (OPGW) cable into the substation as part of their transmission line construction scope.

Appendix - Cumulative Study

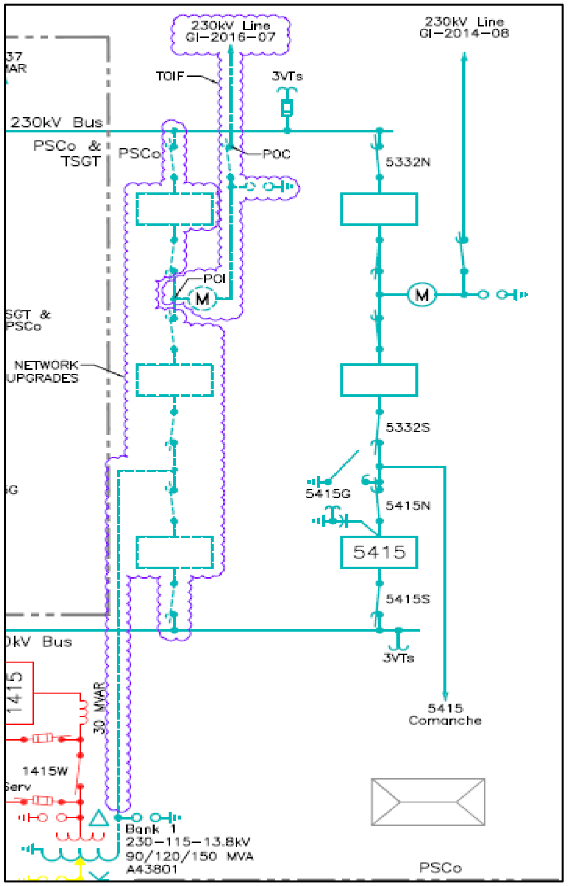


Figure C2 – Preliminary one-line of GI-2016-7 POI within the Boone 230kV Substation - Cumulative Study

Table C5 Generation Dispatch in the Study Area – Cumulative Study (Gross Capacity in Megawatts)

PSCo:

Bus	**Gen ID**	**MW**
Comanche PV	S1	120
Comanche	C2	365
Comanche	C3	805
CEP_1	1	200
CEP_2	1	160
Lamar DC Tie	DC	101
Fountain Valley	G1	36
Fountain Valley	G2	36
Fountain Valley	G3	36
Fountain Valley	G4	36
Fountain Valley	G5	36
Fountain Valley	G6	36
Colorado Green	W1	64.8
Colorado Green	W2	64.8
Twin Butte	W1	60
Twin Butte-II	W1	60
Jackson Fuller	W1&W2	151.9

BHE:

Bus	**Gen ID**	**MW**
BUSCHWRTG1	G1	28.8
BUSCHWRTG2	G2	28.8
BUSCHWRTG2	G3	28.8
E Canon	G1	0
PP_MINE	G1	0
PuebloDiesels	G1	0
Pueblo Plant	G1	0
Pueblo Plant	G2	0.0
R.F. Diesels	G1	0.0
Airport Diesels	G1	0.0
Canyon City	C1	0
Canyon City	C1	0
Baculite 1	G1	90
Baculite 2	G1	90
Baculite 3	G1	40.0
Baculite 3	G2	40.0
Baculite 3	S1	24
Baculite 4	G1	20
Baculite 4	G2	24
Baculite 4	S1	24
Baculite 5	G1	0

CSU:

Bus	**Gen ID**	**MW**
Birdsale1	1	0.0
Birdsale 2	1	0.0
Birdsale 3	1	0.0
RD_Nixon	1	220.5
Tesla	1	13.2
Drake 5	1	0.0
Drake 6	1	80.6
Drake 7	1	137.1
Nixon CT 1	1	0.0
Nixon CT 2	1	0.0
Front Range CC 1	1	137.3
Front Range CC 2	1	136.9
Front Range CC 3	1	161.3

Table C6 Power Flow Analysis Results – Cumulative Study

Note – Thermal overloads for single contingencies are calculated using the normal rating of the facility. All overloads are in red.

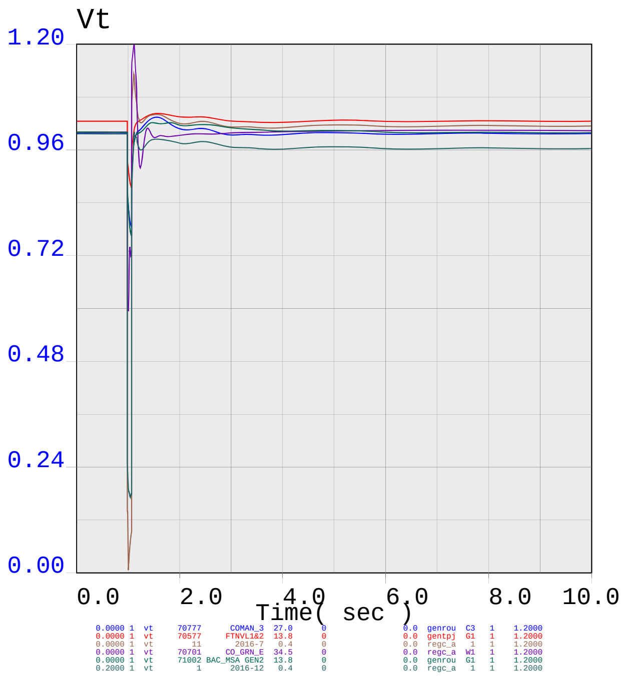
Table C6 – Summary of Thermal Violations from Single Contingency Analysis										
				Facility Loading Without GI-2016-7		Facility Loading With GI-2016-7				
Monitored Facility (Line or Transformer)	Type	Owner	Branch Rating MVA (Norm)	N-1 Flow MVA (Norm)	N-1 Flow % of Rating (Norm)	N-1 Flow MVA (Norm)	N-1 Flow % of Rating (Norm)	% Change	NERC Single Contingency	Network Upgrade Assigned to GI
Canyon City – Skala 115kV	Line	BHCE	119	120.4	101.2%	130.1	109.3%	8.1%	MidwayBR – West Canyon 230kV	GI-2014-12
Fountain Valley – DesertCove 115kV	Line	BHCE	119	103.6	87.1%	120.3	101.1%	14%	Daniels Park – CEP1 345kV	GI-2016-7
Fountain Valley – MidwayBR 115kV	Line	BHCE	115	102.5	89.1%	119.1	103.6%	14.5%	Daniels Park – CEP1 345kV	GI-2016-7
Midway PS 230/115kV	Xfmr	PSCo	97	101.9	105.1%	111.1	114.5%	9.4%	DesertCove – West Station 115kV	GI-2014-12
Midway 230kV Bus Tie	Line	WAPA	430	390.9	90.9%	453.2	105.4%	14.5%	Midway PS – Fuller 230kV	GI-2016-7
Palmer Lake – Monument 115kV	Line	CSU	108	129.5	119.9%	156.2	144.6%	24.7%	Daniels Park – Fuller 230kV	GI-2014-12
Portland – Skala 115kV	Line	BHCE	111	126	113.5%	135.6	122.2%	8.7%	MidwayBR – West Canyon 230kV	Pre-existing
Smelter town – West Canyon 115kV	Line	BHCE	62	61.9	99.8%	69.1	111.4%	11.6%	PonchaBR– West Canyon 230kV	GI-2016-7
Briargate S – Cottonwood S 115kV	Line	CSU	150	187.2	124.8%	200.1	133.4%	8.6%	KettleCreek S – KettleCreek N 115kV	GI-2014-6

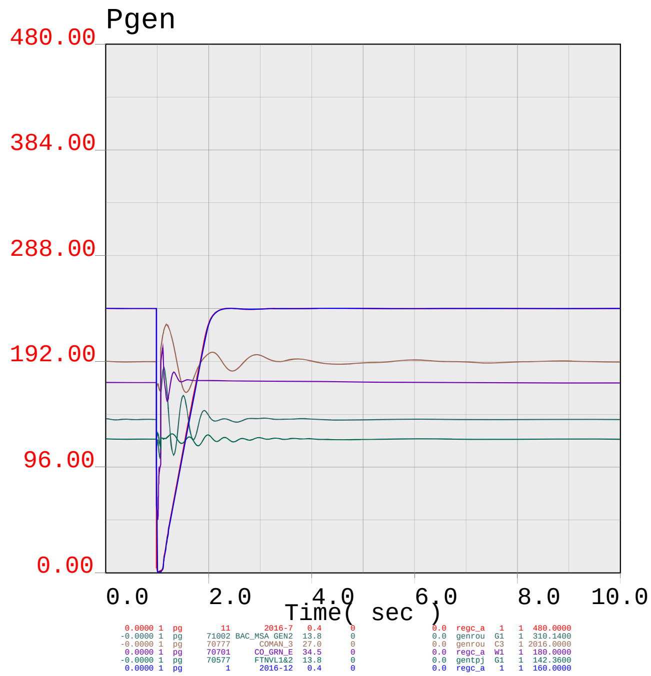
Table C6 – Summary of Thermal Violations from Single Contingency Analysis										
				Facility Loading Without GI-2016-7		Facility Loading With GI-2016-7				
Monitored Facility (Line or Transformer)	Type	Owner	Branch Rating MVA (Norm)	N-1 Flow MVA (Norm)	N-1 Flow % of Rating (Norm)	N-1 Flow MVA (Norm)	N-1 Flow % of Rating (Norm)	% Change	NERC Single Contingency	Network Upgrade Assigned to GI
Cottonwood N – KettleCreek S 115kV	Line	CSU	162	203.3	125.5%	218.2	134.7%	9.2%	Briargate S – Briargate N 115kV	GI-2014-6
Monument – Flyinghorse N 115kV	Line	CSU	142	149.8	105.5%	169.4	119.3%	13.8%	Fuller – Black Squirrel 115kV	GI-2014-6
Flyinghorse S – KettleCreek N 115kV	Line	CSU	162	163.3	100.8%	182.7	112.8%	12%	Fuller – Black Squirrel 115kV	GI-2014-12
Kelker – RD_Nixon 230kV	Line	CSU	376	369.2	98.2%	380.5	101.2%	3%	Kelker – Frontrange 230kV	GI-2016-7

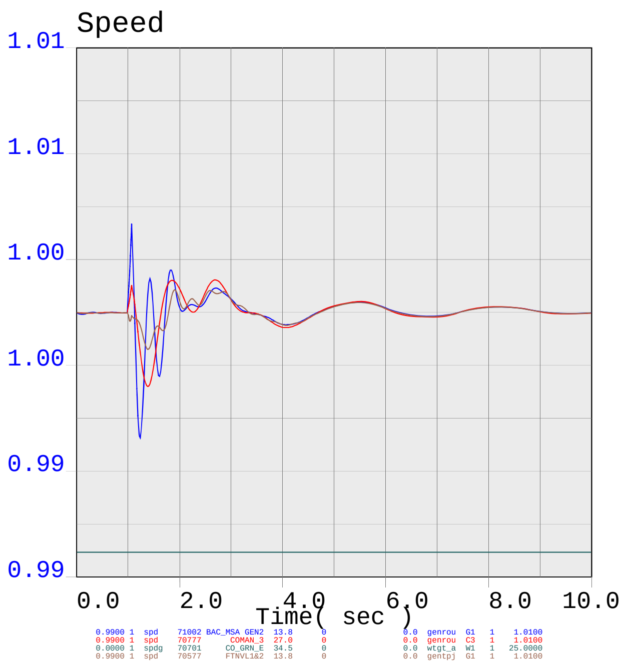
Table C7 Transient Stability Analysis Results – Cumulative Study

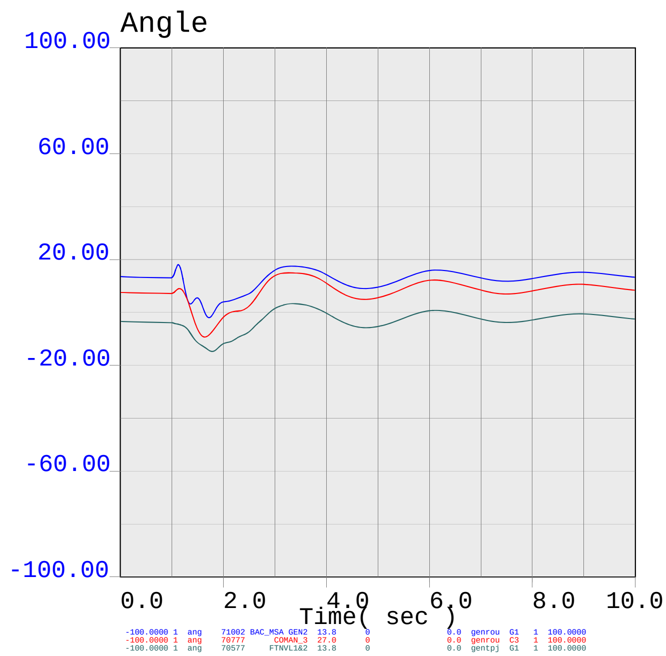
Stability Scenarios						
#	Fault Location	Fault Type	Facility Tripped	Clearing Time (cycles)	Post-Fault Voltage Recovery	Angular Stability
1	Boone 230kV	3ph	Boone 230/115kV Transformer	Primary (5.0)	Maximum transient voltage dips within criteria	Stable with positive damping
2	Boone 230kV	3ph	Lamar – Boone 230kV line and all generation at Lamar	Primary (5.0)	Maximum transient voltage dips within criteria	Stable with positive damping
3	Boone 230kV	3ph	Boone – Comanche 230kV	Primary (5.0)	Maximum transient voltage dips within criteria	Stable with positive damping
4	Boone 230kV	3ph	Boone – Midway 230kV	Primary (5.0)	Maximum transient voltage dips within criteria	Stable with positive damping
5	Comanche 345 kV	3ph	Comanche#3 generator	Primary (4.0)	Maximum transient voltage dips within criteria	Stable with positive damping
6	MidwayPS 230kV	3ph	All Fountain Valley gas units	Primary (5.0)	Maximum transient voltage dips within criteria	Stable with positive damping
7	MidwayPS 345kV	3ph	MidwayPS – Waterton 345kV line & Midway 230/345kV xfmr	Primary (4.0)	Maximum transient voltage dips within criteria	Stable with positive damping
8	Comanche 345kV	3ph	Comanche – Daniels Park 345kV 1 &2	Primary (4.0)	Maximum transient voltage dips within criteria	Stable with positive damping
9	Lamar 230kV	3ph	Lamar – Boone 230kV line and all generation at Lamar	Primary (5.0)	Maximum transient voltage dips within criteria	Stable with positive damping

Table C8 Transient Stability Plots – Cumulative Study









tran_1
Boone 230kV bus fault, lose Boone 230/115kV bank

psec-run-gi-2016-12_7-tran_1.chf

op\Cummulative Study\plts

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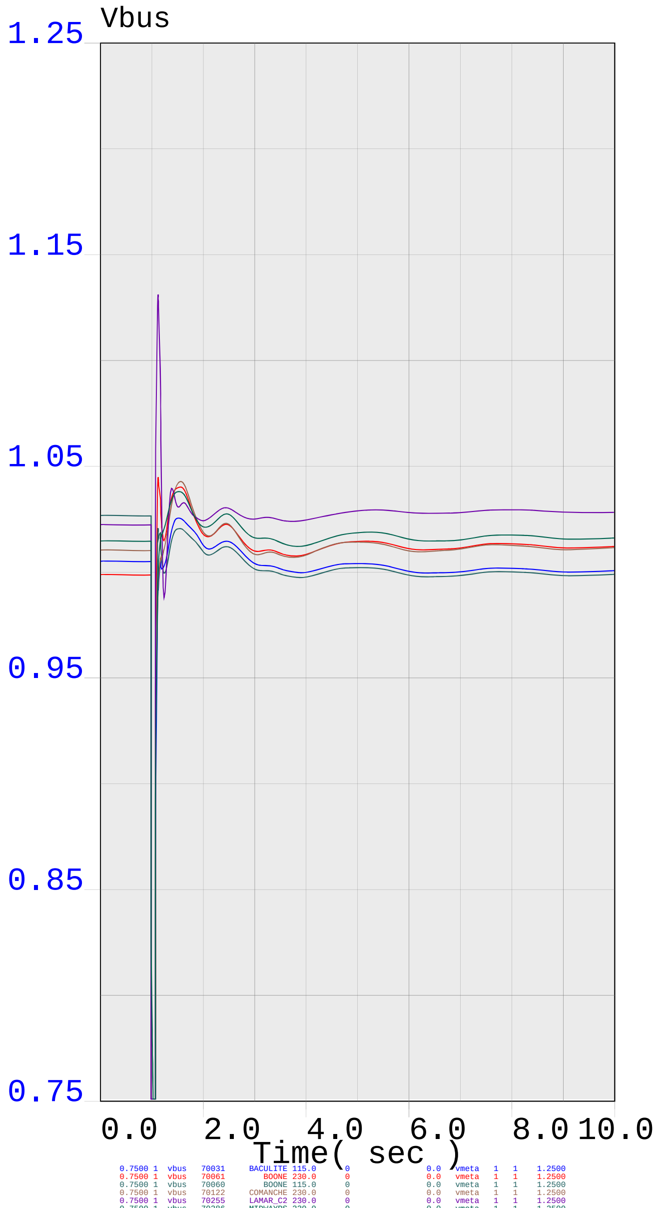
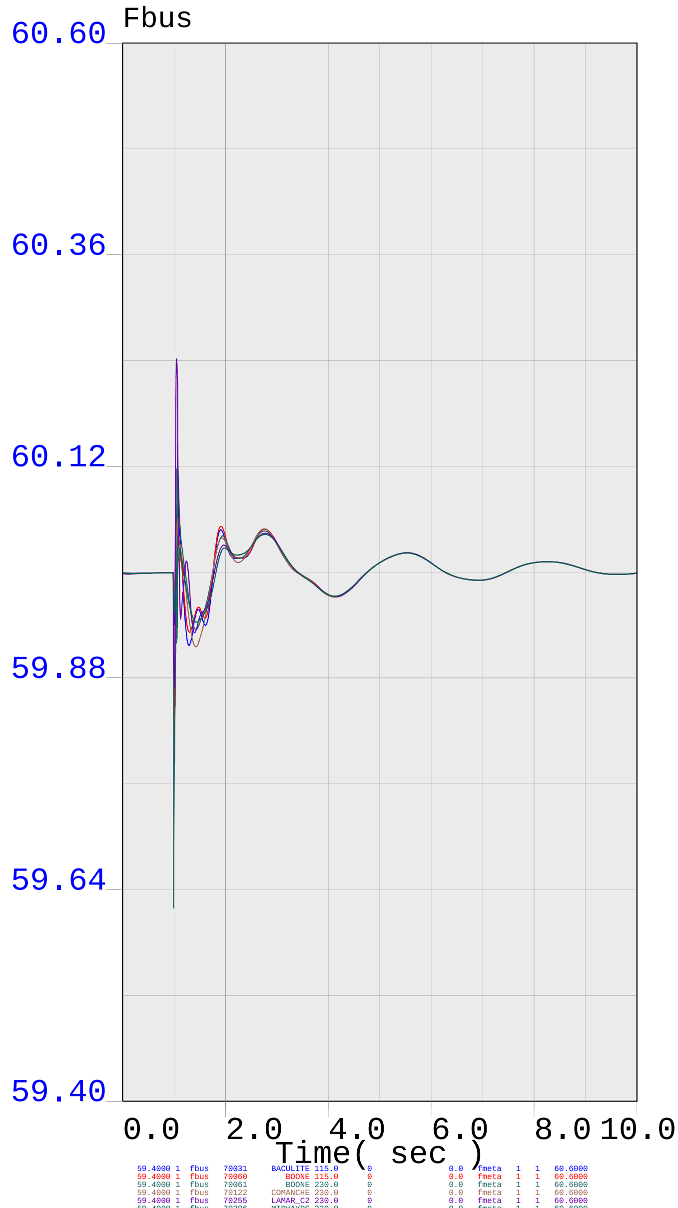
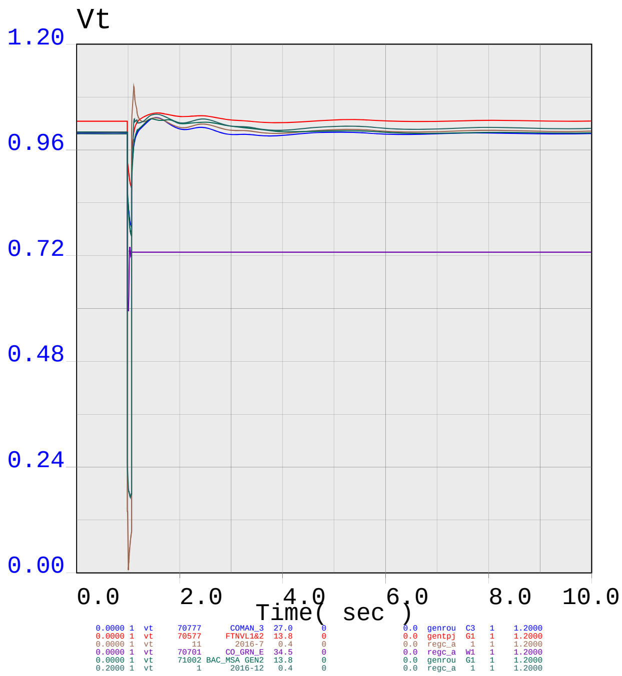
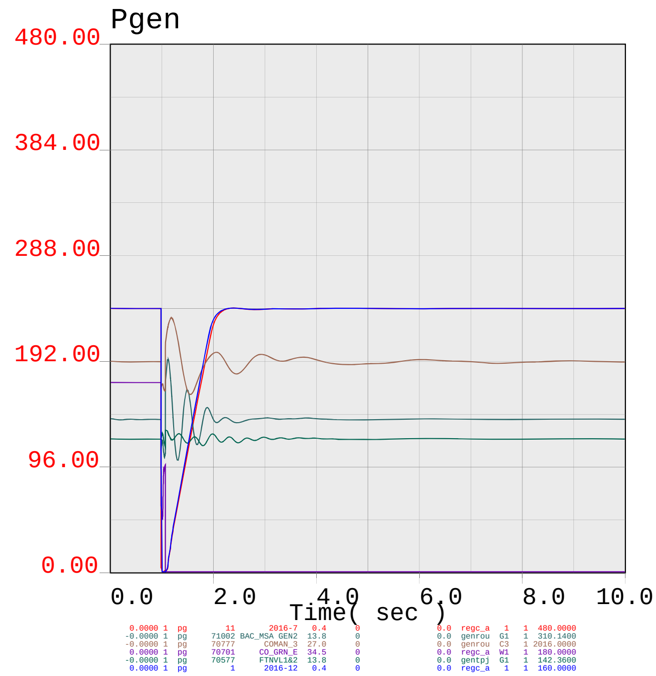
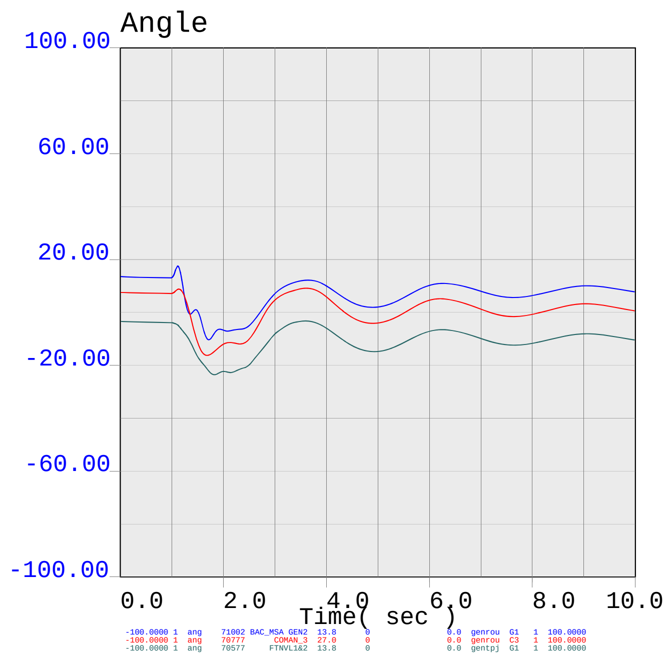




