System Impact Study Report
PID 203
1522 MW (1612 MW Gross) Plant, Grand Gulf, MS

Prepared by:
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Objective:

This System Impact Study is the second step of the interconnection process and is based on PID-203 request for interconnection on Entergy's transmission system at Grand Gulf 500 kV substation. This report is organized in two sections, namely, Section – A, Energy Resource Interconnection Service (ERIS) and Section – B, Network Resource Interconnection Service (NRIS – Section B).

The scope for the ERIS section (Section – A) includes load flow (steady state) analysis, transient stability analysis, and short circuit analysis as defined in FERC orders 2003, 2003A and 2003B. The NRIS section (Section – B) contains details of load flow (steady state) analysis only, however, transient stability analysis and short circuit analysis of Section – A are also applicable to Section – B. Additional information on scope for the NRIS study can be found in Section – B.

Requestor for PID 203 did request NRIS but did not request ERIS, therefore, under Section – A (ERIS) load flow analysis was not performed.

PID-203 intends to install a nuclear unit facility with a maximum capacity of 1933 MVA. The scheduled gross power output of the plant is 1612 MW. An auxiliary/host load of approximately 90 MW is also expected at this site. PID-203 anticipates injecting a total of approximately 1522 MW into the Entergy transmission system.

The proposed in-service date for this facility is January 1, 2015.

Section – A

Energy Resource Interconnection Service

TABLE OF CONTENTS FOR SECTION –B (ERIS)

I. Introduction

This Energy Resource Interconnection Service (ERIS) is based on PID-203 request for interconnection on Entergy's transmission system at Grand Gulf 500 kV substation. The objective of this study is to assess the reliability impact of the new facility on the Entergy transmission system with respect to the steady state and transient stability performance of the system as well as its effects on the system's existing short circuit current capability. It is also intended to determine whether the transmission system meets standards established by NERC Reliability Standards and Entergy's planning guidelines when the plant is connected to Entergy's transmission system. If not, transmission improvements will be identified.

The System Impact Study process required a load flow analysis to determine if the existing transmission lines are adequate to handle the full output from the plant for simulated transfers to adjacent control areas. A short circuit analysis was performed to determine whether the generation would cause the available fault current to surpass the fault duty of existing equipment within the Entergy transmission system. A transient stability analysis was conducted to determine whether the new units would cause a stability problem on the Entergy system.

This ERIS System Impact Study was based on information provided by PID-203 and assumptions made by Southwest Power Pool, Independent Coordinator of Transmission. All supplied information and assumptions are documented in this report. If the actual equipment installed is different from the supplied information or the assumptions made, the results outlined in this report are subject to change.

The load flow results from the ERIS study are for information only. ERIS does not in and of itself convey any transmission service.

II. Short Circuit Analysis / Breaker Rating Analysis

A. Model Information

The short circuit analysis was performed on the Entergy system short circuit model using ASPEN software. This model includes all generators interconnected to the Entergy system or interconnected to an adjacent system and having an impact on this interconnection request, IPP's with signed IOAs, and approved future transmission projects on the Entergy transmission system including the proposed PID-203 unit.

B. Short Circuit Analysis

The method used to determine if any short circuit problems would be caused by the addition of the PID-203 generation is as follows:

1. Three phase and single phase to ground faults were simulated on the Entergy base case short circuit model and the worst case short circuit level was determined at each station. The PID-203 generator as well as the necessary NRIS upgrades shown in Section B, IV were then modeled in the base case to generate a revised short circuit model. The base case short circuit results were then compared with the results from the revised model to identify any breakers that were under-rated as a result of additional short circuit contribution from PID-203 generation. The breakers identified to be upgraded through this comparison are *mandatory* upgrades.

C. Analysis Results

The results of the short circuit analysis indicates that the additional generation due to PID-203 generators does cause an increase in short circuit current such that they exceed the fault interrupting capability of the high voltage circuit breakers within the vicinity of PID-203 plant.

Table I illustrates the station name, worst case fault level, and the number of breakers that were found to be under-rated at the respective locations as a result of the additional short circuit current due to PID-203 generator and includes no priors.

Table I: Underrated Breakers Without Priors

Substation	Breaker	Max Fault w/o PID-203 (amps)	Max Fault with PID-203 (amps)	Interrupting Rating (amps)
LAKEOVER 115 kV	J3208	38904	40930	40000
	J3210	38904	40930	40000

Table II illustrates the station name, worst case fault level, and the number of breakers that were found to be under-rated at the respective locations as a result of the additional short circuit current due to PID-203 generator and includes prior PID's 195 and 198.

Table II: Underrated Breakers With Priors Included

Substation	Breaker	Max Fault w/o PID-203 (amps)	Max Fault with PID-203 (amps)	Interrupting Rating (amps)
LAKEOVER 115 kV	J3208	38908	40934	40000
	J3210	38908	40934	40000
BC #2 500 kV	20535	37803	42302	40000
	20545	37803	42302	40000
	20550	37803	42302	40000
	20560	37803	42302	40000
	20565	37803	42302	40000
	20575	37803	42302	40000
BIG CAJUN 230 kV	T13350	39350	40888	40000
CLECO-ACADIA 138 kV	8901	61818	63477	63000
	8909	61818	63477	63000
	8912	61818	63477	63000
	8916	61429	63083	63000
	8920	61818	63477	63000
	8923	61818	63477	63000
	8927	61818	63477	63000
	8931	61818	63477	63000
	8934	61818	63477	63000
	8938	61818	63477	63000
	8942	61818	63477	63000
	8945	61818	63477	63000
	8949	61475	63130	63000
	8953	61818	63477	63000
	8956	61818	63477	63000
	8964	61818	63477	63000
RICHARD 138	17235	62091	63665	63000

kV	17245	62091	63665	63000
	17250	62091	63665	63000
	17255	61790	63336	63000
	17260	62091	63665	63000
	17265	62091	63665	63000
	17270	61805	63353	63000
	17275	62091	63665	63000
	18425	62091	63665	63000
	18430	61805	63353	63000
	18435	62091	63665	63000
	18440	62091	63665	63000
	27140	62091	63665	63000
	27145	61825	63374	63000
	27150	62091	63665	63000
	27160	62091	63665	63000
	27165	62091	63665	63000

