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

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

Xcel Energy - Transmission Planning West
Xcel Energy
May 21, 2019

Executive Summary

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 month construction timeframe required to build the transmission system improvements, the proposed COD of November 2019 is not achievable.

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 evaluations, 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 5.
The overloads on the Daniels Park – Fuller 230kV line and Greenwood – Prairie3 230kV line can be mitigated by fixing the terminal equipment limitations on these lines. The cost of these PSCo Network Upgrades to mitigate overloads on the two PSCo facilities is given in Table 4 below.

PSCo has informed the Affected Systems regarding the contingency overloads on their facilities. Mitigation measures for each of the contingency overloads on the Affected Systems must be identified and addressed by the Affected Systems in order for GI-2016-7 to achieve 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 the 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 PSCo transmission system improvements required for GI-2016-7 to qualify for:

- **ERIS is $4.083 Million (Tables 2 and 3); and**
- **NRIS is $4.466 Million (Tables 2, 3 and 4)**

The ERIS and NRIS results above are contingent upon the mitigation of all overloads and Network Upgrades identified in the Affected Systems and the PSCo system, and Network Upgrades identified for all applicable higher-queued Interconnection Requests (see footnotes to Table 3 and Table 4).

If there is a change in status of one or more higher-queued Interconnection Requests due to withdrawal from the queue or changing from NRIS to ERIS, and the Network Upgrades identified for the higher queued Interconnection Requests are not constructed, the Network

Upgrade costs would become the responsibility of GI-2016-7 to the extent they are necessary to interconnect GI-2016-7. A restudy will be performed as needed to identify the new Network Upgrade responsibilities.

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.

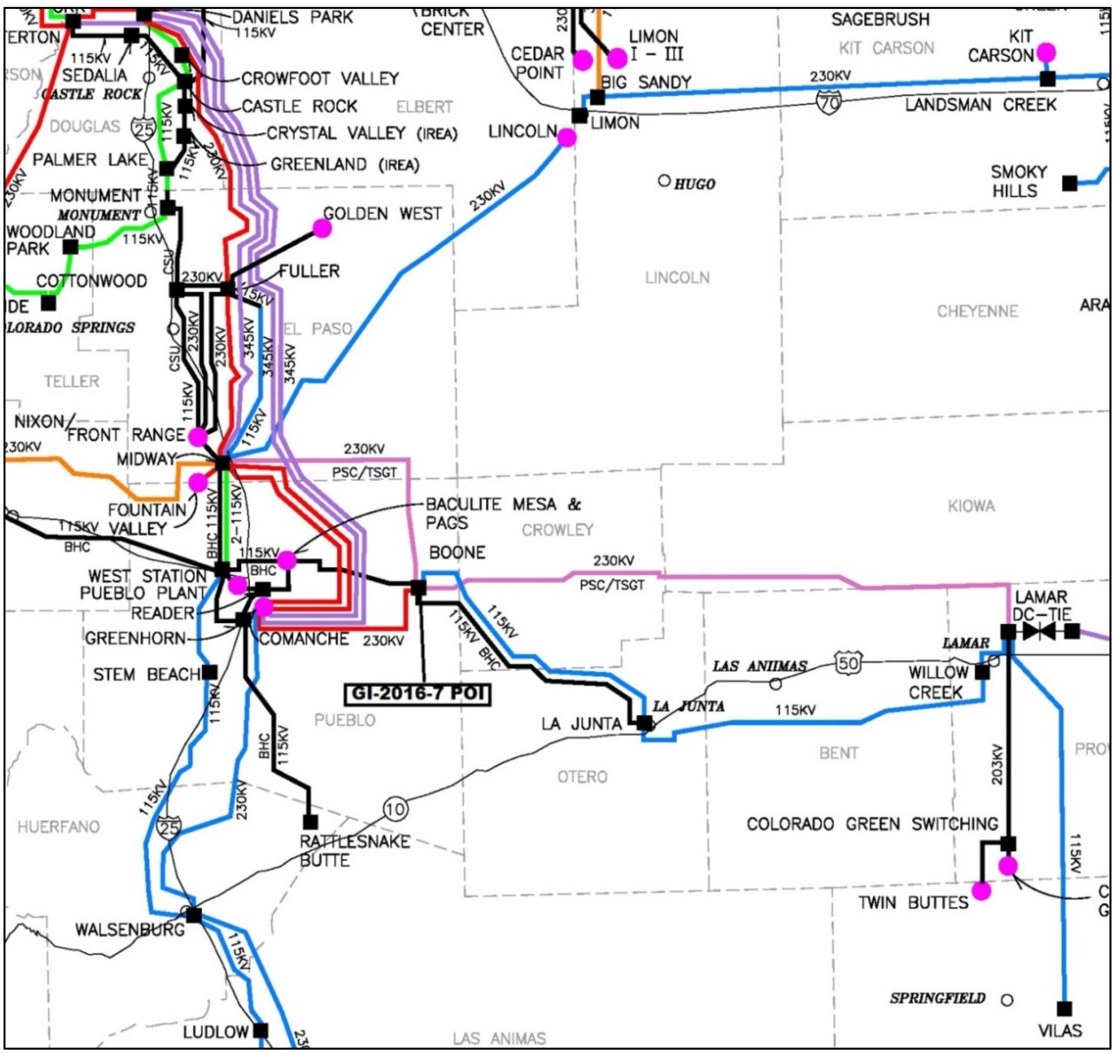

Figure 1 - GI-2016-7 Point of Interconnection and Study Area

Introduction

GI-2016-7 is a 240MW solar photovoltaic generation facility to 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 Customer has originally requested a Commercial Operation Date (COD) of December 31, 2018. During the Feasibility study report reviewing meeting, the Customer has revised the COD to November 30, 2019 and backfeed date to October 1, 2019. Based on the 18 month construction time frame required to build the transmission improvements, the proposed COD is not achievable.

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]. The Interconnection Request has identified that the generation output will be used to serve PSCo native load, so for both the ERIS and NRIS evaluations, the 240 MW rated output of GI-2016-7 is sunk to existing PSCo generation.

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 neighboring 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 neighboring 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 neighboring transmission systems that are impacted by 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

Serial Cumulative Power Flow Case Creation

The Base Case used for the power flow analysis originated from the 2023HS case built for the 2018 TPL1 work group of the Colorado Coordinated Planning Group (CCPG). As part of the case build effort for the TPL1 work group, the case has been reviewed by PSCo and the neighboring utilities within the CCPG foot print. PSCo then made the following changes to the 2023HS case to create the Base Case.

All transmission planned projects in PSCo's 10 year transmission plan (http://www.oasis.oati.com/woa/docs/PSCO/PSCOdocs/Q1_2019_Transmission_Plan.pdf) that are expected to be in-service before July 2023 are modeled in the Base Case, consistent with the case season and year. This includes the following projects:

- Graham Creek 115kV Substation – ISD 2021
- Husky 230/115kV Substation – ISD 2021
- Cloverly 115kV SUbstaion – ISD 2021
- Ault – Husky 230kV line – ISD 2021

- Husky - Graham Creek – Cloverly 115kV line – ISD 2021
- Monument – Flying Horse 115kV Series Reactor – ISD 2021
- Gilman – Avon 115kV line – ISD 2022
- Upgrade Villa Grove – Poncha 69kV Line – ISD 2021
- Upgrade Poncha – San Luis Valley 115kV line – ISD 2021

The following PSCo FAC8 terminal equipment upgrade operational and maintenance projects for which PSCo has plans to increase the line ratings have been modeled at their future ratings in the Base Case:

- Waterton – Martin2 tap 115kV line was modeled at 189MVA
- Malta – Twin Lakes 115kV line was modeled at 143MVA
- Twin Lakes – Otereo 115kV line was modeled at 143MVA
- Otereo – Buena Vista 115kV line was modeled at 150MVA
- Buena Vista – Ray Lewis 115kV line was modeled at 136MVA
- Ray Lewis – Poncha 115kV line was modeled at 164MVA
- Arapahoe – SantaFe – Daniels Park 230kV line was modeled at 560MVA
- 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
- San Luis Valley – Sargent 115kV line was modeled at 120MVA

The Base Case also modeled the Sargent – Poncha 115kV line closed.

The following additional changes were made to TSGT model in the Base Case per further review and comment from TSGT:

- 30MW San Isabel Solar tapping Ludlo Tap – Pinon Canyon 115kV line - existing
- 100MW TSGT_0809 solar facility tapping Gladstone – Walsenburg 230kV line – ISD Q2/2022
- 100MW TSGT_STEM_PV solar facility at Stem Beach 115kV bus – ISD Q3/2020
- Fuller – Vollmer – Black Squirrel 115 kV line modeled at 173 MVA

The following additional changes were made to BHE model in the Base Case per further review and comment from BHE:

- Fountain Valley – DesertCove 115kV line was modeled at 171MVA. Planned upgrade project in 1/2021
- Fountain Valley – MidwayBR 115kV line was modeled at 171MVA. Planned upgrade project in 1/2021
- West Station Substation Rebuild – ISD 5/2019
- 60MW wind generation at Rattle Snake Butte – ISD 9/2019
- Boone – La Junta 115kV line rebuild – ISD 11/2019
- Pueblo West Substation – ISD 1/2021

- North Penrose Substation – ISD 1/2022
- Hogback (Skyline) 115/69kV Substation – ISD 1/2022
- West Station – Greenhorn 115kV line Rebuild – ISD 9/2022

The following additional changes were made to CSU model in the Base Case per further review and comment from CSU:

- The Cottonwood – Tesla 34.5kV line is modeled open and Kettle Creek – Tesla 34.5kV line is modeled closed on the CSU system
- Grazing Yak Solar – ISD 2020
- Cottonwood 230/115kV auto-transformer replacement – ISD 2019
- Nixon – Kelker 230kV line uprate – ISD 2019

The Base Case model includes the existing PSCo generation resources at the time of this study.

The Base Case was updated to include the higher-queued generation with LGIAs (active or suspended) and their associated Network Upgrades that were not included in the Base Case. In addition, all higher-queued generation in the current PSCo GIR queue and their associated upgrades are modeled. The higher-queued LGIAs modeled are GI-2009-8, GI-2010-8, GI-2014-2, GI-2014-12, GI-2014-13 and GI-2014-14. The higher-queued GIRs modeled are: GI-2014-6, GI-2014-8, GI-2014-9, GI-2014-12 and GI-2016-4. While the higher-queued NRIS requests are dispatched at 100% nameplate, the higher-queued ERIS requests are dispatched at 0MW.

The following PSCo Network Upgrades identified in the higher-queued GIs are modeled in the GI-2016-7 Base Case:

- MidwayPS 230/115kV, 100MVA transformer replaced with 150MVA unit – Network Upgrade assigned to GI-2014-12

The Benchmark Case was created from the Base Case by changing the generation dispatch to reflect 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 7 below. The generation dispatch of the neighboring systems is provided by the neighboring utilities.

For the power flow analysis, the Study Case for GI-2016-7 was created by adding GI-2016-7 model to the Benchmark Case. The 240MW output from GI-2016-7 was sunk uniformly to the PSCo units outside the study area.

A power flow analysis was performed and the results of the Benchmark Case and Study Case were compared to determine the impacts of the interconnection of GI-2016-7.
The steady state analysis was performed using PTI’s PSSE Ver. 33.6.0 program and the ACCC contingency analysis tool.
Transient stability analysis was performed using General Electric’s PSLF Ver.21.0_02 program.
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.

Power Flow Analysis Results

The results of the single contingency analysis (P1 and P2) are given in Table 5. The following new facility overloads are caused by the addition of GI-2016-7:

- Daniels Park – Fuller 230kV line loading increased from 91.9% to 103.4% (PSCo facility)
- Greenwood – Prairie3 230kV line loading increased from 94.4% to 101.6% (PSCo facility)
- Midway 230kV bus tie line loading increased from 94.2% to 109.0% (WAPA facility)
- Kelker E – Templeton 115kV line loading increased from 99.5% to 102.7% (CSU facility)
- Vollmer – Fuller 115kV line loading increased from 93.7% to 102.0% (TSGT facility)
- Vollmer – Black Squirrel 115kV line loading increased from 93.7% to 102.0% (TSGT facility)
- Black Forest – Black Squirrel MV 115kV line loading increased from 93.3% to 103.2% (TSGT facility)

The overloads on the Daniels Park – Fuller 230kV line and Greenwood – Prairie3 230kV line can be mitigated by fixing the terminal equipment limitations on these lines. The new ratings of the Daniels Park – Fuller 230kV line will be 557MVA and the Greenwood – Prairie3 230kV line will be 637MVA. The cost of PSCo Network Upgrades to mitigate overloads on the two PSCo facilities is given in Table 4 below.

In addition to PSCo system overloads, GI-2016-7 caused new overloads on the WAPA, CSU and TSGT systems. For facility overloads that were existing in the Benchmark Case and where the addition of GI-2016-7 caused an increase in the pre-existing Benchmark Case overload, the overloads are assigned to higher-queued GIs as noted in Table 5. However, GI-2016-7 is responsible to mitigate overloads on facilities caused by the GI-2016-7 project itself, taking into consideration the Network Upgrades that would be mitigated by the higher queued projects. Therefore, WAPA, CSU, TSGT and BHE have been identified as Affected Systems for GI-2016-7. PSCo has informed the Affected Systems regarding the contingency overloads on their facilities. Mitigation measures for each of the contingency overloads on the Affected Systems must be identified and addressed by the Affected Systems in order for GI-2016-7 to achieve NRIS of 240MW.

Voltage Regulation and Reactive Power Capability

The 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).

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).

Any wind generating plant interconnections must also fulfill the performance requirements specified in FERC Order 661-A.

Transient Stability Study Results

The transient stability analysis for GI-2016-7 simulated nine disturbances in the Study Case.

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 A. 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.

<u>Short Circuit and Breaker Duty Analysis</u>

The calculated short circuit levels and Thevenin system equivalent impedances at the Boone 230kV POI are shown in Table 1.

Table 1 – Short Circuit Parameters at the GI-2016-7 Boone 230kV bus POI

	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.

<u>Costs Estimates and Assumptions</u>

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 2 and Table 3.

Table 2: “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 3: “Network Upgrades required for Interconnection (applicable for either ERIS or NRIS)” includes the nature and estimated cost of the Transmission Provider's Network

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

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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 2 and Table 3 are illustrated in Figure 2 in the Appendix A 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 4.

Table 4: "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.

Conclusion:

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

- **ERIS is $4.083 Million (Tables 2 and 3); and**
- **NRIS is $4.466 Million (Tables 2, 3 and 4)**

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).

The ERIS and NRIS results above are contingent upon the mitigation of all overloads and Network Upgrades identified in the Affected Systems and the PSCo system, and Network Upgrades identified for all applicable higher-queued Interconnection Requests (see footnotes to Table 3 and Table 4).

If there is a change in status of one or more higher-queued Interconnection Requests due to withdrawal from the queue or changing from NRIS to ERIS, and the Network Upgrades identified for the higher queued Interconnection Requests are not constructed, the Network Upgrade costs would become the responsibility of GI-2016-7 to the extent they are necessary to interconnect GI-2016-7. A restudy will be performed as needed to identify the new Network Upgrade responsibilities.

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

Table 2 –Transmission Provider's Interconnection Facilities

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	**$1.39**
Time Frame	**Site, design, procure and construct**	**18 Months**

Table 3 - Network Upgrades for Interconnection (applicable for either ERIS or NRIS) *

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 4 – Additional Network Upgrades for NRIS *

Element	Description	Cost Est. (Millions)
PSCo's Daniels Park 230kV Bus	Upgrade the 230kV terminal to Jackson Fuller to the next highest rating of 557MVA	$0.063
5707 Greenwood-Prairie 3 230 Line/Sub	Upgrade 230kV line for 5707 to the next highest rating of 637MVA	$0.320
	Total Cost Estimate for Network Upgrades for Delivery (NRIS)	**$0.383**
Time Frame	**Site, design, procure and construct**	**18 Months**
	Total Project Estimate	**$4.466**

*** Contingent on completion of the Network Upgrades for NRIS and the mitigation of overloads identified in Affected Systems for higher-queued Interconnection Requests GI-2009-8, GI-2010-8, GI-2014-2, GI-2014-12, GI-2104-13, GI-2014-14, GI-2014-6, GI-2014-8, GI-2014-9, GI-2014-12 and GI-2016-4. 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 is 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 its Contractor's) 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.

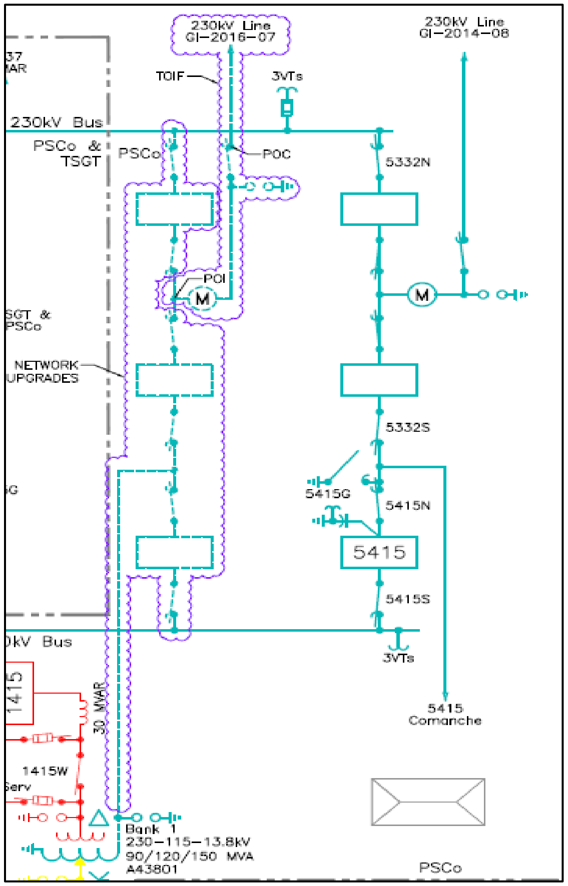


Figure 2 – Preliminary one-line of GI-2016-7 POI within the Boone 230kV Substation

Table 5 Power Flow Analysis Results

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

Table 5 – 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
Daniels Park – Fuller 230kV	Line	PSCo	478	439.3	91.9%	494.2	103.4%	11.5%	Midway – Waterton 345kV	GI-2016-7
Greenwood – Prairie3 230kV	Line	PSCo	478	451.2	94.4%	485.6	101.6%	7.2%	Daniels Park – Prairie1 230kV	GI-2016-7
Midway 230kV bus tie	Line	WAPA	432	406.9	94.2%	470.9	109.0%	14.8%	Midway PS – Fuller 230kV	GI-2016-7
Palmer Lake – Monument 115kV	Line	CSU	108	118.9	110.1%	137.0	126.9%	16.8%	Daniels Park – Fuller 230kV	GI-2014-8
Smelter town – West Canyon 115kV	Line	BHCE	62	64.5	104.0%	71.8	115.8%	11.8%	PonchaBR– West Canyon 230kV	GI-2014-12
Brairgate S – Cottonwood S 115kV	Line	CSU	150	157.6	105.1%	162.7	108.5%	3.4%	Cottonwood N – KettleCreek S 115kV	GI-2014-8
Cottonwood N – KettleCreek S 115kV	Line	CSU	162	162.8	100.5%	168.5	104.0%	3.5%	Brairgate S – Cottonwood S 115kV	GI-2014-12
Kelker E – Templeton 115kV	Line	CSU	131	130.3	99.5%	134.5	102.7%	3.2%	Kelker W – Rock Island 115kV	GI-2016-7
Vollmer – Fuller 115kV	Line	TSGT	173	162.2	93.7%	176.5	102.0%	8.3%	Daniels Park – Fuller 230kV	GI-2016-7
Vollmer – Black Squirrel 115kV	Line	TSGT	173	162.2	93.7%	176.5	102%	8.3%	Daniels Park – Fuller 230kV	GI-2016-7
Black Forest - Black Squirrel MV 115kV	Line	TSGT	143	133.4	93.3%	147.6	103.2%	9.9%	Daniels Park – Fuller 230kV	GI-2016-7

Table 6 Transient Stability Analysis Results

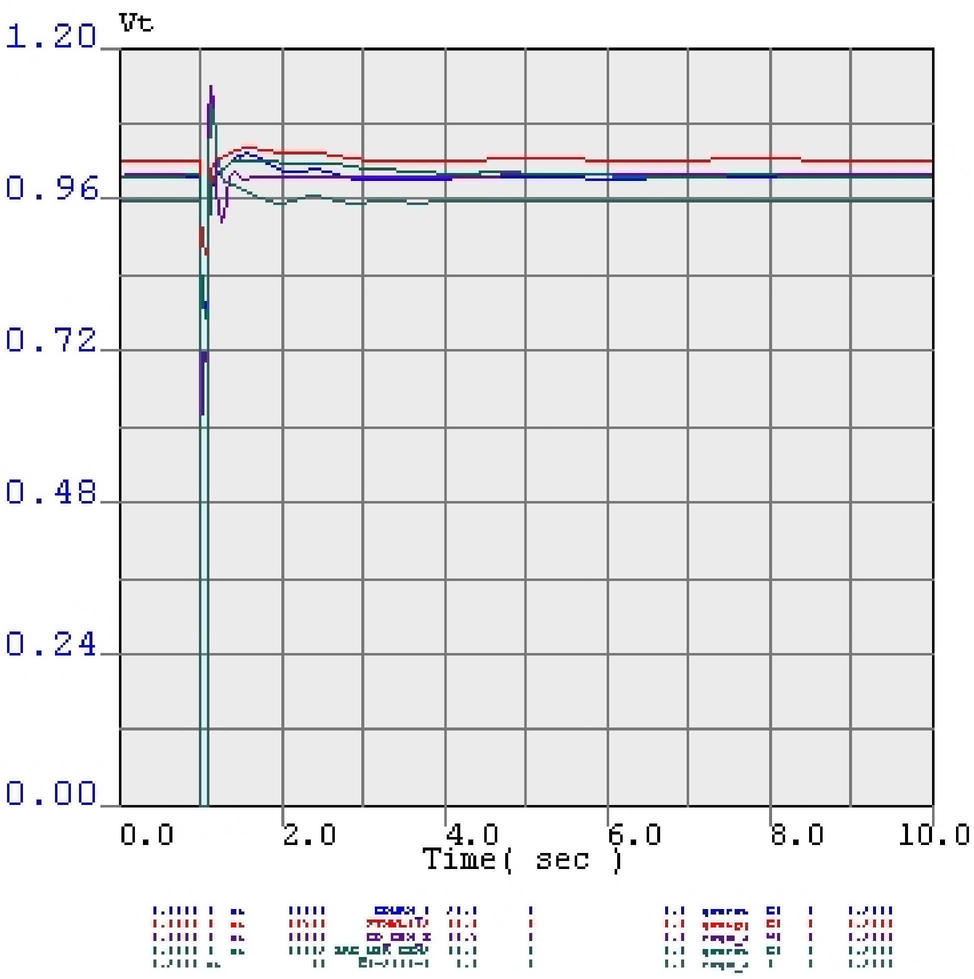
Stability Scenarios						
#	Fault Location	Fault Type	Facility Tripped	Clearing Time (cycles)	Post-Fault Voltage Recovery	Angular Stability
1	Boone 230kV	3ph	Boone 230/115kV Transformer	Primary (5.0)	Maximum transient voltage dips within criteria	Stable with positive damping
2	Boone 230kV	3ph	Lamar – 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