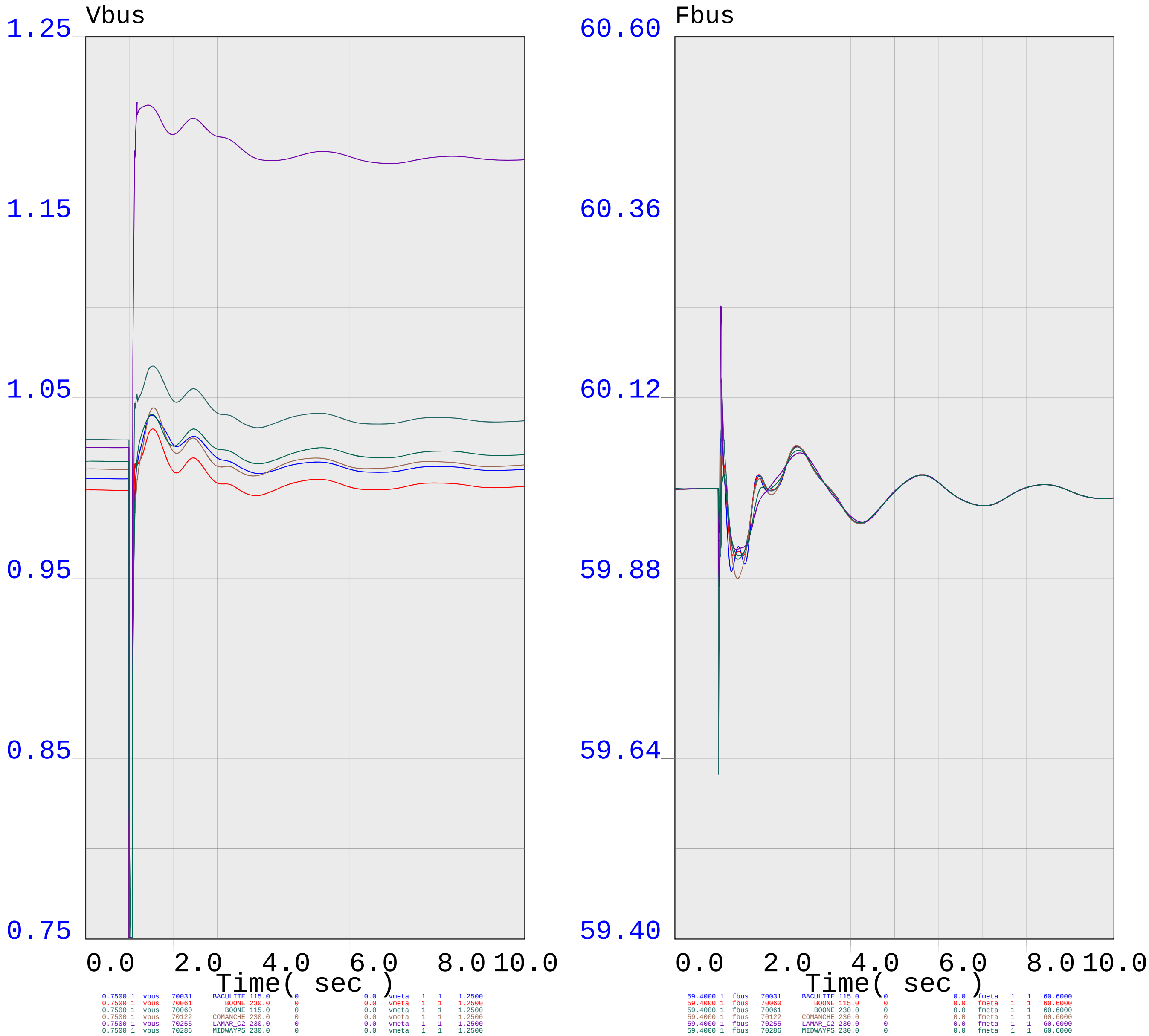
tran_1
Boone 230kV bus fault, lose Boone 230/115kV bank







Line_2
Boone 230kV bus fault, lose Boone-Lamar 230kV and Lamar gen



Line_2
Boone 230kV bus fault, lose Boone-Lamar 230kV and Lamar gen

psec-run-gi-2016-12_7-Line_2.chf

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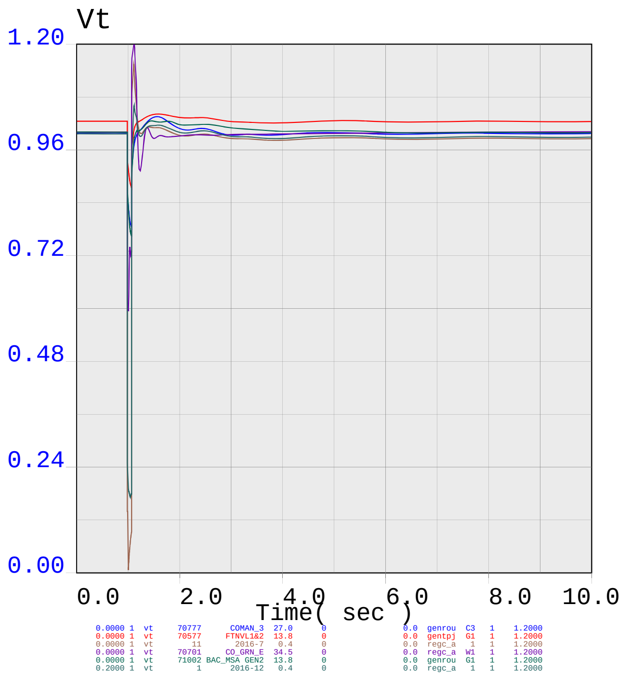
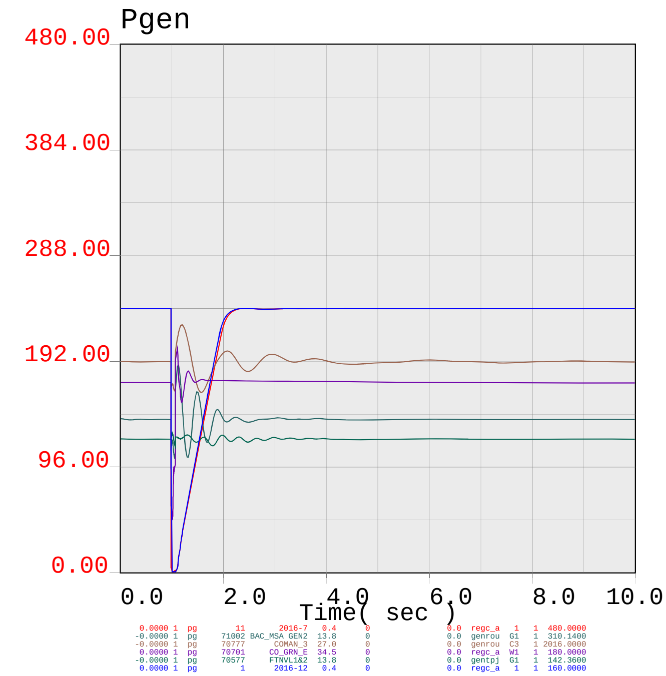
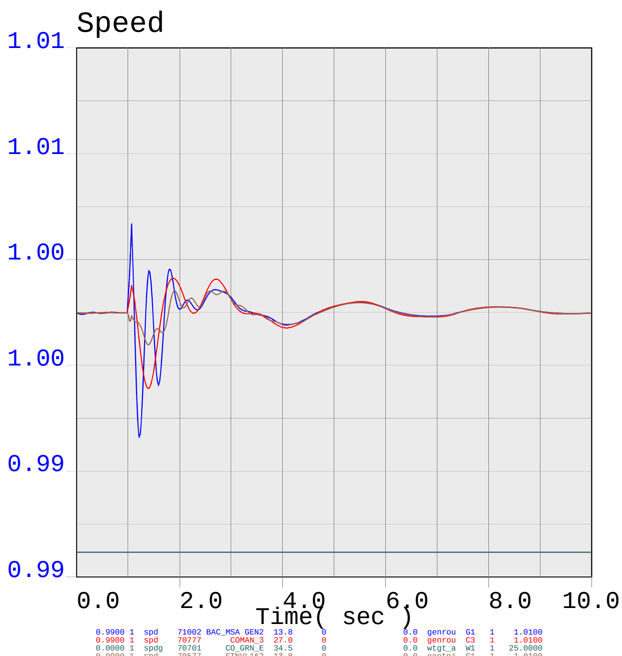
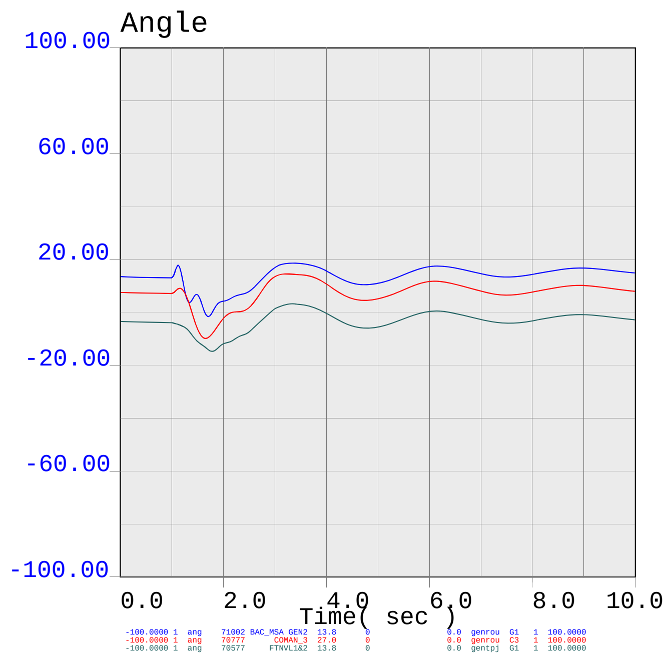
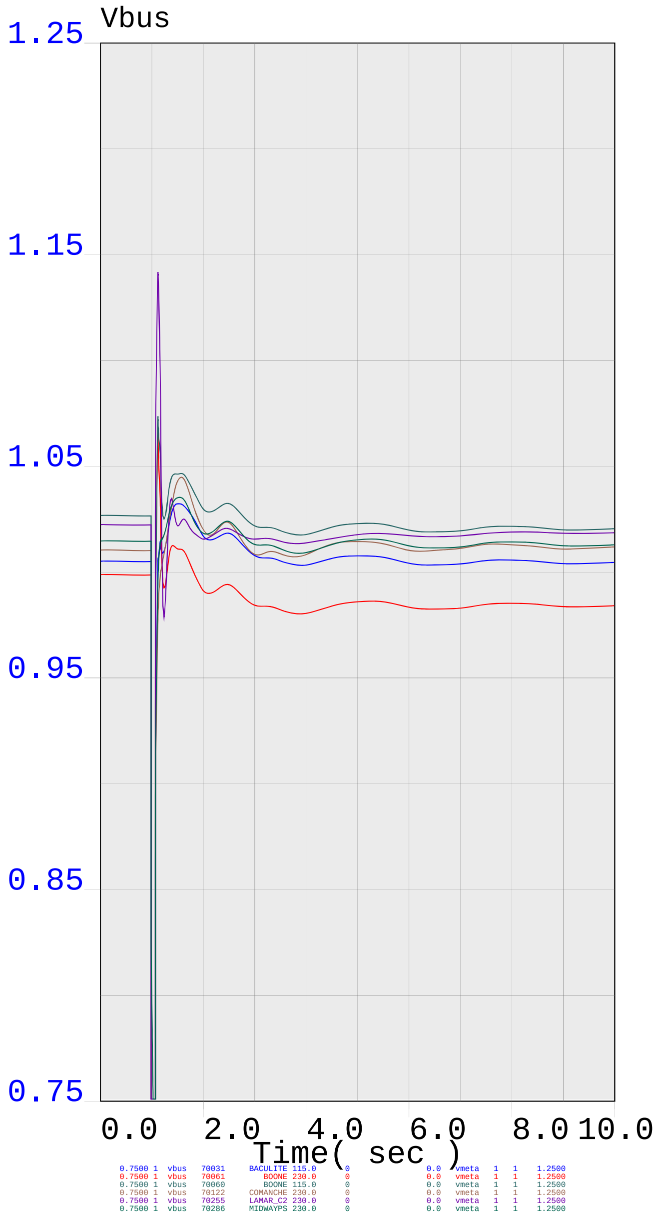


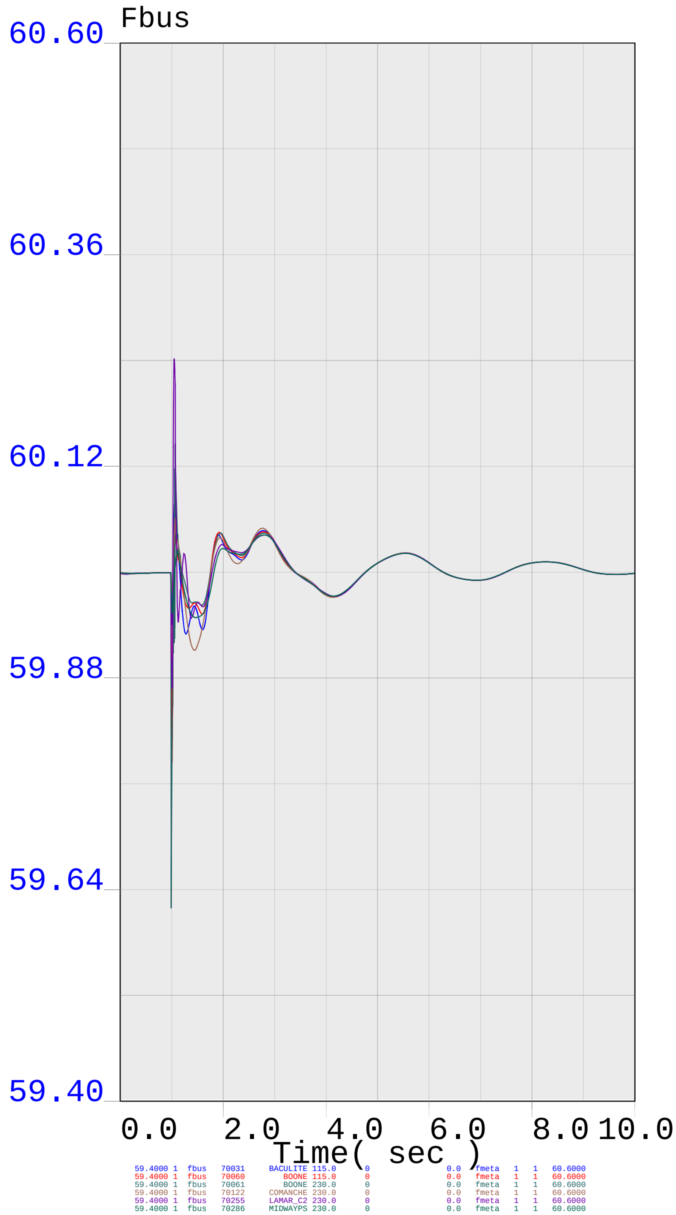




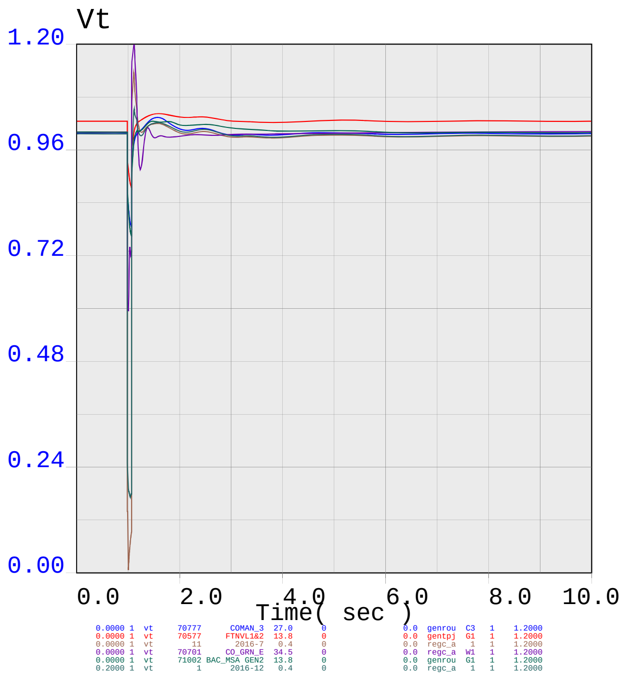


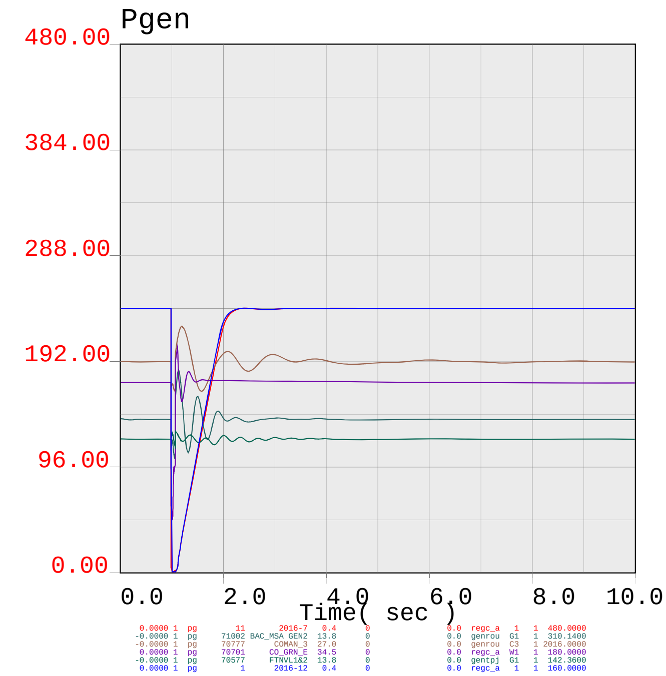
Line_3
Fault at Boone 230kV, lose Boone-Comanche 230kV

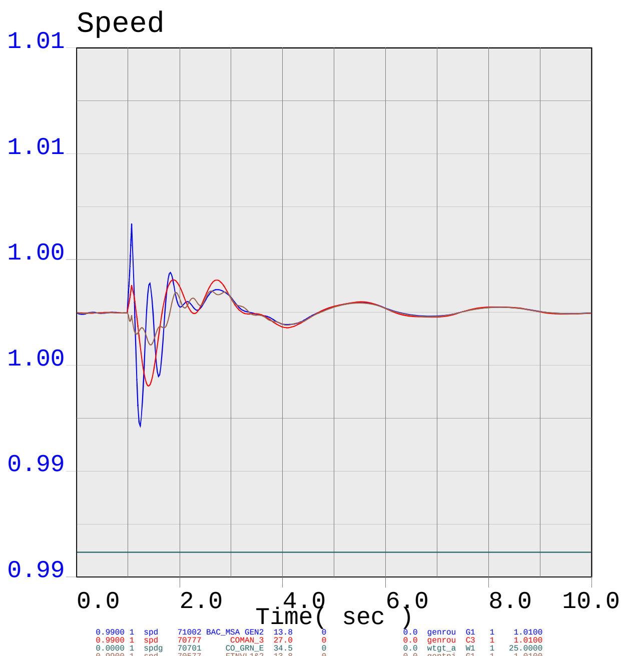


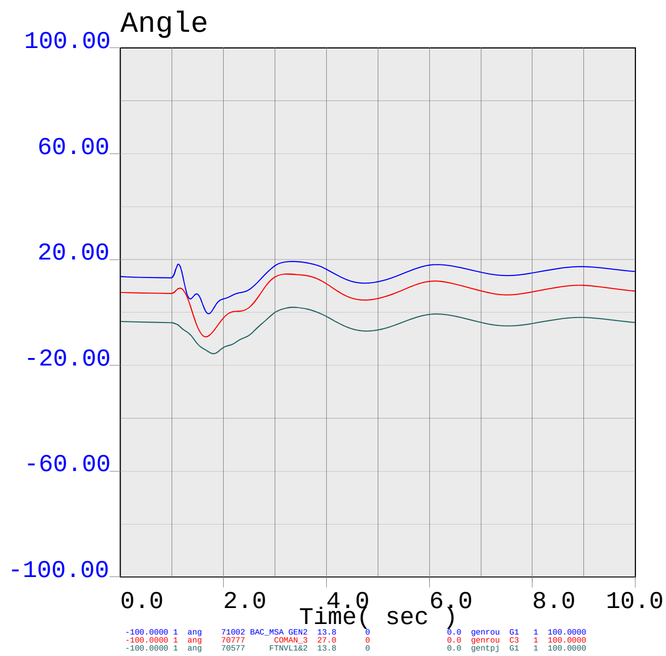


Line_3
Fault at Boone 230kV, lose Boone-Comanche 230kV









Line_4
Fault at Boone 230kV, lose Boone-Midway 230kV

psec-run-gi-2016-12_7-Line_4.chf

p\Cummulative Study\chans

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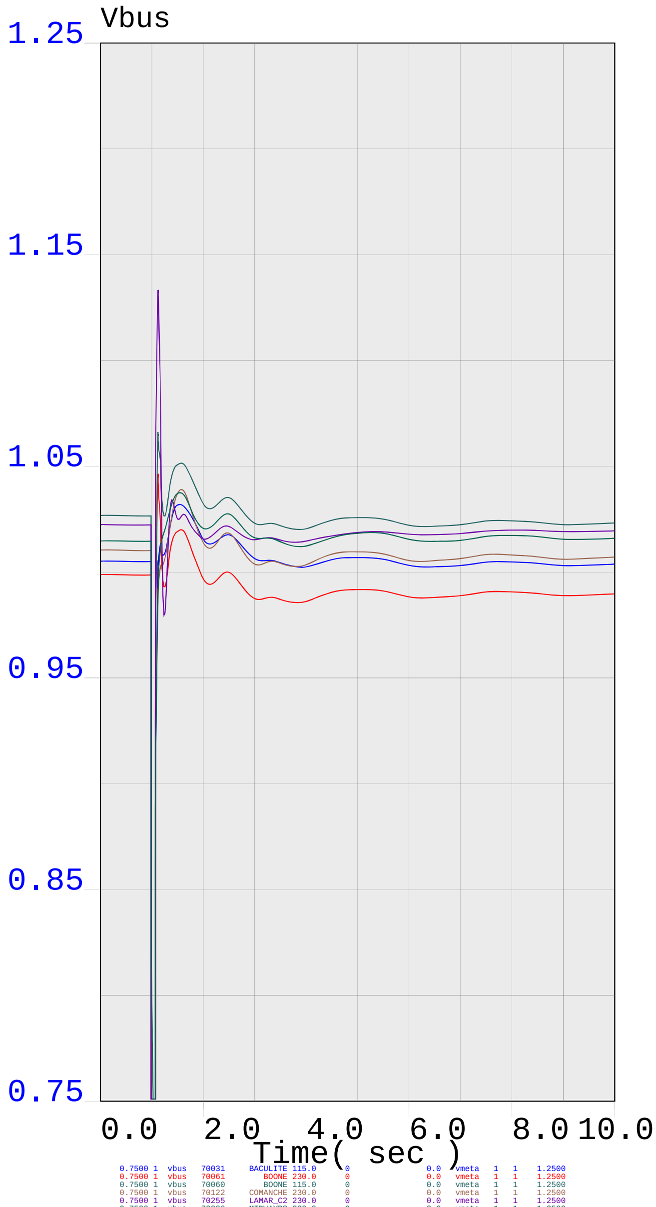

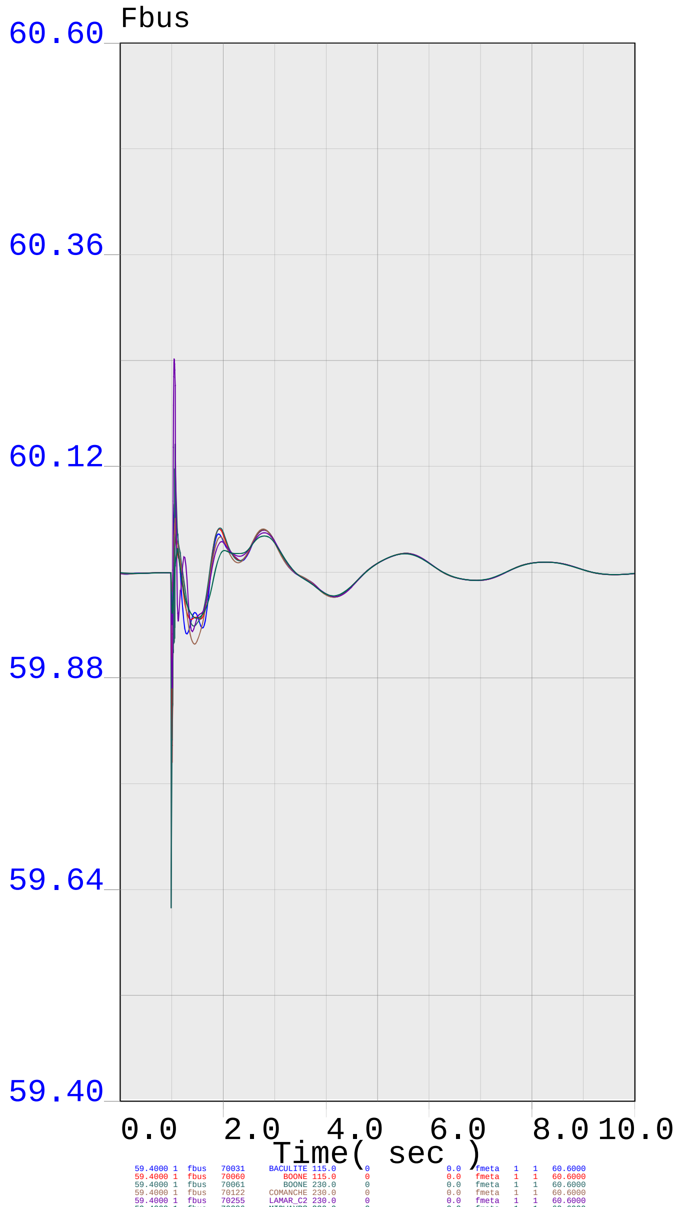

Line_4
Fault at Boone 230kV, lose Boone-Midway 230kV

psec-run-gi-2016-12_7-Line_4.chf

p\Cummulative Study\chans

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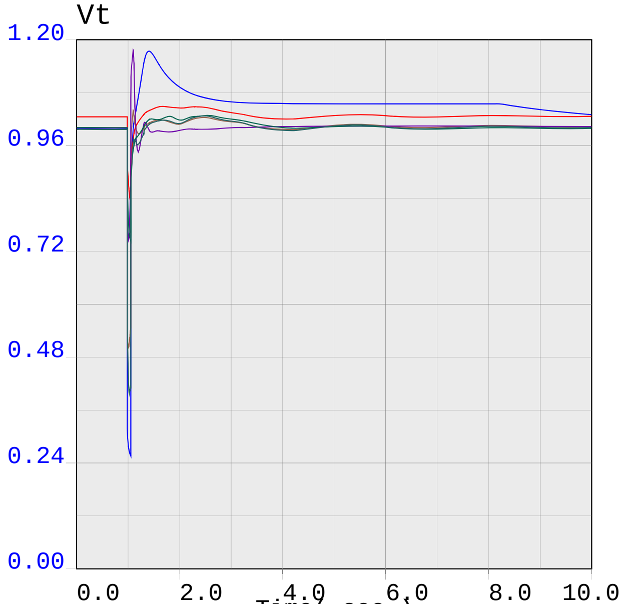
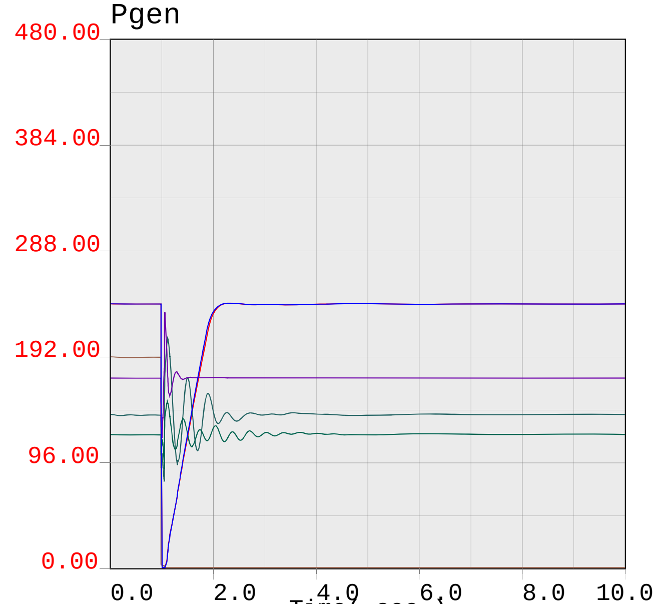
Vt