D. Problem Resolution

Table III illustrates the station name, and the cost associated with upgrading the breakers at each station both for mandatory and optional breaker upgrades.

Substation	Number of Breakers	Estimated cost of Breaker Upgrades ($)
LAKEOVER 115 kV	2	$570,000
BC #2 500 kV	6	$5,400,000
BIG CAJUN 230 kV	4	$1,338,800
CLECO-ACADIA 138 kV	16	*$7,200,000
RICHARD 138 kV	17	*$7,650,000

*Price based on 230 kV 80 kA Breakers

The impact on breaker rating due to line upgrades will be evaluated during facilities study phase.

The results of the short circuit analysis are subject to change. They are based upon the current configuration of the Entergy transmission system and Generation Interconnection Study queue.

III. Transient Stability Analysis

A. Model Information

The dynamic database representing the 2012 summer peak was used in this analysis. The analysis was carried out on the power flow case with the upgrades identified for PID-203. The following upgrades/ changes were included in the Powerflow case with PID-203 (see Figure III-1 and Figure III-2 for details).

- Add a 48 mile 500 kV transmission line from Grand Gulf 500 kV to Ray Braswell 500 kV.
- Remove the existing Baxter Wilson to Ray Braswell 500 kV line from Ray Braswell substation, and extend this line 22 miles to Lakeover 500 kV.
- Add a 500 kV line from Big Cajun 2 500 kV to Richard 500 kV, removing the planned 230 kV line
- Add 2nd 500/230 kV transformer at Audubon 230 kV Connecting to Big Cajun 2 500 kV

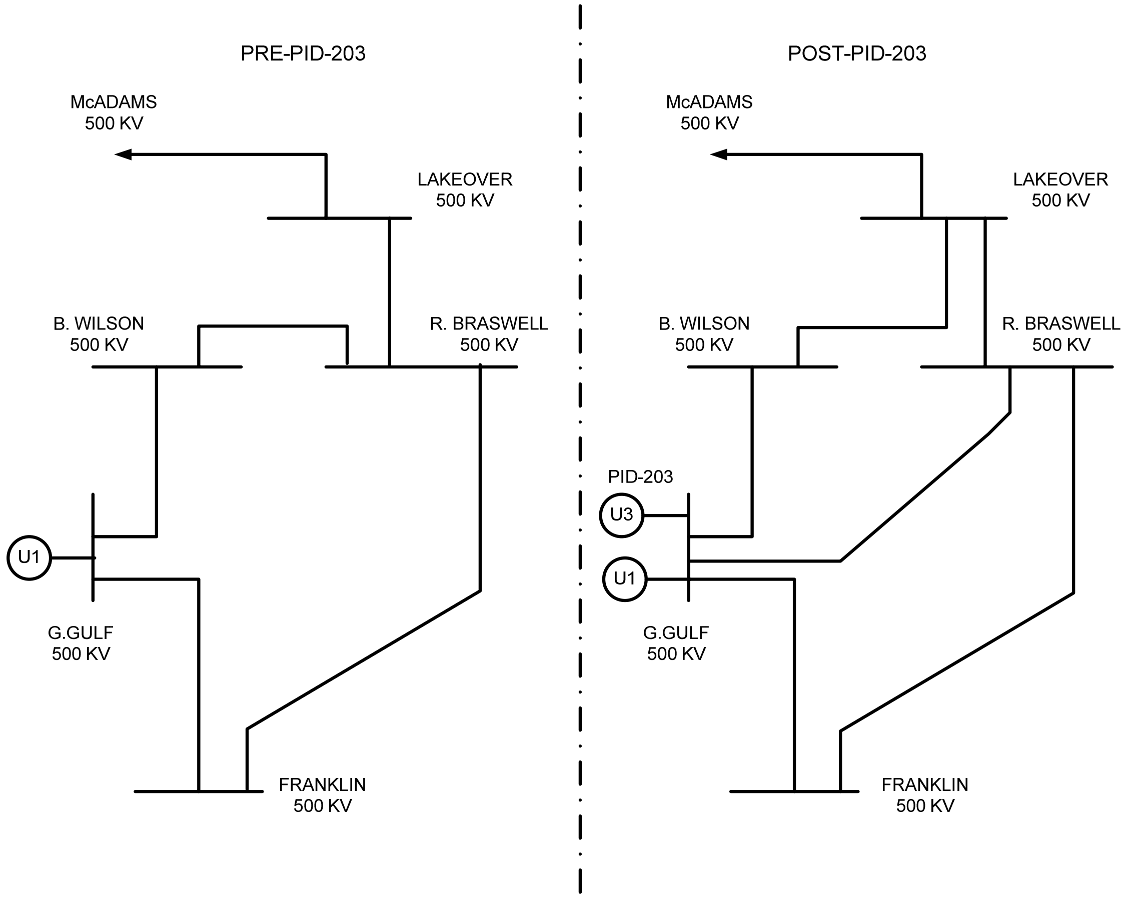


Figure III-1. Transmission line configuration at G. Gulf 500 kV with and without PID-203