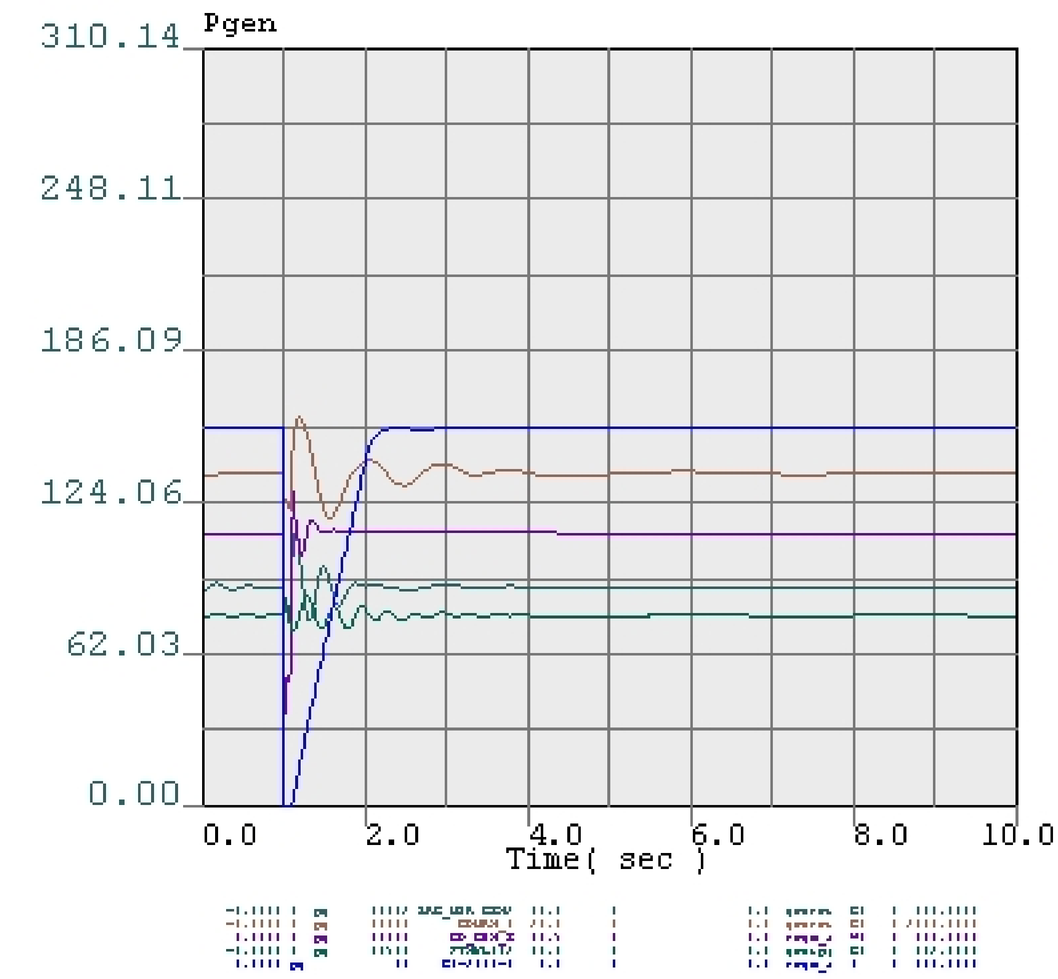
Xcel Energy

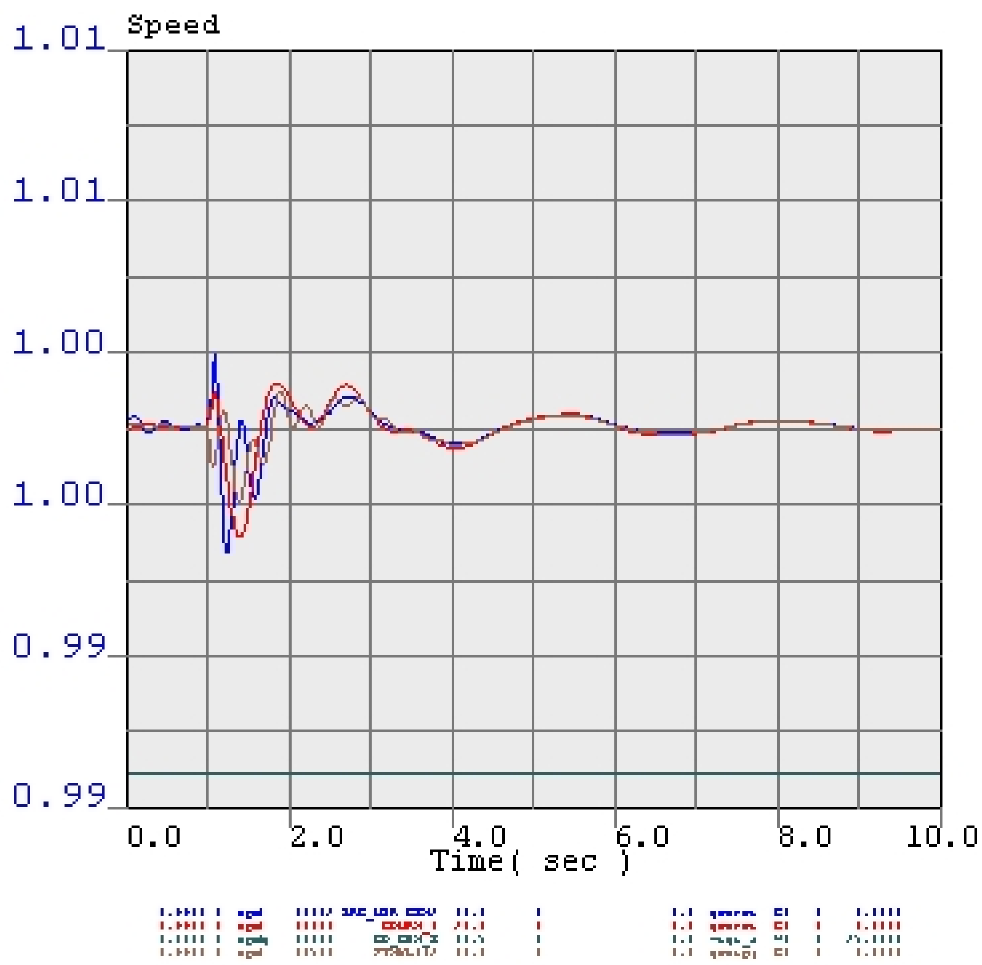
Table 7 – Generation Dispatch Used to Stress the Benchmark Case (MW is Gross Capacity)

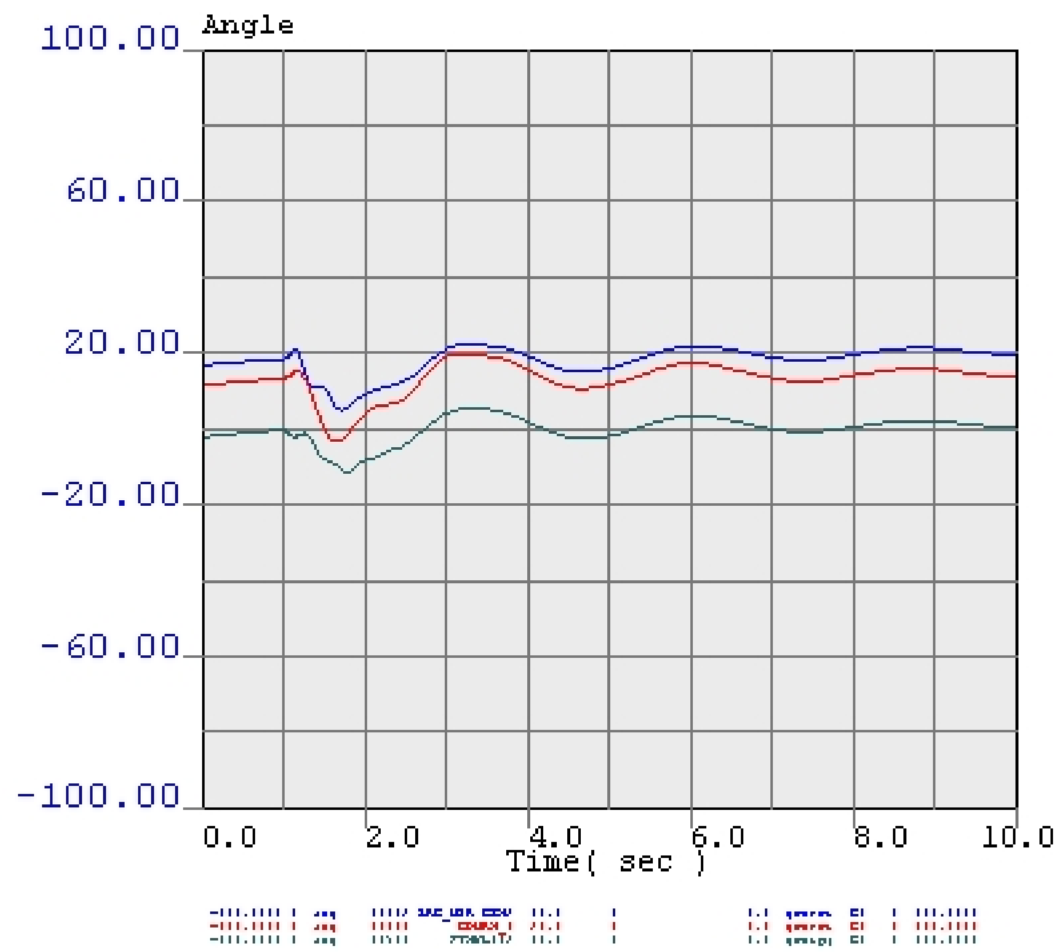
Bus Name	ID	Status	PGen (MW)	PMax (MW)	Owner
APT_DSLS 4.1600	G1	0	0	10	BHE
BAC_MSA GEN113.800	G1	1	90	90	BHE
BAC_MSA GEN213.800	G1	1	90	90	BHE
BAC_MSA GEN413.800	G1	1	35	40	BHE
BAC_MSA GEN413.800	G2	1	35	40	BHE
BAC_MSA GEN413.800	S1	1	20	24.8	BHE
BAC_MSA GEN513.800	G1	1	30	40	BHE
BAC_MSA GEN513.800	G2	1	30	40	BHE
BAC_MSA GEN513.800	S1	1	20	24.8	BHE
BAC_MSA GEN613.800	G1	1	0	40	BHE
BUSCHRNCH_LO0.7000	1	1	20	60	BHE
BUSCHRWTG1 0.7000	G1	1	14	28.8	BHE
E_CANON 69.000	G1	0	0	8	BHE
PP_MINE 69.000	G1	0	0	3	BHE
PUB_DSLS 4.1600	G1	0	0	10	BHE
R.F.DSLS 4.1600	G1	0	10	10	BHE
RTLSNKWNDLO 0.7000	G1	1	22	60	BHE
ALMSACT1 13.800	G1	0	17	17	PSCo
ALMSACT2 13.800	G2	0	19	14	PSCO
COGENTRIX_PV34.500	S3	1	19.5	30	PSCO
COMAN_1 24.000	1	1	357	360	PSCO
COMAN_2 24.000	C2	1	365	365	PSCO
COMAN_3 27.000	C3	1	788	780	PSCO
COMAN_PV 34.500	S1	1	102	120	PSCO
CO_GRN_E 34.500	W1	1	64.8	81	PSCo
CO_GRN_W 34.500	W2	1	64.8	81	PSCo
FTNVL1&2 13.800	G1	1	36	40	PSCO
FTNVL1&2 13.800	G2	1	36	40	PSCO
FTNVL3&4 13.800	G3	1	36	40	PSCO
FTNVL3&4 13.800	G4	1	36	40	PSCO
FTNVL5&6 13.800	G5	1	36	40	PSCO
FTNVL5&6 13.800	G6	1	36	40	PSCO
GSANDHIL_PV 34.500	S1	1	12.4	19	PSCO
JKFULGEN 0.6900	W1	1	200	249.43	PSCO
LAMAR_DC 230.00	DC	0	101	210	PSCO
SOLAR_GE 34.500	S2	1	19.5	30	PSCO

SUNPOWER 34.500	S1	1	33.8	52	PSCO
TWNBUTTE 34.500	W1	1	60	75	PSCO
SI_GEN 0.6000	1	1	6.1	30	TSGT
STEM_PV 0.4800	PV	1	80	100	TSGT
TBII_GEN 0.6900	W	1	60	76	TSGT
TSGT_0809 0.6200	PV	1	80	100	TSGT