Pgen



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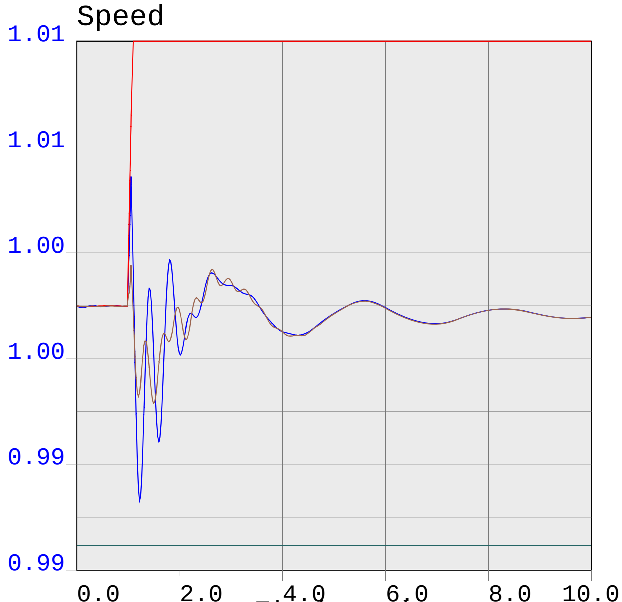
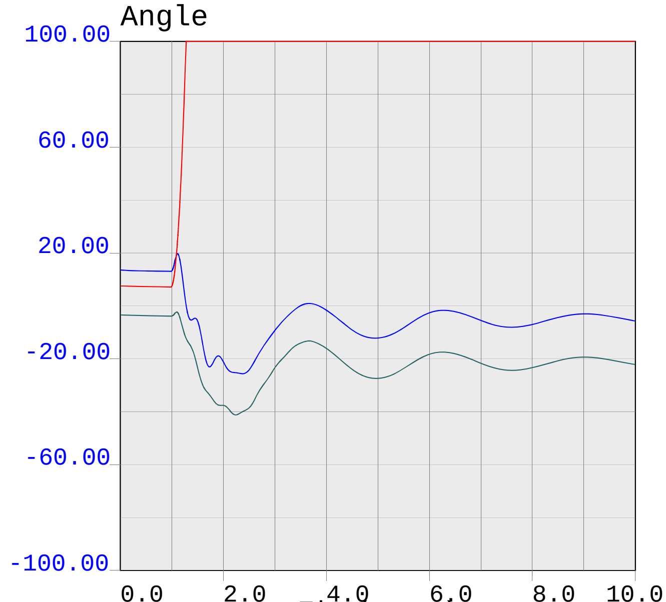


Angle



Line_5
Fault at Comanche 345kV, lose Comanche 3

psec-run-gi-2016-12_7-Line_5.chf

p\Cummulative Study\chans

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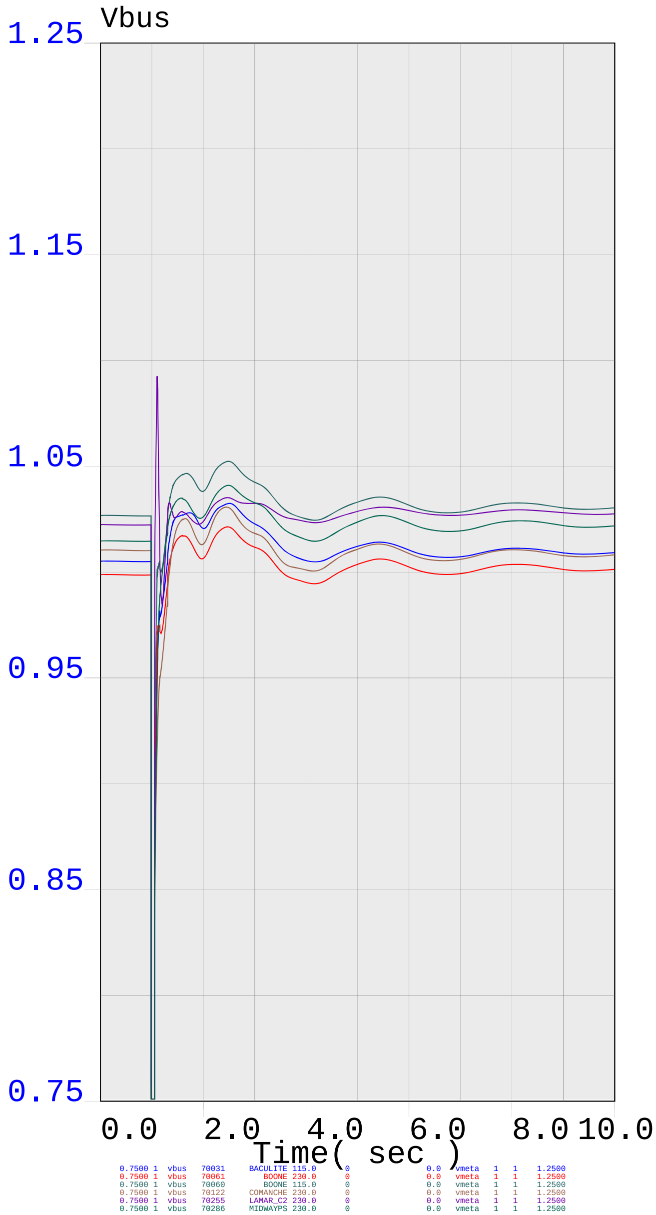

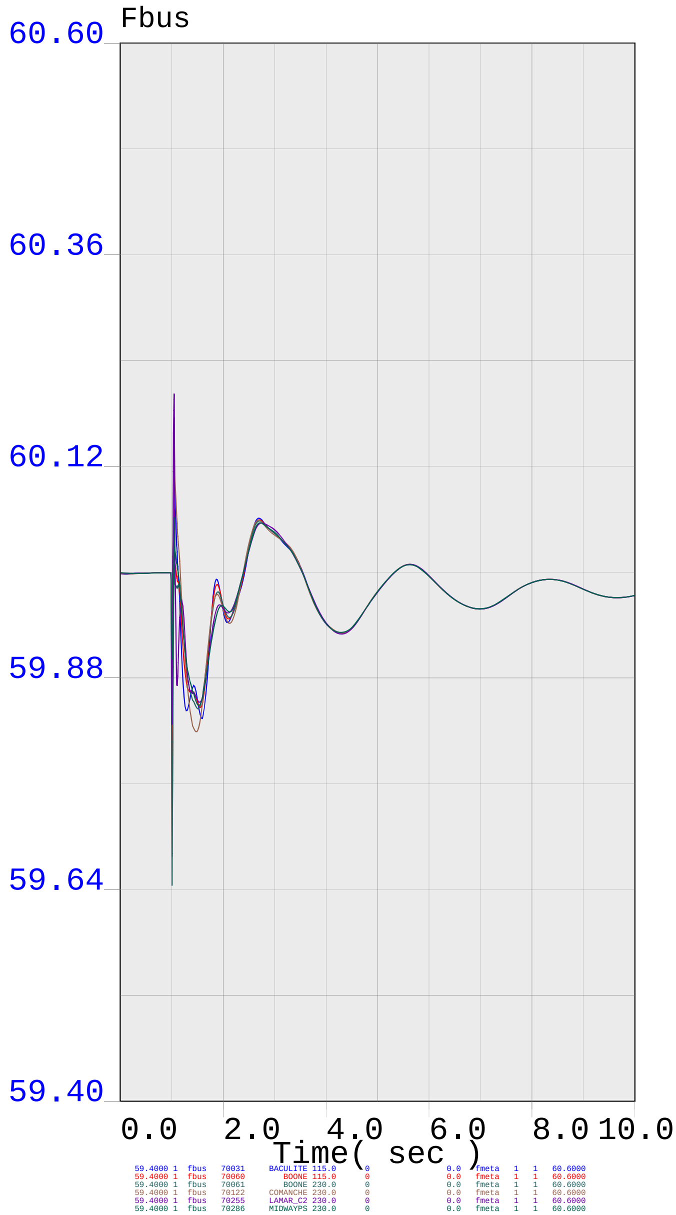

Line_5
Fault at Comanche 345kV, lose Comanche 3

psec-run-gi-2016-12_7-Line_5.chf

p\Cummulative Study\chans

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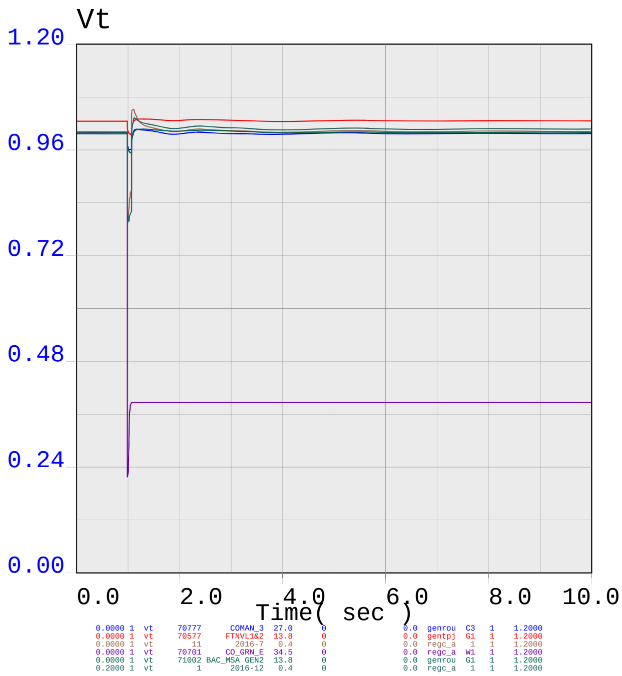

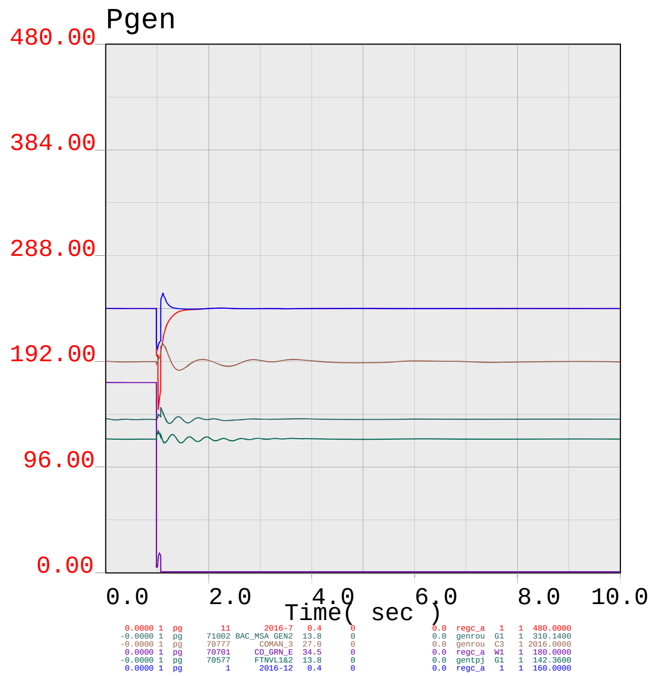

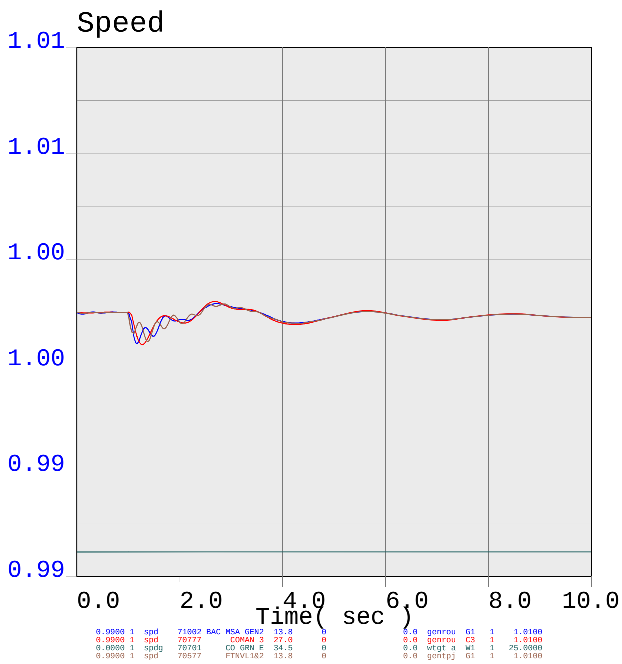

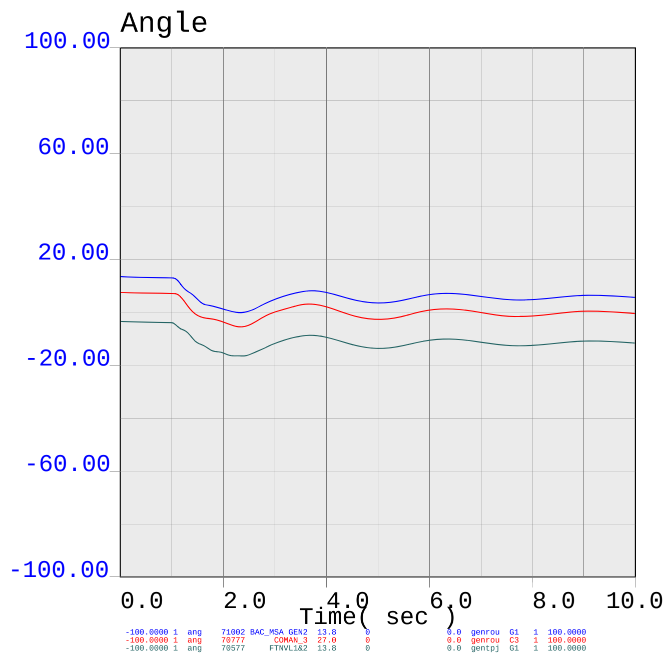

Line_6
Lamar 230kV bus fault, lose Lamar-Boone 230kV and Lamar gen

psec-run-gi-2016-12_7-Line_6.chf

p\Cummulative Study\chans

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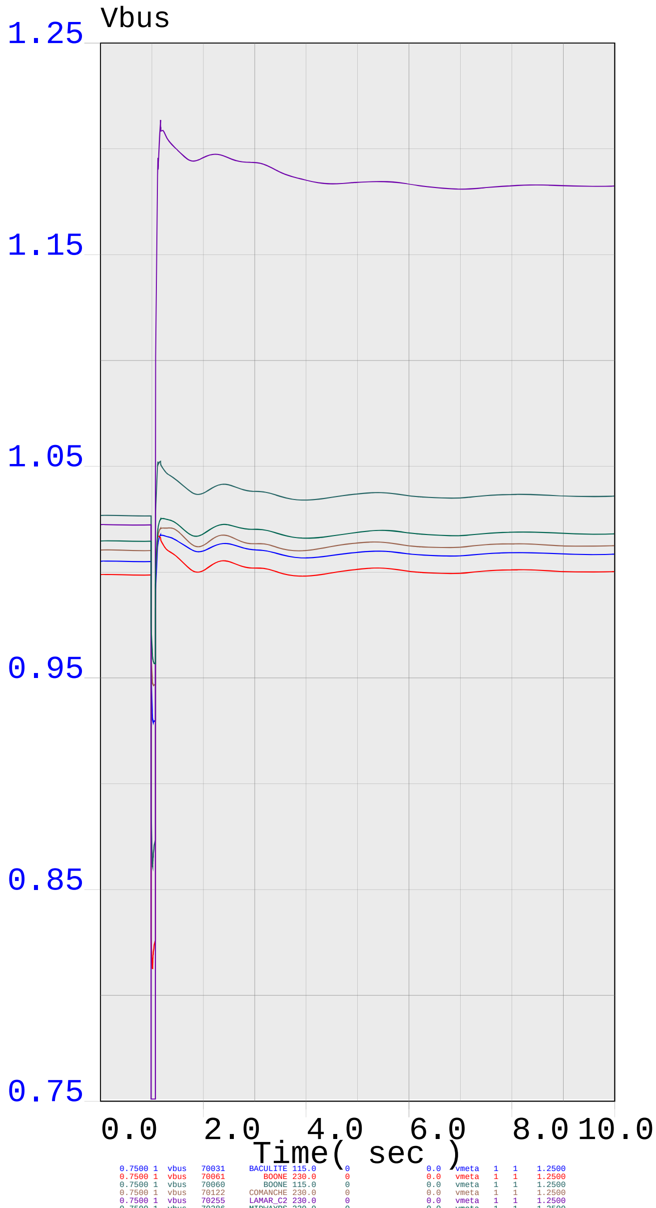

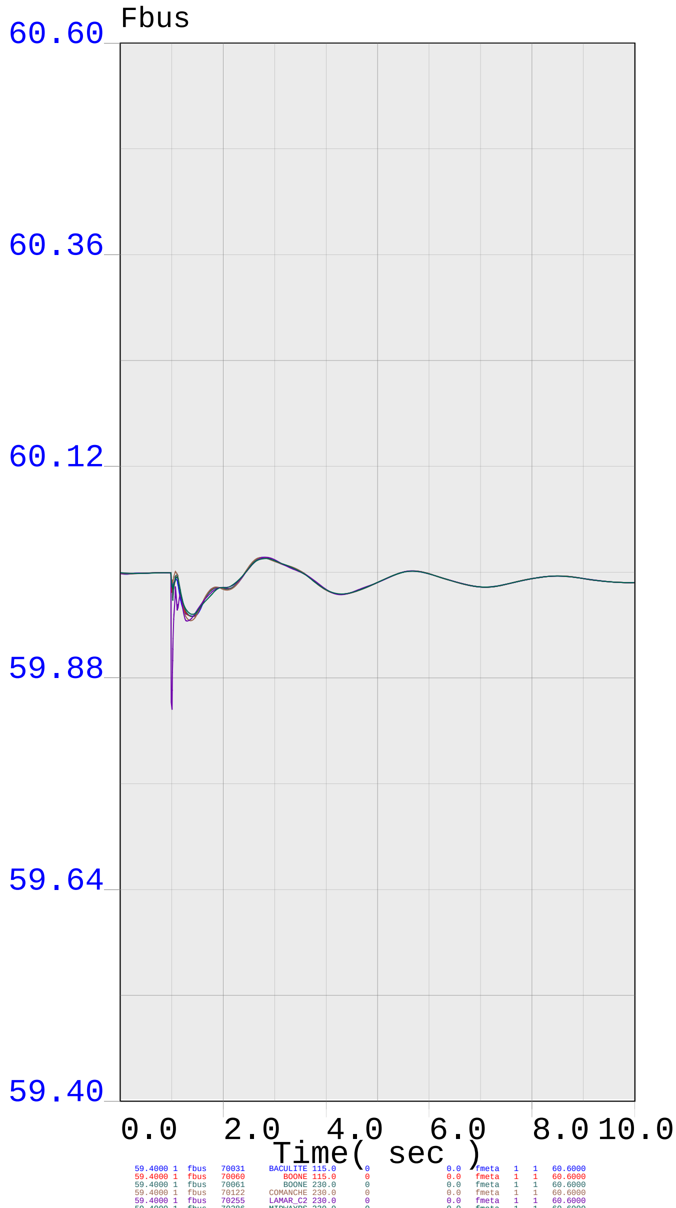

Line_6
Lamar 230kV bus fault, lose Lamar-Boone 230kV and Lamar gen

psec-run-gi-2016-12_7-Line_6.chf

p\Cummulative Study\chans

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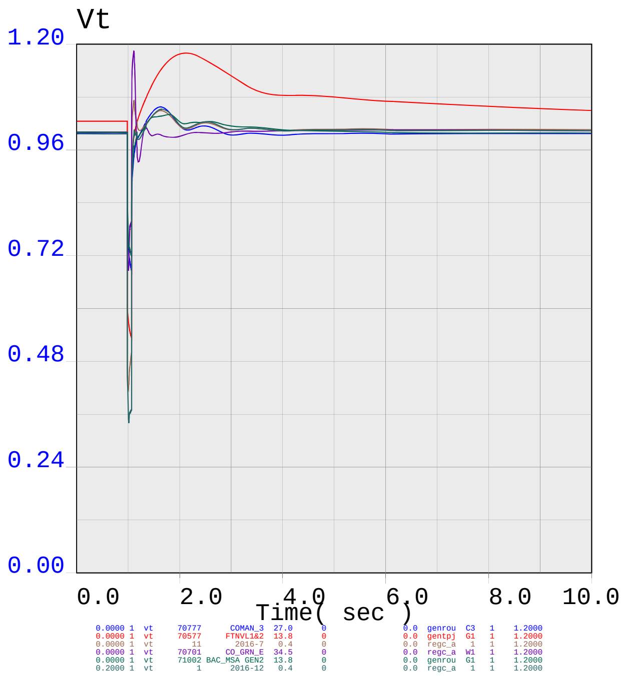