PID 203 Grand Gulf 1522 with Priors

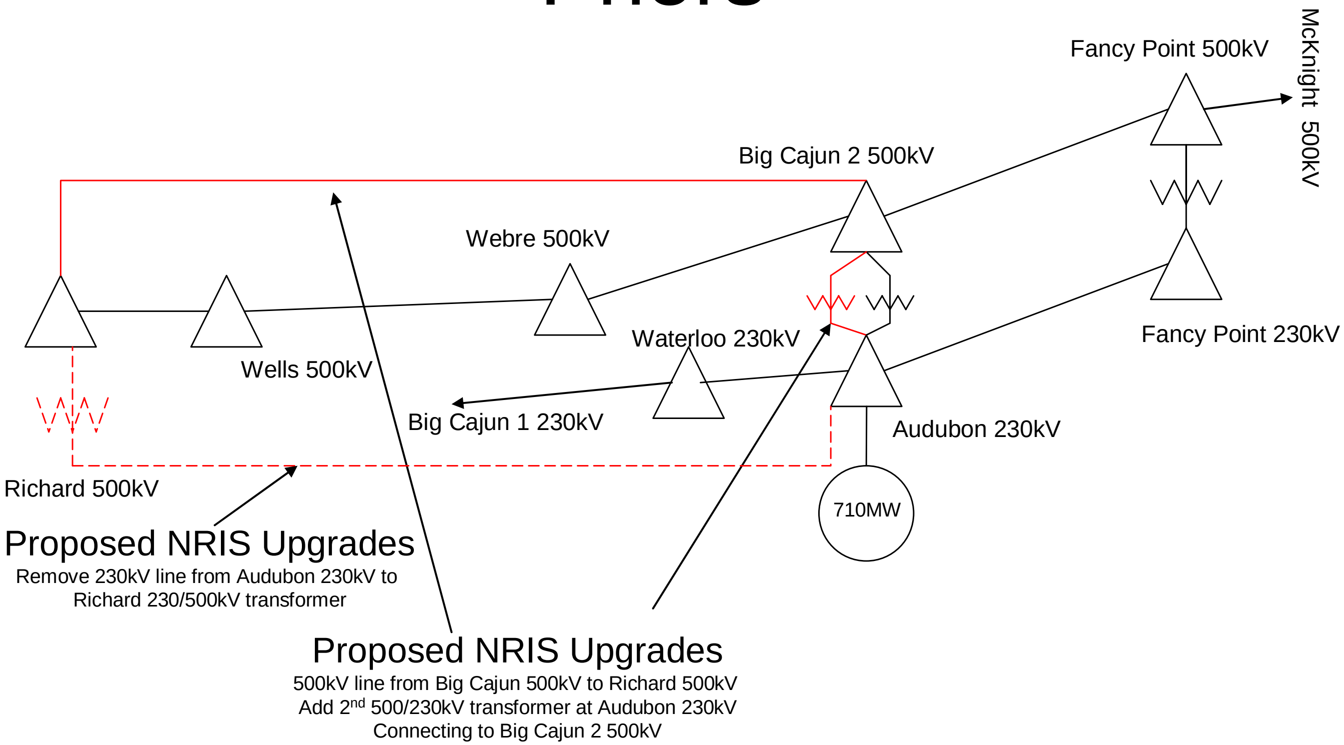


Figure III-2. Reinforcements for PID-203

The new PID-203 generation and auxiliary load (90 MW) were also added to the model at a proposed G. Gulf 500 kV bus. Figure III-3 and Figure III-4 show the one-line diagram of the local area of the Entergy system without and with PID-203, respectively. The PID-203 generation was dispatched against the load in the selected zones in PSS/E database.

The stability studies were conducted to assess the impact of the power injection of 1522 MW into Entergy's system. The loads in the Entergy system were represented as follows: for the active part, 100% was modeled with a constant current model; all of the reactive part, on the other hand, was modeled with a constant impedance model. The simulations were conducted with the PID-203 unit approximately generating 1612 MW total and injecting 1522 MW net into the Entergy System.

PID-203 provided dynamic model of their generation equipment for use in this study. The generator was modeled using the standard PSS/E **GENROU** model.

PID-203 also provided data for the excitation systems. The data for the PID-203 excitation system represents a static excitation system, and was modeled using the PSS/E **ESST4B** model. Also Power System Stabilizer (PSS) data was provided with the interconnection request. The PSS was modeled using the PSS/E **PSS2A** model. PID-203 provided the data for the turbine-governor controls. The turbine-governor model was modeled using the PSS/E **IEEEG1** model.

The data used to for the proposed PID-203 generator, exciter, and governor models are shown in **Appendix A-A.**