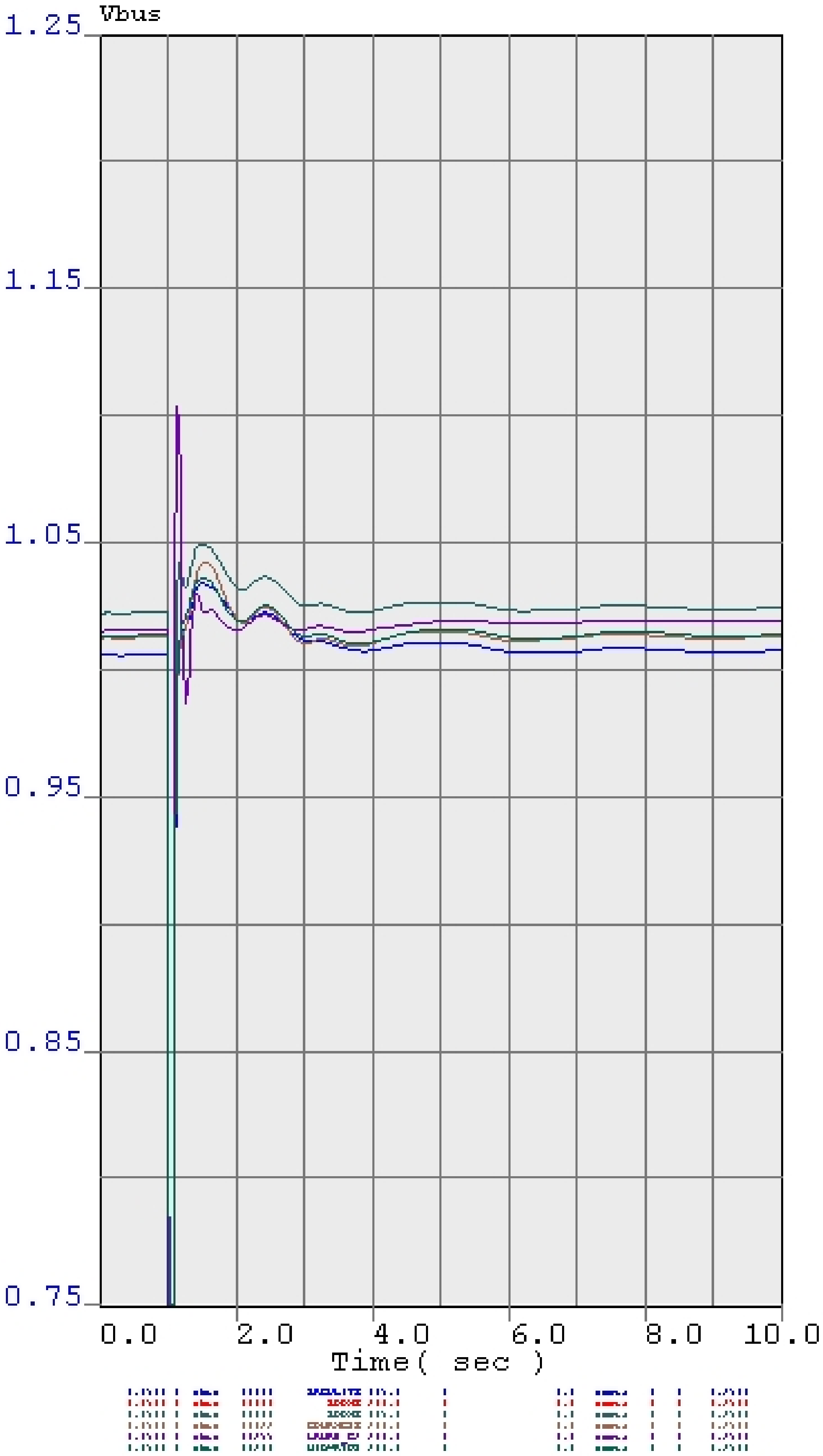


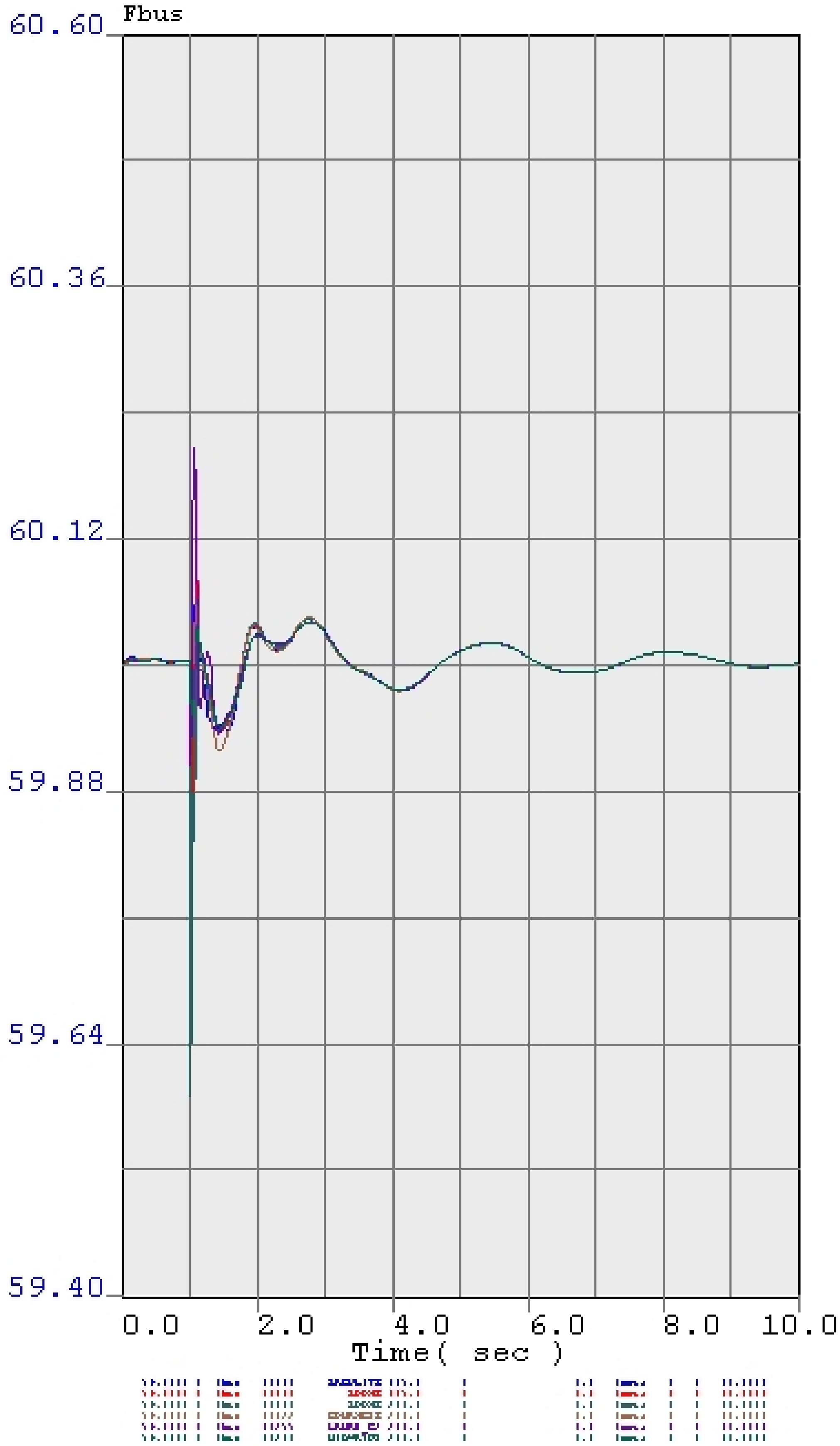






tran_1
Boone 230kV bus fault, lose Boone 230/115kV bank





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

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

April_2019-revision\chans
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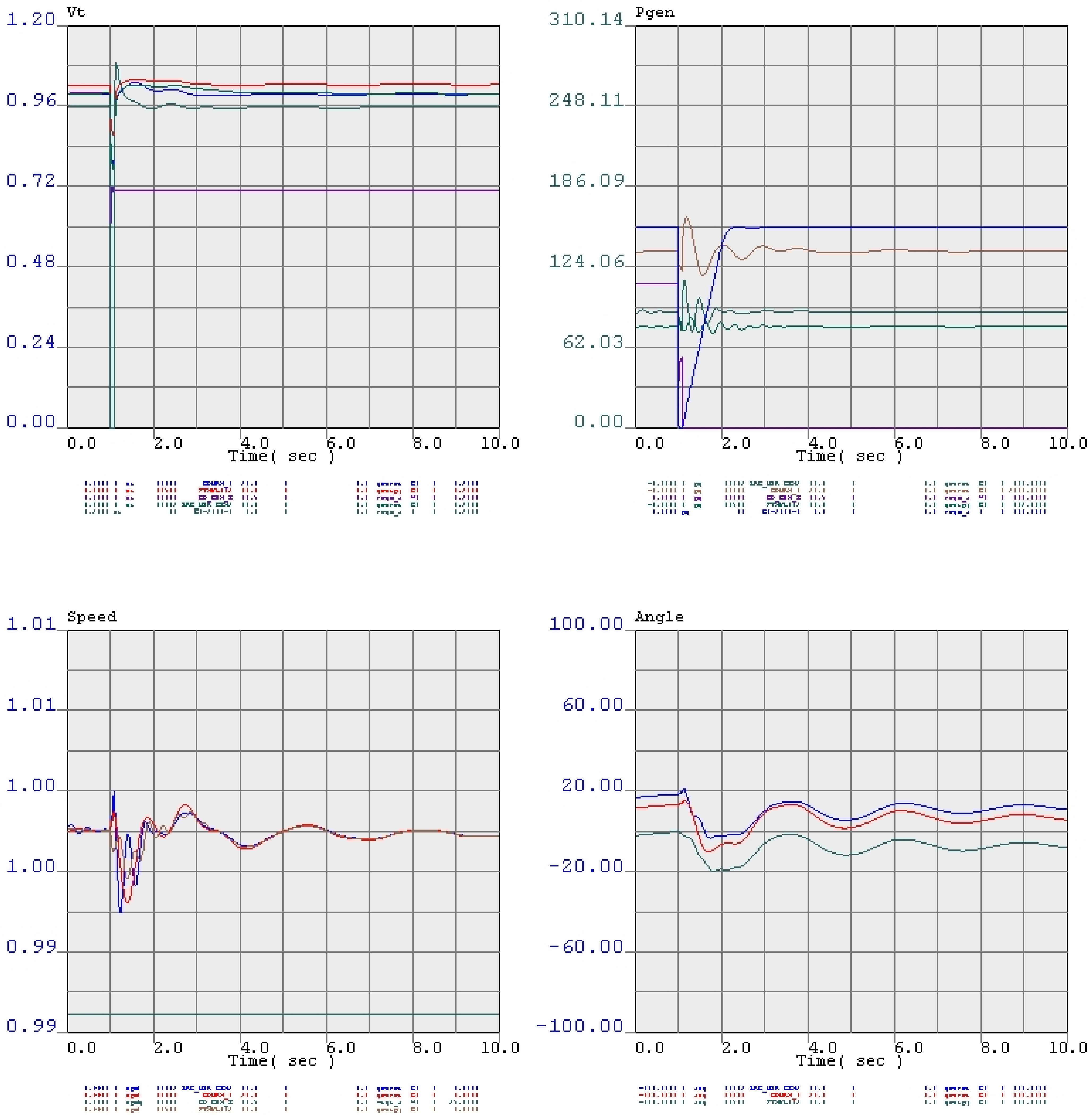

Line_2
Boone 230kV bus fault, lose Lamar-Boone 230kV and Lamar gen

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

April_2019-revision\chans
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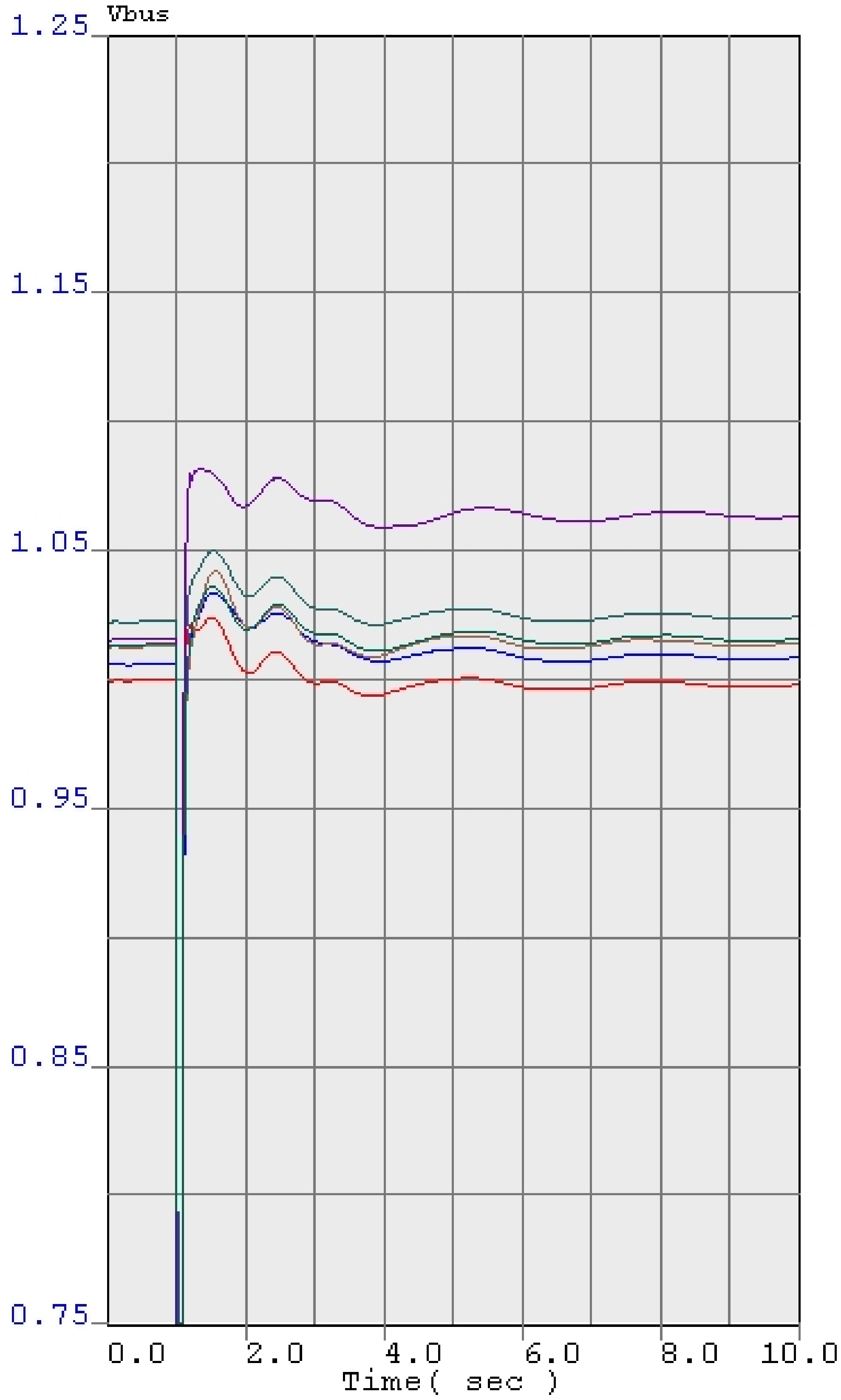

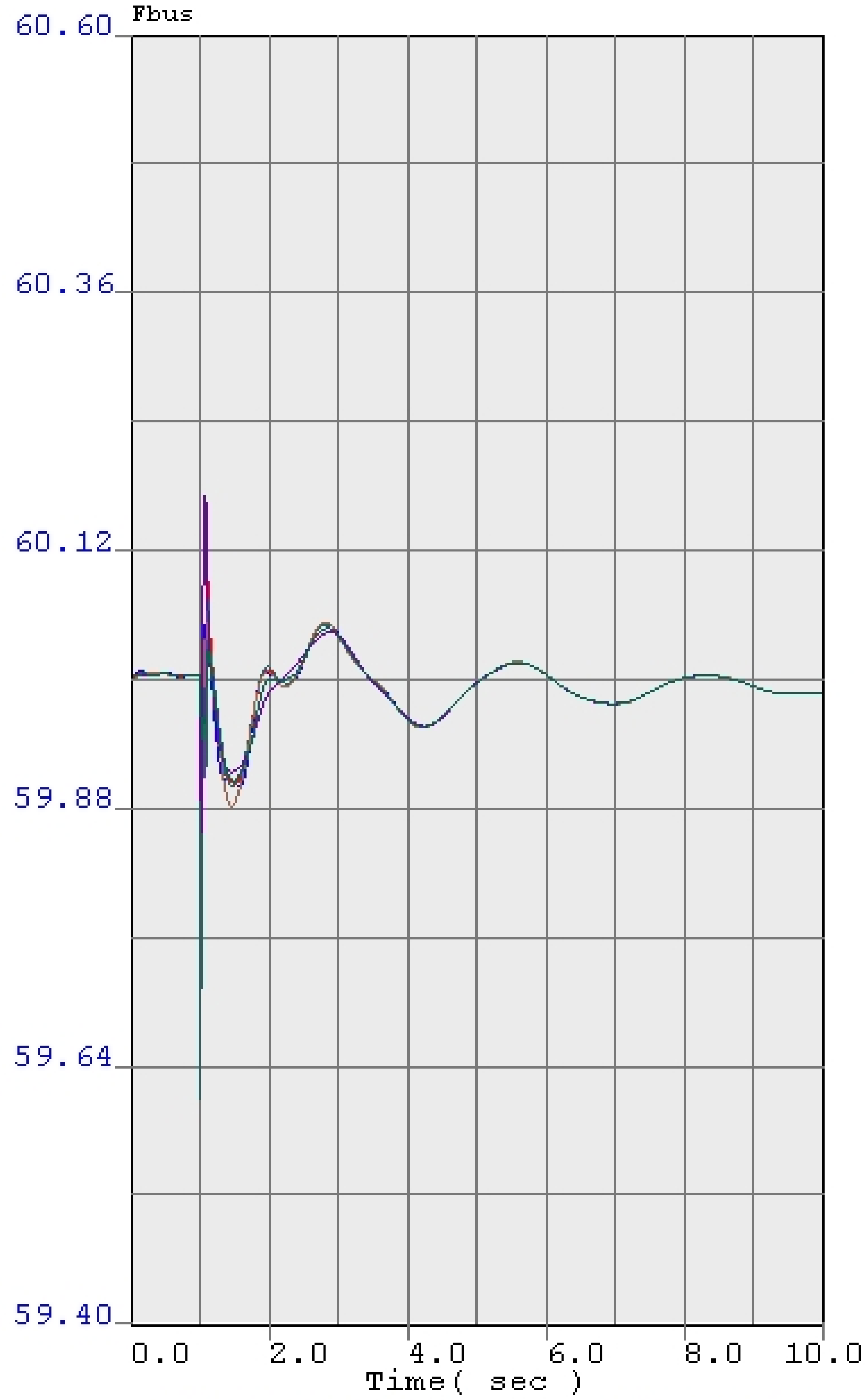

Line_2
Boone 230kV bus fault, lose Lamar-Boone 230kV and Lamar gen

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

April_2019-revision\chans
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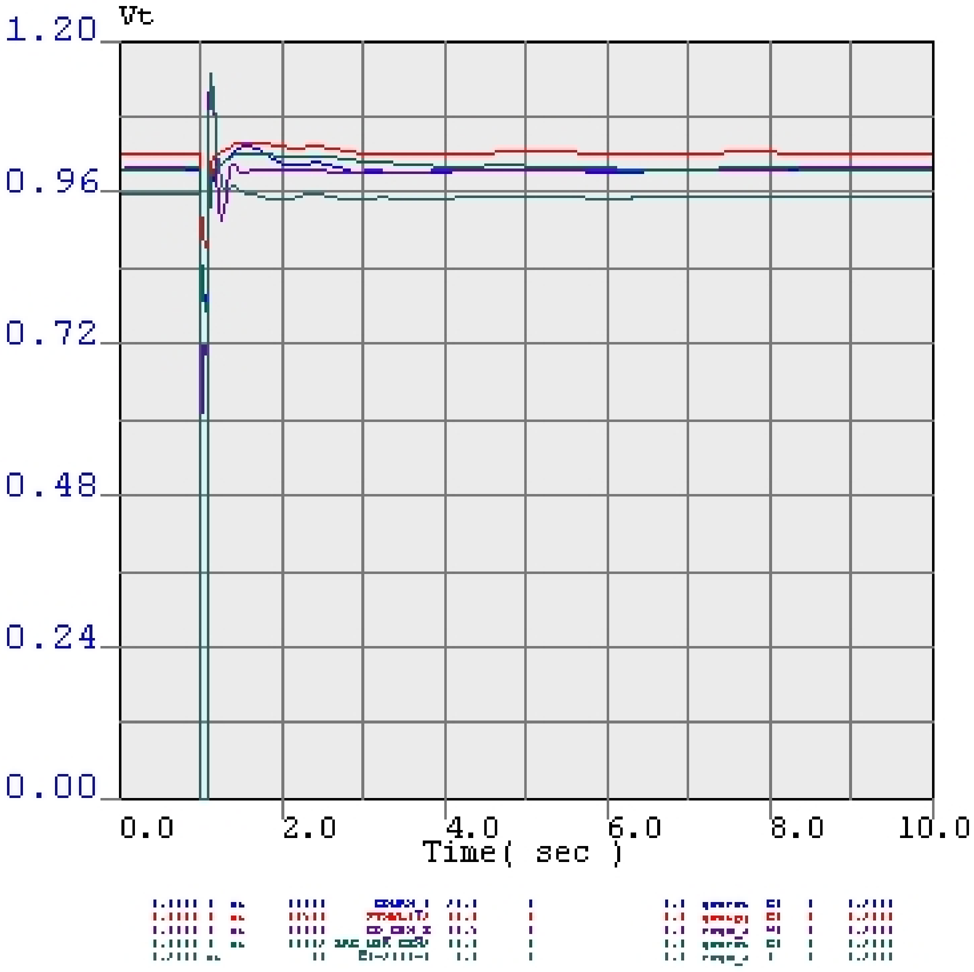
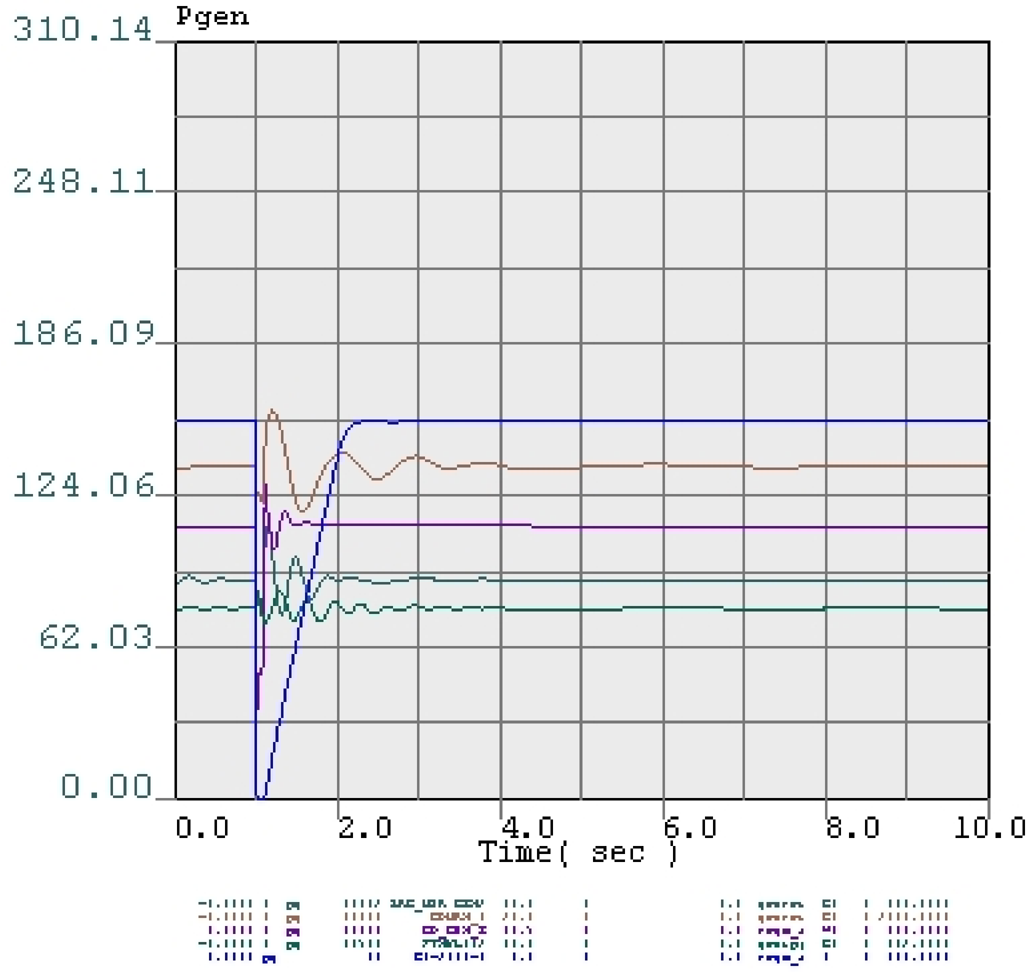
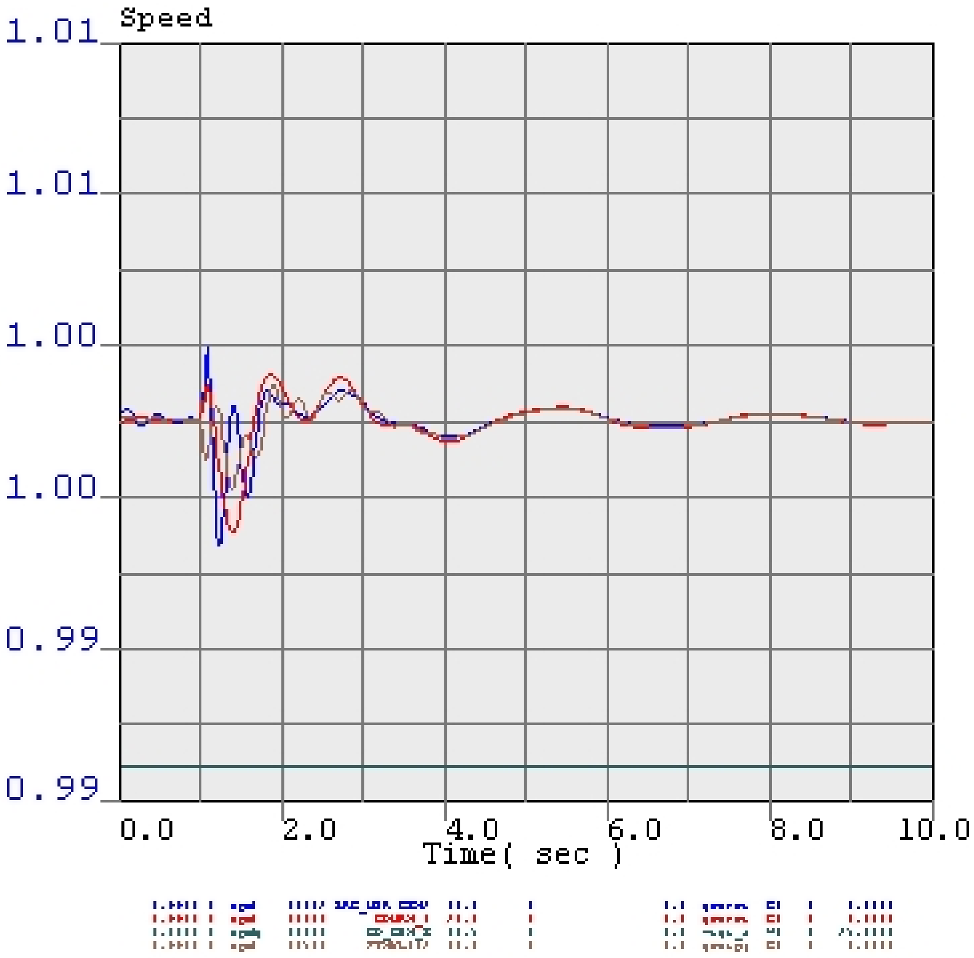
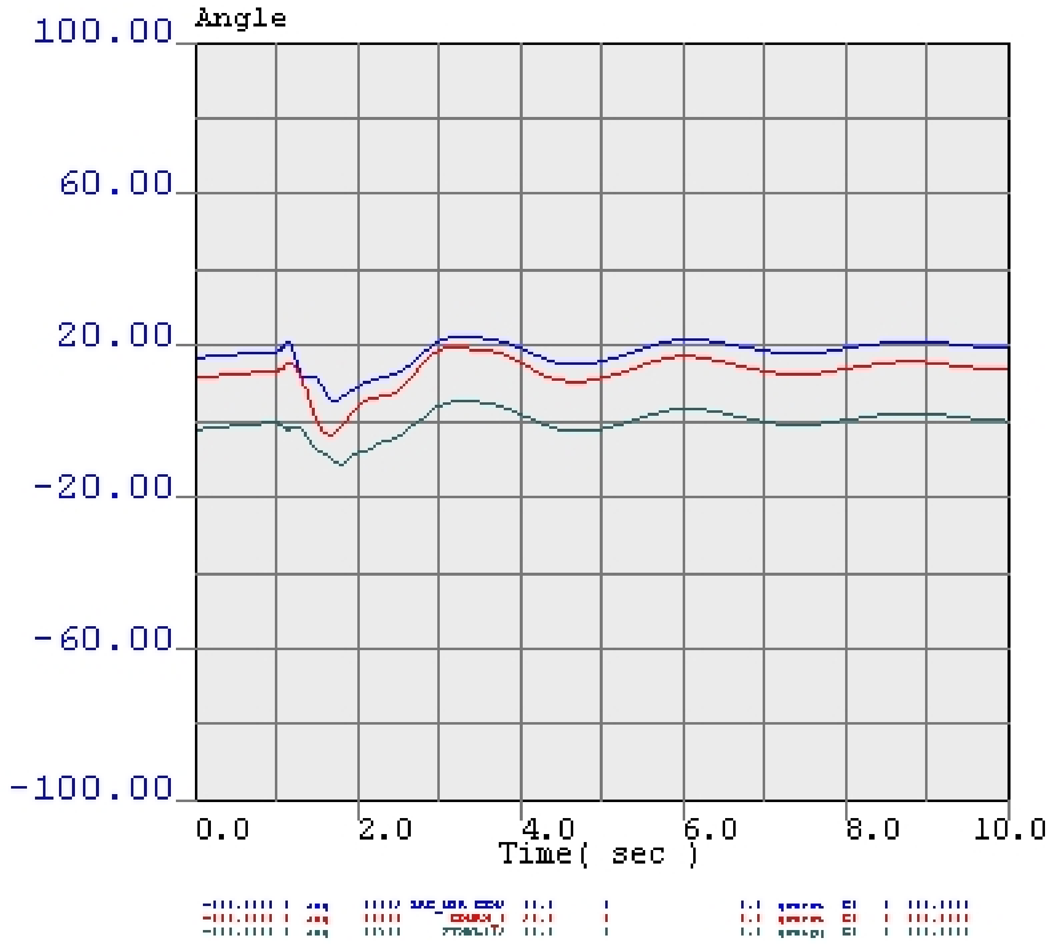
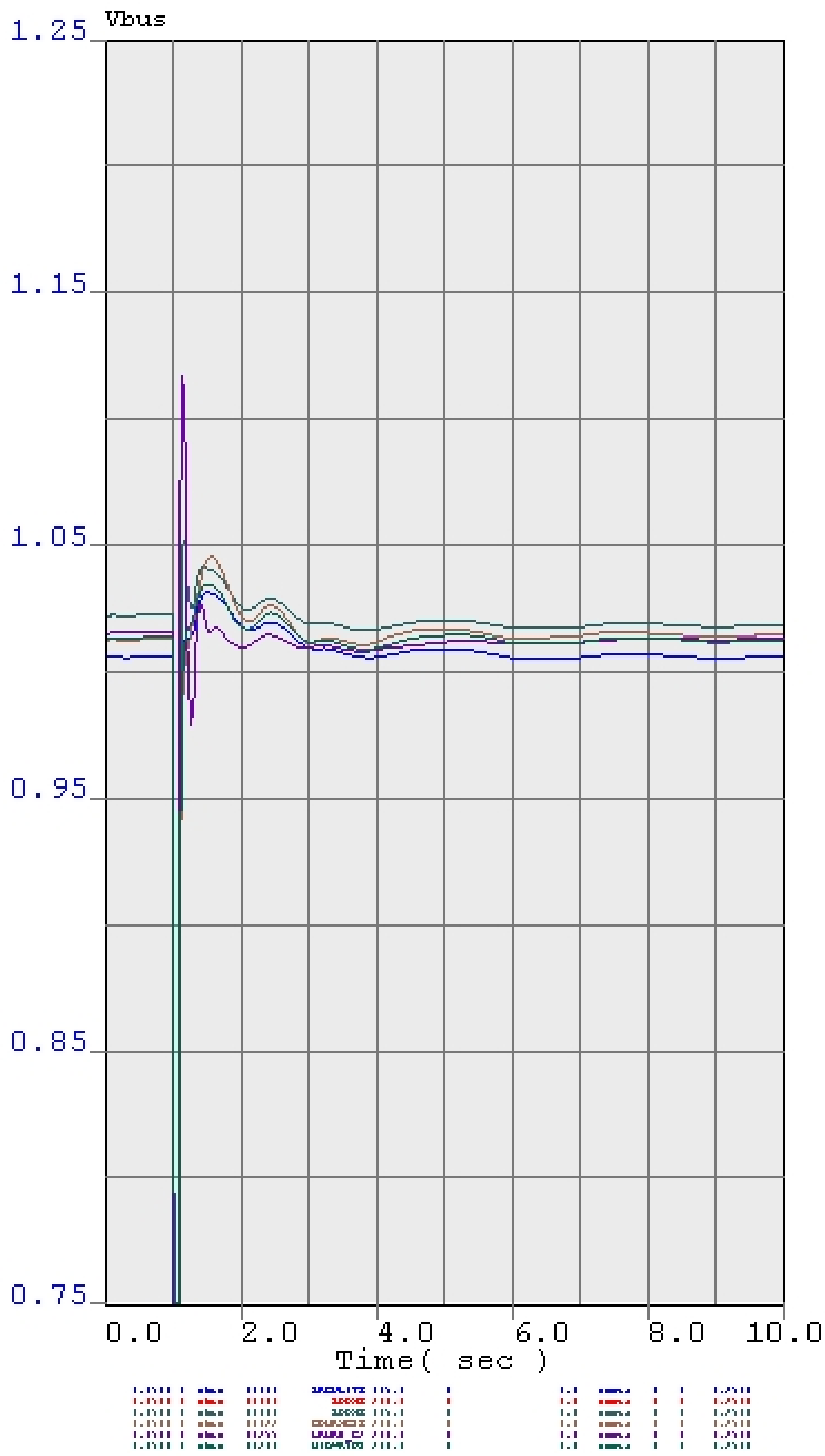