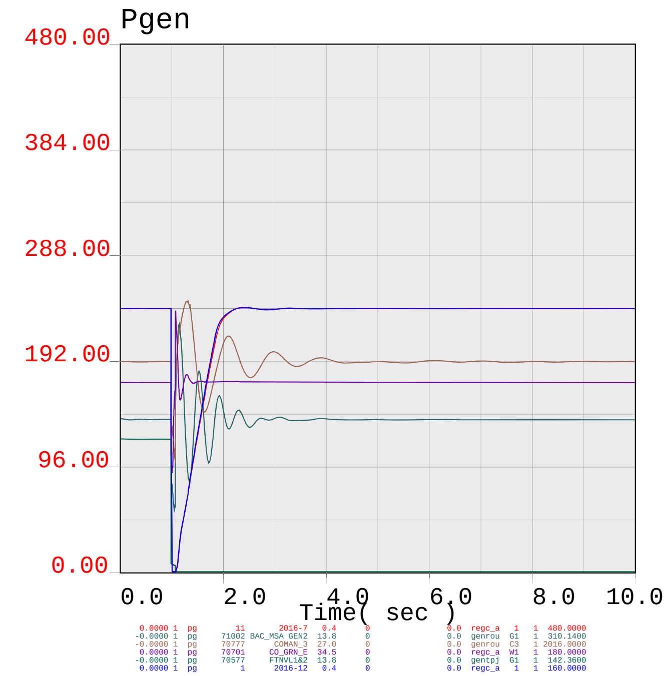

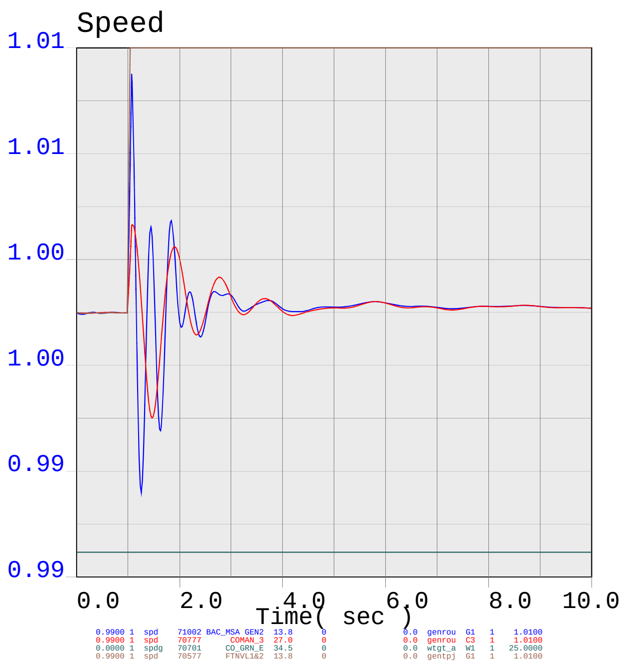

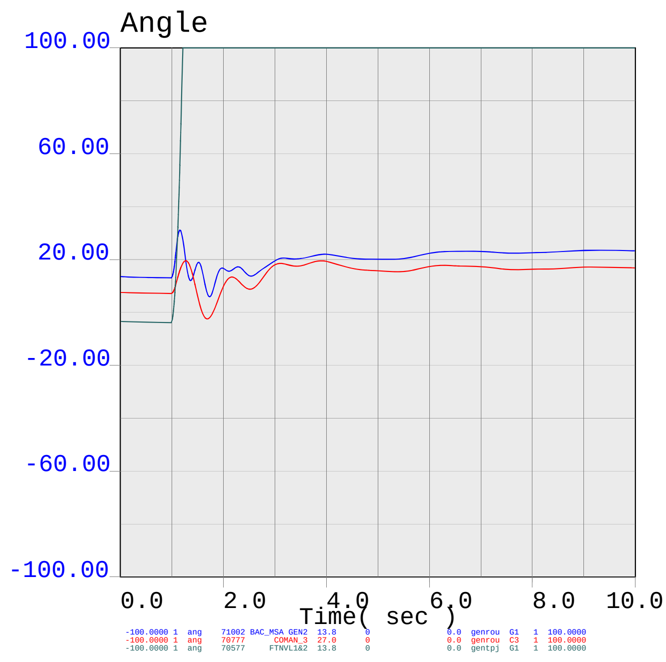

Line_7
Fault at Midway 230kV, lose Fountain Valley gen

psec-run-gi-2016-12_7-Line_7.chf

p\Cummulative Study\chans

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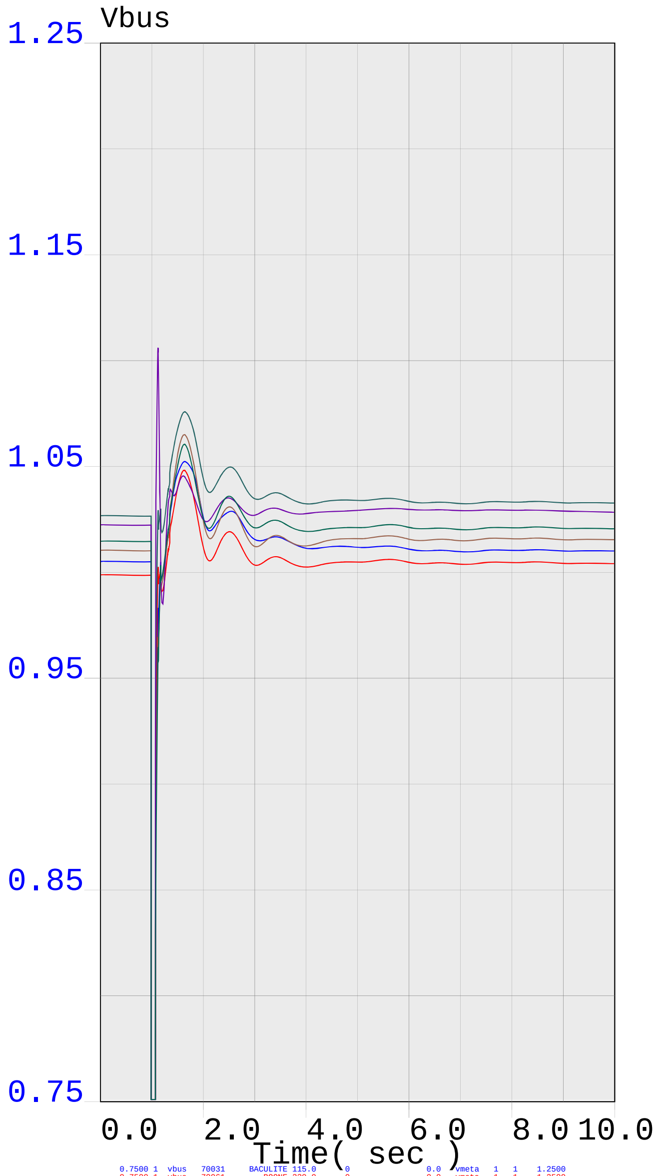
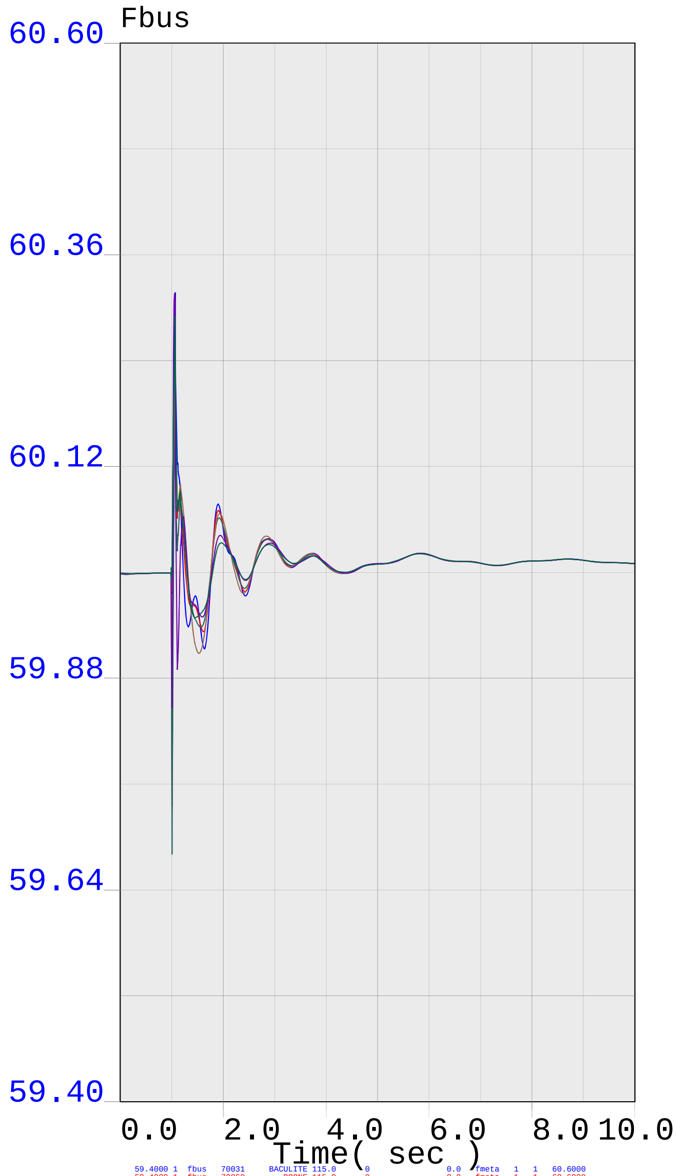


0.7500	1	vbus	70031	BACULITE	115.0	0	0.0	vmeta	1	1	1.2500
0.7500	1	vbus	70061	BOONE	230.0	0	0.0	vmeta	1	1	1.2500
0.7500	1	vbus	70060	BOONE	115.0	0	0.0	vmeta	1	1	1.2500
0.7500	1	vbus	70122	COMANCHE	230.0	0	0.0	vmeta	1	1	1.2500
0.7500	1	vbus	70255	LAMAR_C2	230.0	0	0.0	vmeta	1	1	1.2500
0.7500	1	vbus	70286	MIDWAYPS	230.0	0	0.0	vmeta	1	1	1.2500



59.4000	1	fbus	70031	BACULITE	115.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	70060	BOONE	115.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	70061	BOONE	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	70122	COMANCHE	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	70255	LAMAR_C2	230.0	0	0.0	fmeta	1	1	60.6000
59.4000	1	fbus	70286	MIDWAYPS	230.0	0	0.0	fmeta	1	1	60.6000

Line_7
Fault at Midway 230kV, lose Fountain Valley gen

Attachment 1

Generation Interconnection Request # GI-2016-7
Interconnection System Impact Study
Stand-alone Study Report
(For Information Only)

Executive Summary

This attachment provides the results of GI-2016-7 studied without higher queued projects not yet in-service or their associated upgrades in the model and is for informational purposes only.

The power flow analyses identified the several overloads on the PSCo system and the Affected Party system.

The transient stability analysis determined that all generating units are stable (remain in synchronism), display positive damping and the maximum transient voltage dips are within acceptable dynamic performance criteria.

The short-circuit and breaker duty analysis determined that no breaker replacements are needed at the POI station and/or in neighboring PSCo stations.

The total estimated costs of the recommended system improvements to interconnect the GI-2016-7 project when evaluated on a stand-alone basis include:

- $ 0.992 million for Transmission Provider's Interconnection Facilities
- $ 1.065 million for Network Upgrades required for Interconnection (either ERIS or NRIS)
- $ 0.084 million for additional Network Upgrades for NRIS

The total estimated (illustrative) cost of the transmission system improvements required for GI-2016-7 to qualify for:

- **ERIS is $2.057 Million (Tables S2 and S3); and**
- **NRIS is $2.141 Million (Tables S2, S3 and S4)**

Introduction

The GI-2016-7 is a 240MW solar photovoltaic generation facility that will be located in Pueblo County, Colorado. The Generating Facility (GF) will be made up of one hundred and twenty (120) SMA Sunny Central 2200-US inverters equally distributed over three groups and each group will consist of twenty 4MVA generator step-up transformers. The three groups will connect to a 240MVA main step-up transformer which will connect to the Boone 230kV Primary Point of Interconnection (POI) using a Generator Interconnection Customer owned 230kV tie-line.

The main purpose of this Interconnection System Impact Study is to determine the system impact of interconnecting 240 MW of generation at the Boone 230kV POI without higher queued projects (not yet in-service) or their associated upgrades in the model and is for informational purposes only. As per the Interconnection Study Request, GI-2016-7 was studied for both Energy Resource Interconnection Service (ERIS)[4] and Network Resource Interconnection Service (NRIS)[5]. For both ERIS and NRIS evaluation, the 240 MW rated output of GI-2016-7 is assumed to be delivered to PSCo network load, so existing PSCo generation is used to adjust generation.

The original Commercial Operation Date (COD) proposed was December 31, 2018. During the System Impact Study scoping meeting held on October 4, 2016, the Interconnection Customer has changed the COD of GI-2016-7 to November 30, 2019 and proposed new backfeed date is October 1, 2019.

Study Scope and Analysis Criteria

The scope of this report includes steady state (power flow) analysis, transient stability analysis, short circuit analysis and scoping level cost estimates with +/-30% accuracy. The power flow analysis identifies thermal and voltage violations in the PSCo system and the Affected Systems as a result of the interconnection of the GI. Several single contingencies were studied. Short circuit analysis determines the maximum available fault current at the POI and determines if any breakers at the POI and/or in the neighboring PSCo stations exceed their breaker duty ratings and need to be replaced.

PSCo adheres to applicable NERC Reliability Standards & Western Electricity Coordinating Council (WECC) Reliability Criteria, as well as its internal transmission planning criteria for studies. The steady state analysis criteria are as follows:

---

[4] Energy Resource Interconnection Service shall mean an Interconnection Service that allows the Interconnection Customer to connect its Generating Facility to the Transmission Provider's Transmission System to be eligible to deliver the Generating Facility's electric output using the existing firm or non-firm capacity of the Transmission Provider's Transmission System on an as available basis. Energy Resource Interconnection Service in and of itself does not convey transmission service.

[5] Network Resource Interconnection Service shall mean an Interconnection Service that allows the Interconnection Customer to integrate its Large Generating Facility with the Transmission Provider's Transmission system (1) in a manner comparable to that in which the Transmission Provider integrates its generating facilities to serve native load customers; or (2) in an RTO or ISO with market based congestion management, in the same manner as all other Network Resources. Network Resource Interconnection Service in and of itself does not convey transmission service.

P0 - System Intact conditions:
Thermal Loading: <=100% of the normal facility rating
Voltage range: 0.95 to 1.05 per unit
P1-P2 – Single Contingencies:
Thermal Loading: <=100% Normal facility rating
Voltage range: 0.90 to 1.10 per unit
Voltage deviation: <=5% of pre-contingency voltage

The study area is the electrical system consisting of PSCo's transmission system and the Affected Party's transmission system that is impacted or that will impact interconnection of GI-2016-7. The study area for GI-2016-7 includes WECC designated zones 121, 700, 703, 704, 705, 709, 710, 712, 752 and 757.

Transient stability criteria require that all generating machines remain in synchronism and all power swings should be well damped following a contingency event. Also, transient voltage performance should meet the following WECC Disturbance-Performance criteria:

- Following fault clearing, the voltage shall recover to 80% of the pre-contingency voltage within 20 seconds for all contingencies
- For all contingencies, following fault clearing and voltage recovery above 80%, voltage at each applicable BES bus serving load shall neither dip below 70% of pre-contingency voltage for more than 30 cycles nor remain below 80% of pre-contingency voltage for more than two seconds.
- For contingencies without a fault, voltage dips at each applicable BES bus serving load shall neither dip below 70% of pre-contingency voltage for more than 30 cycles nor remain below 80% of pre-contingency voltage for more than two seconds

Stand-alone Power Flow Analysis

The study was performed using the Western Electricity Coordinating Council (WECC) 2022HS1 power flow case released on 08/31/2016. The generation dispatch in the WECC base case was adjusted to create a heavy south to north flow on the Comanche – Midway – Jackson Fuller – Daniels Park transmission system. This was accomplished by adopting the generation dispatch given in Table S5 in the "Appendix – Stand-alone Study" below. Two power flow models were created from the 2022HS1 case – a Benchmark case which models the planned transmission system topology before the proposed GI-2016-7 interconnection and a study case that includes the 240MW from GI-2016-7.

The GI-2016-7 was modeled using the power flow and dynamic modeling data provided by the GI Customer.
The steady state analysis was performed using PTI's PSSE Ver. 33.10.0 program and the ACCC contingency analysis tool. The results of the single contingency analysis are given in Table S6 in the "Appendix – Stand-alone Study".

- Midway 230kV Bus Tie loading increased from 84.1% to 101.9% (WAPA facility)
- Fountain Valley – DesertCove 115kV line loading increased from 82.9% to 106.0% (BHCE facility)
- Fountain Valley – MidwayBR 115kV line loading increased from 85.7% to 109.6% (BHCE facility)
- Palmer Lake – Monument 115kV line loading increased from 107.0% to 126.7% (CSU facility)
- Briargate South – Cottonwood South 115kV line loading increased from 116.0% to 125.5% (CSU facility)
- Cottonwood North – Kettle Creek South 115kV line loading increased from 116.8% to 127.0% (CSU facility)
- Monument – Flyinghorse 115kV line loading increased from 97.5% to 115.9% (CSU facility)
- KettleCreek N – Flyinghorse S 115kV line loading increased from 94.3% to 110.4% (CSU facility)

Voltage Regulation and Reactive Power Capability

Interconnection Customer is required to interconnect its Large Generating Facility with Public Service of Colorado's (PSCo) Transmission System in accordance with the *Xcel Energy Interconnection Guidelines for Transmission Interconnected Producer-Owned Generation Greater Than 20 MW* (available at:

http://www.transmission.xcelenergy.com/staticfiles/microsites/Transmission/Files/PDF/Interconnection/Interconnections-POL-TransmissionInterconnectionGuidelineGreat20MW.pdf).

In addition, if the GI is a wind generating plant interconnection, it must also fulfill the performance requirements specified in FERC Order 661-A. Accordingly, the following voltage regulation and reactive power capability requirements at the POI are applicable to this interconnection request:

- To ensure reliable operation, all Generating Facilities interconnected to the PSCo transmission system are expected to adhere to the *Rocky Mountain Area Voltage Coordination Guidelines (RMAVCG)*. Accordingly, since the POI for this interconnection request is located within Southeast Colorado - Region 4 defined in the *RMAVCG*; the applicable ideal transmission system voltage profile range is 1.02 – 1.03 per unit at regulated buses and 1.0 – 1.03 per unit at non-regulated buses.

- Xcel Energy's OATT (Attachment N effective 10/14/2016) requires all non-synchronous Generator Interconnection (GI) Customers to provide dynamic reactive power within the power factor range of 0.95 leading to 0.95 lagging at the high side of the generator substation. Furthermore, Xcel Energy requires every Generating Facility to have dynamic voltage control capability to assist in maintaining the POI voltage schedule specified by the

Transmission Operator as long as the Generating Facility does not have to operate outside its 0.95 lag – 0.95 lead dynamic power factor range capability.

- It is the responsibility of the Interconnection Customer to determine the type (switched shunt capacitors and/or switched shunt reactors, etc.), the size (MVAR), and the locations (34.5kV or 230kV bus) of any additional static reactive power compensation needed within the generating plant in order to have adequate reactive capability to meet the +/- 0.95 power factor and the 1.02 – 1.03 per unit voltage range standards at the POI. Further, for wind generating plants to meet the LVRT (Low Voltage Ride Through) performance requirements specified in FERC Order 661-A, an appropriately sized and located dynamic reactive power device (DVAR, SVC, etc.) may also need to be installed within the generating plant. Finally, it is the responsibility of the Interconnection Customer to compensate their generation tie-line to ensure minimal reactive power flow under no load conditions.

The Interconnection Customer is required to demonstrate to the satisfaction of PSCo Transmission Operations prior to the commercial in-service date of the generating plant that it can safely and reliably operate within the required power factor and voltage ranges (noted above).

Stand-alone Transient Analysis

Transient stability analysis was performed using General Electric's PSLF Ver.21.0_02 program. A study case was created by modeling GI-2016-7 in the 2022HS1 case. Three phase faults were simulated for selected single and multiple contingencies using standard clearing times. Bus voltage, bus frequency, and generator angle were recorded and analyzed. Also, any generators that went out of synchronism were recorded. PSLF's DYTOOLS EPCL program was used to simulate the disturbances.

The transient stability analysis for GI-2016-7 System Impact Study simulated nine disturbances for the study case (power flow case with GI-2016-7 modeled).

It is determined that GI-2016-7 produced no adverse system stability impact. The following results were obtained for every case and disturbance analyzed:

- ✓ No machines lost synchronism with the system
- ✓ No transient voltage drop violations were observed
- ✓ Machine rotor angles displayed positive damping

Transient stability plots showing surrounding bus voltages, bus frequencies, generator terminal voltages, generator relative angles, generator speeds, and generator power output for each of the disturbances run for each study scenario have been created and documented in "Appendix – Stand-alone". Furthermore, it is the responsibility of the Interconnection Customer to ensure that its generating facility is capable of meeting the voltage ride-through and frequency ride-through (VRT and FRT) performance specified in the NERC Reliability Standard PRC-024.

Stand-alone Short Circuit and Breaker Duty Analysis

The calculated short circuit levels and Thevenin system equivalent impedances at the Boone 230kV POI are tabulated below.

Table S1 – Short Circuit Parameters at (GI-2016-7) Boone 230kV bus POI – Stand-alone Study

	Before GI-2016-7 Interconnection	After GI-2016-7 Interconnection
Three Phase Current	11068A	11279A
Single Line to Ground Current	9610A	9817A
Positive Sequence Impedance	1.204+j11.937 ohms	1.204+j11.937 ohms
Negative Sequence Impedance	1.225+j11.938 ohms	1.225+j11.938 ohms
Zero Sequence Impedance	2.950+j17.228 ohms	2.947+j16.973 ohms

A preliminary breaker duty study did not identify any circuit breakers that became -over-dutied"[6] as a result of adding this generation.

Conclusion (for informational purposes only)

This stand-alone System Impact Study concludes that the GI-2016-7 interconnection cannot achieve 240MW NRIS until the identified Network upgrades on the PSCo system and the Affected Party transmission system are in-service.

This study identifies the required transmission improvements and cost estimates assuming no higher queued projects or their associated transmission facilities are in-service and so the results are for information only.

Table S2, Table S3, and Table S4, below provide the cost estimates for the Transmission Provider Interconnection Facilities and Network Upgrades identified in this stand-alone System Impact Study. The cost responsibilities associated with these transmission system improvements shall be handled as per the current FERC guidelines.
The total estimated cost of the transmission system improvements required for GI-2016-7 to qualify for:

- **ERIS is $2.057 Million (Tables S2 and S2); and**
- **NRIS is $2.057 Million (Tables S2, S3 and S4)**

Figure S1 in "Appendix – Stand-alone Study" below represents a budgetary one-line diagram of the proposed interconnection of GI-2016-7 at the Boone 230kV POI on a stand-alone basis.

[6] Over-dutied" circuit breaker: A circuit breaker whose short circuit current (SCC) rating is less than the available SCC at the bus.

Illustrative Stand-alone Costs Estimates and Assumptions

Table S2 –Transmission Provider's Interconnection Facilities

Element	Description	Cost Est. (Millions)
PSCo's Boone 230kV Transmission Substation	Interconnect Customer to the 230kV bus at the Boone Substation. The new equipment includes: • One (1) motor operated 230kV disconnect switch • Three (3) 230kV combination CT/PT metering units • Power Quality Metering (230kV line from Customer) • Three (3) surge arresters • Two (2) relay panels • Associated bus, wiring and equipment • Associated foundations and structures • Associated transmission line communications, relaying and testing	**$0.937**
	Transmission line tap into substation. Conductor, hardware, and installation labor.	**$0.055**
	Total Cost Estimate for Transmission Provider's Interconnection Facilities	**$0.992**
Time Frame	**Site, design, procure and construct**	**18 months**

Table S3 - Network Upgrades for Interconnection (applicable for either ERIS or NRIS)

Element	Description	Cost Estimate (Millions)
PSCo's Boone 230kV Transmission Substation	Interconnect Customer to the 230kV bus at the Boone 115kV Substation. The new equipment includes: • One (1) 230kV circuit breaker • Two (2) 230kV gang switches • One (1) 230kV CCVT • Associated communications, supervisory and SCADA equipment • Associated line relaying and testing • Associated bus, miscellaneous electrical equipment, cabling and wiring • Associated foundations and structures Associated road and site development, fencing and grounding	**$1.065**
	Siting and Land Rights support for Substation land acquisition and construction:	**$0.00**
	Total Cost Estimate for Network Upgrades for Interconnection	**$1.065**
Time Frame	**Site, design, procure and construct**	**18 Months**

Table S4 – Additional Network Upgrades for NRIS

Element	Description	Cost Est. (Millions)
N/A	N/A	N/A
	Total Project Estimate	**$2.057**

Cost Estimate Assumptions

- Scoping level cost estimates for Interconnection Facilities and Network Upgrades have a specified accuracy of +/- 30%.
- Estimates are based on 2017 dollars (appropriate contingency and escalation applied, AFUDC is not included).
- Labor is estimated for straight time only – no overtime included.
- Lead times for materials were considered for the schedule.
- Estimates are developed assuming typical construction costs for previous completed projects. These estimates include all applicable labor and overheads associated with the siting support, engineering, design, material/equipment procurement, construction, testing and commissioning of these new substation and transmission line facilities.
- The Generation Facility is not in PSCo's retail service territory. Therefore, no costs for retail load metering are included in these estimates.
- PSCo (or it's Contractor) crews will perform all construction, wiring, and testing and commissioning for PSC owned and maintained facilities.
- The estimated time to site, design, procure and construct the Transmission Provider's Interconnection Facilities and Network Upgrades required for Interconnection is approximately 18 months after authorization to proceed has been obtained.
- A CPCN will not be required for the interconnection facilities construction.
- Line and substation bus outages will be necessary during the construction period. Outage availability could potentially be problematic and necessitate extending the back-feed date.
- Estimates do not include the cost for any Customer owned equipment and associated design and engineering.
- The Customer will be required to design, procure, install, own, operate and maintain a Load Frequency/Automated Generation Control (LF/AGC) RTU at the Customer Substation. PSCo / Xcel will need indications, readings and data from the LFAGC RTU.
- Power Quality Metering (PQM) will be required on the Customer's 230 kV line terminating into the Boone Substation.
- Customer will string optical ground wire (OPGW) cable into the substation as part of their transmission line construction scope.