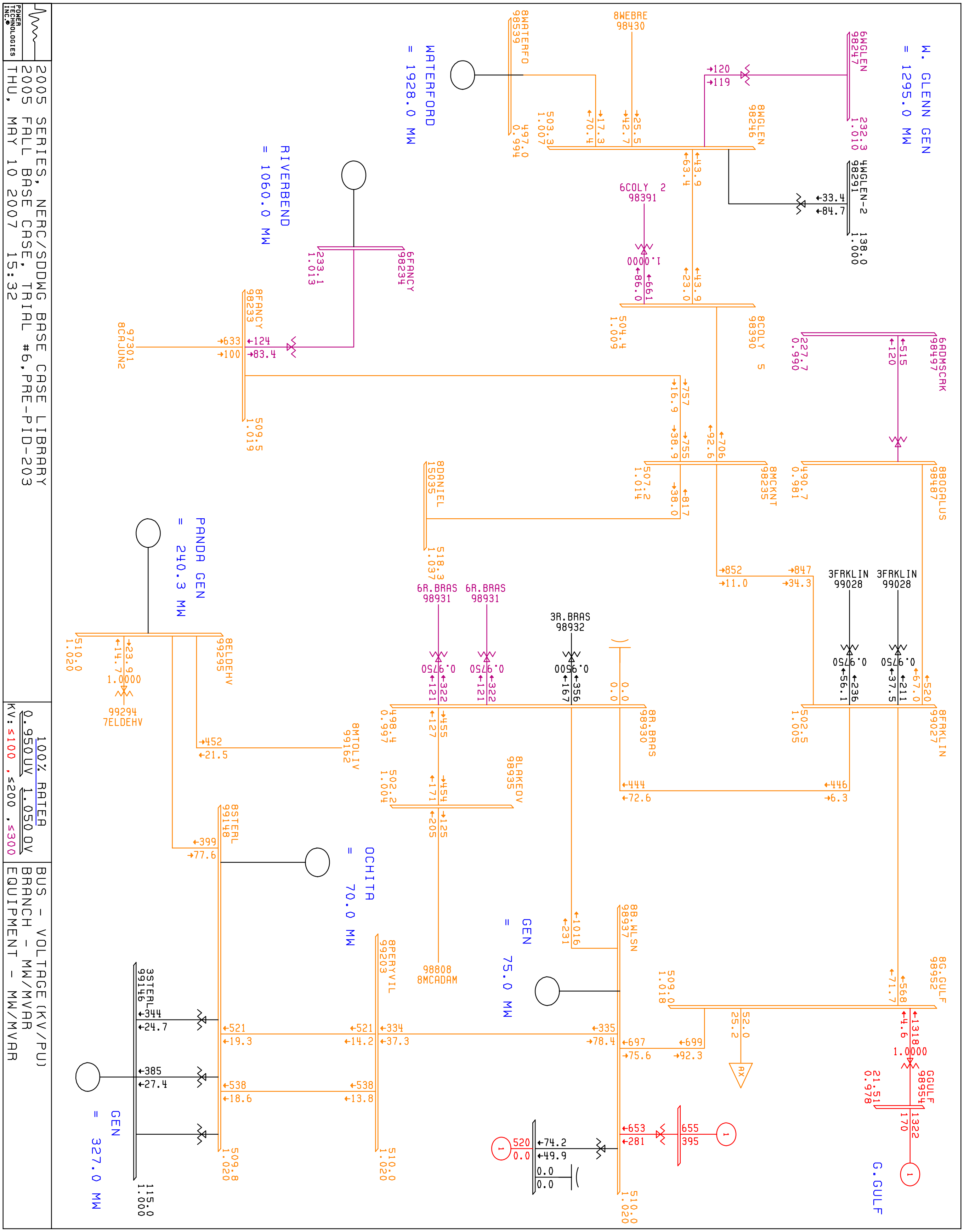


Figure III-3. Single Line Diagram of the Stability Study Area of Focus WITHOUT PID-203