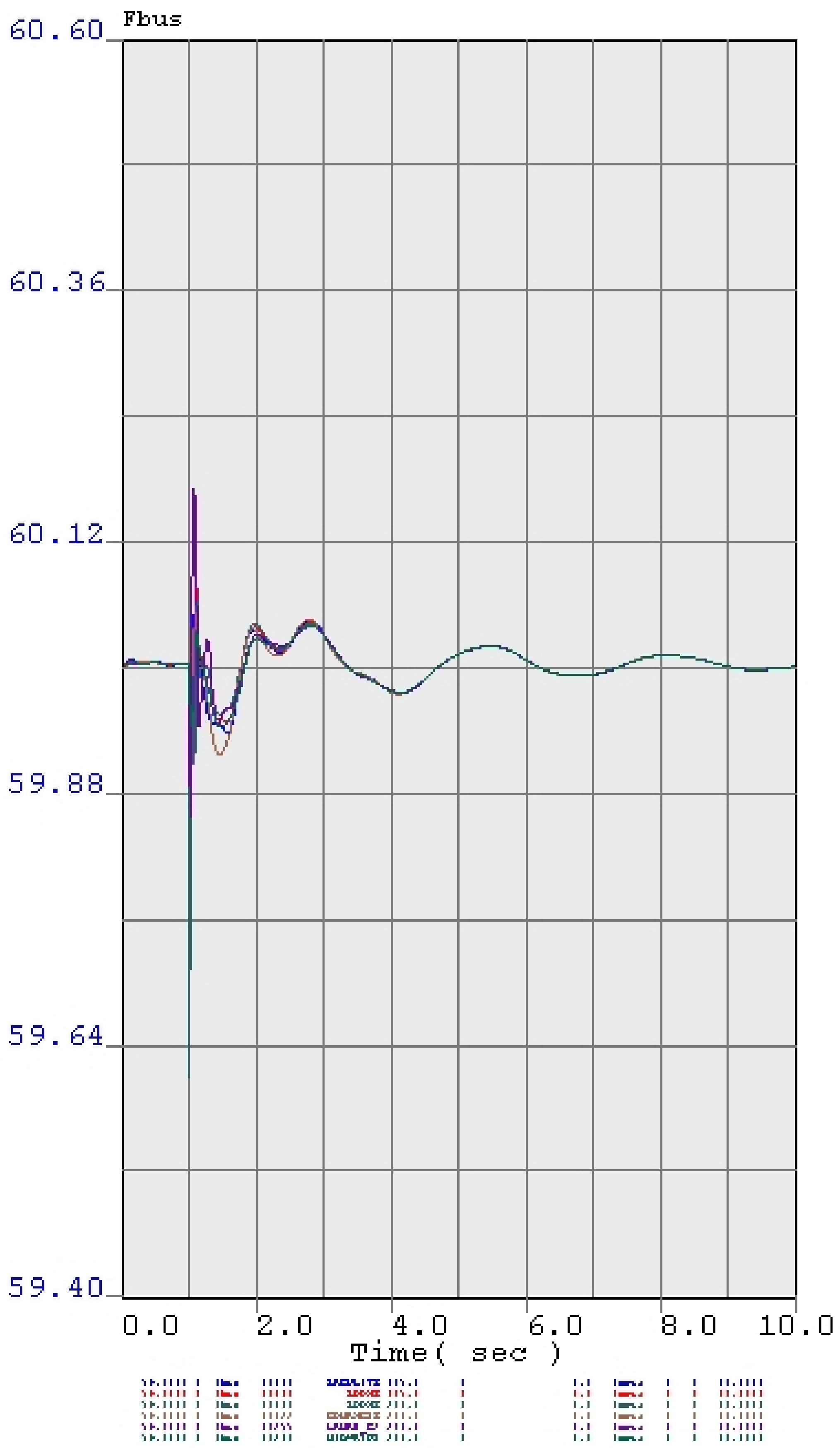






Line_3
Fault at Boone 230kV, lose Boone-Comanche 230kV





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

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

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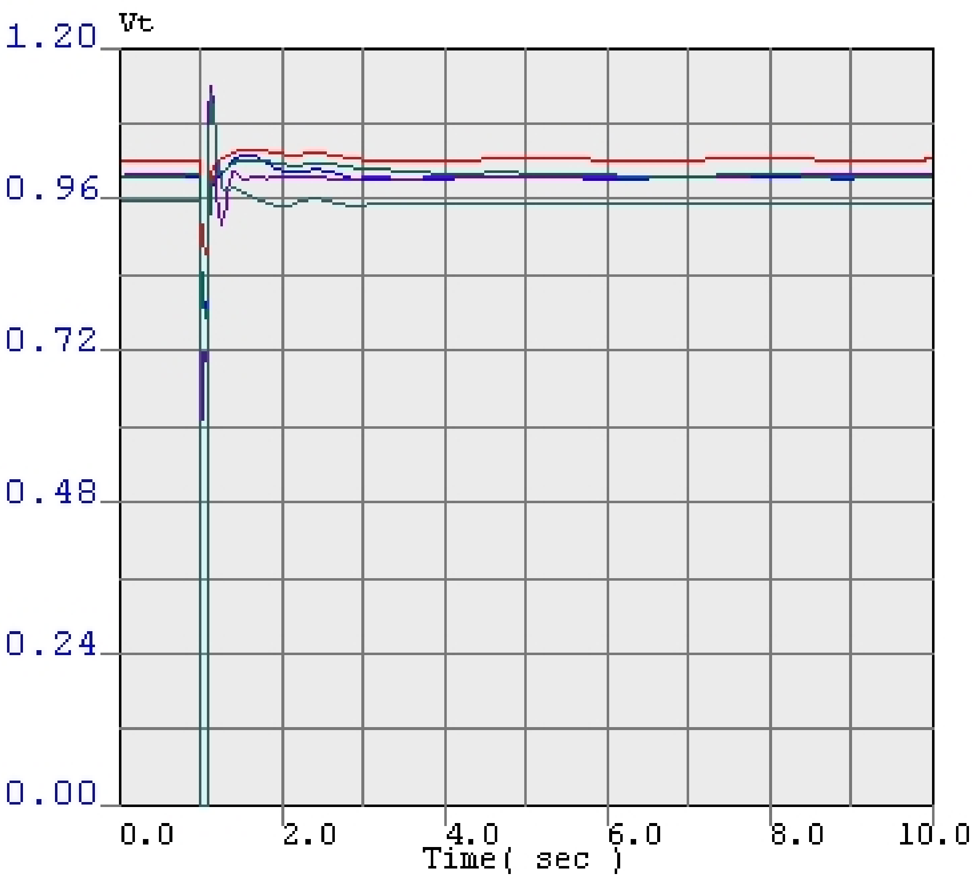
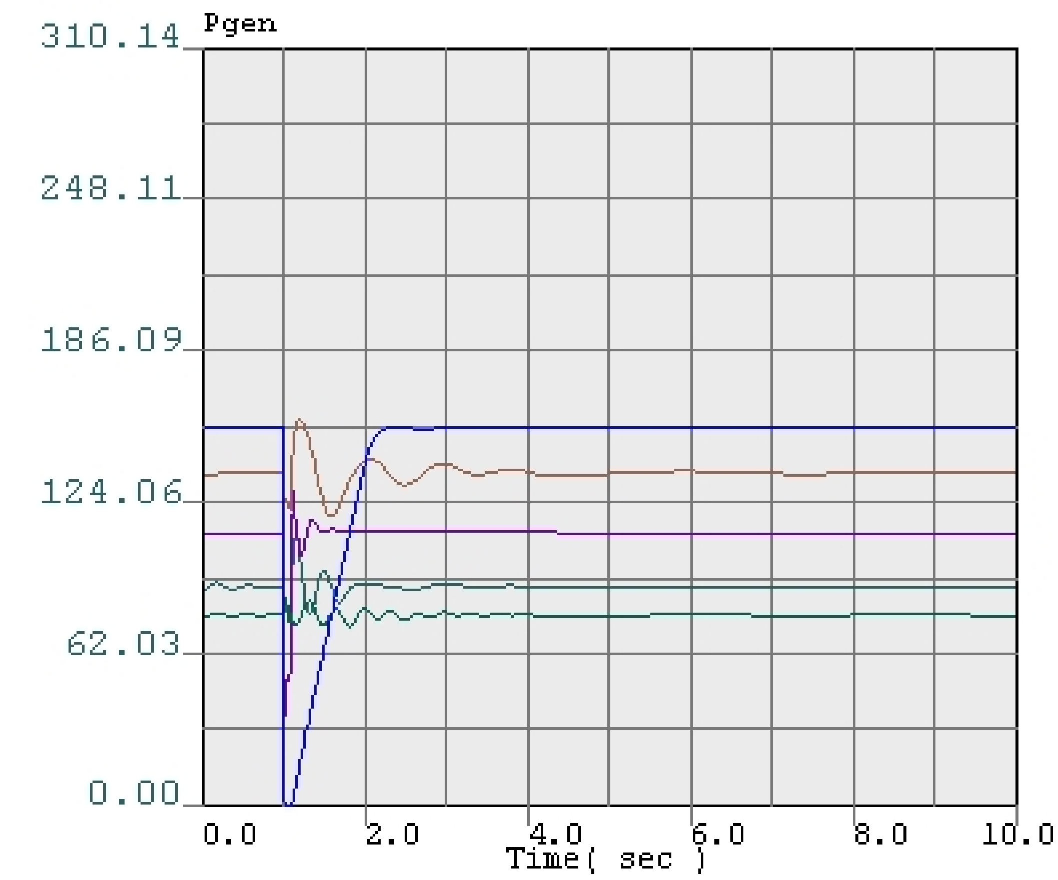
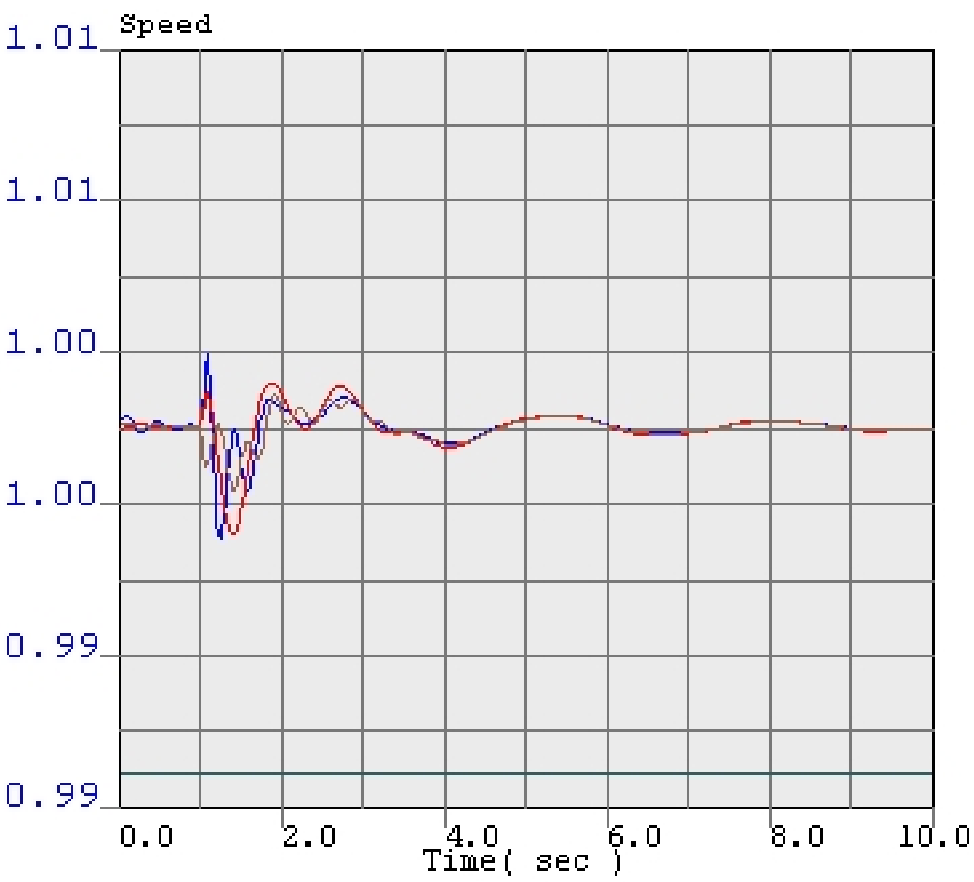
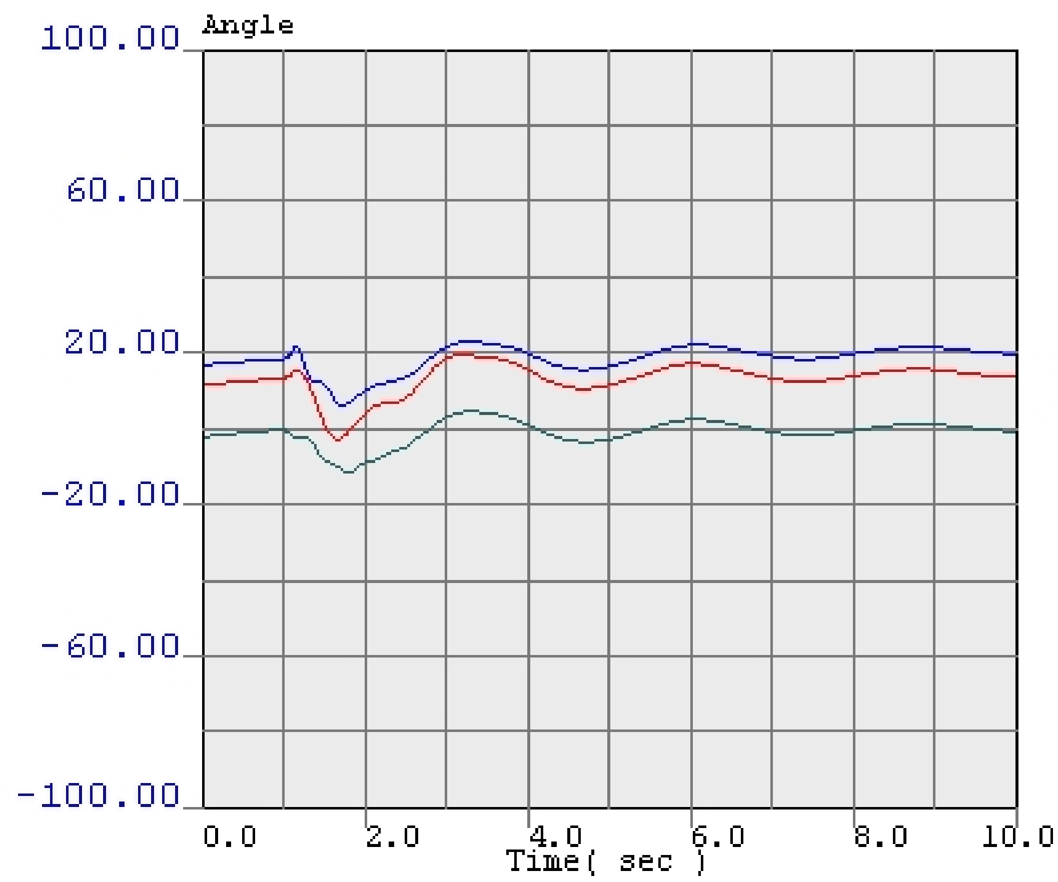