Appendix - Stand-alone Study

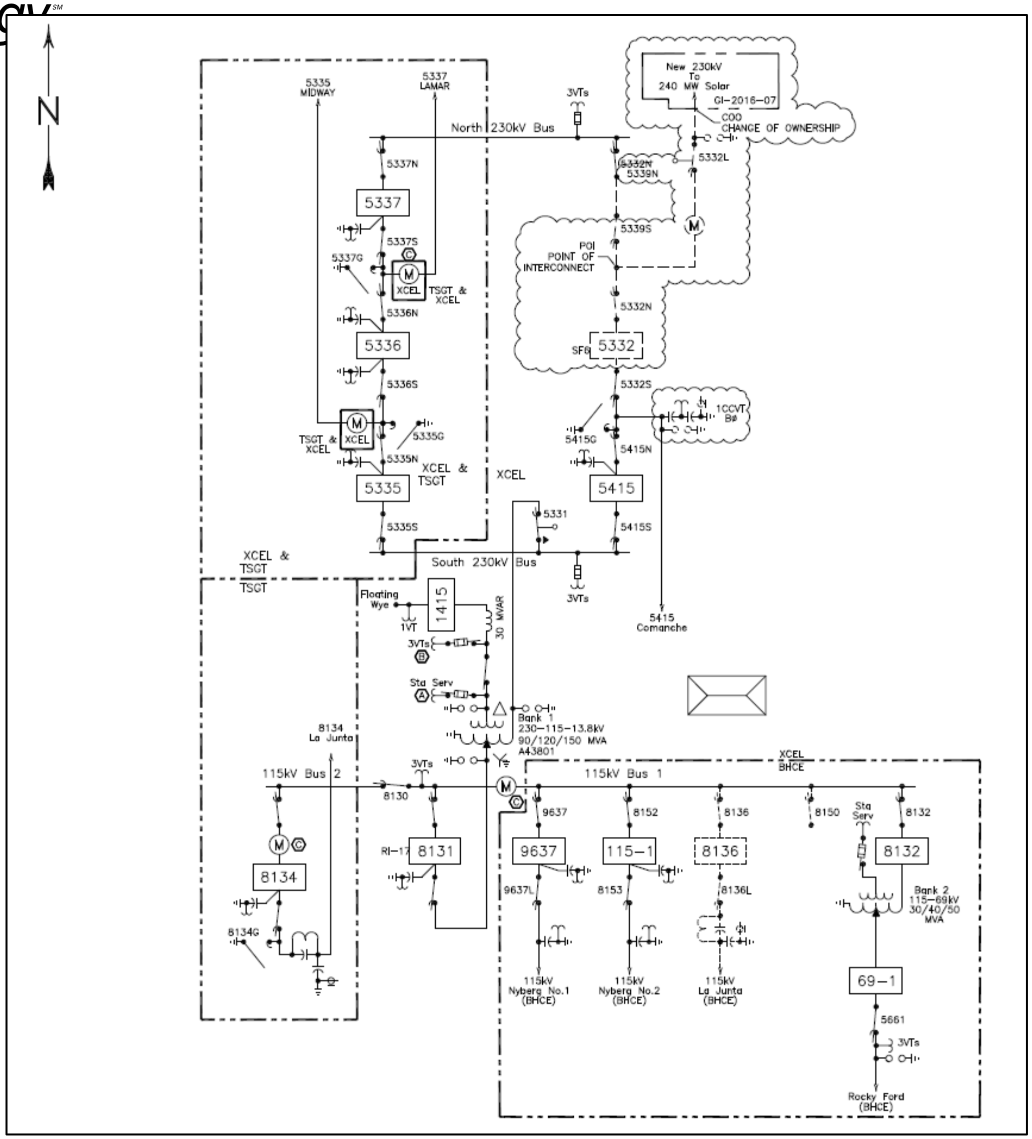


Figure S1 – Preliminary one-line of GI-2016-7 Switching Station at the Primary POI – Stand-alone Study

Table S5– Generation Dispatch in the Study area (MW is Gross Capacity) - Stand-alone Study

PSCo:

Bus	Gen ID	MW
Comanche PV	S1	102
Comanche	C1	357
Comanche	C2	365
Comanche	C3	795
Lamar DC Tie	DC	101
Fountain Valley	G1	36
Fountain Valley	G2	36
Fountain Valley	G3	36
Fountain Valley	G4	36
Fountain Valley	G5	36
Fountain Valley	G6	36
Colorado Green	W1	64.8
Colorado Green	W2	64.8
Twin Butte	W1	60
Twin Butte-II	W1	60
Jackson Fuller	W1&W2	151.9

BHE:

Bus	Gen ID	MW
BUSCHWRTG1	G1	28.8
BUSCHWRTG2	G2	28.8
BUSCHWRTG2	G3	28.8
E Canon	G1	0

PP_MINE	G1	0
PuebloDiesels	G1	0
Pueblo Plant	G1	0
Pueblo Plant	G2	0.0
R.F. Diesels	G1	0.0
Airport Diesels	G1	0.0
Canyon City	C1	0
Canyon City	C1	0
Baculite 1	G1	90
Baculite 2	G1	90
Baculite 3	G1	40.0
Baculite 3	G2	40.0
Baculite 3	S1	24
Baculite 4	G1	20
Baculite 4	G2	24
Baculite 4	S1	24
Baculite 5	G1	0

CSU:

Bus	Gen ID	MW
Birdsale1	1	0.0
Birdsale 2	1	0.0
Birdsale 3	1	0.0
RD_Nixon	1	220.5
Tesla	1	13.2
Drake 5	1	0.0
Drake 6	1	80.6
Drake 7	1	137.1

Nixon CT 1	1	0.0
Nixon CT 2	1	0.0
Front Range CC 1	1	137.3
Front Range CC 2	1	136.9
Front Range CC 3	1	161.3

Table S6 Power Flow Analysis Results – Stand-alone Study

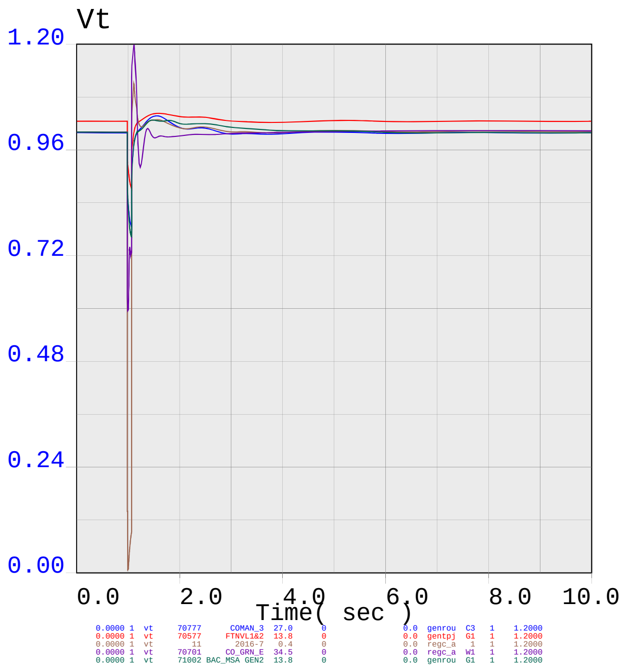
Note – Thermal overloads for single contingencies are calculated using the normal rating of the facility. All overloads are in red.

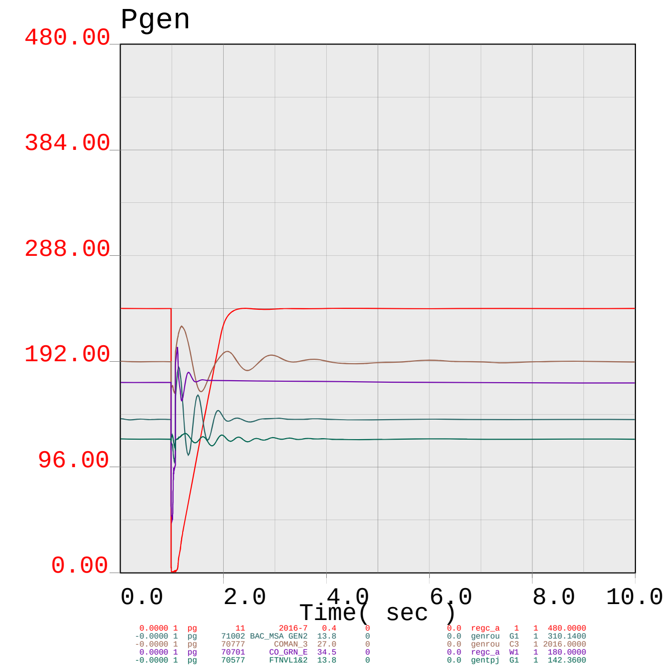
Table S6 – Summary of Thermal Violations from Single Contingency Analysis									
				Facility Loading Without GI-2016-7		Facility Loading With GI-2016-7			
Monitored Facility (Line or Transformer)	**Type**	**Owner**	**Branch Rating MVA (Norm/Emer)**	**N-1 Flow MVA (Norm)**	**N-1 Flow % of Rating (Norm)**	**N-1 Flow MVA (Norm)**	**N-1 Flow % of Rating (Norm)**	**% Change**	**NERC Single Contingency**
Fountain Valley – DesertCove 115kV	Line	BHCE	119	98.6	82.9%	126.1	106.0%	23.1%	Boone – MidwayPS 230kV line
Fountain Valley – MidwayBR 115kV	Line	BHCE	115	98.5	85.7%	126.0	109.6%	23.9%	Boone – MidwayPS 230kV line
Midway 230kV Bus Tie	Line	WAPA	430	361.6	84.1%	438.2	101.9%	17.8%	MidwayPS – Fuller 230kV line
Palmer Lake – Monument 115kV	Line	CSU	142	151.9	107.0%	179.9	126.7%	19.7%	Daniels Park – Fuller 230kV line
Briargate S – Cottonwood S 115kV	Line	CSU	150	174	116.0%	188.2	125.5%	9.5%	Cottonwood N – KettleCreek S 115kV line
Cottonwood N – KettleCreek S 115kV	Line	CSU	162	189.2	116.8%	205.7	127.0%	10.2%	Briargate S – Cottonwood S 115kV line
Monument – Flying Horse 115kV	Line	CSU	142	138.4	97.5%	164.6	115.9%	18.4%	Daniels Park – Fuller 230kV line
Flying Horse – Kettle Creek S 115kV	Line	CSU	162	152.8	94.3%	178.8	110.4%	16.1%	Daniels Park – Fuller 230kV line

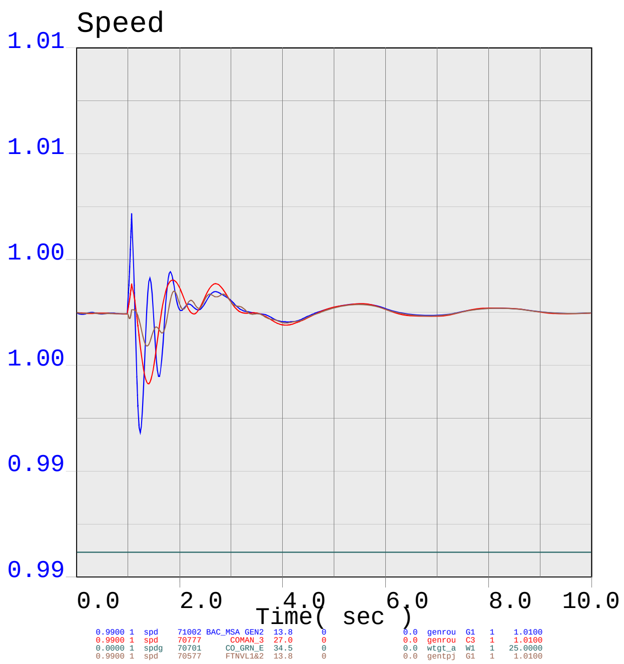
Table S7 – Transient Stability Analysis Results – Stand-alone Study

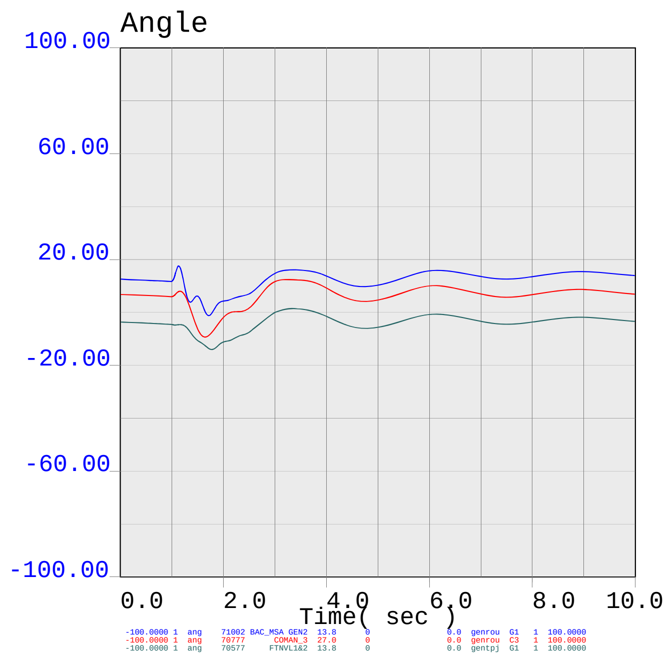
Stability Scenarios						
#	**Fault Location**	**Fault Type**	**Facility Tripped**	**Clearing Time (cycles)**	**Post-Fault Voltage Recovery**	**Angular Stability**
1	Boone 230kV	3ph	Boone 230/115kV Transformer	Primary (5.0)	Maximum transient voltage dips within criteria	Stable with positive damping
2	Boone 230kV	3ph	Lamar – Boone 230kV line and all generation at Lamar	Primary (5.0)	Maximum transient voltage dips within criteria	Stable with positive damping
3	Boone 230kV	3ph	Boone – Comanche 230kV	Primary (5.0)	Maximum transient voltage dips within criteria	Stable with positive damping
4	Boone 230kV	3ph	Boone – Midway 230kV	Primary (5.0)	Maximum transient voltage dips within criteria	Stable with positive damping
5	Comanche 345 kV	3ph	Comanche#3 generator	Primary (4.0)	Maximum transient voltage dips within criteria	Stable with positive damping
6	MidwayPS 230kV	3ph	All Fountain Valley gas units	Primary (5.0)	Maximum transient voltage dips within criteria	Stable with positive damping
7	MidwayPS 345kV	3ph	MidwayPS – Waterton 345kV line & Midway 230/345kV xfmr	Primary (5.0)	Maximum transient voltage dips within criteria	Stable with positive damping
8	Comanche 345kV	3ph	Comanche – Daniels Park 345kV 1 &2	Primary (4.0)	Maximum transient voltage dips within criteria	Stable with positive damping
9	Lamar 230kV	3ph	Lamar – Boone 230kV line and all generation at Lamar	Primary (5.0)	Maximum transient voltage dips within criteria	Stable with positive damping

Table S8 Transient Stability Plots – Stand-alone Study









tran_1
Boone 230kV bus fault, lose Boone 230/115kV bank

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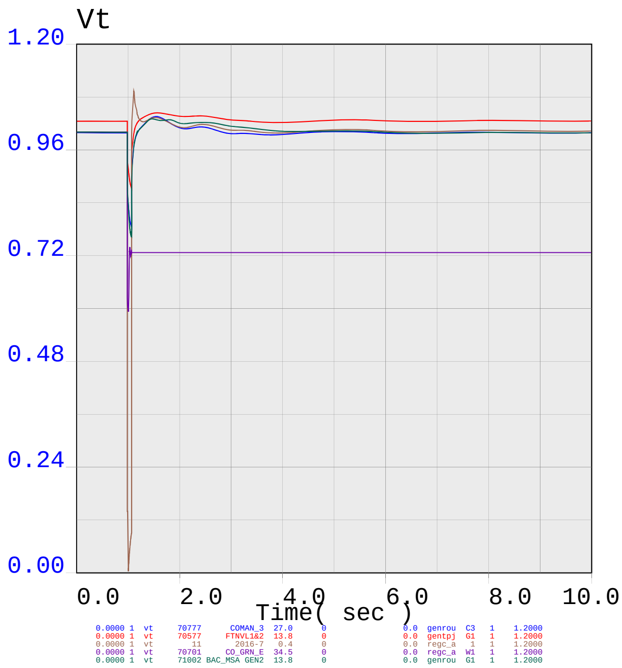

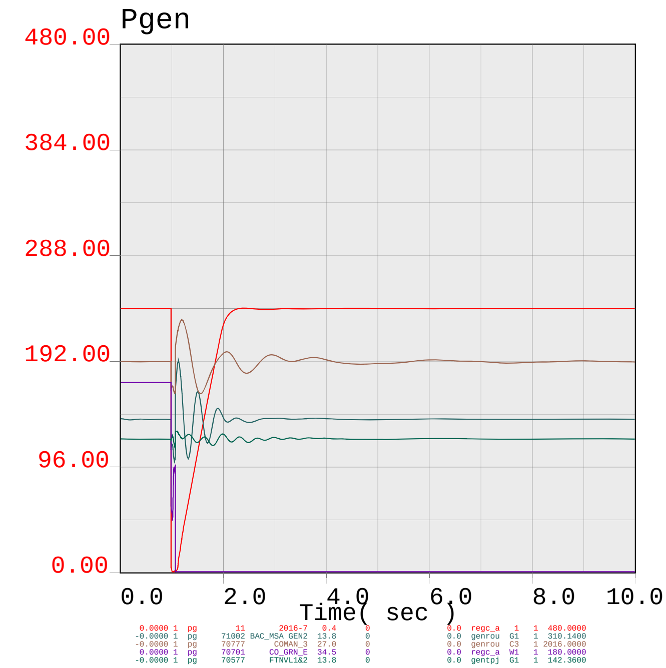

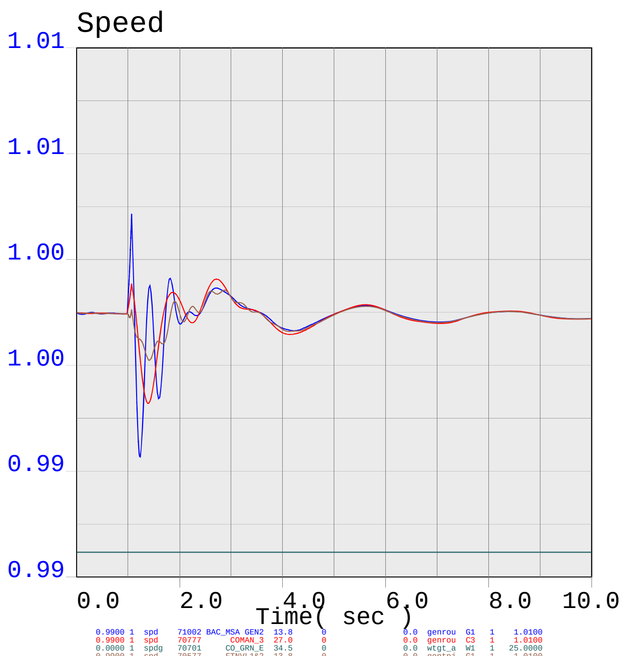

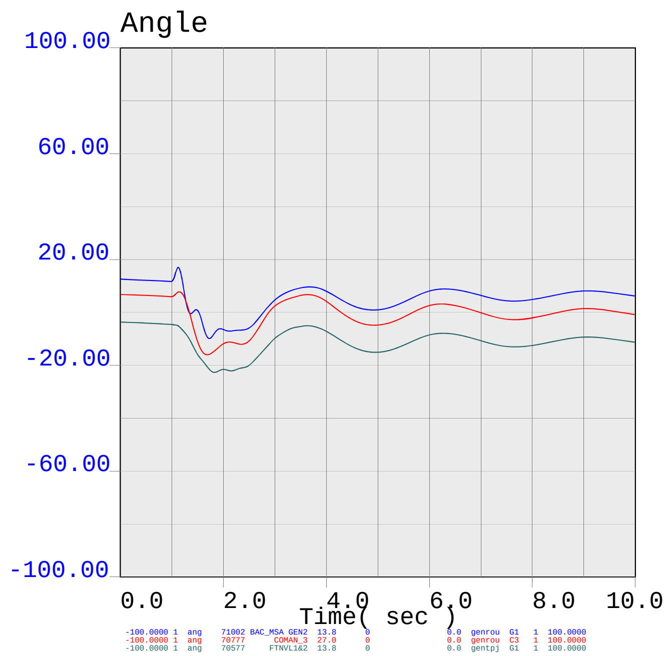

Line_2
Boone 230kV bus fault, lose Lamar-Boone 230kV and Lamar gen

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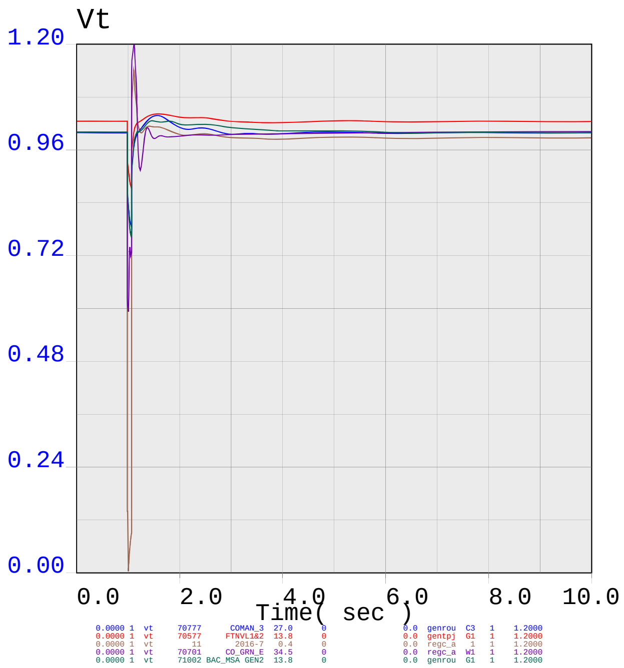
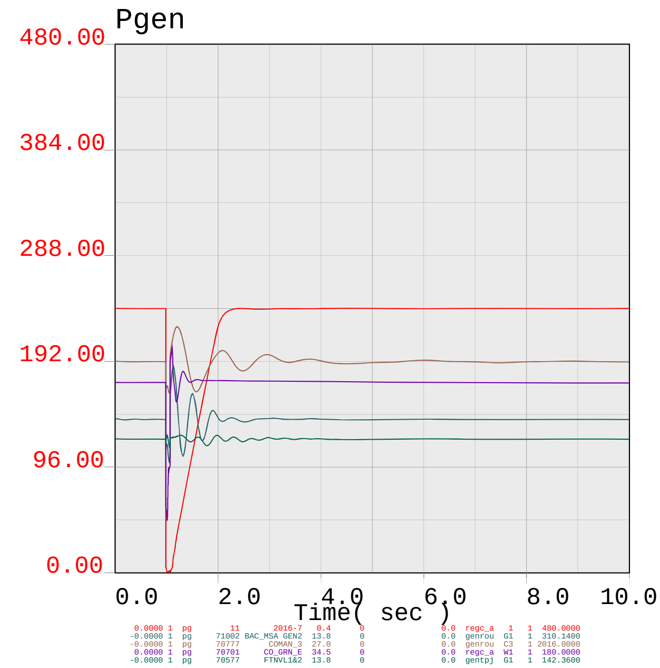
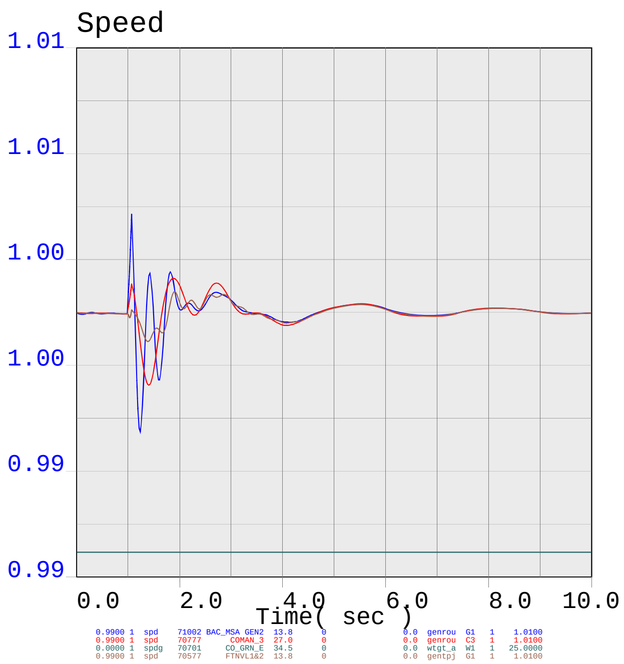
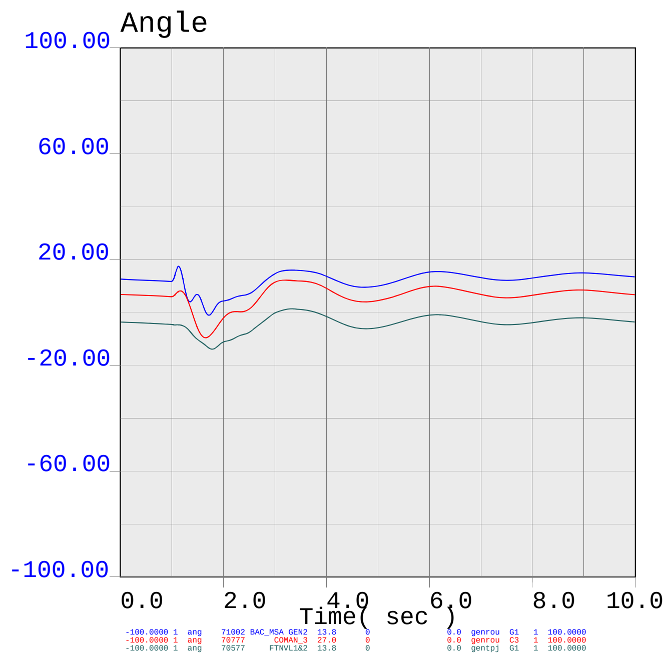
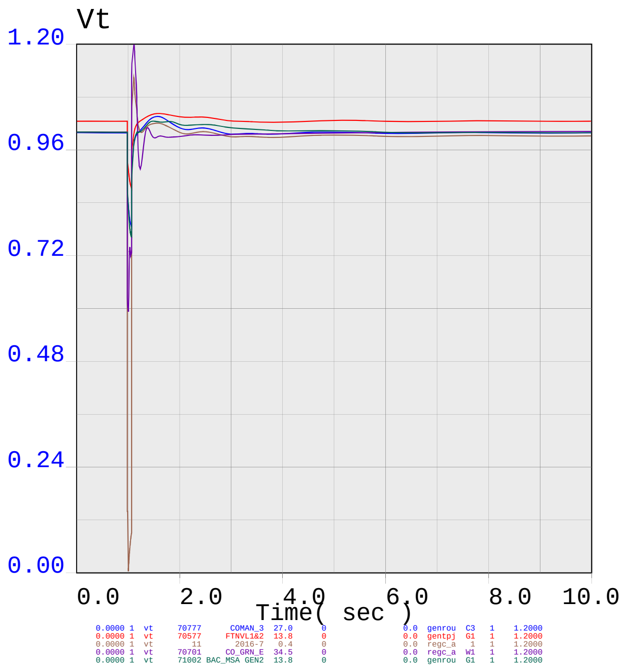