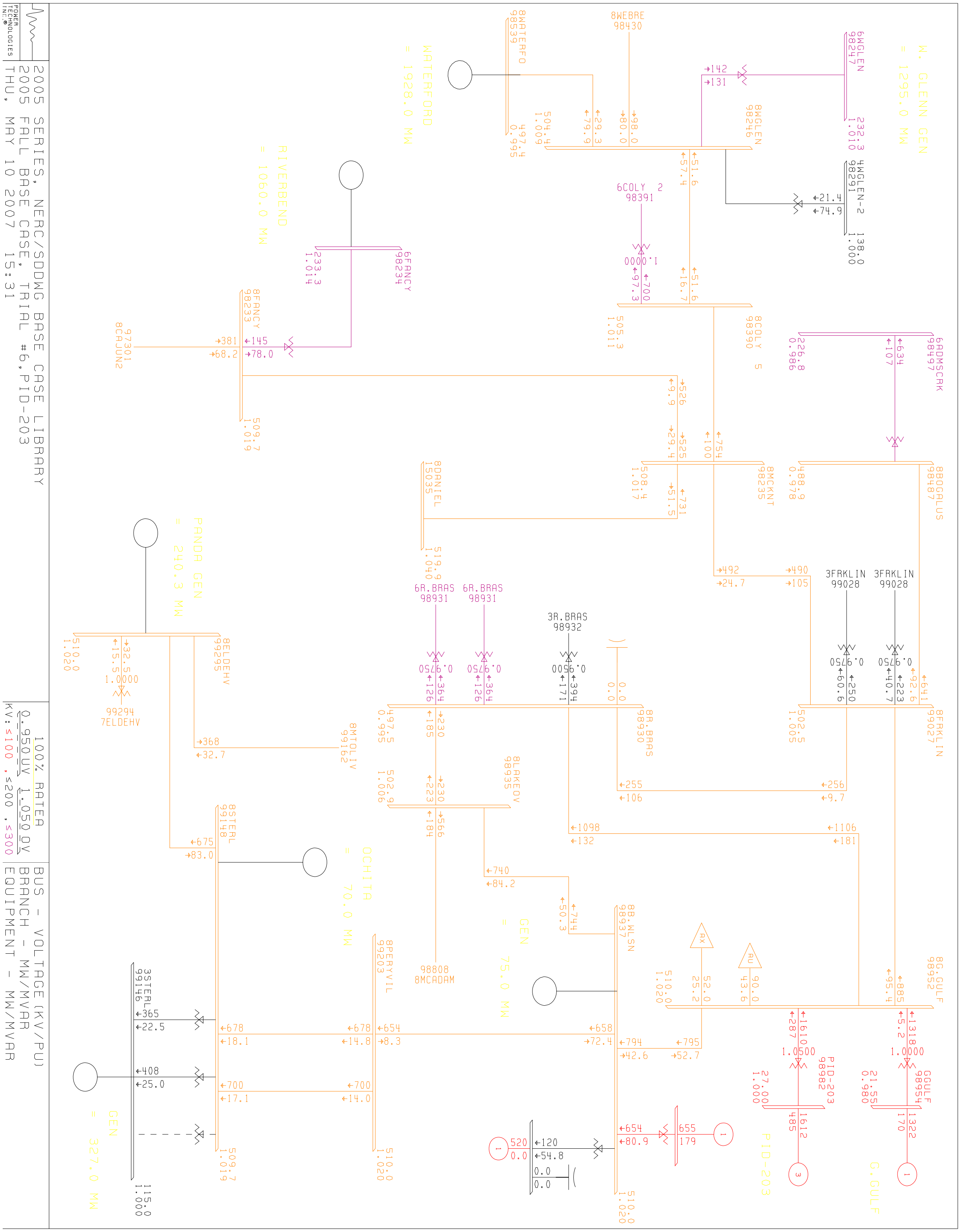


Figure III-4. Single Line Diagram of the Stability Study Area of Focus WITH PID-203

B. Transient Stability Analysis

Stability simulations were run to examine the transient behavior of the PID-203 generator and its effect on the Entergy system. Stability analysis was performed using the following procedure. First, three-phase faults with single-phase breaker failure were simulated on the transmission lines connected to the G. Gulf 500 kV station and on key adjacent stations, since the 500 kV breakers are independent pole operated. If a three phase fault with single-phase breaker failure was found to be unstable, then a single phase fault followed by breaker failure and a normally cleared three phase fault were studied. This procedure is being followed since if the units are stable for a more severe fault (such as three phase fault with breaker failure), the need to study stability for a less severe fault (such as single-phase fault with breaker failure and normally cleared three phase) does not arise. The stability analysis was performed using the PSS/E dynamics program. The fault clearing times used for the simulations are given in Table III-1.

Table III-1 Fault Clearing Times

Contingency at kV level	Normal Clearing	Delayed Clearing
230	6 cycles	6+9 cycles
500	5 cycles	5+9 cycles

The breaker failure scenario was simulated with the following sequence of events:

1) At the normal clearing time for the primary breakers, the faulted line is tripped at the far end from the fault by normal breaker opening.

2) The fault remains in place for three-phase stuck-breakers. For single-phase faults, the fault is appropriately adjusted to account for the line trip of step 1). For an IPO breaker, the 3-phase fault is replaced by a line-to-ground fault (2 phases of the faulted-end breaker clear and one phase sticks).

3) The fault is then cleared by back-up clearing. If the system is shown to be unstable for this condition, then stability of the system without the PID-203 plant needs to be verified.

All line trips are assumed to be permanent (i.e. no high speed re-closure).

The stability analysis was performed using the PSS/E dynamics program. The PSS/E dynamics program only simulates the positive sequence network. Unbalanced faults involve the positive, negative, and zero sequence networks. For unbalanced faults, the equivalent fault admittance must be inserted in the PSS/E positive sequence model between the faulted bus and ground to simulate the effect of the negative and zero sequence networks. For a single-line-to-ground (SLG) fault, the fault admittance equals the inverse of the sum of the positive, negative and zero sequence Thevenin impedances at the faulted bus. Since PSS/E inherently models the positive sequence fault impedance, the sum of the negative and zero sequence Thevenin impedances needs to be added and entered as the fault impedance at the faulted bus.

For three-phase faults, a fault admittance of –j2E9 is used (essentially infinite admittance or zero impedance).

Table III-2A and Table III-2B list all the fault cases that were simulated in this study. Fault scenarios were formulated by examining the system configuration shown in Figure III-5. The substation configurations for the adjacent substations with the fault locations are included in the Appendix A-J for reference.

Faults 1 through 17 represent the normal clearing 3-phase faults. Faults 1a through 17a represent the stuck breaker cases with the appropriate delayed back-up clearing times. Additional selected faults were simulated at Big Cajun 2 500 kV, Richard 500 kV and Fancy PT. 500 kV substations to evaluate any impact on the Entergy transmission system after addition of the Proposed reinforcements for PID-203. Faults 18 through 22 represent the normal clearing faults related to the reinforcements. Faults 18a through 22b represent the selected stuck breaker fault cases with appropriate delayed back-up clearing times.

For all cases analyzed, the initial disturbance was applied at t = 0.1 seconds. The breaker clearing was applied at the appropriate time following this fault inception.