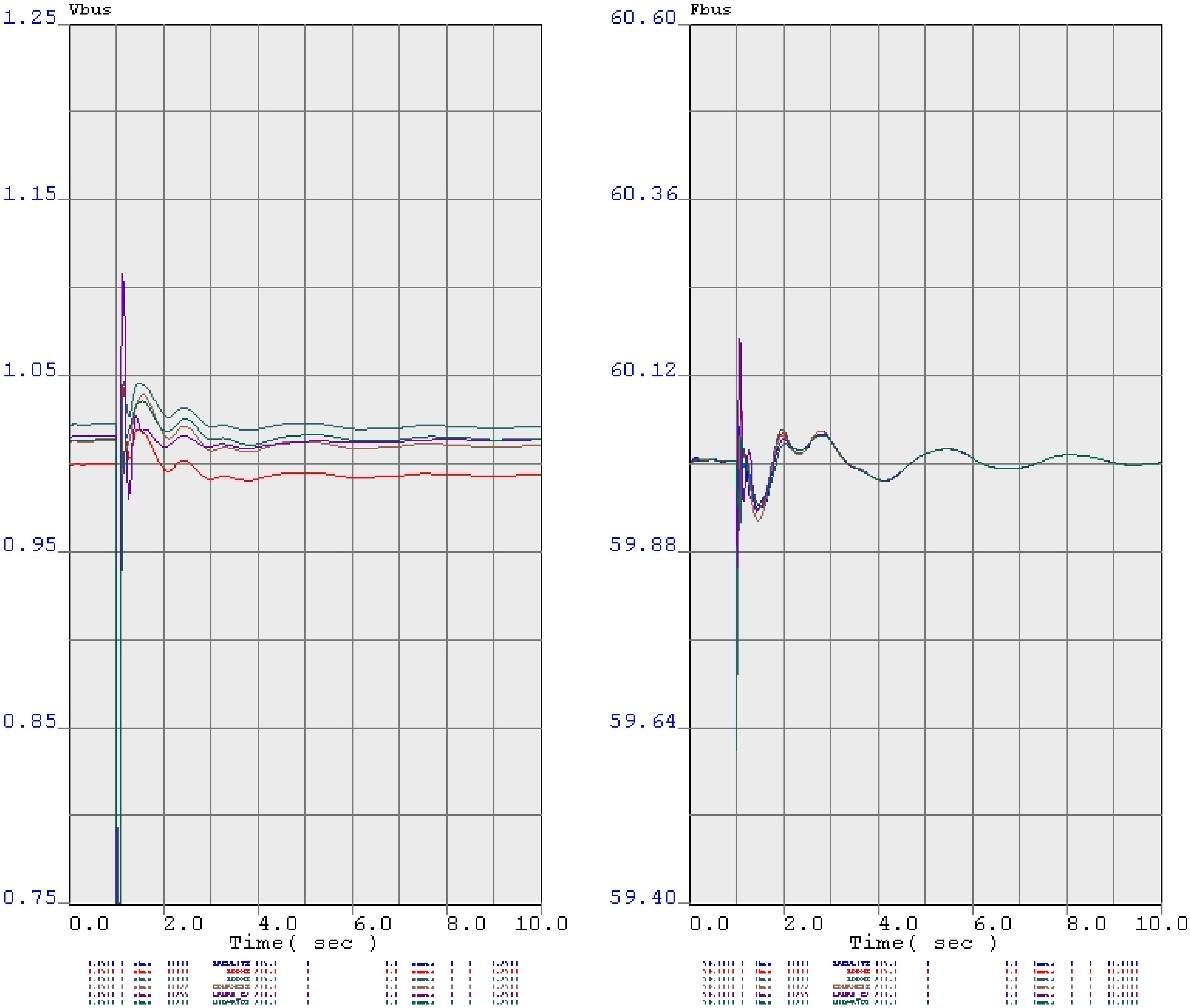






Line_4

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



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

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

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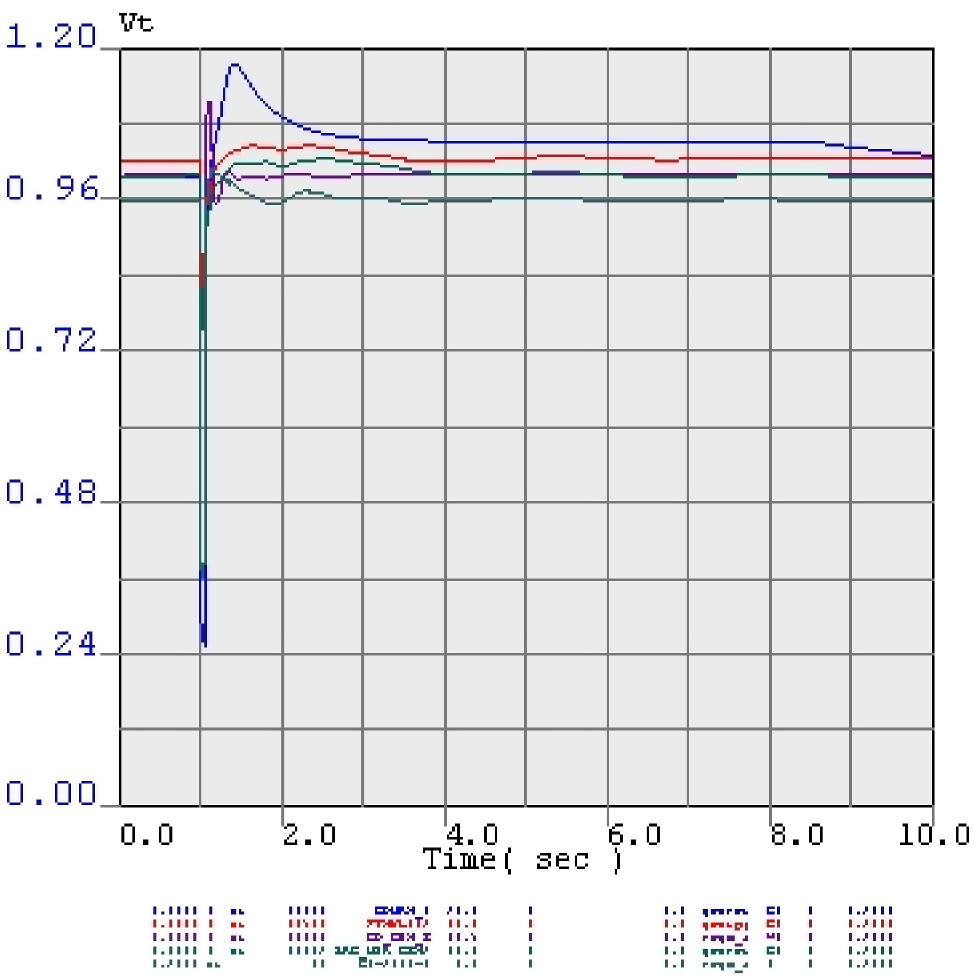
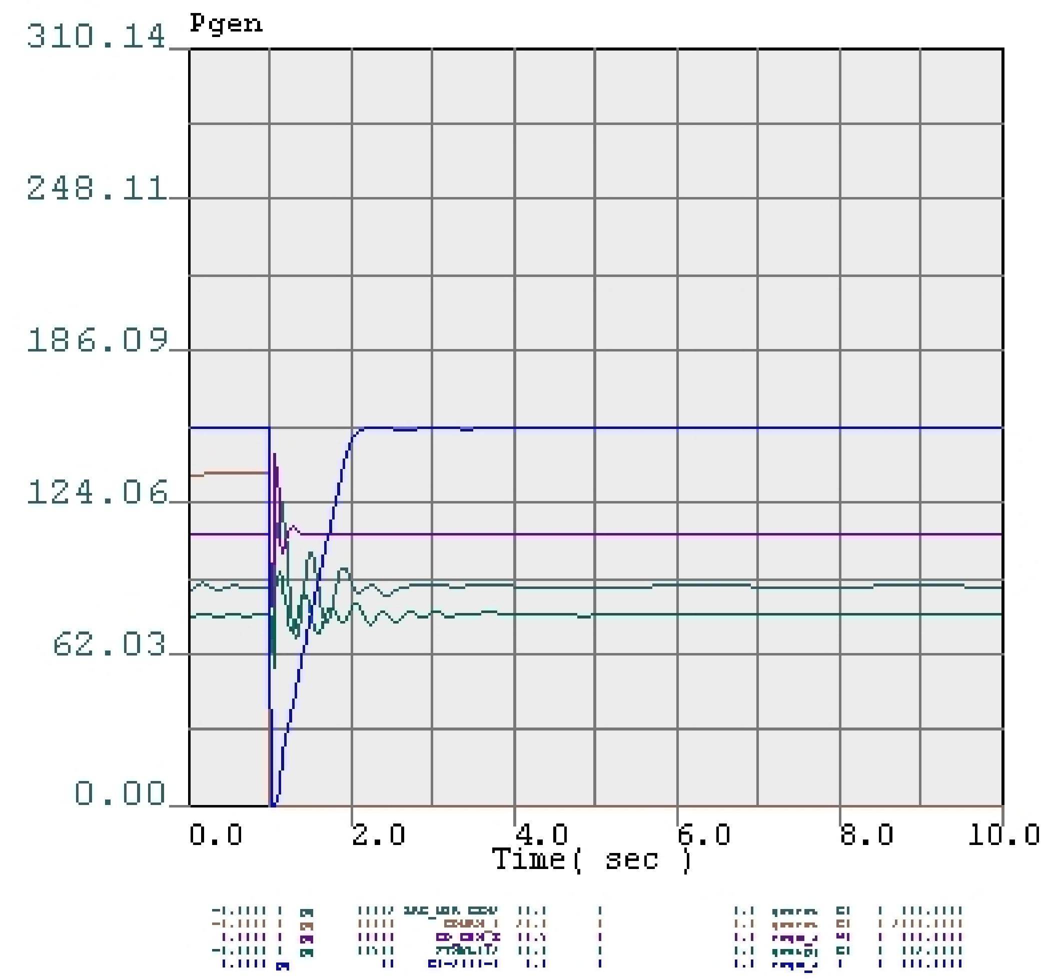
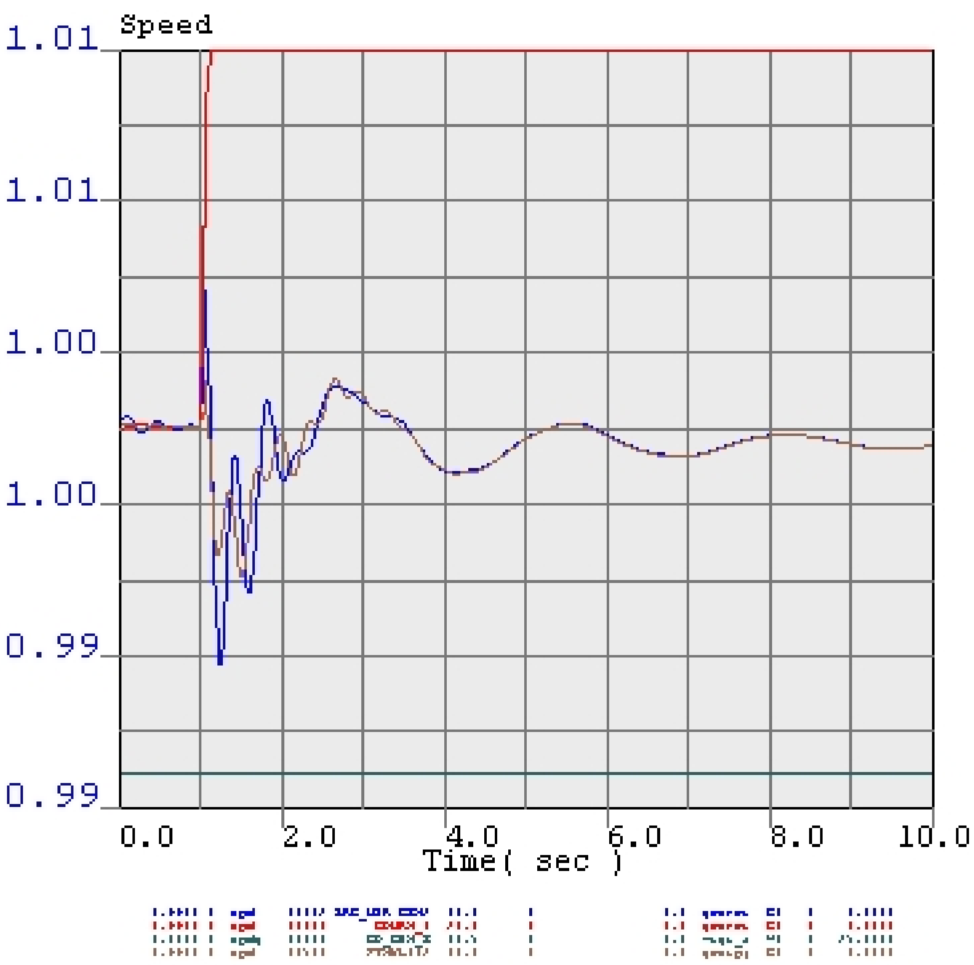
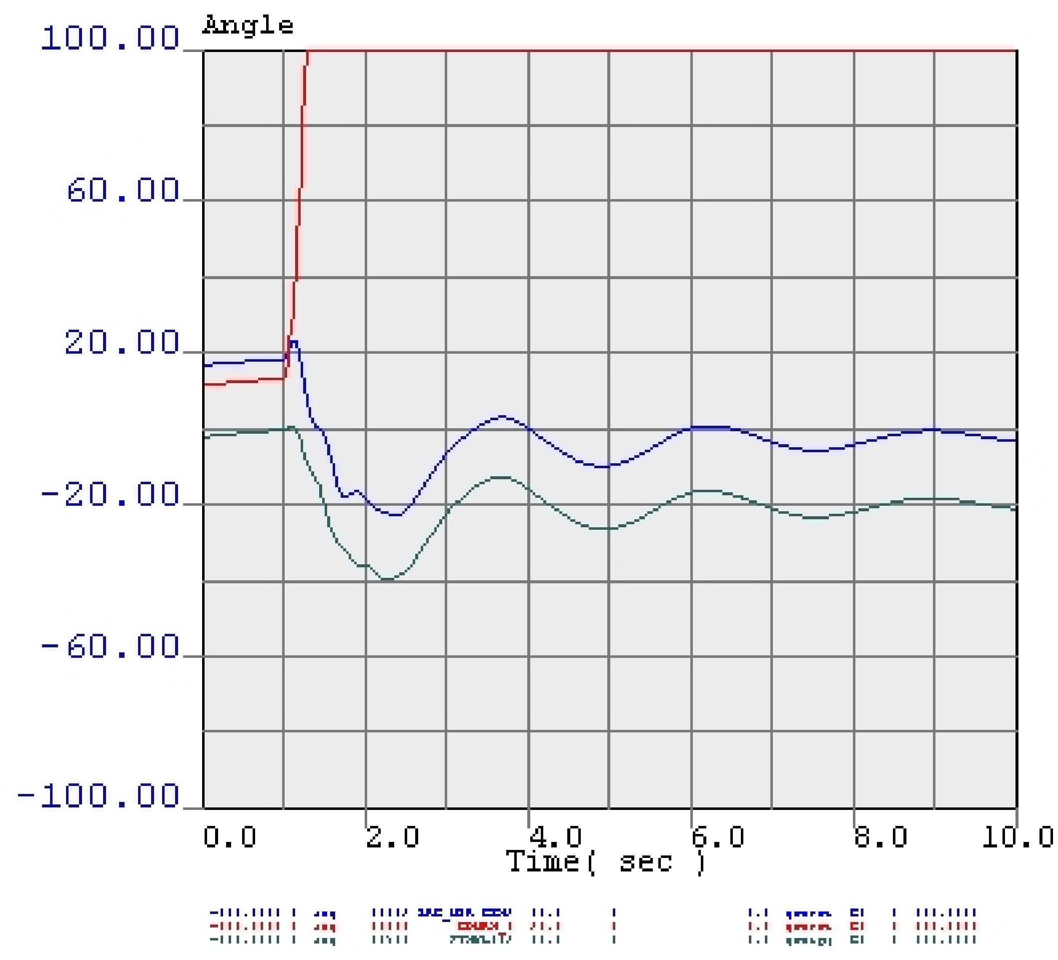
Mon May 20 14:49:23 2019