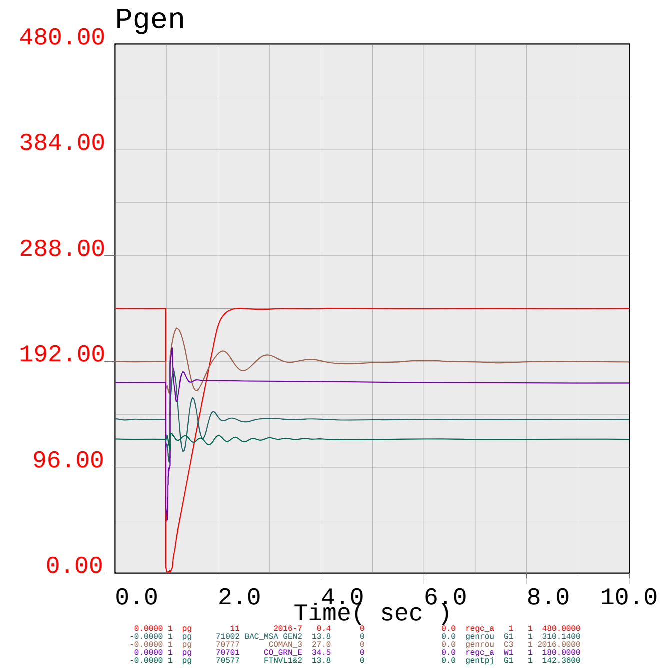


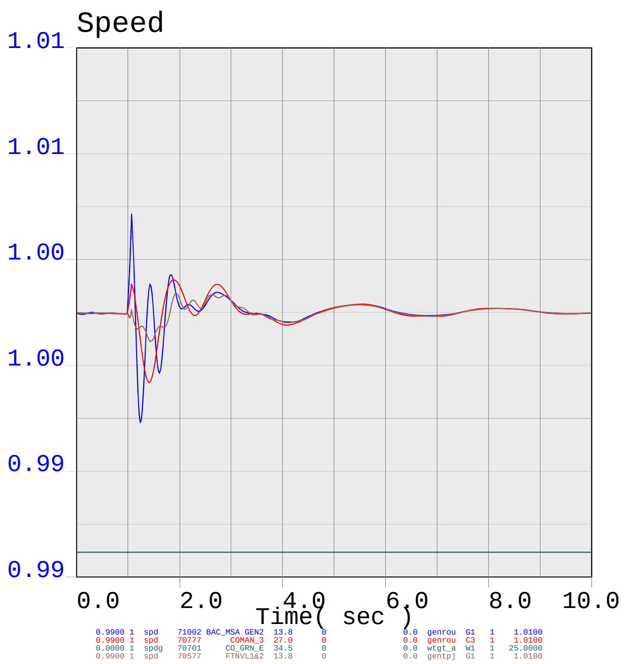


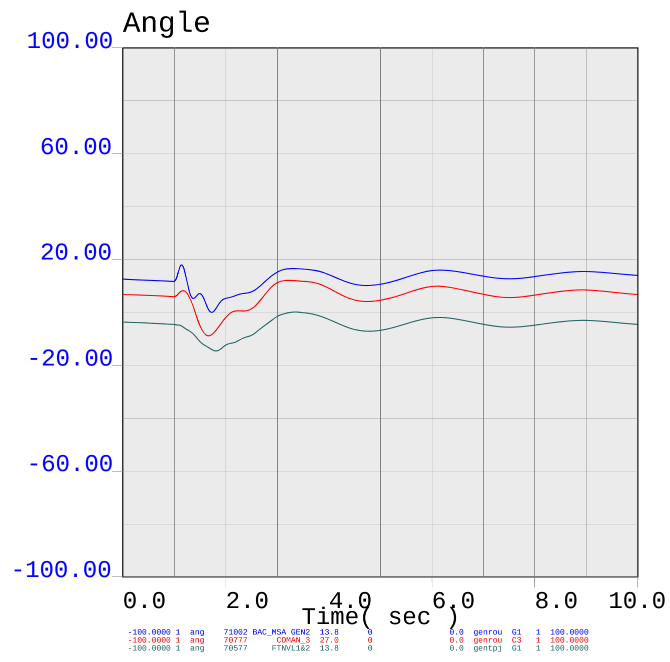


Line_3
Fault at Boone 230kV, lose Boone-Comanche 230kV









Line_4
Fault at Boone 230kV, lose Boone-Midway 230kV

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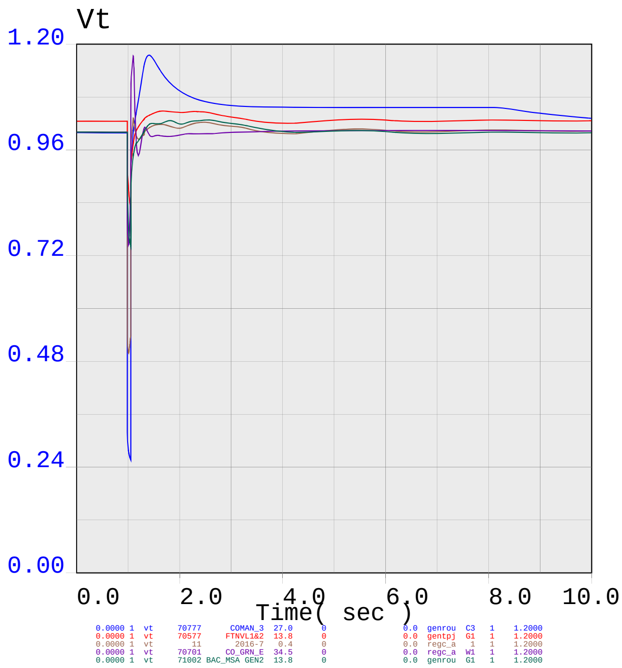

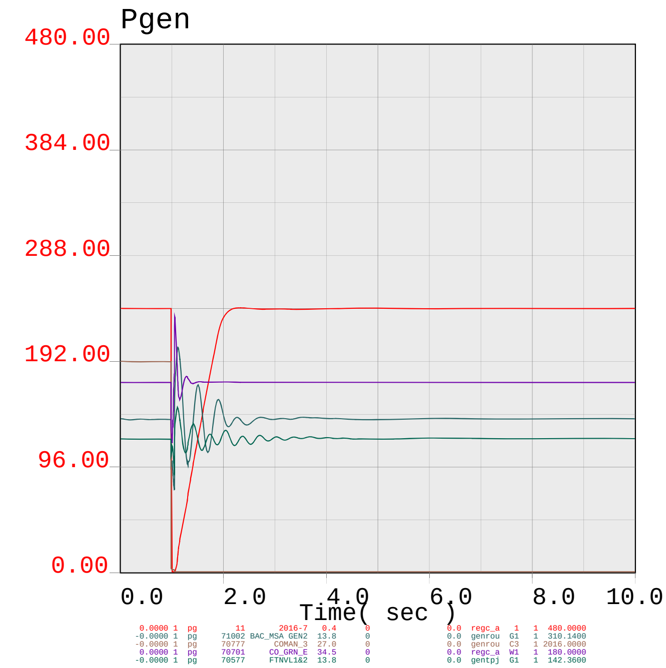

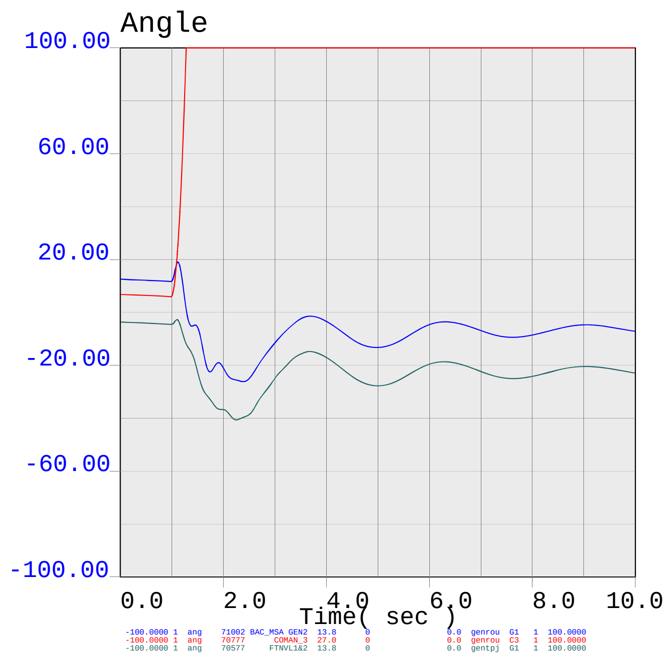

Line_5
Fault at Comanche 345kV, lose Comanche 3

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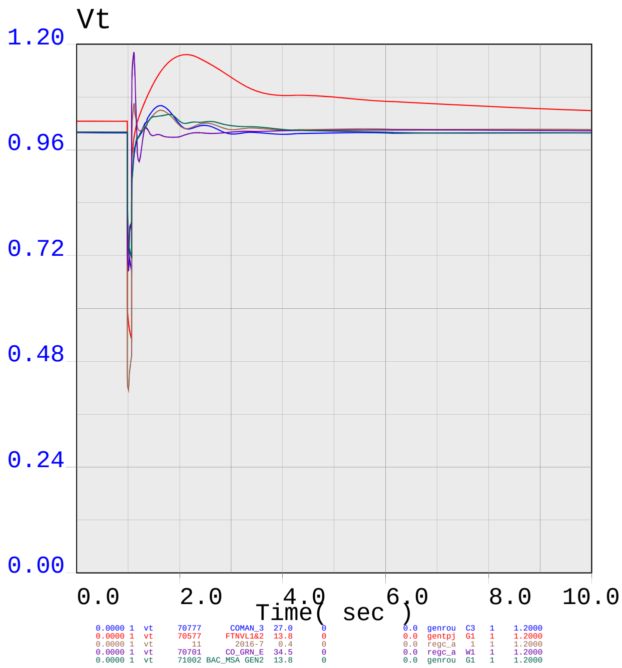

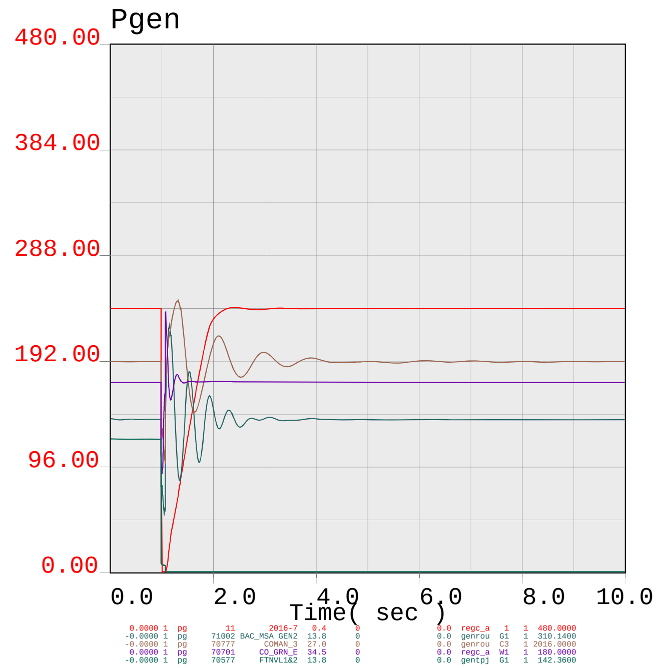

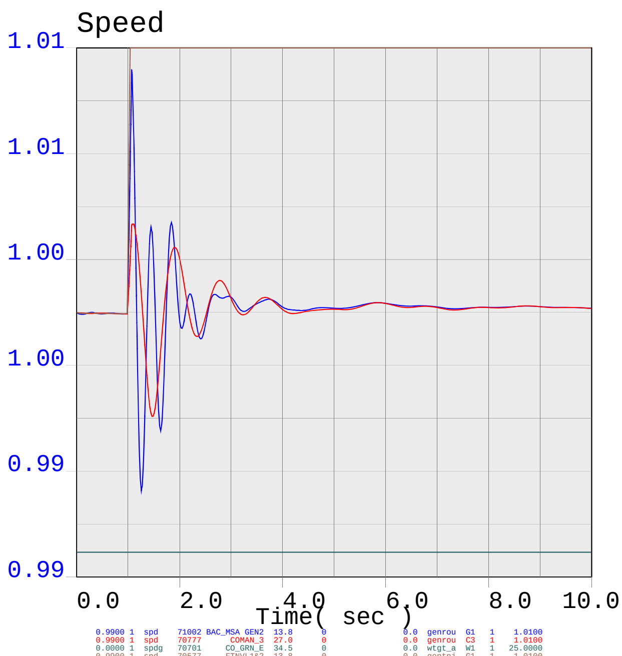

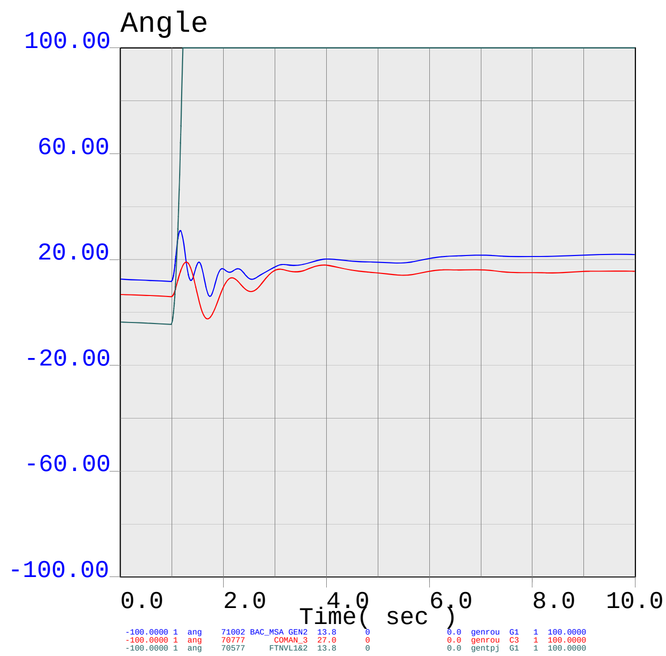

Line_6
Fault at Midway 230kV, lose Fountain Valley gen

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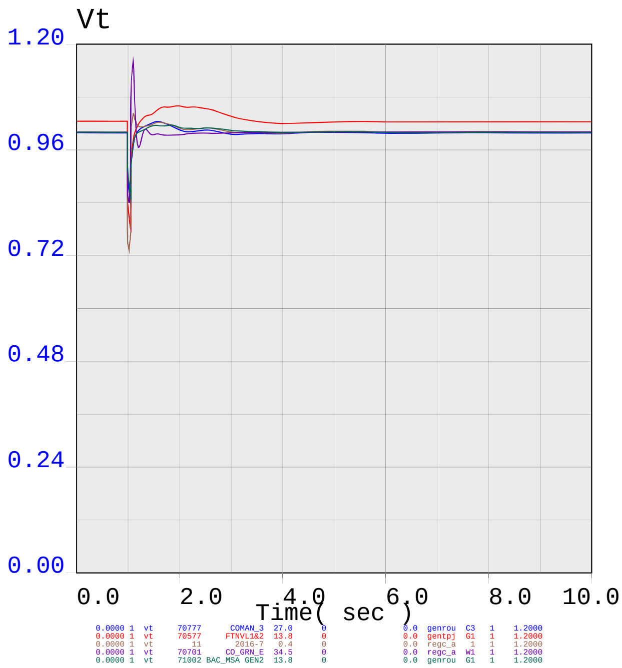
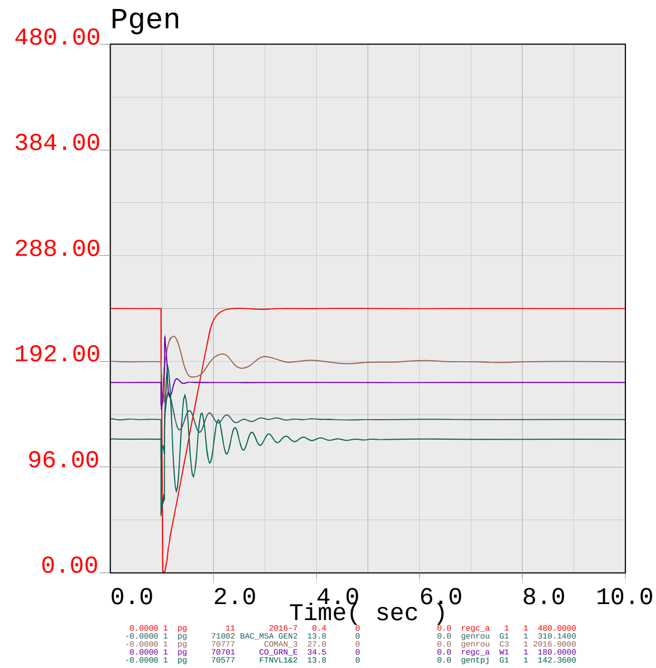
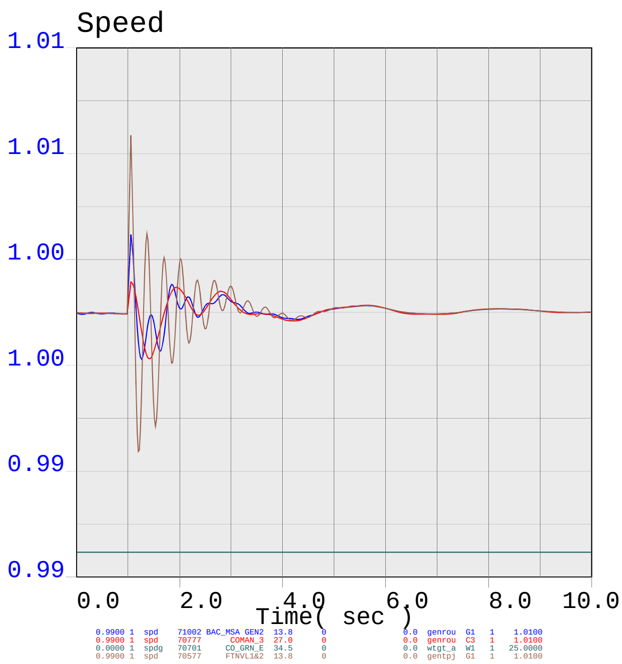
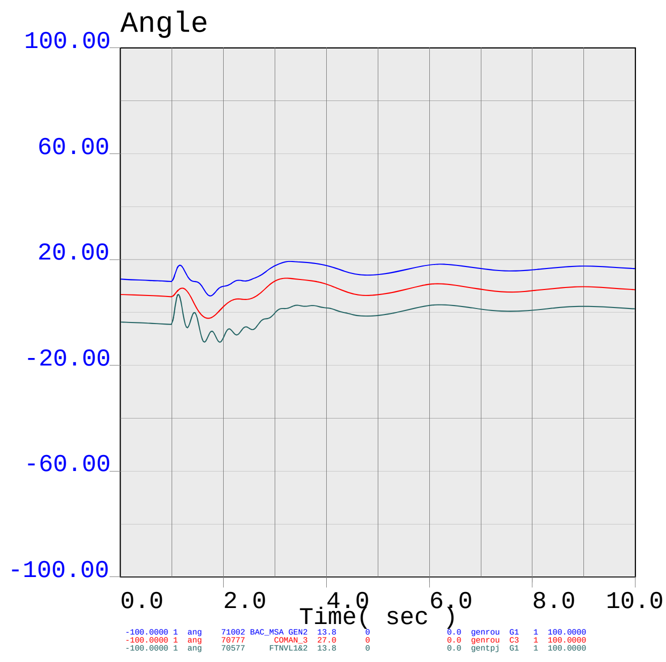
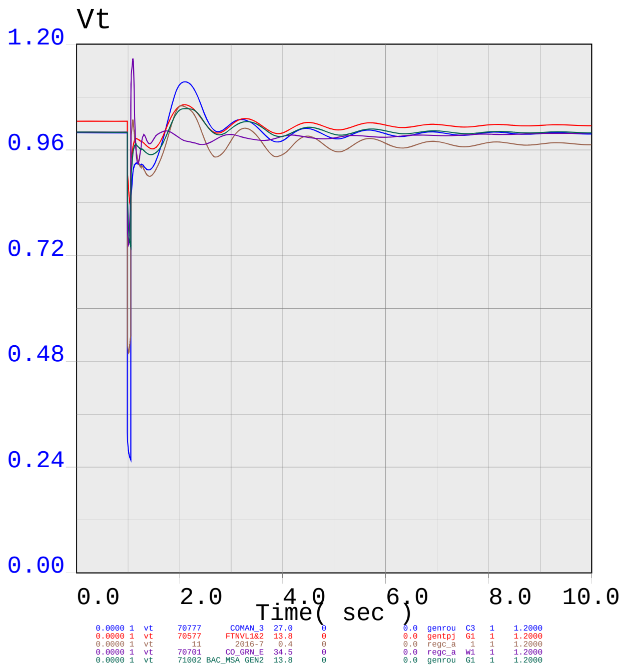


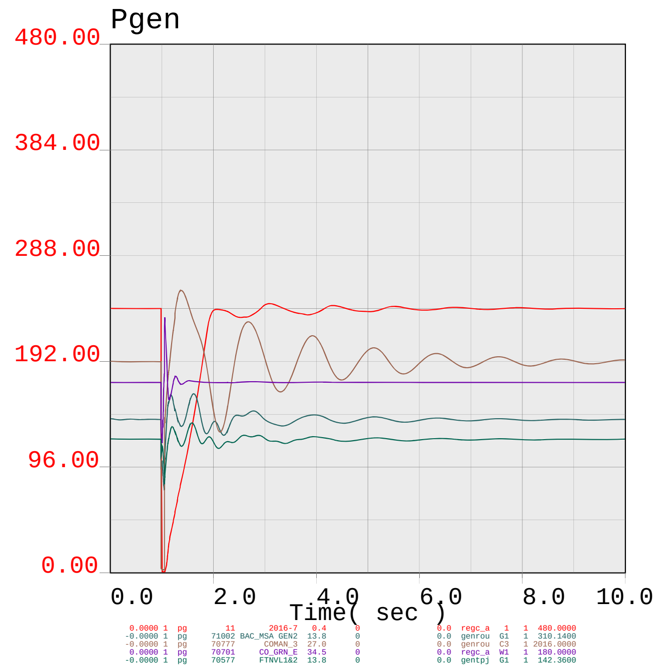


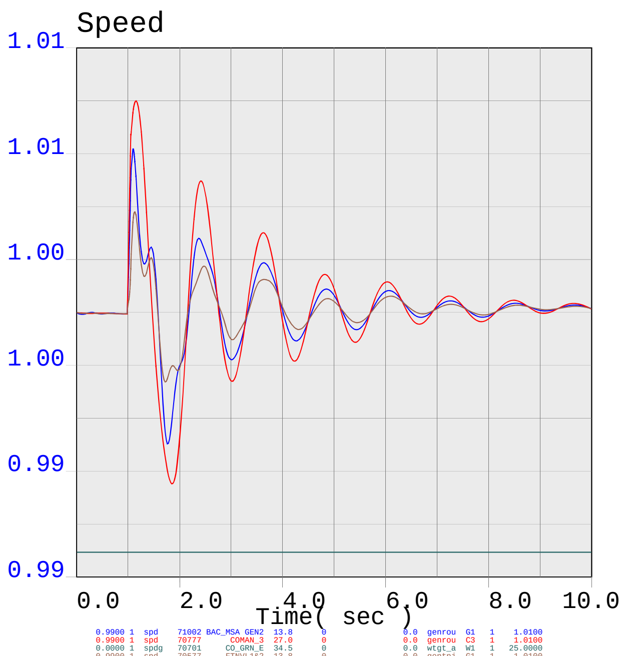


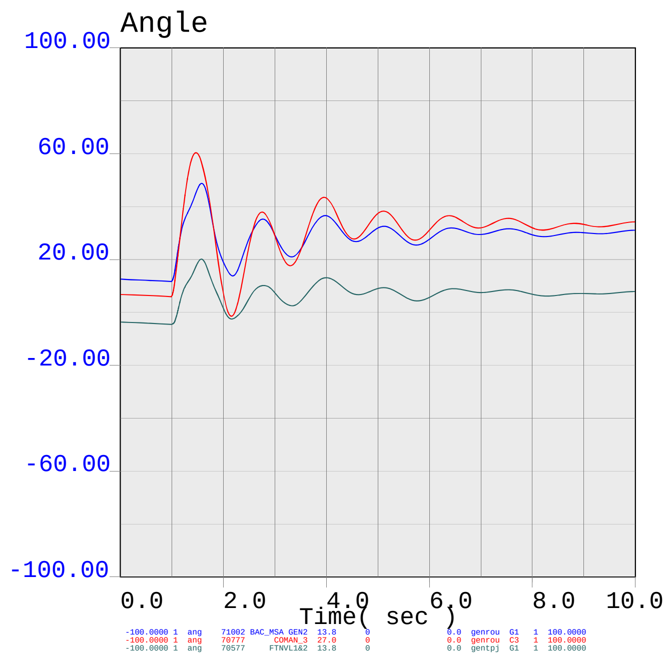


Fault_7
Fault at Midway 345kV, lose MidwayPS 345/20kV and MidwayPS - Waterton345kV line

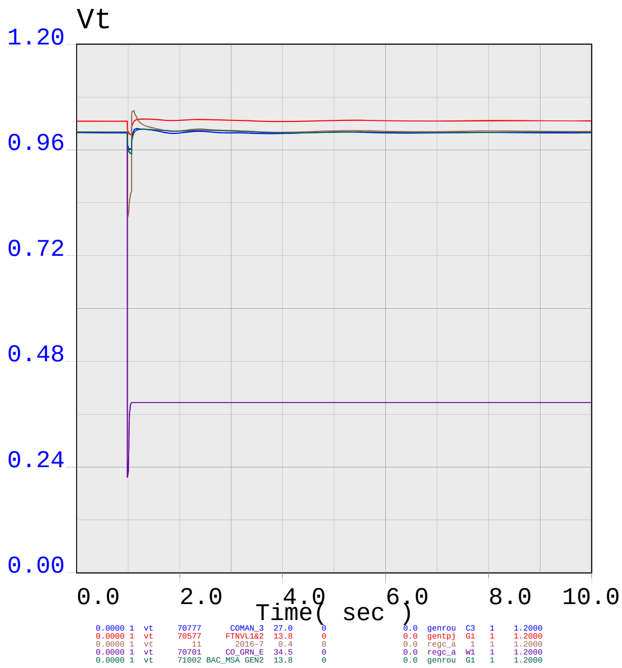


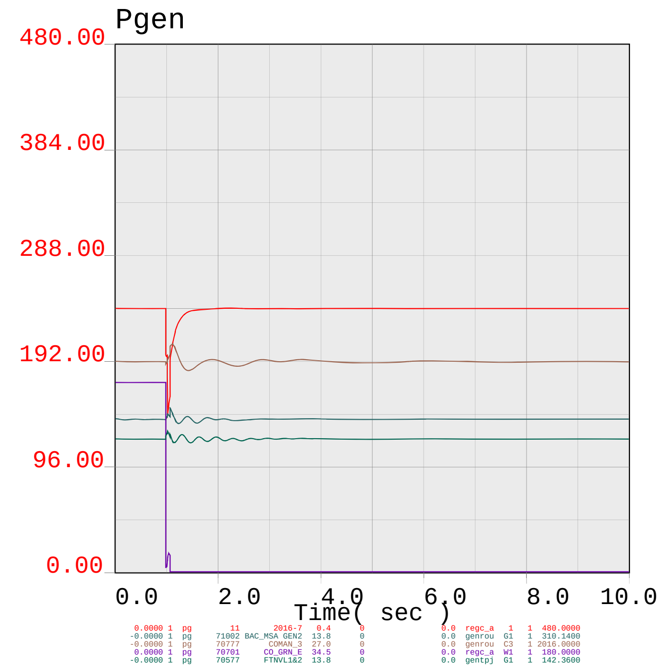


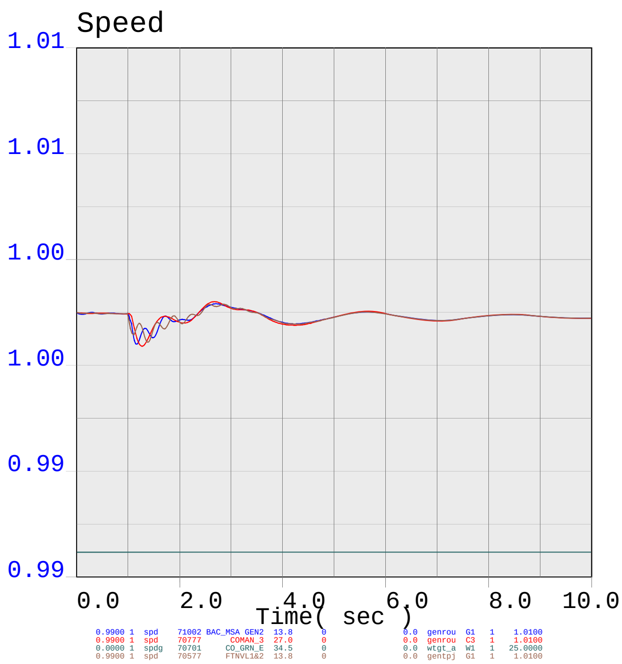


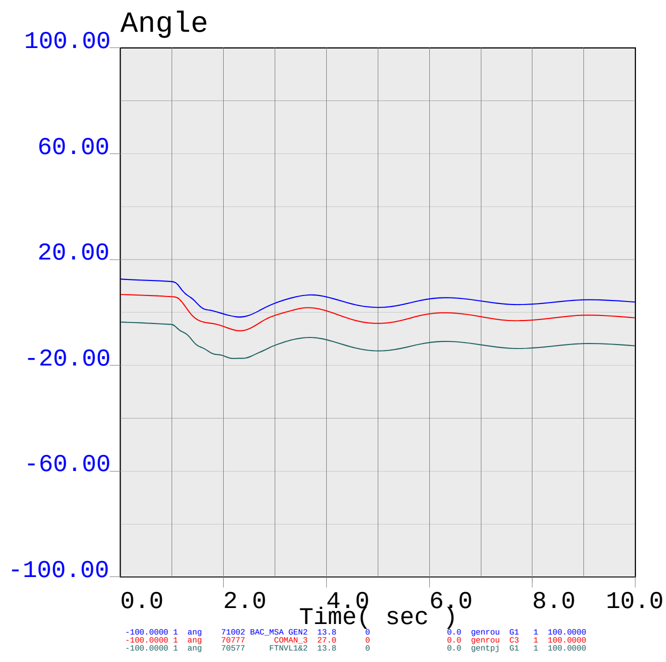


Fault_8
Fault at Comanche 345kV, lose Comanche - Daniels Park 345kV double circuit