Table III-2A Fault Cases Simulated in this Study: 3phase faults with normal clearing

CASE	LOCATION	TYPE	CLEARING TIME (cycles)	TRIPPED FACILITIES	Stable ?	Acceptable Voltages ?
FAULT-1	G. Gulf - B. Wilson 500 kV	3 PH	5	G. Gulf - B. Wilson 500 kV	YES	YES
FAULT-2	G. Gulf - Ray Braswell 500 kV	3 PH	5	G. Gulf - Ray Braswell 500 kV	YES	YES
FAULT-3	G. Gulf - Franklin 500 kV	3 PH	5	G. Gulf - Franklin 500 kV	YES	YES
FAULT-4	G. Gulf Unit 1	3 PH	5	G. Gulf Generation #1 (Existing)	YES	YES
FAULT-5	Ray Braswell - Lakeover 500 kV	3 PH	5	Ray Braswell - Lakeover 500 kV	YES	YES
FAULT-6	Ray Braswell - Franklin 500 kV	3 PH	5	Ray Braswell - Franklin 500 kV	YES	YES
FAULT-7	Ray Braswell 500/ 230 kV Transformer #1	3 PH	5	Ray Braswell 500/ 230 kV Transformer #1	YES	YES
FAULT-8	Ray Braswell 500/ 115 kV Transformer #1	3 PH	5	Ray Braswell 500/ 115 kV Transformer #1	YES	YES
FAULT-9	B. Wilson - Lakeover 500 kV	3 PH	5	B. Wilson - Lakeover 500 kV	YES	YES
FAULT-10	B. Wilson - Perryville 500 kV	3 PH	5	B. Wilson - Perryville 500 kV	YES	YES
FAULT-11	Franklin - Mcknight 500 kV	3 PH	5	Franklin - Mcknight 500 kV	YES	YES
FAULT-12	Franklin - Bogalusa 500 kV	3 PH	5	Franklin - Bogalusa 500 kV	YES	YES
FAULT-13	Franklin - Ray Braswell 500 kV	3 PH	5	Franklin - Ray Braswell 500 kV	YES	YES
FAULT-14	Franklin 500 / 115 kV	3 PH	5	Franklin 500 / 115 kV	YES	YES
FAULT-15	B. Wilson 500/115 kV transformer #1	3PH	5	B. Wilson 500/115 kV transformer #1	YES	YES
FAULT-16	Lakeover - McAdams 500 kV	3 PH	5	Lakeover - McAdams 500 kV	YES	YES
FAULT-17	G.Gulf 500/27 kV (PID-203 GSU)	3 PH	5	G. Gulf 500/27 kV GSU and G. Gulf Unit #3 (PID-203)	YES	YES
FAULT-18	Fancy PT 500/230 kV Auto Transformer	3PH	5	Fancy PT 500/230 kV Auto Transformer	YES	YES
FAULT-19	Fany PT - B. Cajun 2 500 kV	3 PH	5	Fany PT - B. Cajun 2 500 kV	YES	YES
FAULT-20	B. Cajun 2 - Fancy PT 500 kV	3 PH	5	B. Cajun 2 - Fancy PT 500 kV	YES	YES
FAULT-21	Richard - Wells 500 kV	3 PH	5	Richard - Wells 500 kV	YES	YES
FAULT-22	Richard - B. Cajun 2 500 kV	3 PH	5	Richard - B. Cajun 2 500 kV	YES	YES

Table III-2B Fault Cases Simulated in this Study: faults with stuck breaker

CASE	LOCATION	TYPE	CLEARING TIME (cycles)		SLG FAULT IMPEDANCE (MVA)	STUCK BRK #	PRIMARY BRK TRIP #	SECONDARY BRK TRIP	TRIPPED FACILITIES	Stable ?	Acceptable Voltages ?
			PRIMARY	Back-up							
FAULT-1a	G. Gulf - B. Wilson 500 kV	3PH-1PH	5	9	675.23-j10951.98	BRK F	GCB #J2240, GCB #J2244, BRK E	BRK B, BRK D, J5204, J5216, J5228, J5240	G. Gulf - B. Wilson 500 kV	YES	--
FAULT-2a	G. Gulf - Ray Braswell 500 kV	3PH-1PH	5	9	756.09-j12420.14	J5216	J5224, BRK @ R. Braswell 500 kV	BRK B, BRK D, BRK F, J5204, J5228, J5240	G. Gulf - Ray Braswell 500 kV	YES	--
FAULT-3a	G. Gulf - Franklin 500 kV	3PH-1PH	5	9	746.53-j12160.41	J5240	GCB #J2425, GCB #J2420, J5248	BRK B, BRK D, BRK F, J5204, J5228, J5216	G. Gulf - Franklin 500 kV	YES	--
FAULT-4a	G. Gulf Unit 1	3PH-1PH	5	9	683.12-j10572.93	J5228	J5232	BRK B, BRK D, BRK F, J5204, J5216, J5240	G. Gulf Unit 1	YES	--
FAULT-5a	R. Braswell - Lakeover 500 kV	3PH-1PH	5	9	613.21-j5486.35	J4908	GCB#J9218, GCB#J9234, J4928	J4904, J4944, J4932	R. Braswell - Lakeover 500 Kv	YES	--
FAULT-6a	R. Braswell - Franklin 500 kV	3PH-1PH	5	9	681.73-j6057.23	J4944	J4914, GCB#J2404, GCB#J2412	J4908, J4904, J4932	R. Braswell - Franklin 500 kV	YES	--
FAULT-6b	R. Braswell - Franklin 500 kV	3PH-1PH	5	9	681.73-j6057.23	J4914	J4944, GCB#J2404, GCB#J2412	J4952, R. Braswell 500/ 230 kV transformer breakers	R. Braswell - Franklin 500 kV, R. Braswell 500/230 kV transformer	YES	--
FAULT-7a	R. Braswell 500/230 kV	3PH-1PH	5	9	836.79-j6602.49	J4914	J4952,R. Braswell 500/ 230 kV transformer breakers	J4944, GCB#J2404, GCB#J2412	R. Braswell 500/230 kV transformer, R. Braswell - Franklin 500 kV	YES	--
FAULT-8a	R. Braswell 500/115 kV	3PH-1PH	5	9	830.71-j6509.82	J4917	J4904, R. Braswell 500/ 115 kV transformer breakers	J4936, J4952	R. Braswell 500/115 kV transformer	YES	--
FAULT-9a	B. Wilson - Lakeover 500 kV	3PH-1PH	5	9	680.64-j7946.18	J2233	GCB#J4928, GCB#J4920, J2230	GCB#R7372, GCB#R9872, J2218	B. Wilson - Lakeover 500 kV, B. Wilson Perryville 500 kV	YES	--
FAULT-10a	B. Wilson - Perryville 500 kV	3PH-1PH	5	9	632.86-j7577.59	J2233	GCB#R7372, GCB#R9872, J2218	GCB#J4928, GCB#J4920, J2230	B. Wilson Perryville 500 Kv, B. Wilson - Lakeover 500 kV	YES	--
FAULT-11a	Franklin - Mcknight 500 kV	3PH-1PH	5	9	627.61-j4449.69	J2416	GCB#21105, GCB#21110, J2412	GCB#S4402, GCB#S4405, J2420	Franklin - Mcknight 500 kV, Franklin - Bogalusa 500 kV	YES	--