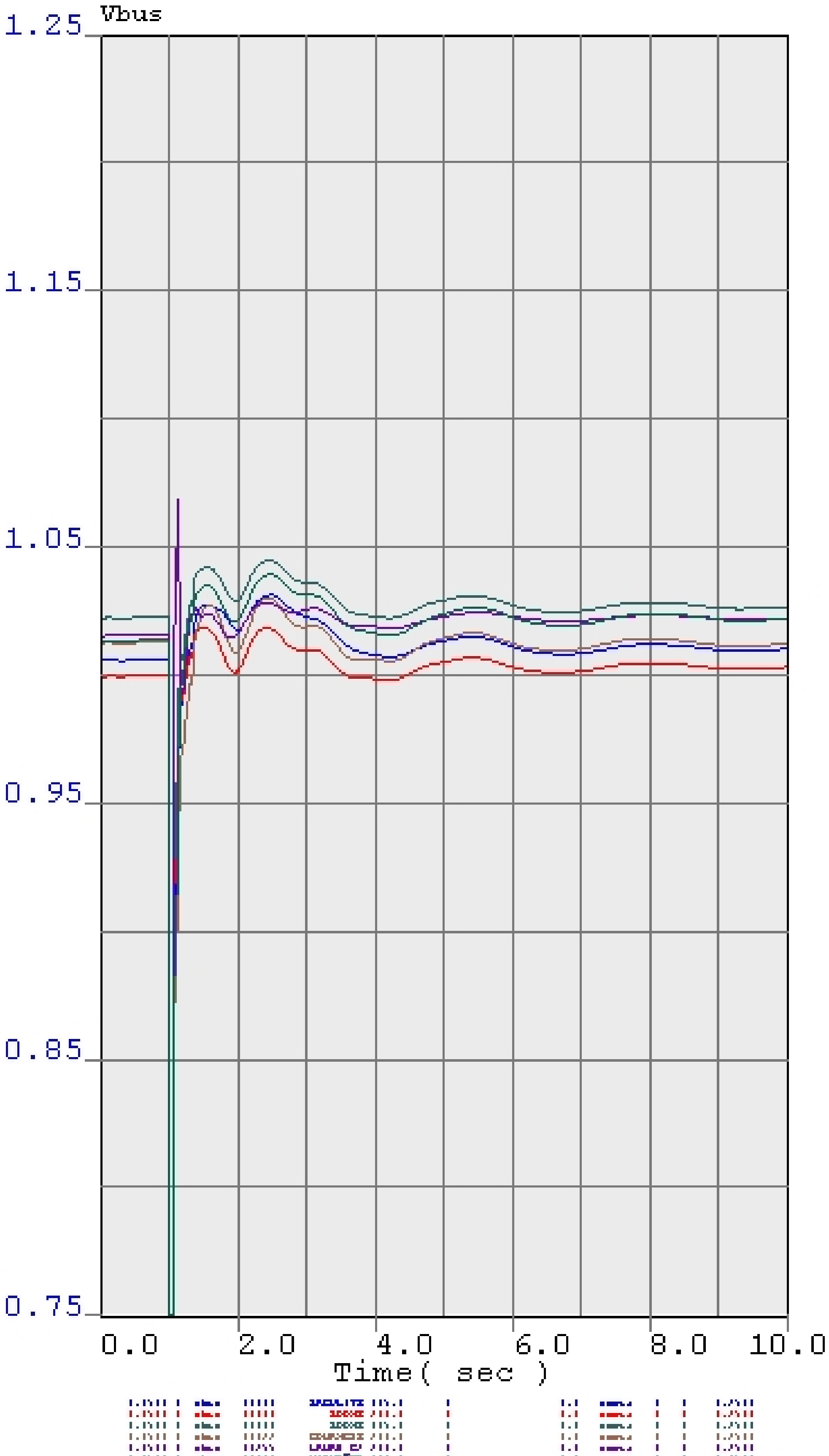


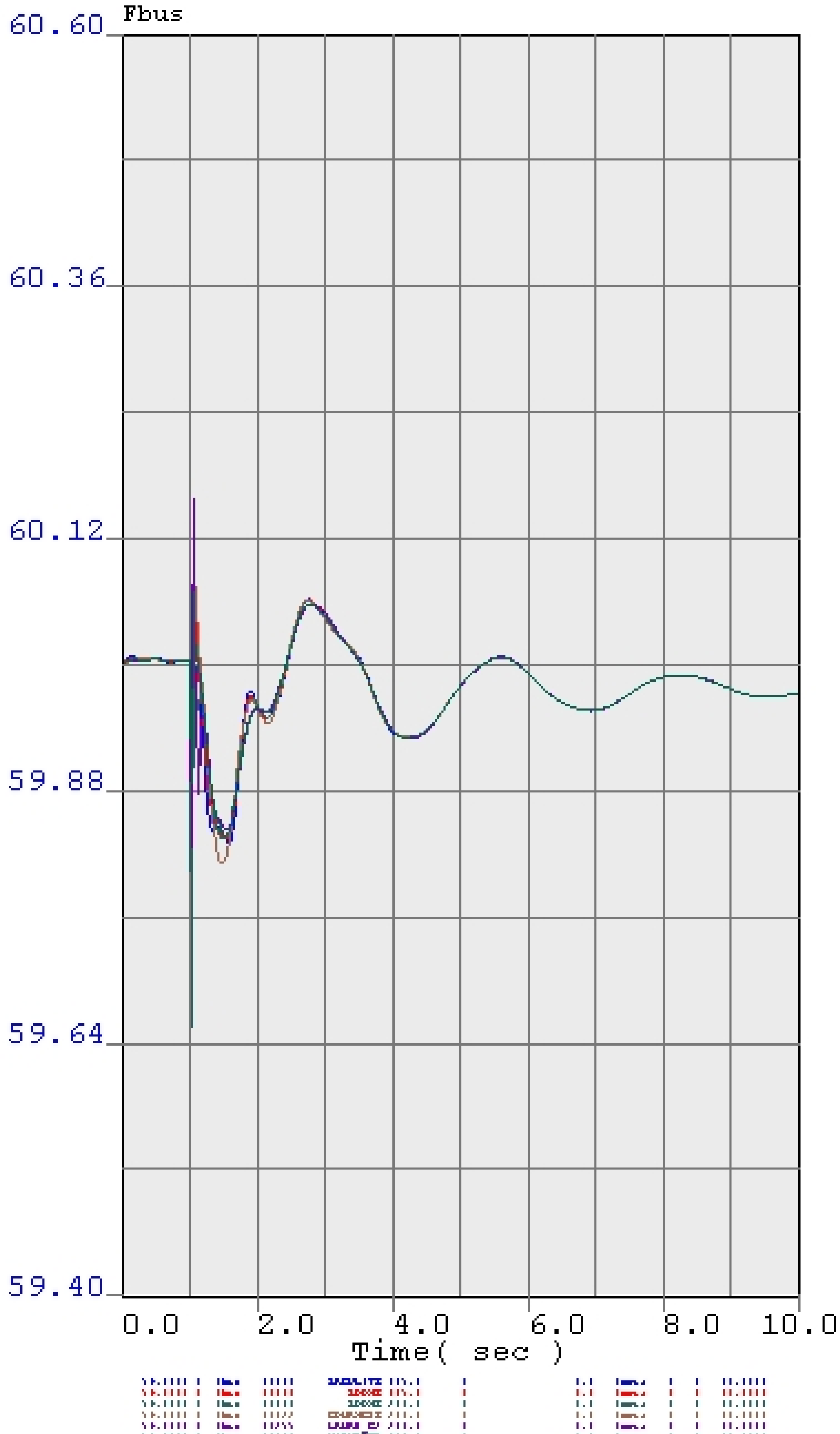






Line_5
Fault at Comanche 345kV, lose Comanche 3





Line_5
Fault at Comanche 345kV, lose Comanche 3

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

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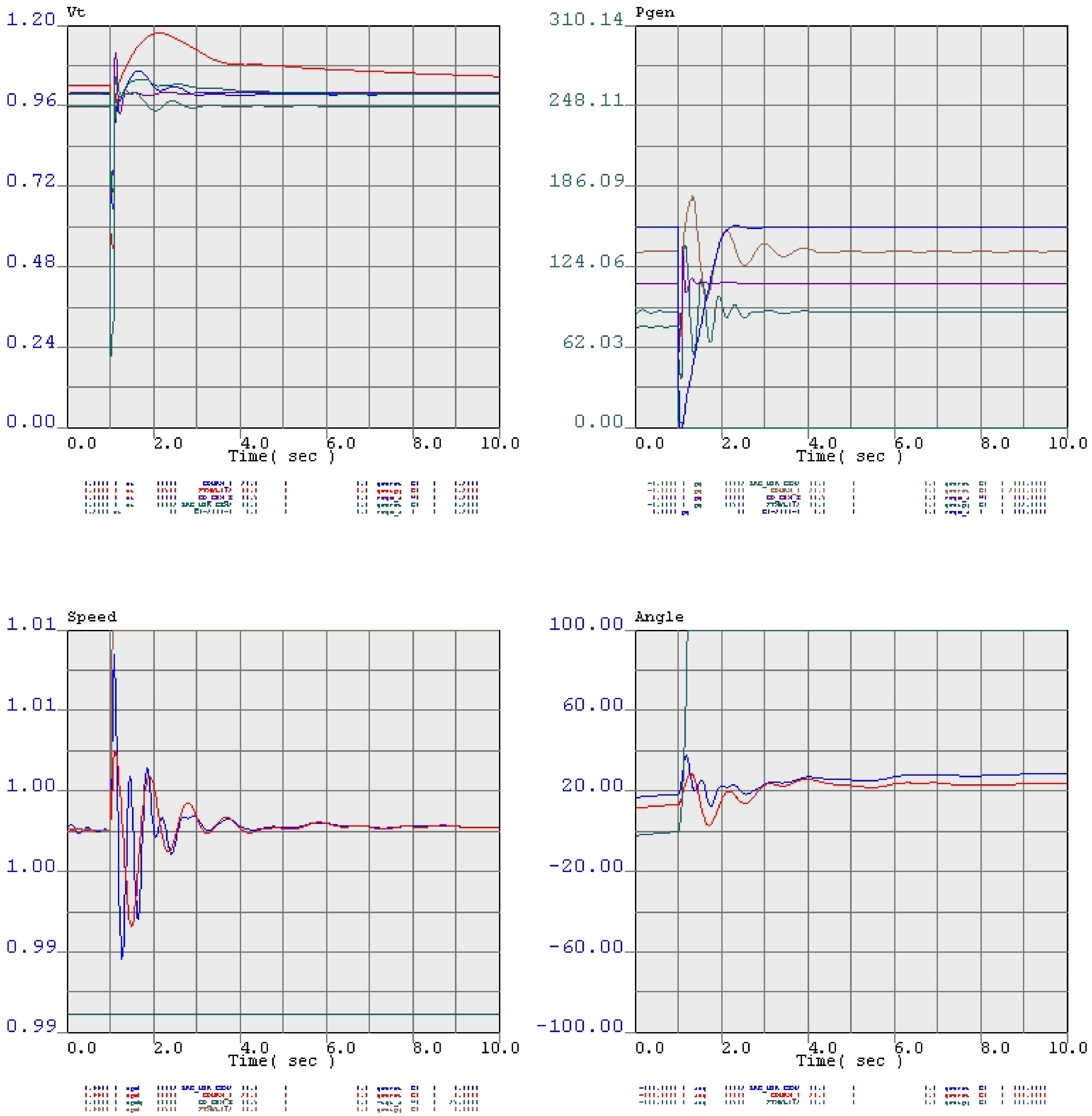
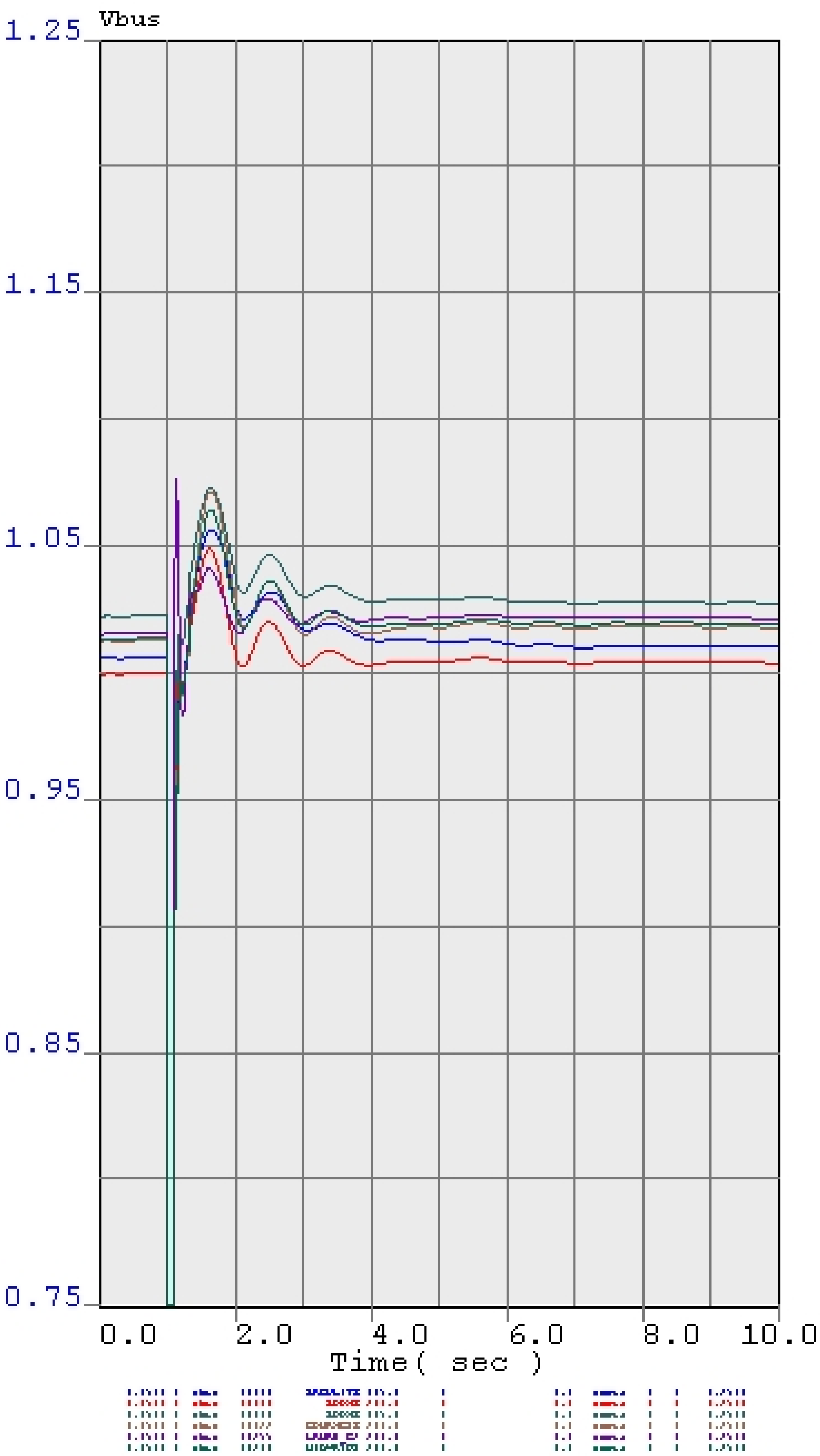
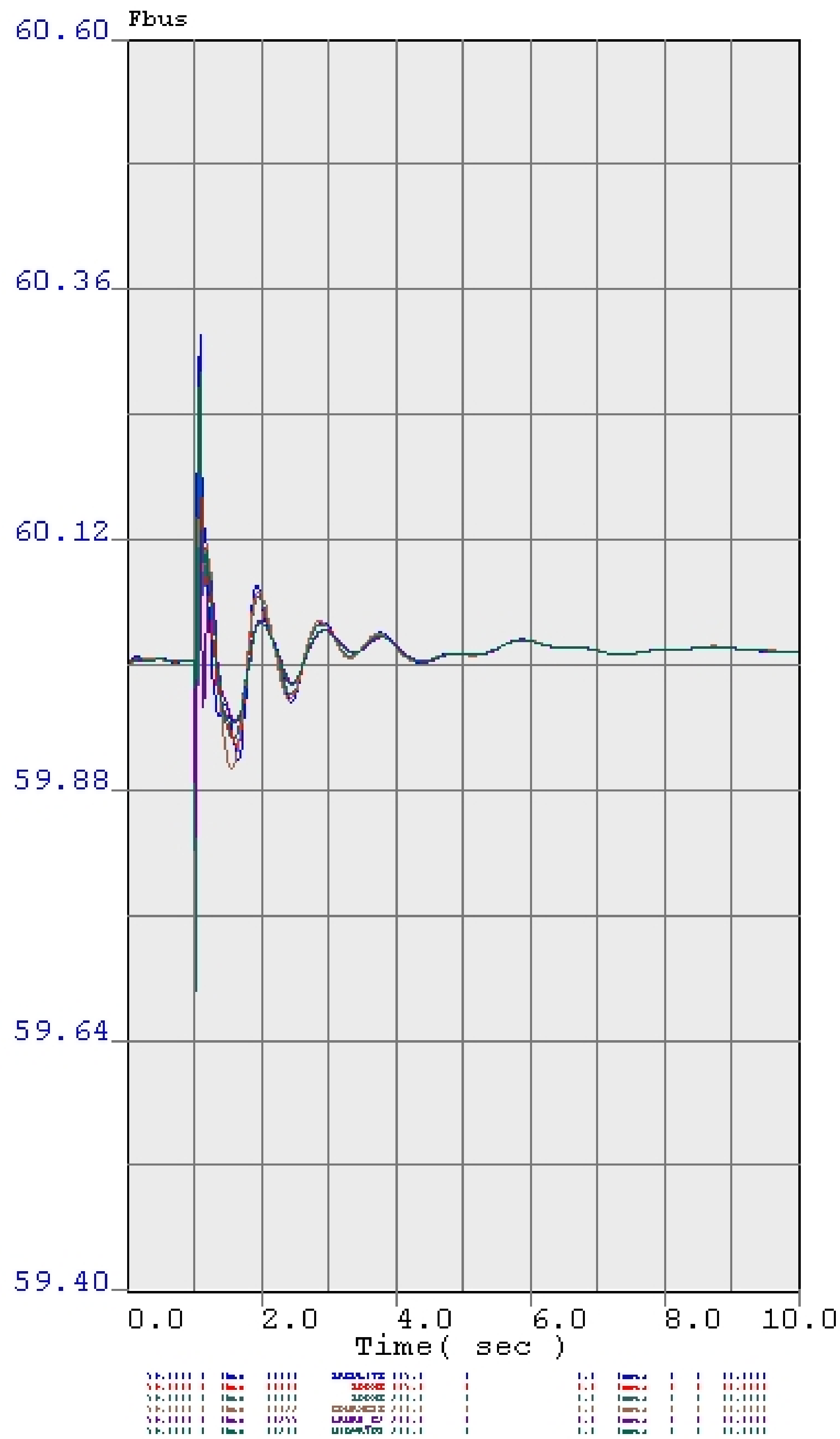


Line_6
Fault at Midway 230kV, lose Fountain Valley gen





Line_6
Fault at Midway 230kV, lose Fountain Valley gen

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

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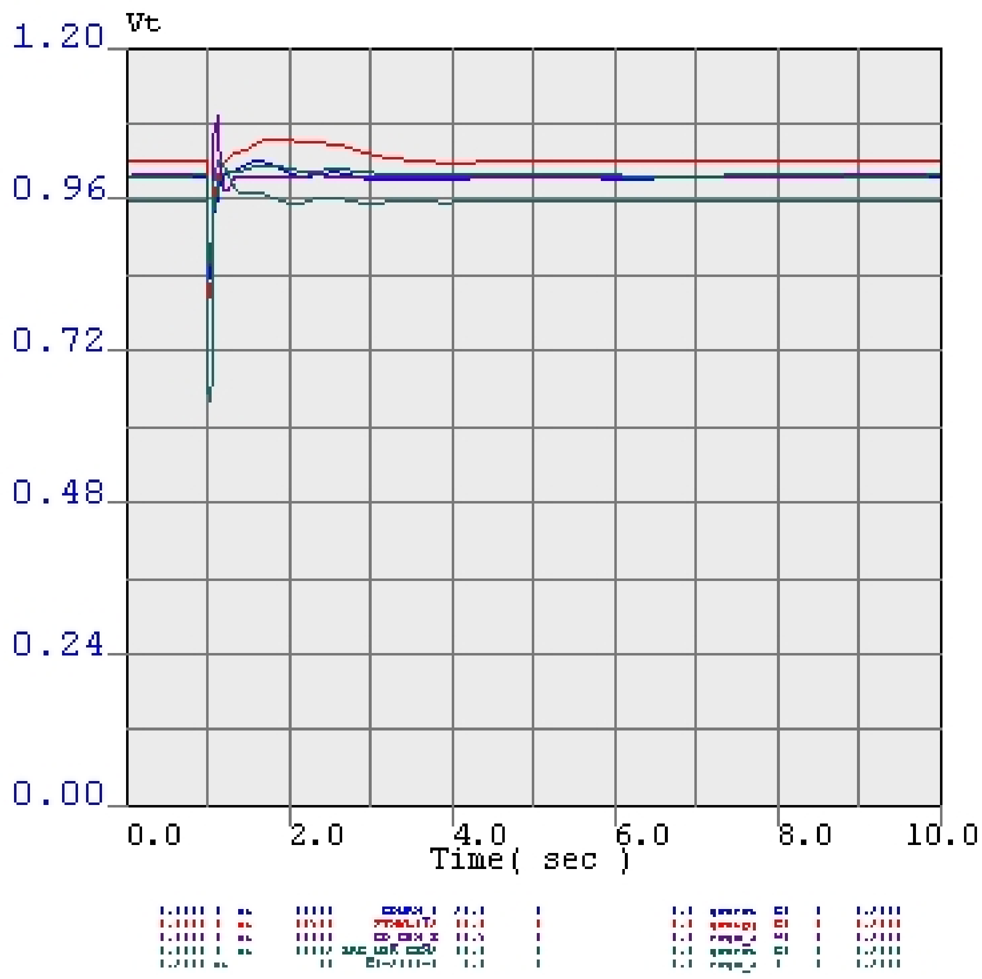