Line_9
Lamar 230kV bus fault, lose Lamar-Boone 230kV and Lamar gen

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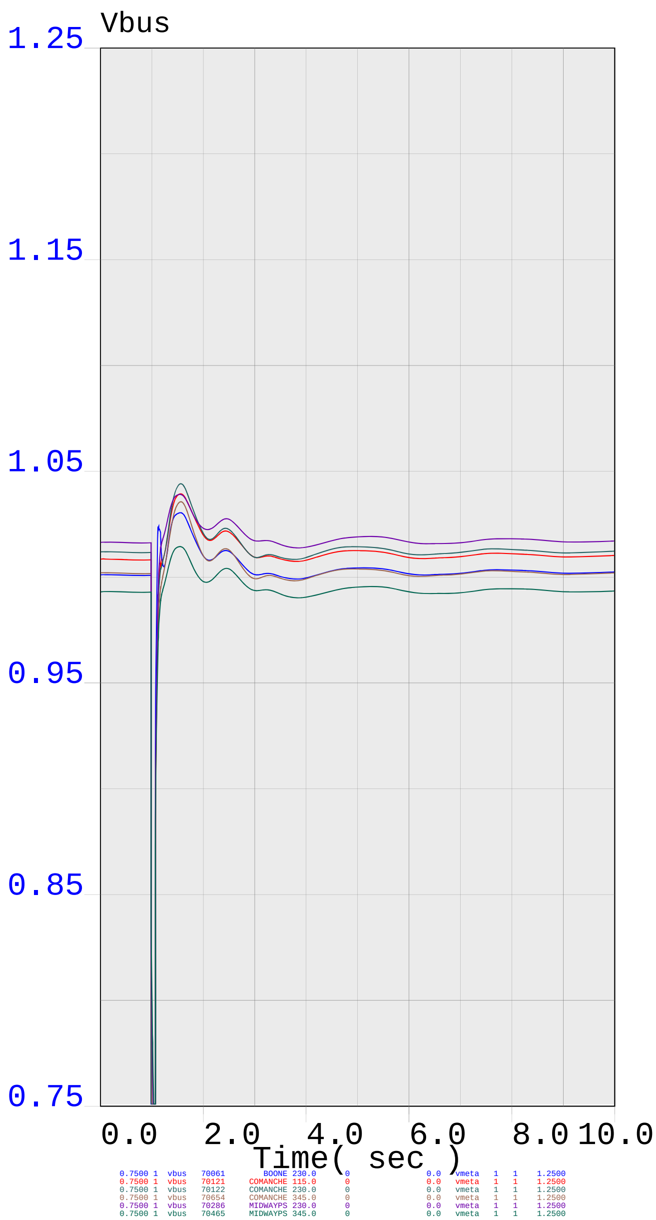

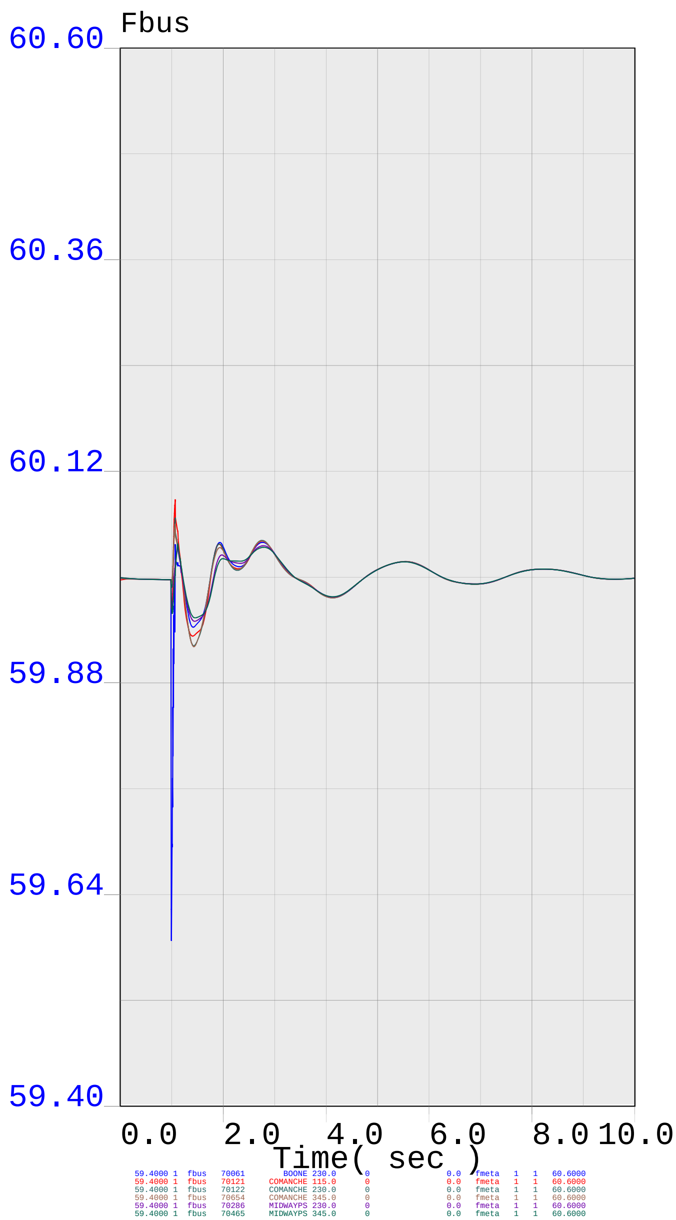

tran_1
Boone 230kV bus fault, lose Boone 230/115kV bank

psec-run-gi-2016-7-tran_1.chf

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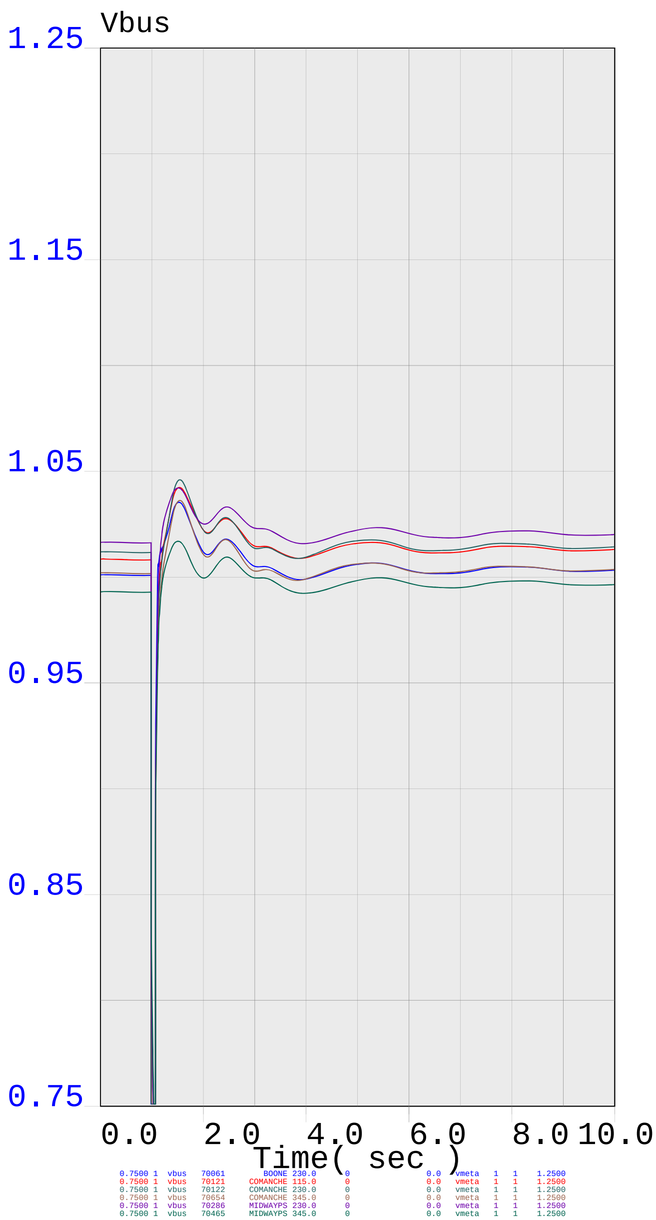
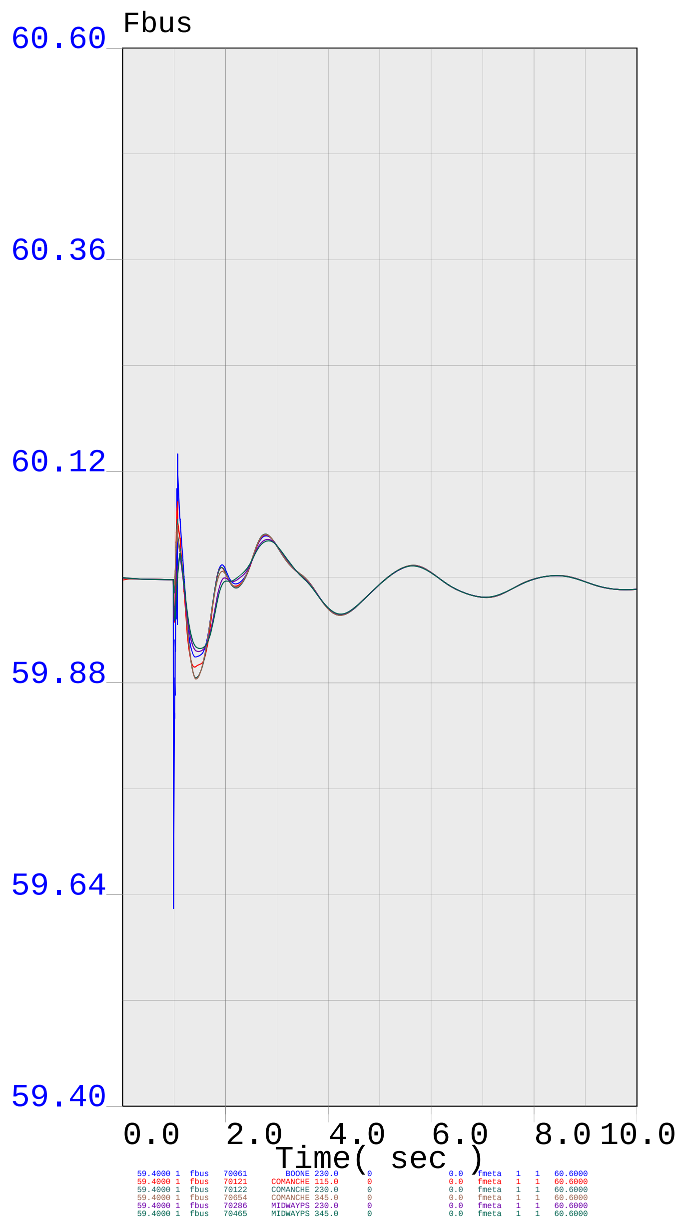


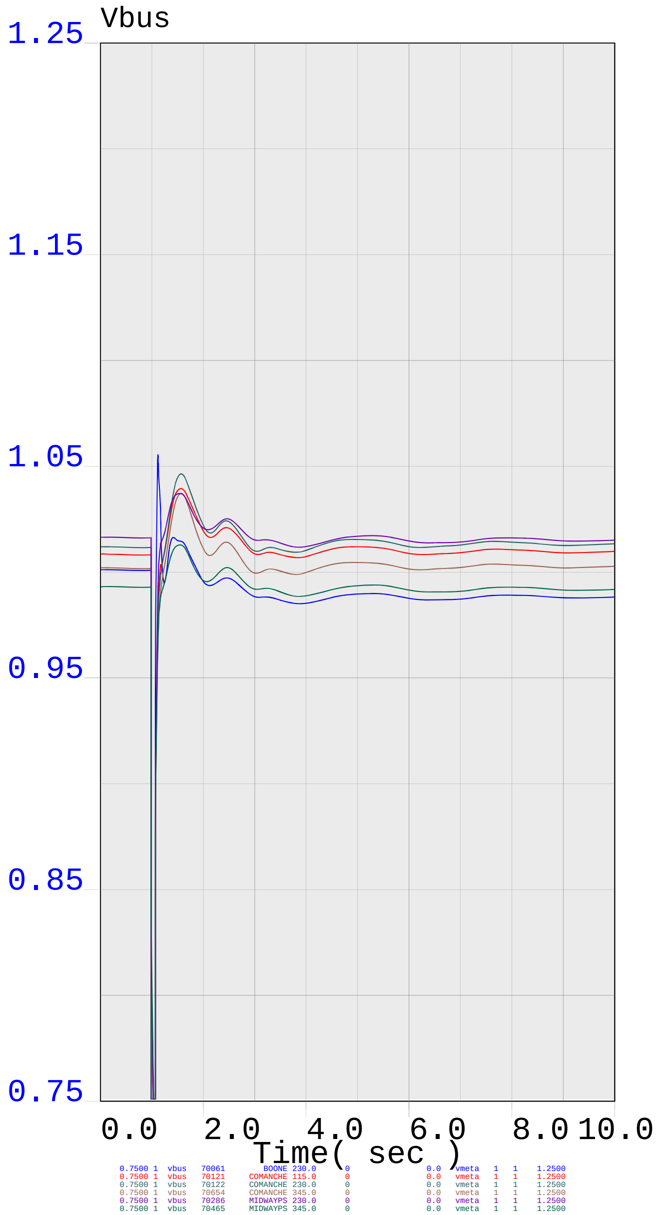


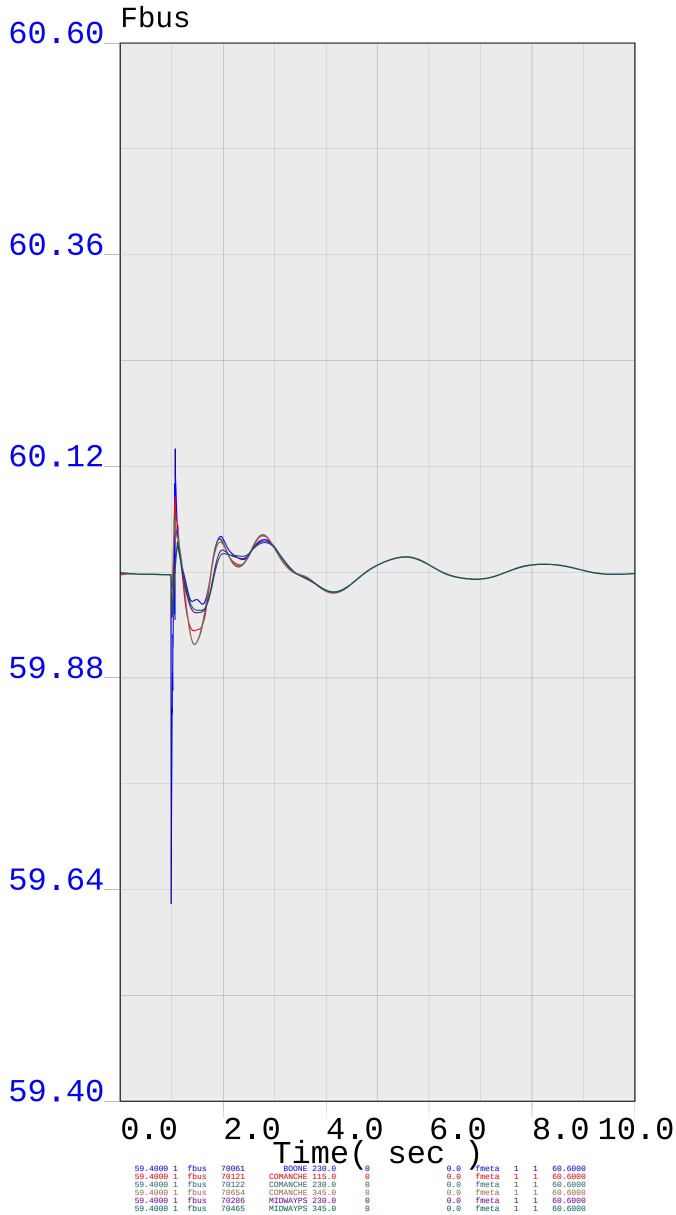
Line_2
Boone 230kV bus fault, lose Lamar-Boone 230kV and Lamar gen

psec-run-gi-2016-7-Line_2.chf

16-7\SIS\DYTOOLS-HD\chans

Sat Sep 01 11:55:44 2018



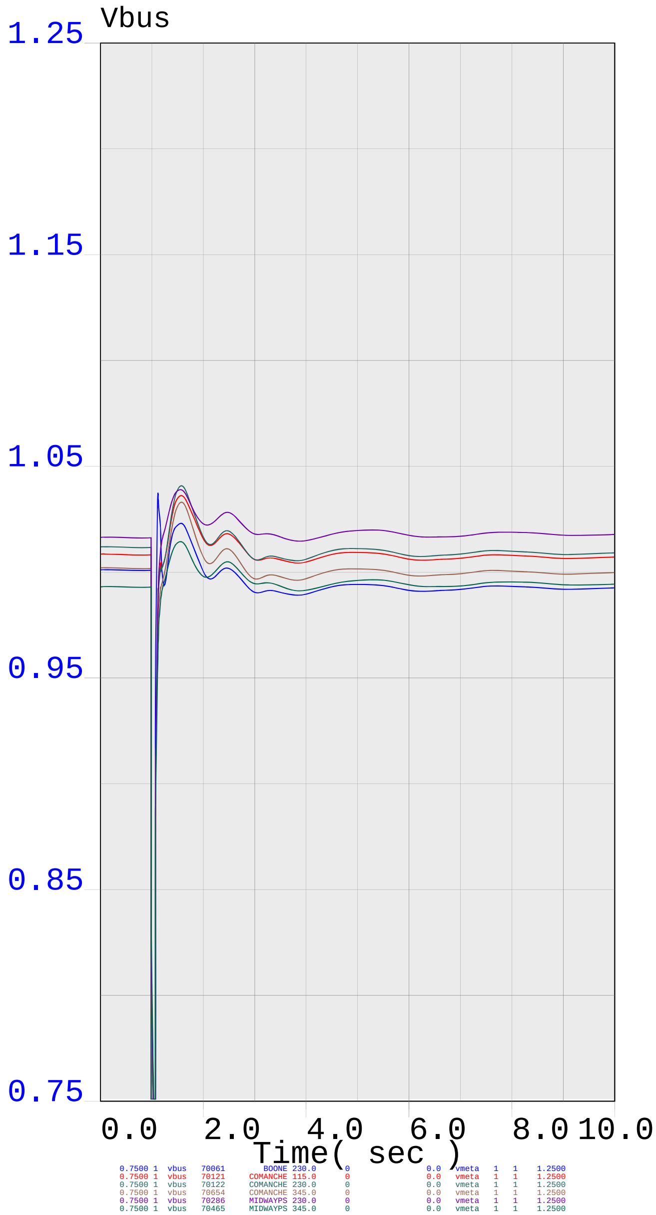


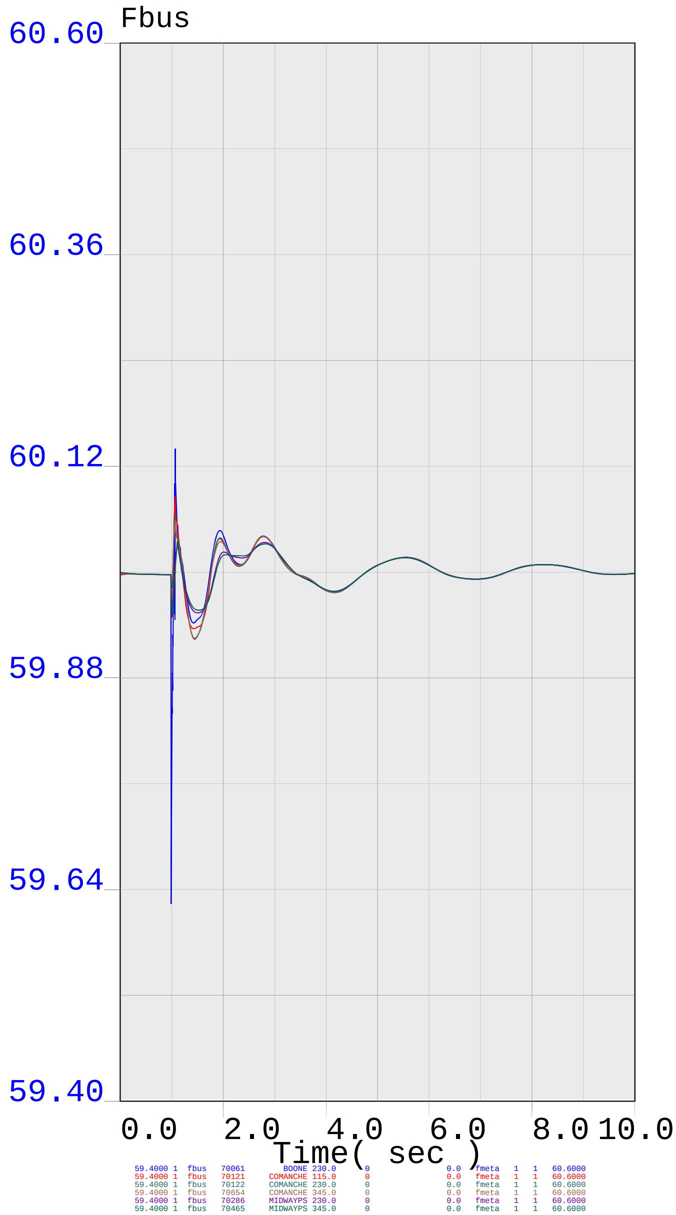
Line_3
Fault at Boone 230kV, lose Boone-Comanche 230kV