CASE	LOCATION	TYPE	CLEARING TIME (cycles)		SLG FAULT IMPEDANCE (MVA)	STUCK BRK #	PRIMARY BRK TRIP #	SECONDARY BRK TRIP	TRIPPED FACILITIES	Stable ?	Acceptable Voltages ?
			PRIMARY	Back-up							
FAULT-11b	Franklin - Mcknight 500 kV	3PH-1PH	5	9	627.61-j4449.69	J2412	GCB#21105, GCB#21110, J2416	J2408, Franklin 500/115 kV transformer #2 breakers	Franklin - Mcknight 500 kV, Franklin 500/115kV	YES	--
FAULT-12a	Franklin - Bogalusa 500 kV	3PH-1PH	5	9	756.89-j5320.66	J2416	GCB#S4402, GCB#S4405, J2420	GCB#21105, GCB#21110, J2412	Franklin - Mcknight 500 kV, Franklin - Bogalusa 500 kV	YES	--
FAULT-13a	Franklin - Ray Braswell 500 kV	3PH-1PH	5	9	694.49-j5005.78	J2408	J2404, GCB#J4904, GCB#4908	J2412, Franklin 500/115 kV transformer #2 breakers	Franklin - Ray Braswell 500 kV, Franklin 500/115 kV	YES	--
FAULT-14a	Franklin 500 / 115 kV	3PH-1PH	5	9	890.5-j5756.85	J2412	500/115 kV transformer breakers, J2408	GCB#21105, GCB#21110, J2416	Franklin 500 / 115 kV, Franklin - Mcknight 500 kV	YES	--
FAULT-14b	Franklin 500 / 115 kV	3PH-1PH	5	9	890.5-j5756.85	J2408	500/115 kV transformer breakers, J2412	GCB#J4904, GCB#4908, J2404	Franklin 500 / 115 kV, Franklin - R. Braswell 500 kV	YES	--
FAULT-15a	B. Wilson 500/115 kV transformer #1	3PH-1PH	5	9	825.01-j8079.07	J2214	500/115 kV transformer breakers, J2222	J2218, J2252, J2225	B. Wilson 500/115 kV transformer #1	YES	--
FAULT-16a	Lakeover - McAdams 500 kV	3PH-1PH	5	9	393.96-j3393.78	J9234	J9214, GCB#J3924, GCB#3920	J2918, GCB#4908, GCB#4928	Lakeover - McAdams 500 Kv, Lakeover- R. Braswell 500 kV	YES	--
FAULT-16b	Lakeover - McAdams 500 kV	3PH-1PH	5	9	393.96-j3393.78	J9214	J9234, GCB#J3924, GCB#3920	J9218, J3214,	Lakeover - McAdams 500 Kv, Lakeover 500/115 kV transformer	YES	--
FAUL-17a	G.Gulf 500/27 kV (PID-203 GSU)	3PH	5	9	860.41-j13556.68	BRK I	BRK H, C, D		G. Gulf 500/27 kV GSU and G. Gulf Unit #3 (PID-203)	YES	--
FAULT-18a	Fancy PT - B. Cajun 1 230 kV	1PH	6	9	625.11-j9430.52	20740	20745, GCB#13365, GCB#13345	20735, 20770, 20765	Fancy PT- B. Cajun 1 230 kV, Fancy PT 500/230 kV autotransformer	YES	YES
FAULT-19a	Fany PT - B. Cajun 2 500 kV	3PH-1PH	5	9	464.75-j5923.48	20770	20775, GCB#20535, GCB#20450	20765, 20740, 20735	Fany PT - B. Cajun 2 500 kV, Facny PT 500/230 kV autotransformer	YES	--
FAULT-19b	Fany PT - B. Cajun 2 500 kV	3PH-1PH	5	9	464.75-j5923.48	20775	20770, GCB#20535, GCB#20450	20765, GCB#21115, GCB#21110	Fany PT - B. Cajun 2 500 kV, Fancy PT - McKnight 500 kV	YES	--
FAULT-20a	B. Cajun 2 - Fancy PT 500 kV	3PH-1PH	5	9	787.6-j12502.64	20540	20770, 20775, 20535	20545	B. Cajun 2 - Fancy PT 500 Kv, B. Cajun 2 Unit #1	YES	--
FAULT-21a	Richard - Wells 500 kV	3PH-1PH	5	9	662.19-j5831.52	18415	13065, GCB#13725, GCB#13735	13000, OCB#17270, OCB#17275	Richard - Wells 500 kV, Richard 500/138 kV Xmer #2	YES	--
FAULT-22a	RIchard - B. Cajun 2 500 kV	3PH-1PH	5	9	686.14-j6287.89	13000	E, BRK IN B. Cajun 2 Stations	18415, OCB#17270, OCB#17275	RIchard - B. Cajun 2 500 Kv, Richard 500/138 kV Xmer #2	YES	--