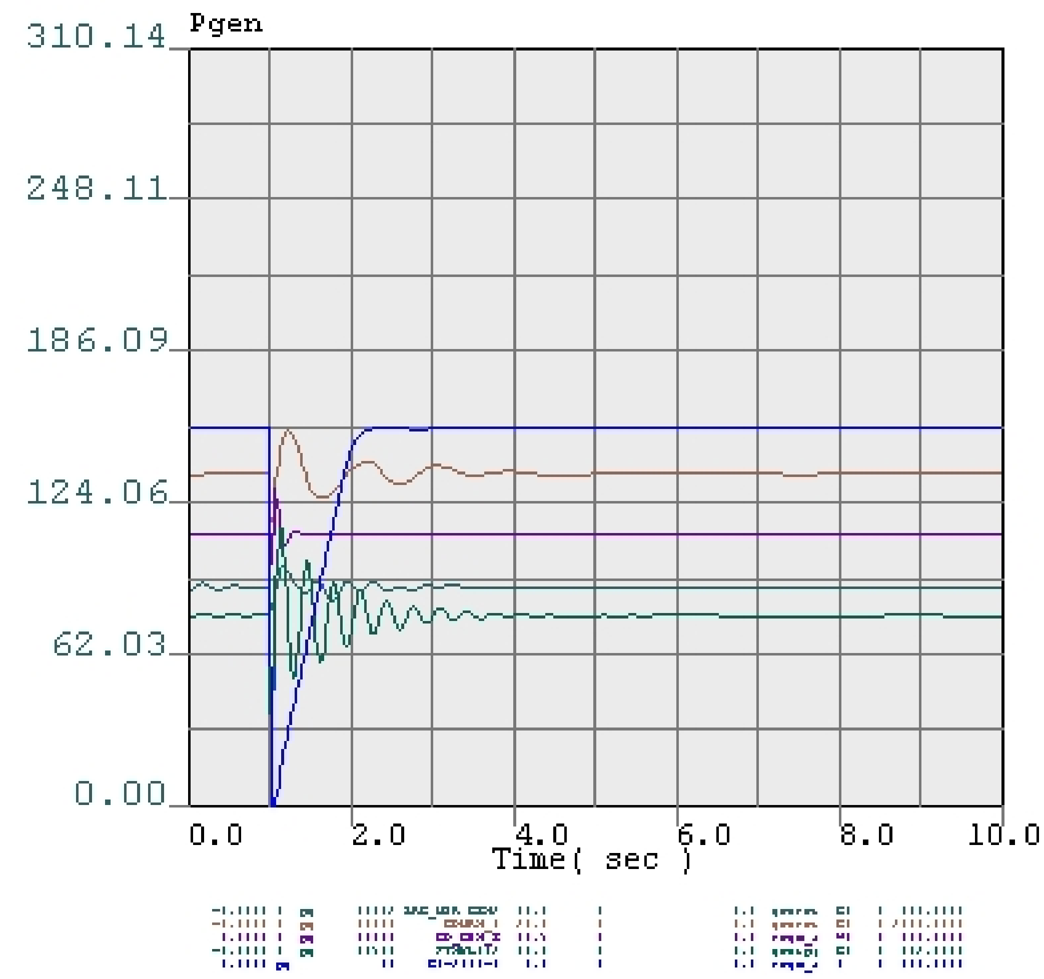

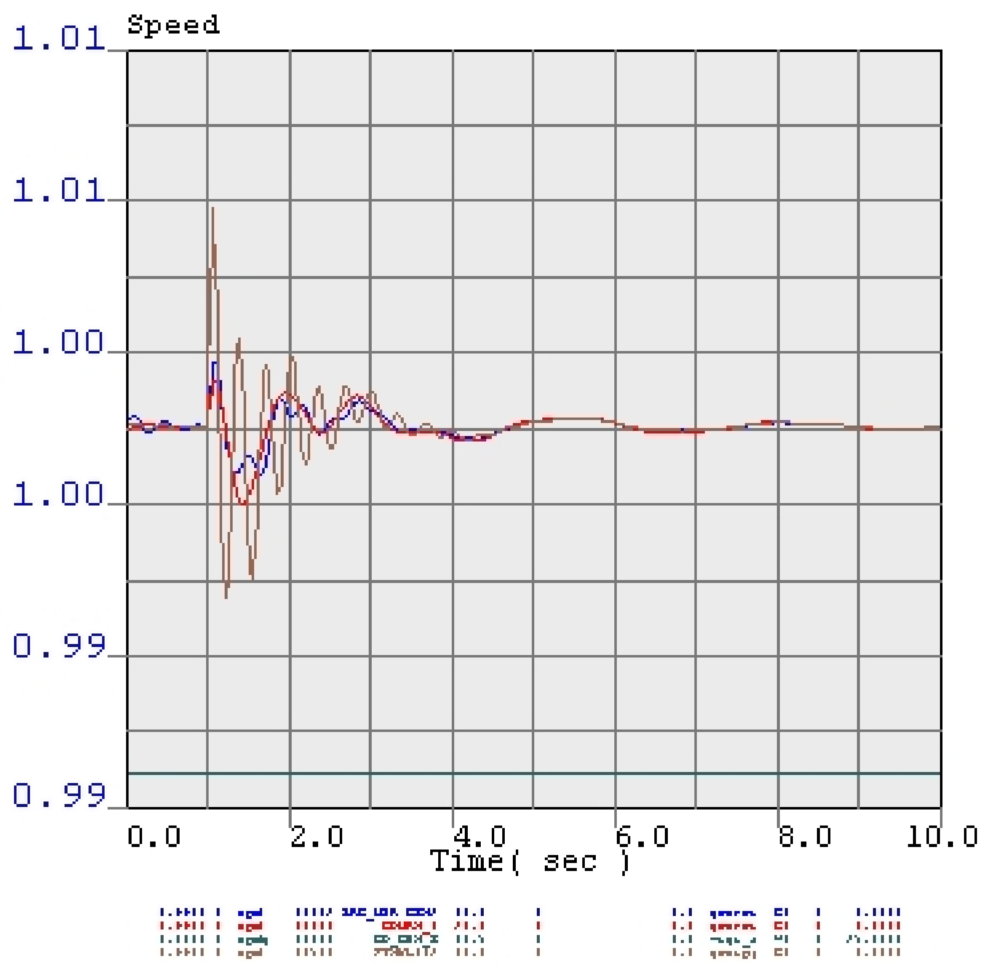

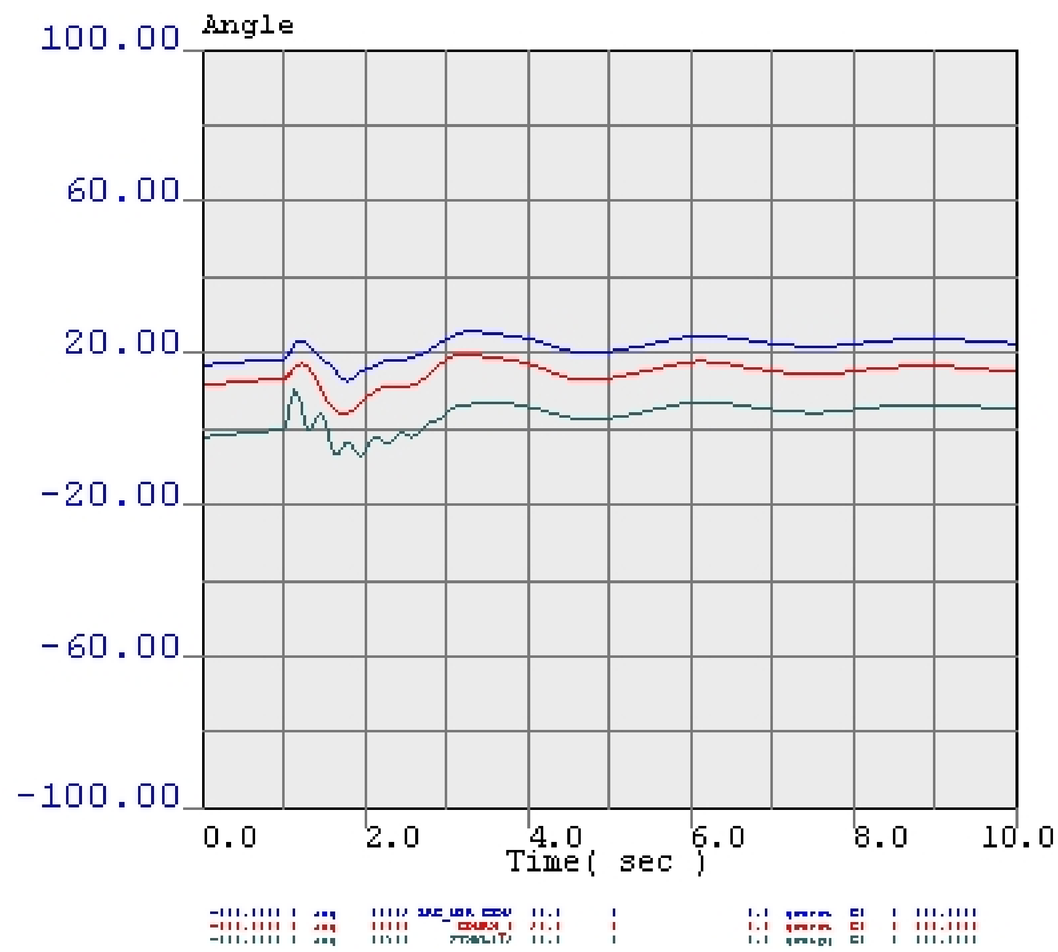

Fault_7
Fault at Midway 345kV, lose MidwayPS 345/20kV and MidwayPS - Waterton345kV line

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

April_2019-revision\chans
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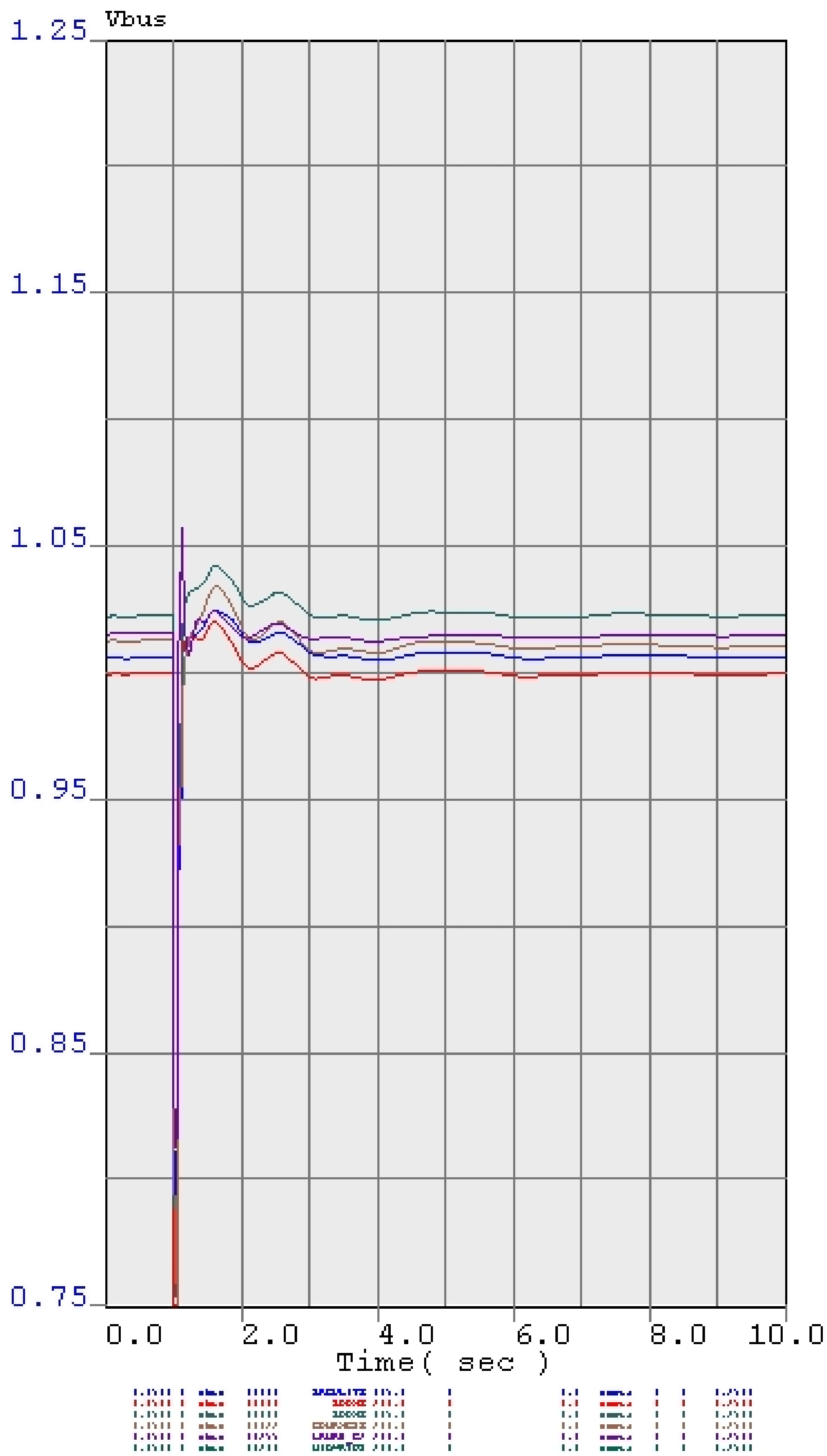

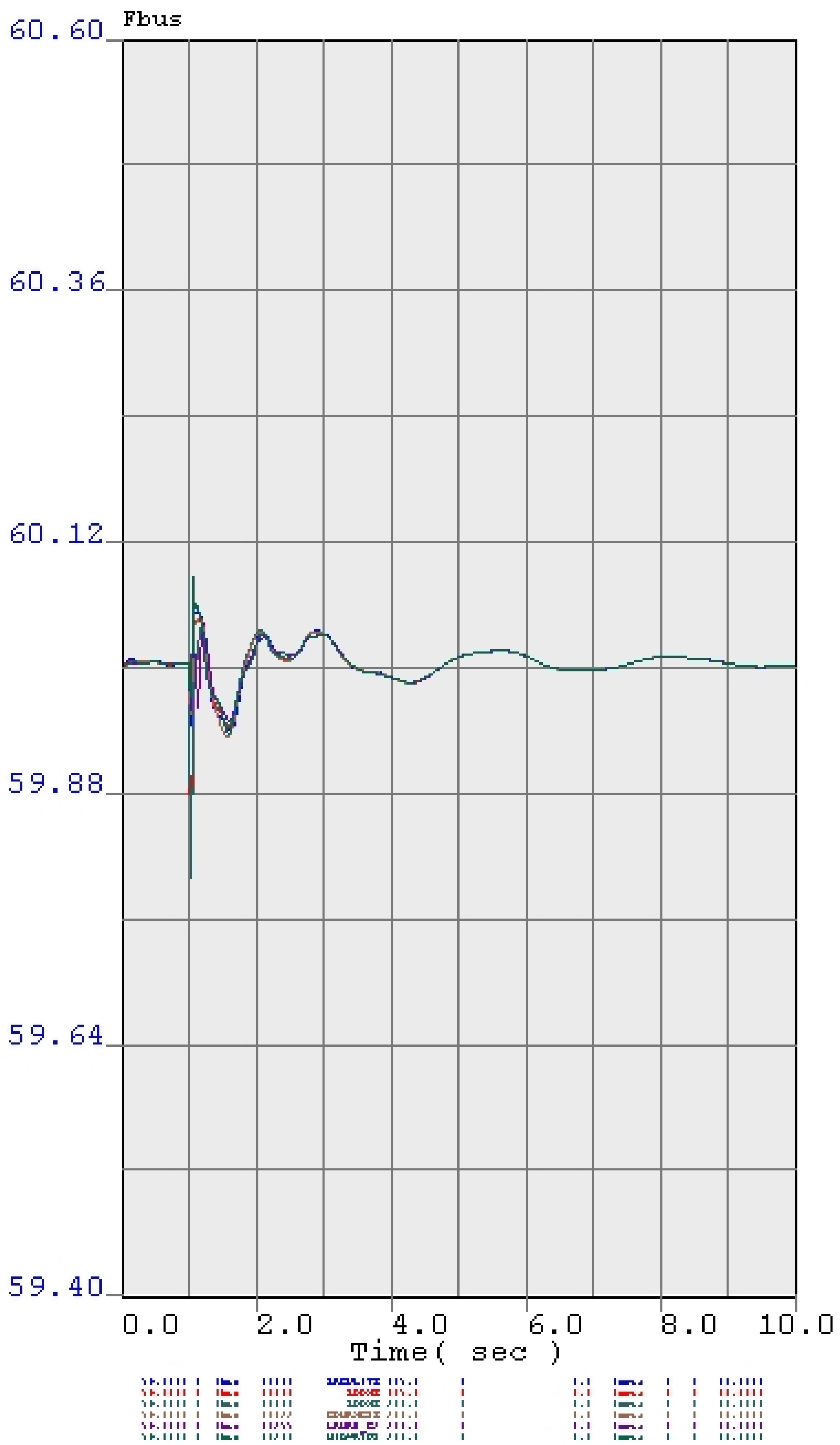

Fault_7
Fault at Midway 345kV, lose MidwayPS 345/20kV and MidwayPS - Waterton345kV line

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

April_2019-revision\chans
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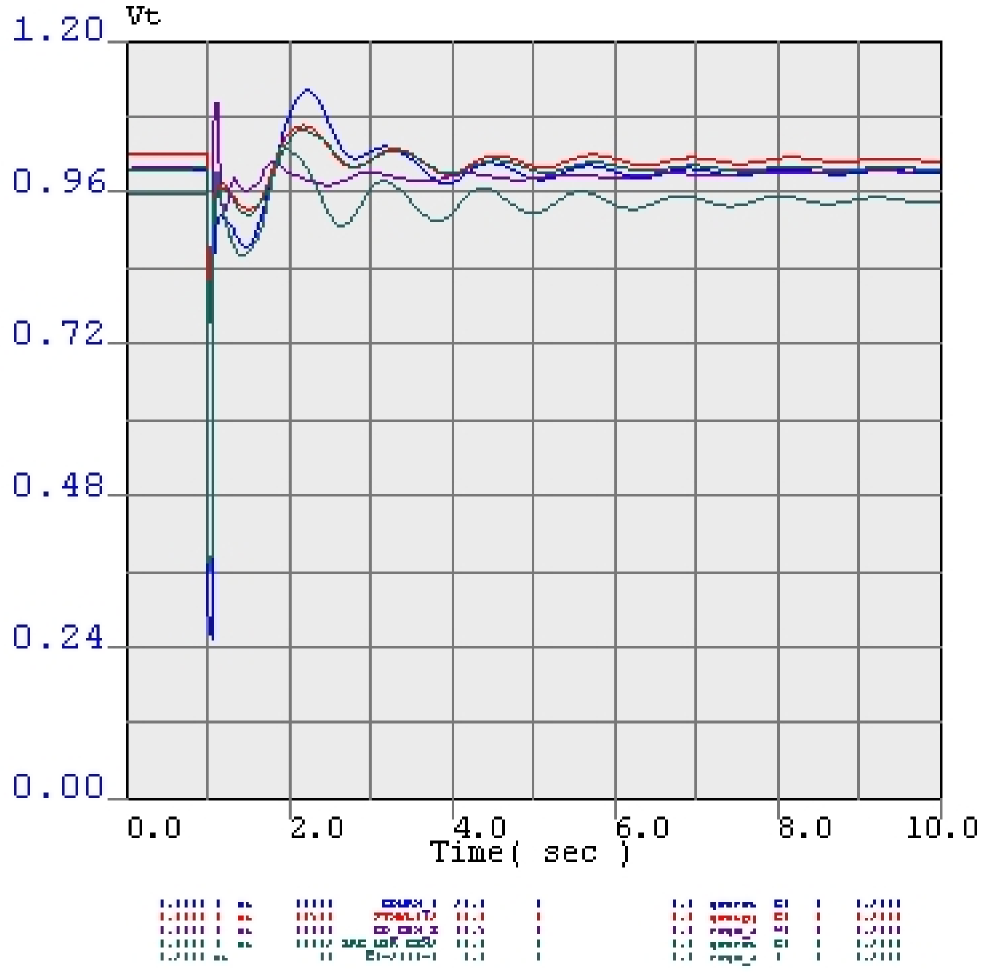
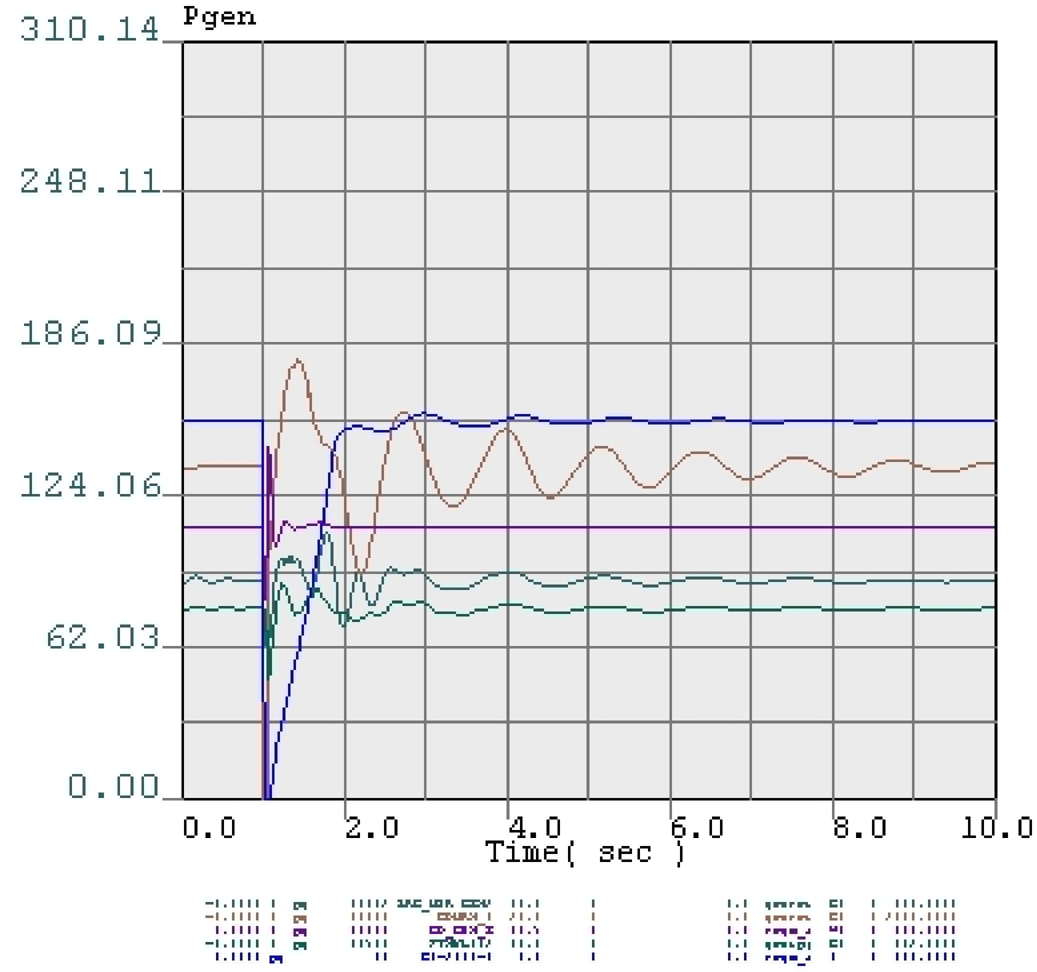
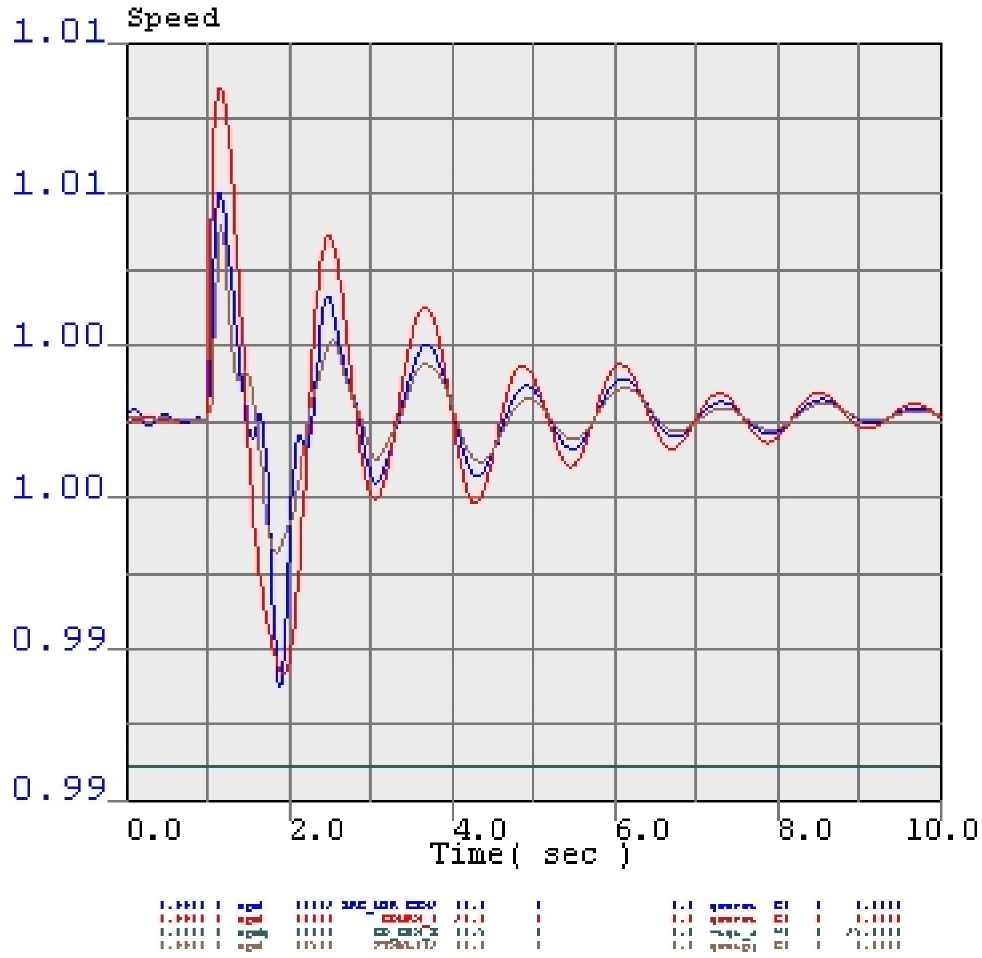
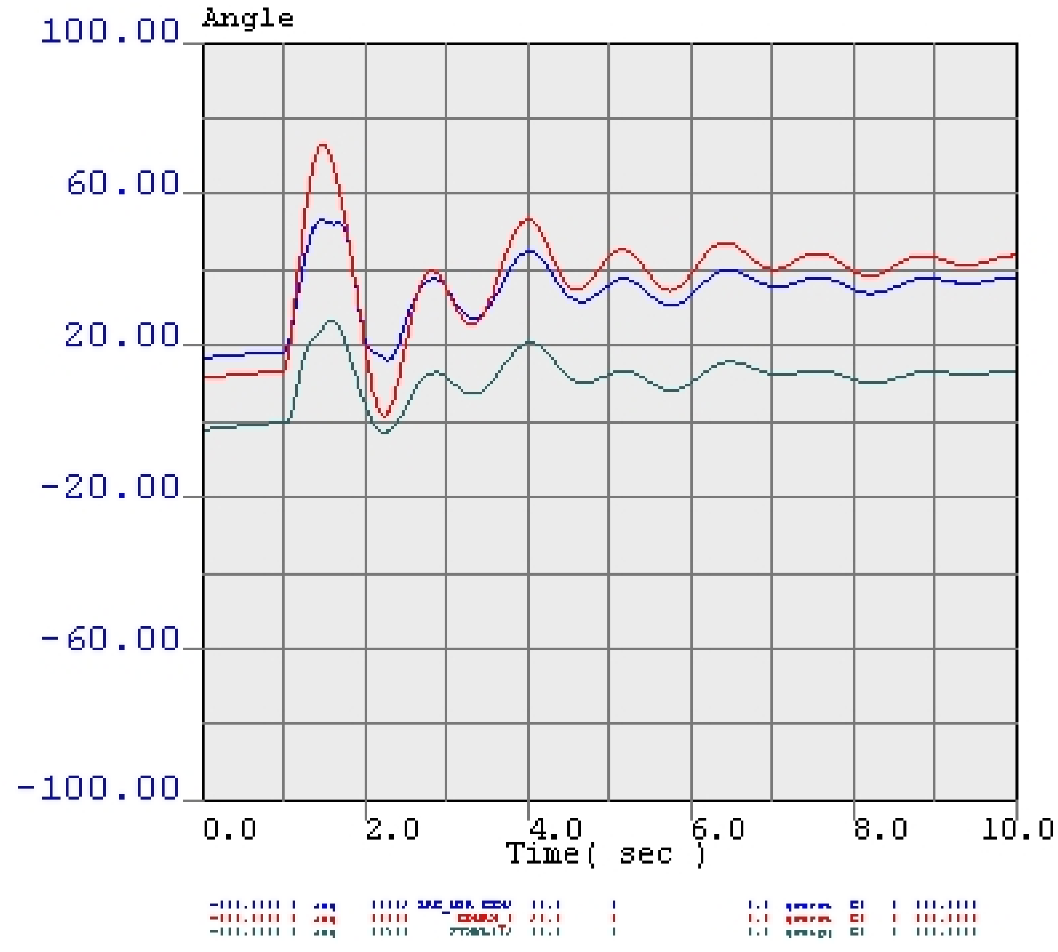
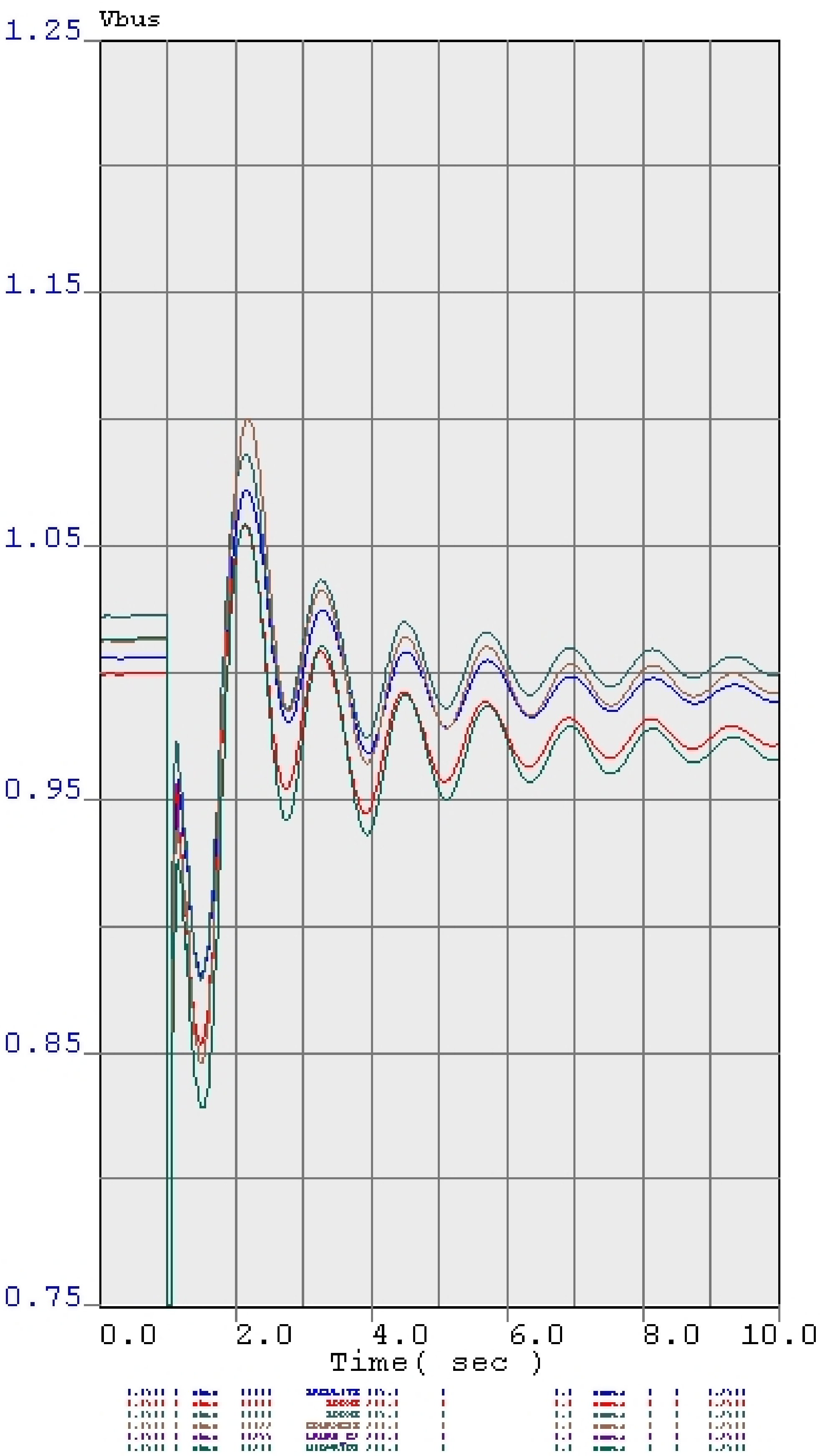