psec-run-gi-2016-7-Line_3.chf

16-7\SIS\DYTOOLS-HD\chans

Sat Sep 01 11:56:54 2018



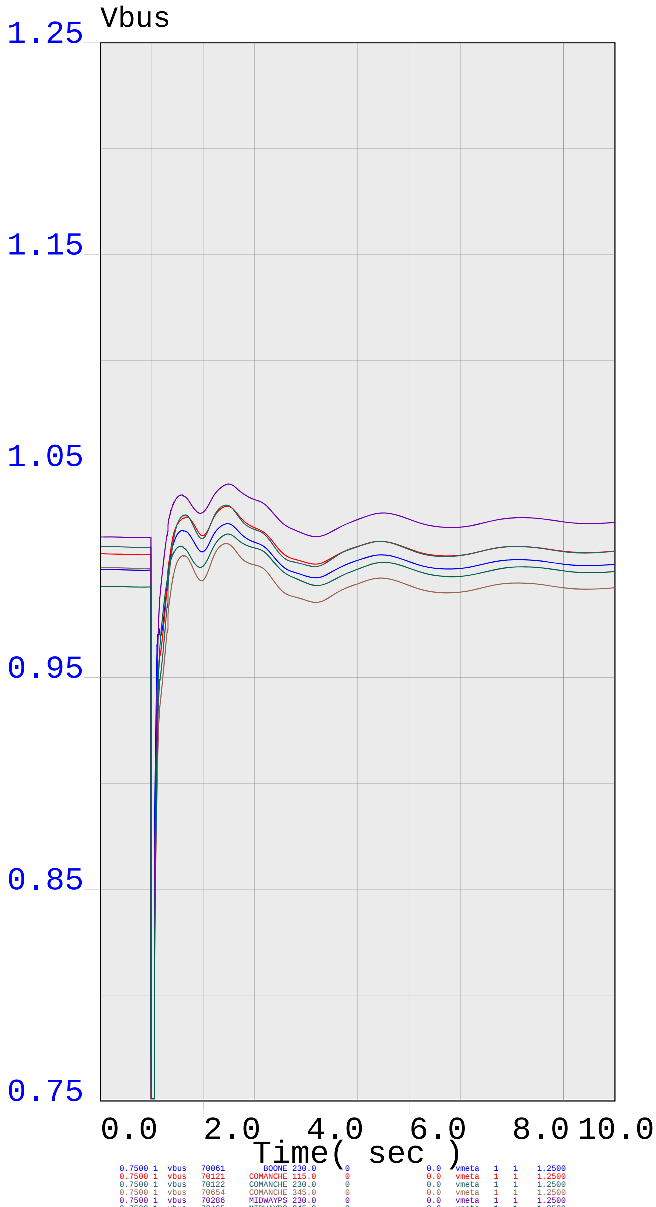


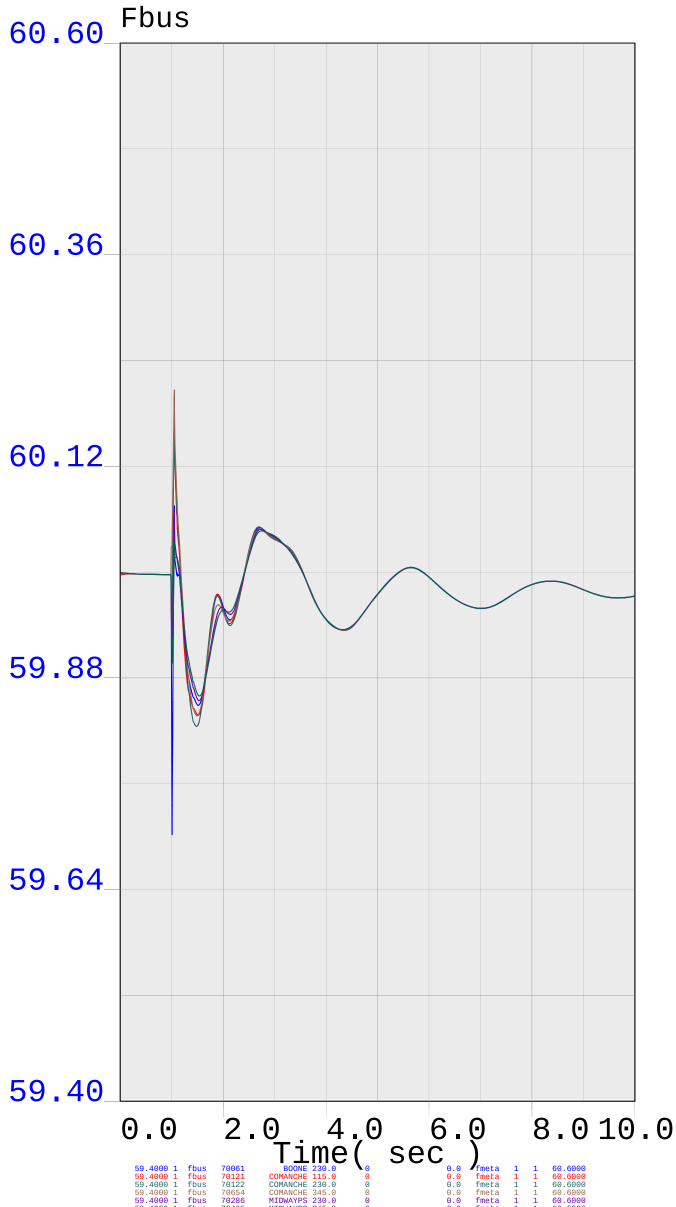
Line_4
Fault at Boone 230kV, lose Boone-Midway 230kV

psec-run-gi-2016-7-Line_4.chf

16-7\SIS\DYTOOLS-HD\chans

Sat Sep 01 11:57:22 2018



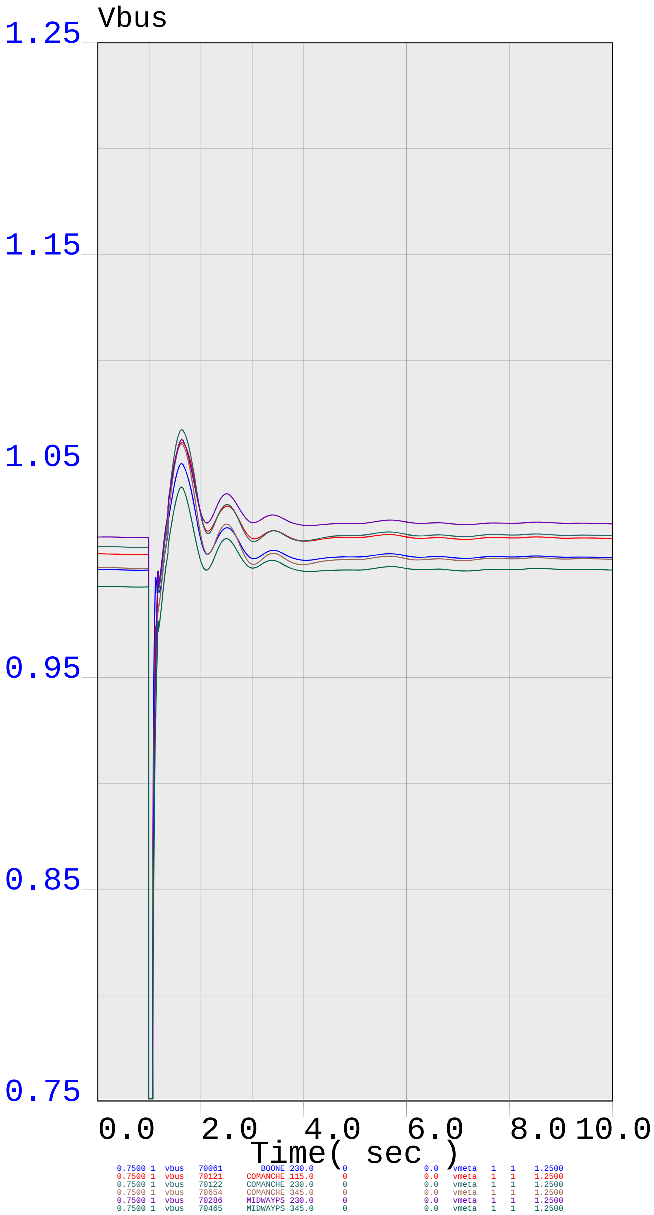


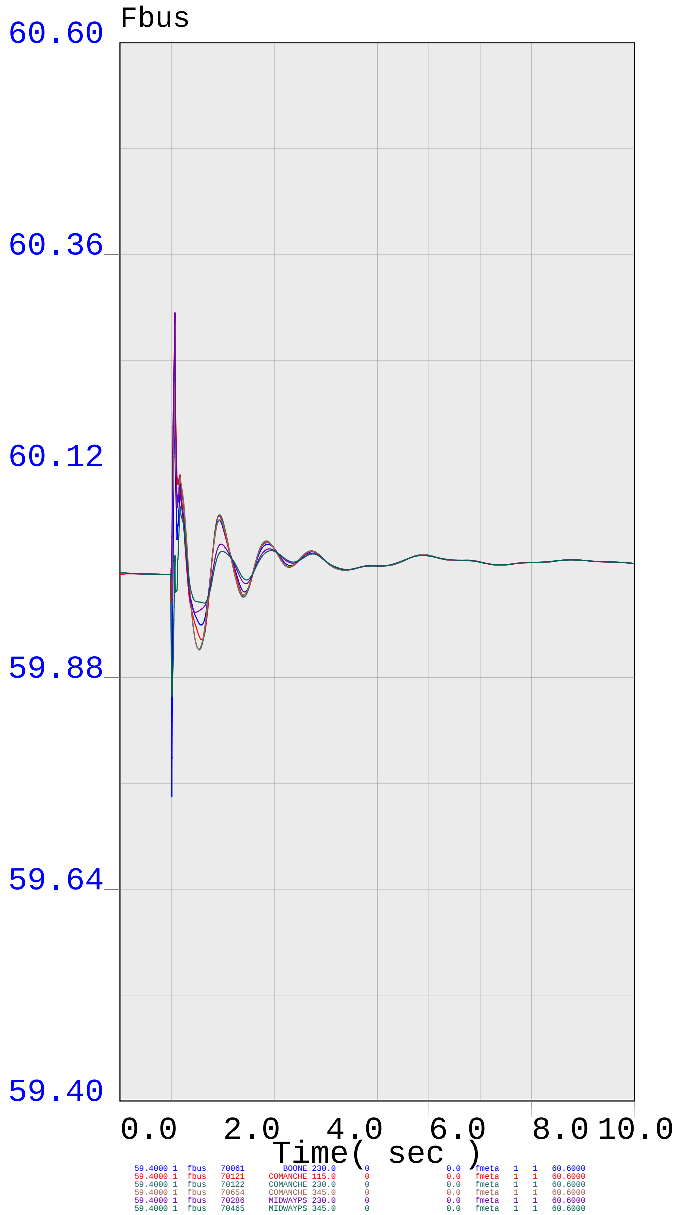
Line_5
Fault at Comanche 345kV, lose Comanche 3

psec-run-gi-2016-7-Line_5.chf

16-7\SIS\DYTOOLS-HD\chans

Sat Sep 01 11:57:52 2018



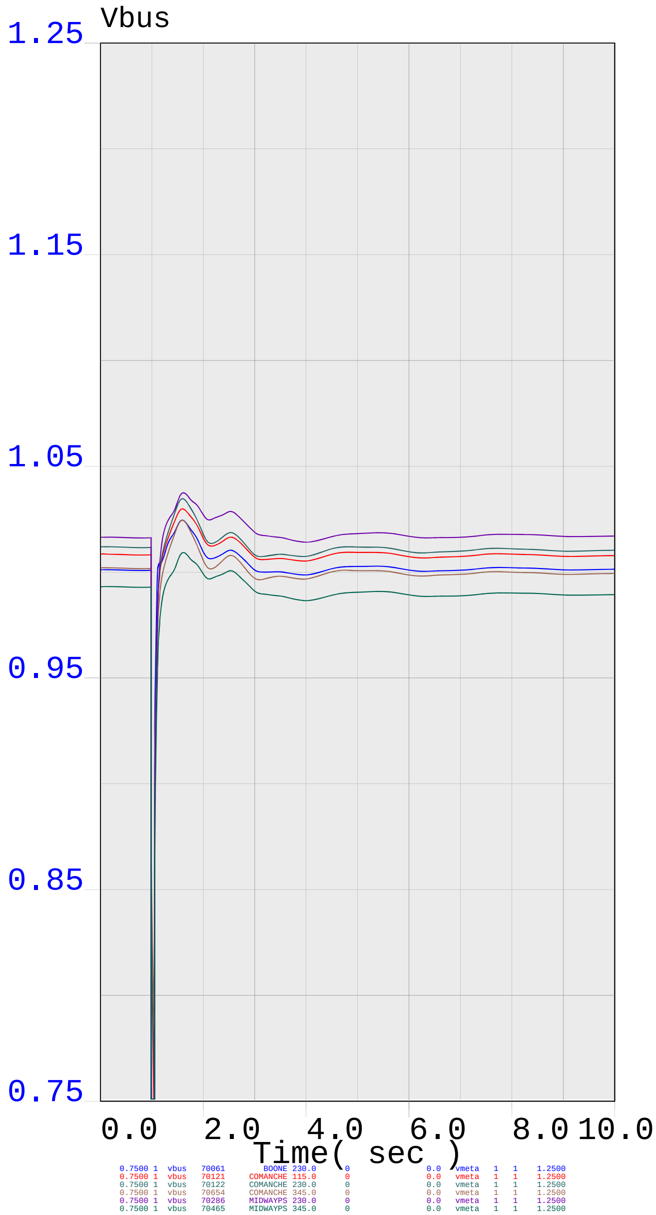


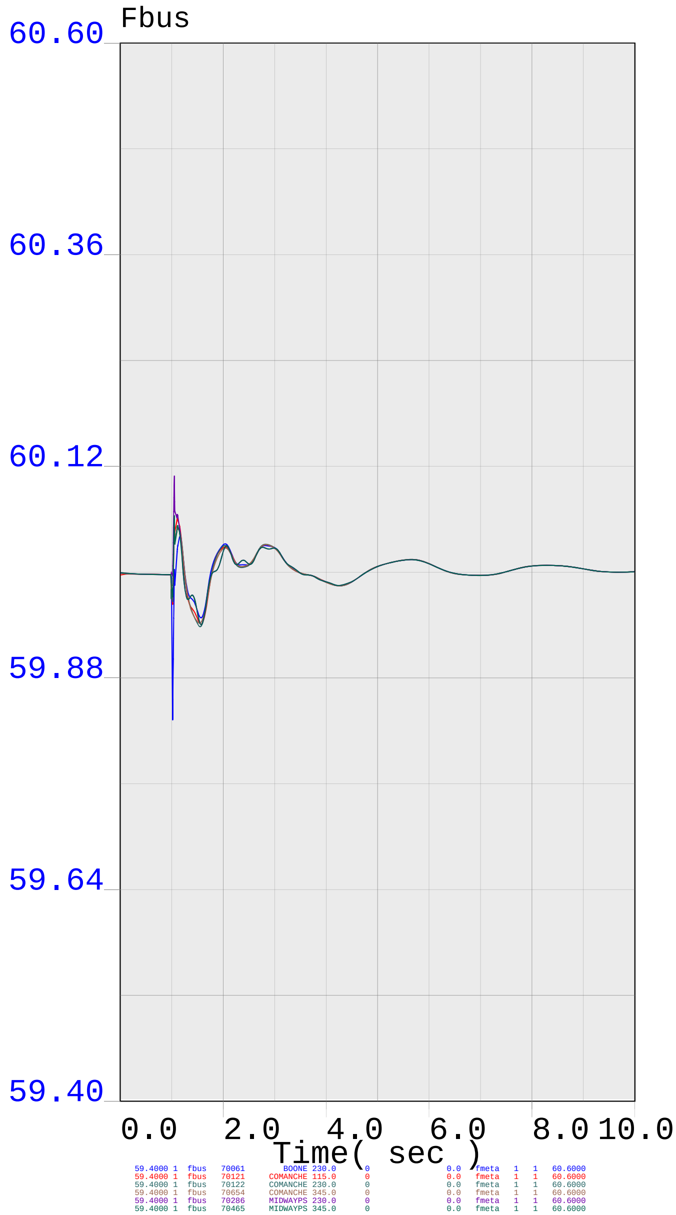
Line_6
Fault at Midway 230kV, lose Fountain Valley gen

psec-run-gi-2016-7-Line_6.chf

16-7\SIS\DYTOOLS-HD\chans

Sat Sep 01 11:58:32 2018



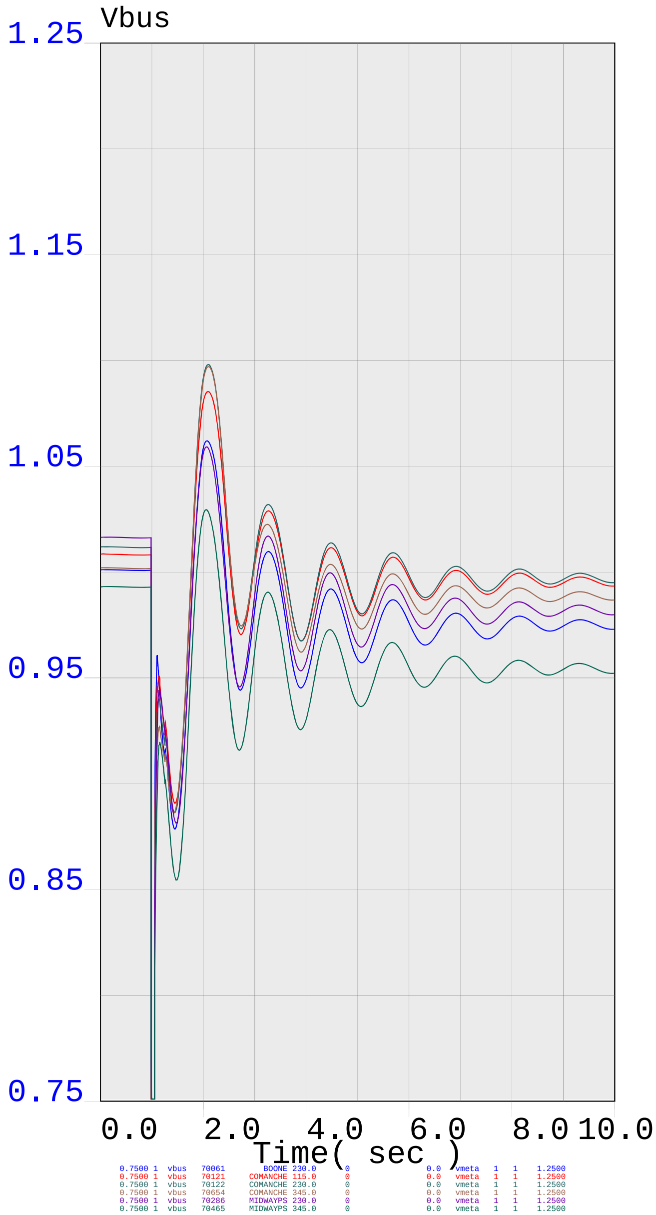


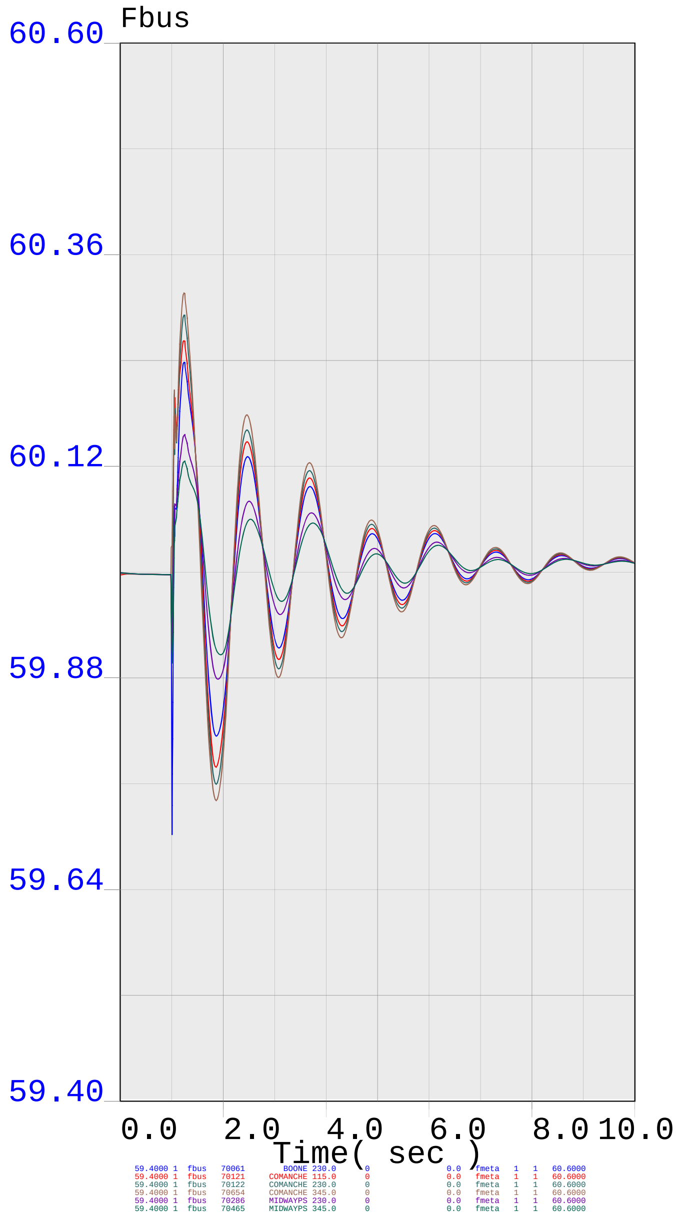
Fault_7
Fault at Midway 345kV, lose MidwayPS 345/20kV and MidwayPS - Waterton345kV line

psec-run-gi-2016-7-Fault_7.chf

16-7\SIS\DYTOOLS-HD\chans

Sat Sep 01 11:59:03 2018





Fault_8
Fault at Comanche 345kV, lose Comanche - Daniels Park 345kV double circuit

psec-run-gi-2016-7-Fault_8.chf

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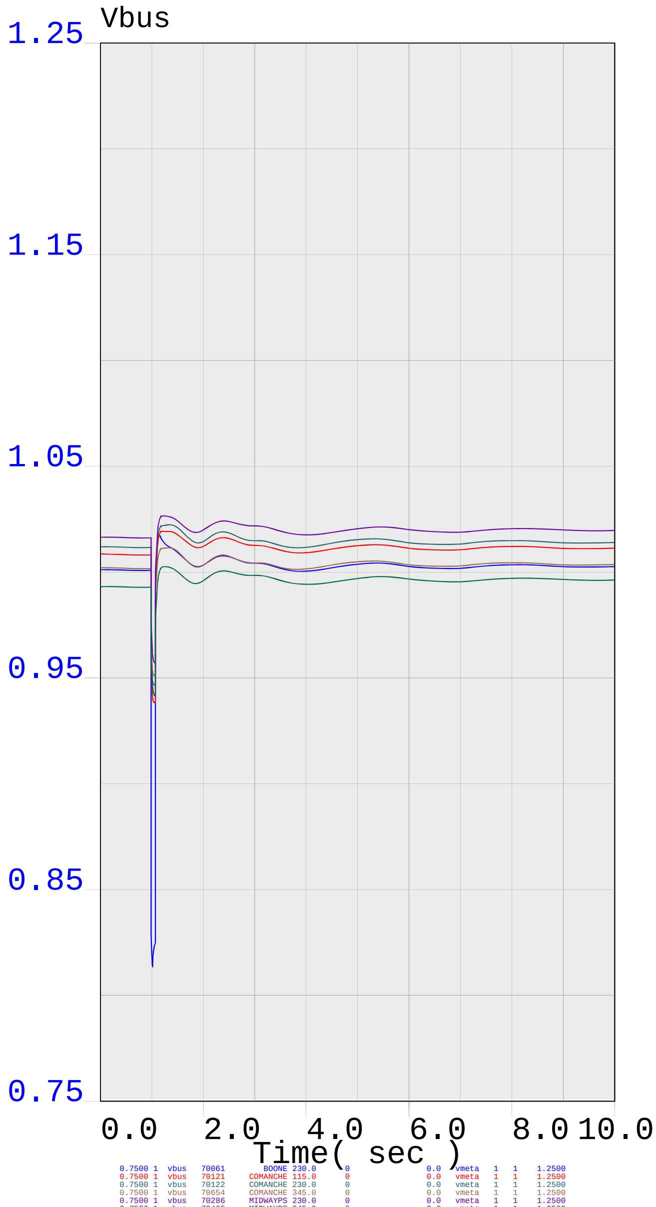
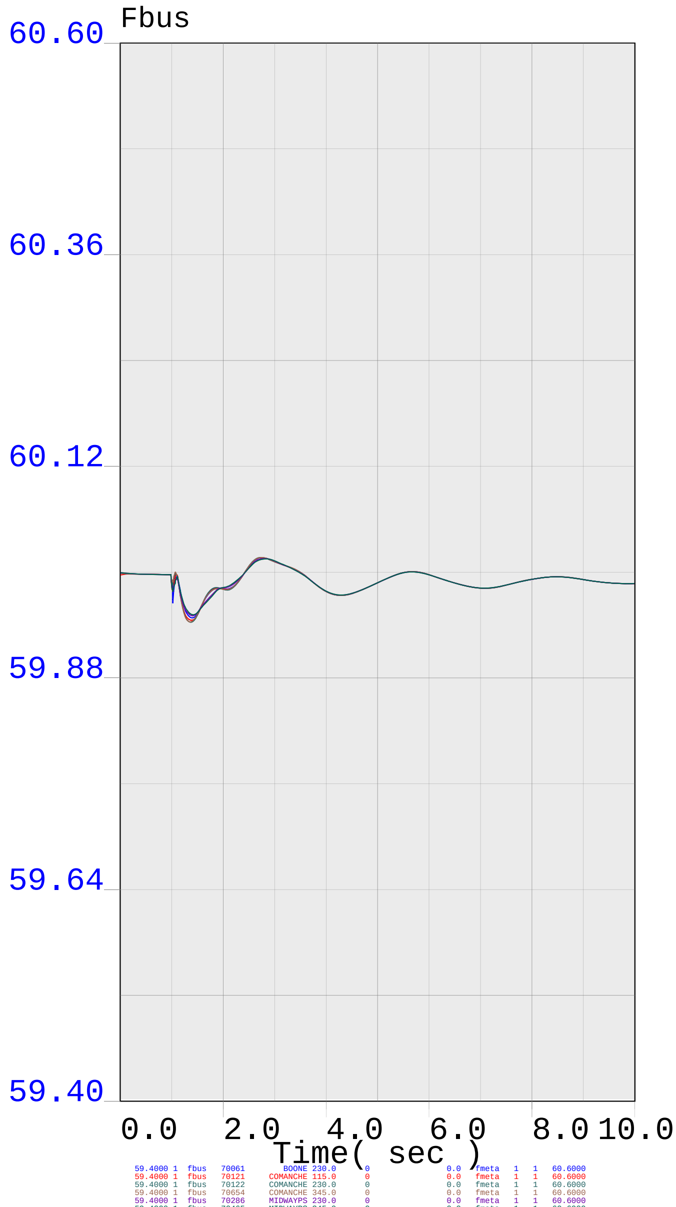
Sat Sep 01 11:59:35 2018





Line_9
Lamar 230kV bus fault, lose Lamar-Boone 230kV and Lamar gen

psec-run-gi-2016-7-Line_9.chf

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Sat Sep 01 12:00:06 2018