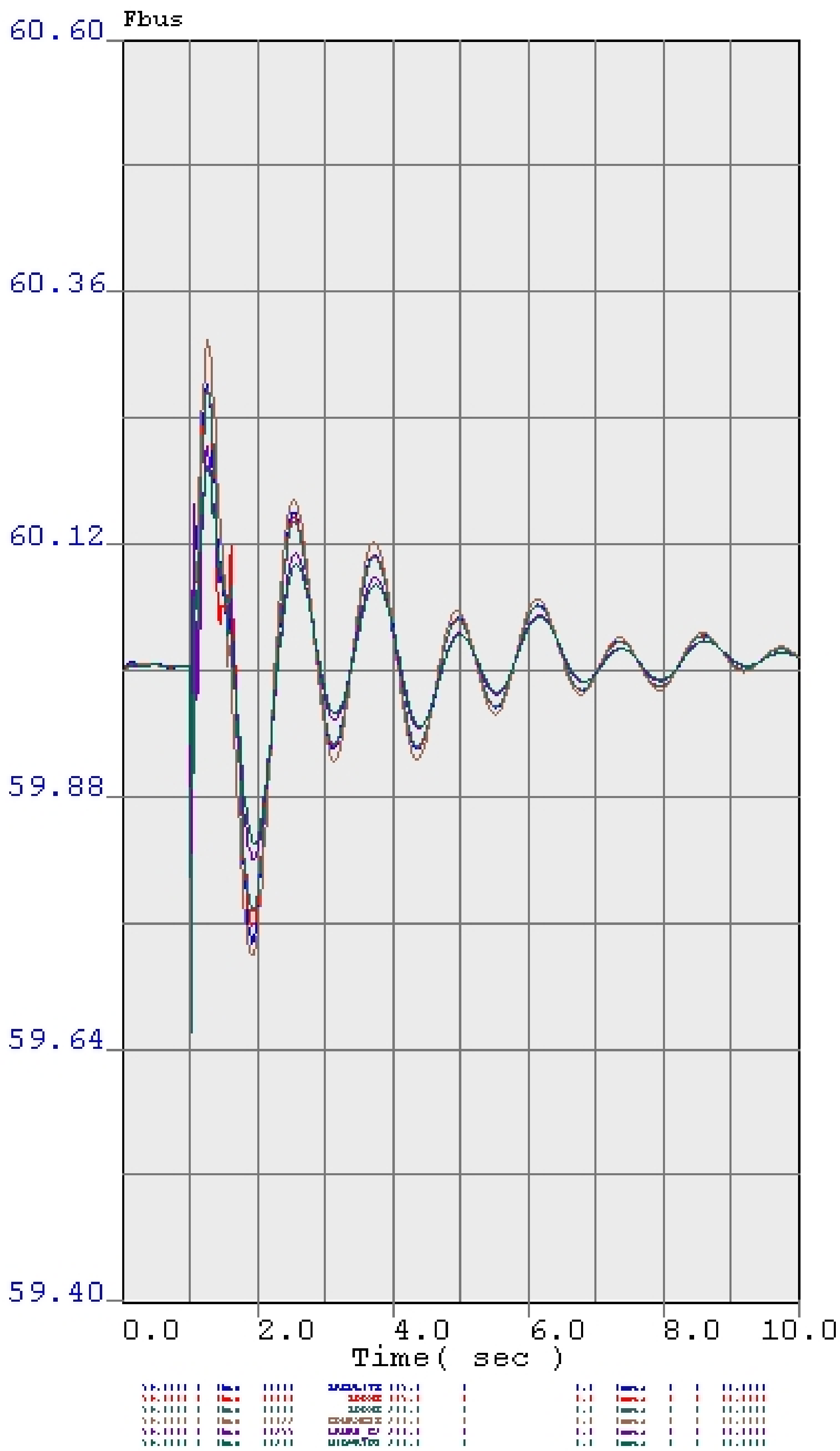






Fault_8
Fault at Comanche 345kV, lose Comanche - Daniels Park 345kV double circuit





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

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

April_2019-revision\chans
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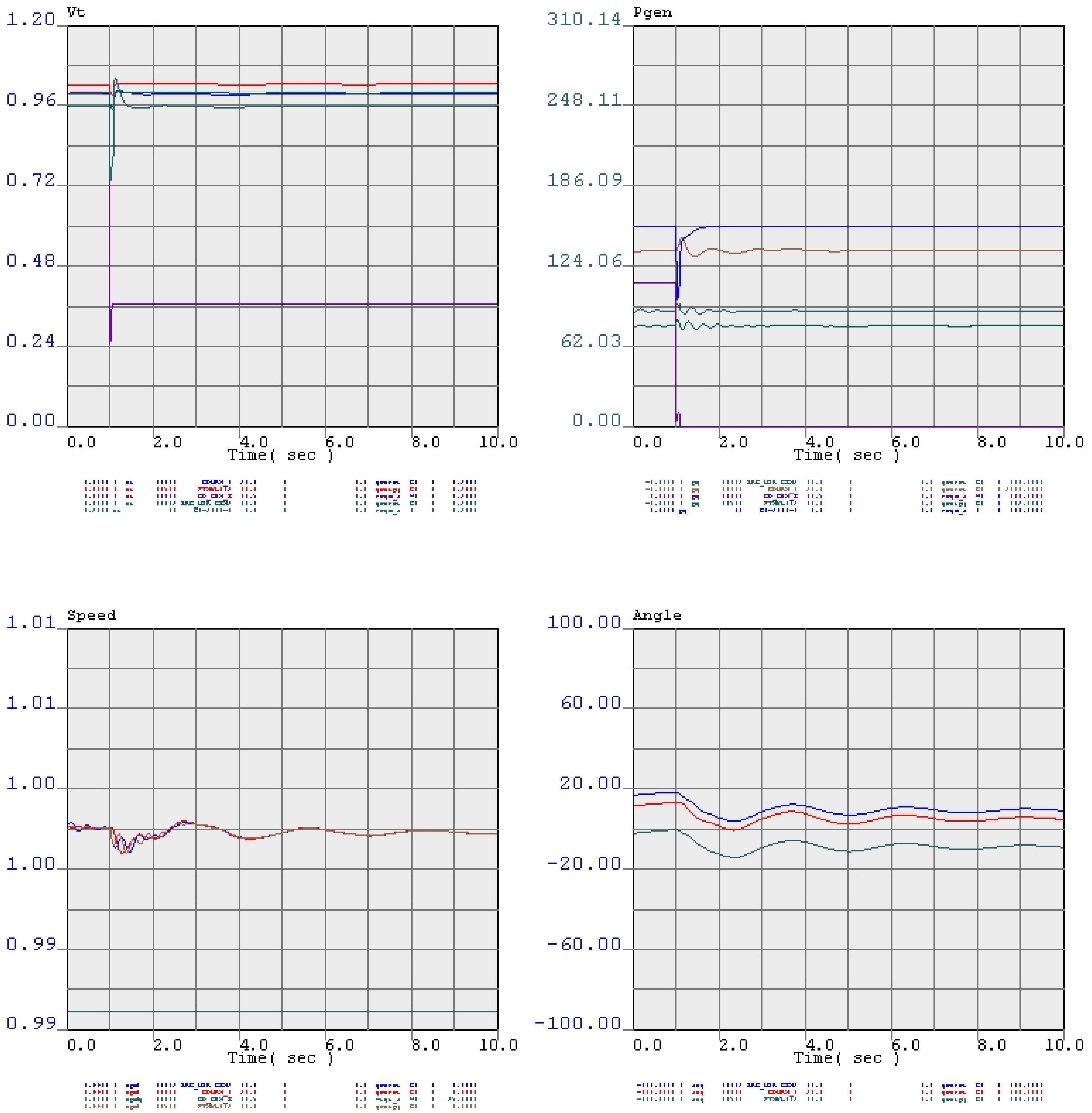

Line_9
Lamar 230kV bus fault, lose Lamar-Boone 230kV and Lamar gen

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

April_2019-revision\chans
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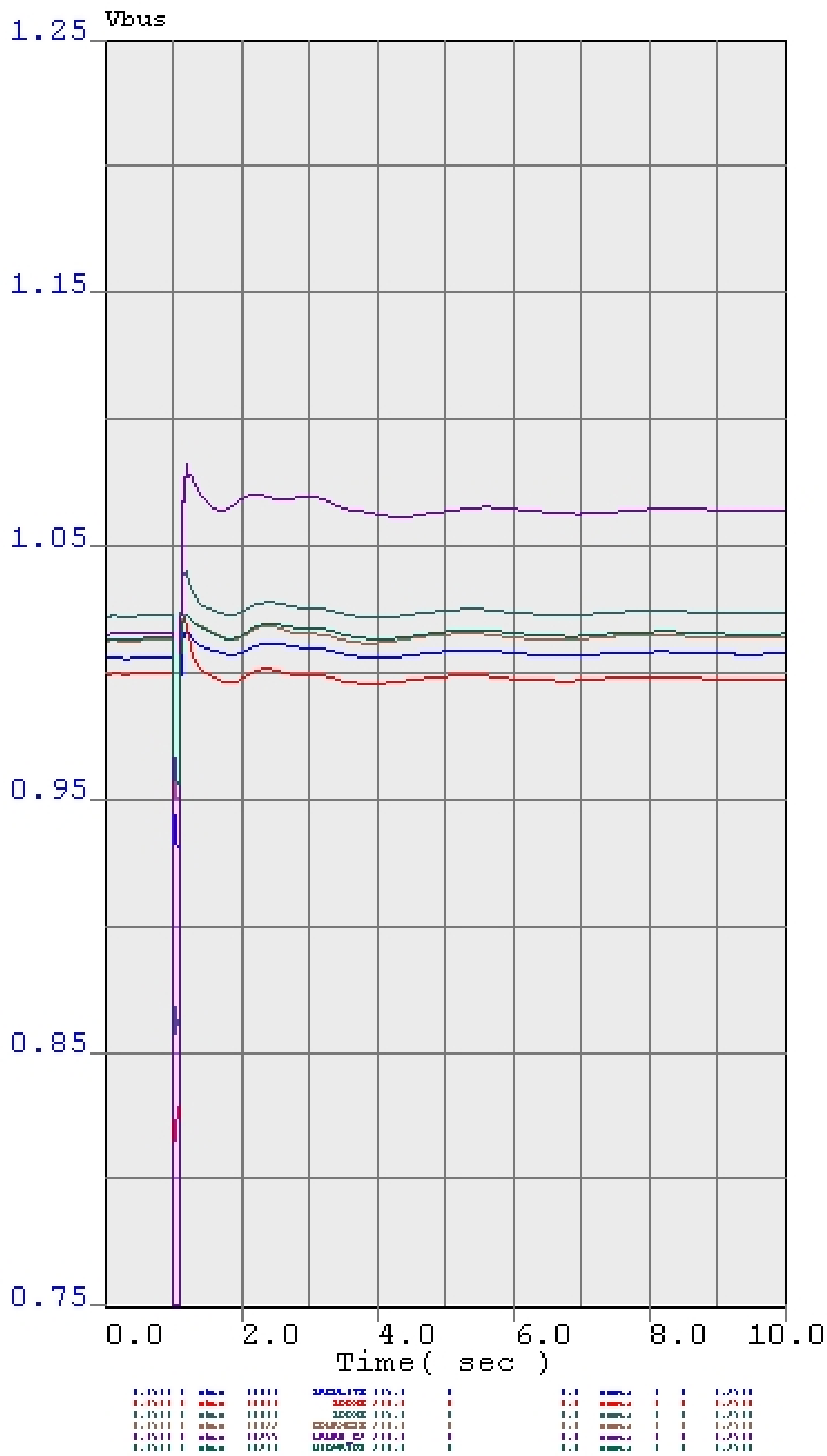

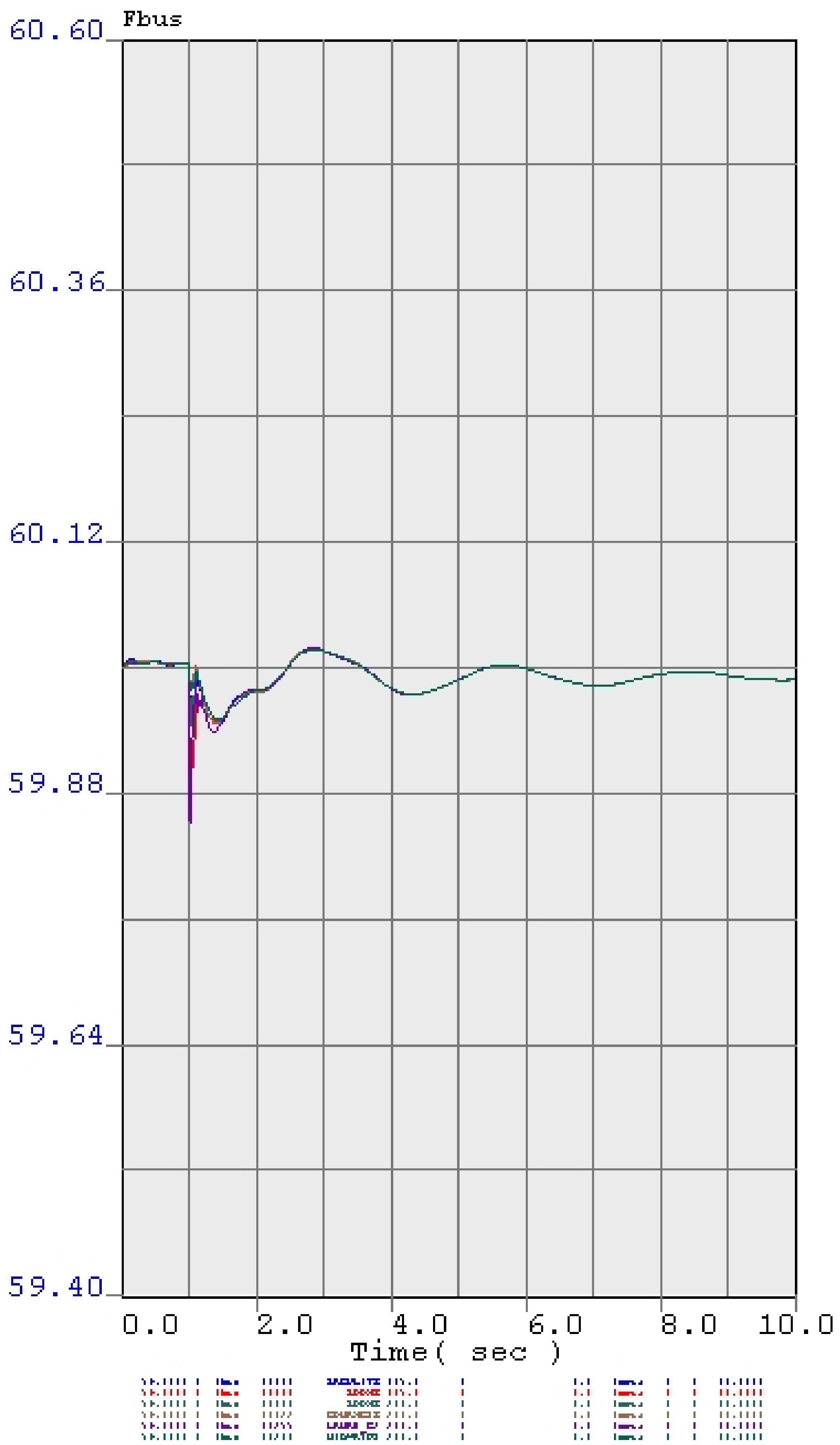

Line_9
Lamar 230kV bus fault, lose Lamar-Boone 230kV and Lamar gen

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

April_2019-revision\chans
Mon May 20 14:51:09 2019