CASE	LOCATION	TYPE	CLEARING TIME (cycles)		SLG FAULT IMPEDANCE (MVA)	STUCK BRK #	PRIMARY BRK TRIP #	SECONDARY BRK TRIP	TRIPPED FACILITIES	Stable ?	Acceptable Voltages ?
			PRIMARY	Back-up							
FAULT-22b	RIchard - B. Cajun 2 500 kV	3PH-1PH	5	9	686.14-j6287.89	E	13000, BRK IN B. Cajun 2 Station	13070, GCB#13105, GCB#13060	RIchard - B. Cajun 2 500 kV, Richard - Nelson 500 kV	YES	--

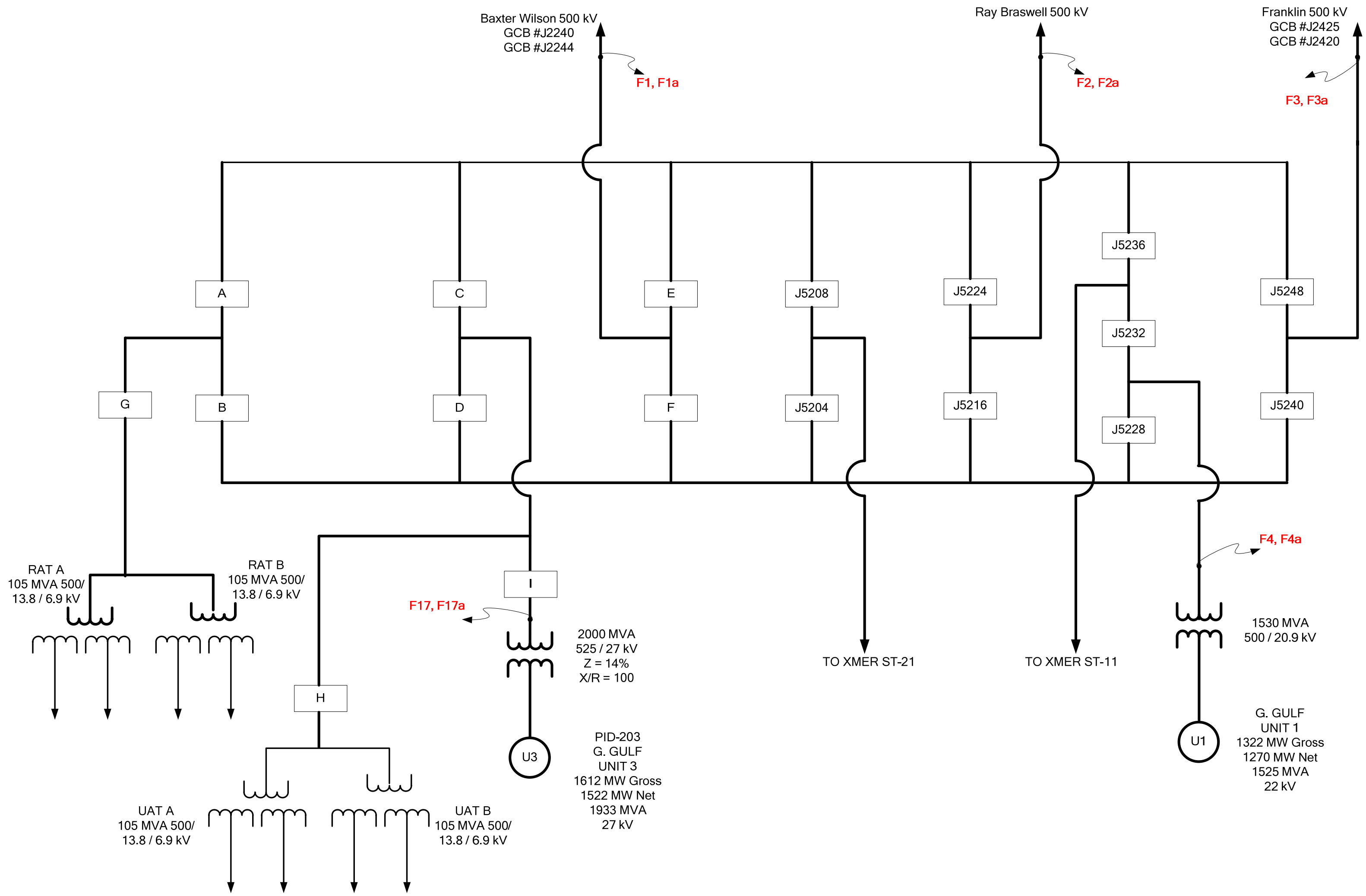


Figure III-5. Bus/Breaker Configuration of the G. GULF 500 kV Station

C. Analysis Results

All of the normally-cleared, three-phase faults simulated were found to be stable. Likewise, all of the 500 kV IPO stuck-breaker faults were found to be stable. The plots are provided in Appendix A.E.

In addition to criteria for the stability of the machines, Entergy has evaluation criteria for the transient voltage dip as follows:

- 3-phase fault or single-line-ground fault with normal clearing resulting in the loss of a single component (generator, transmission circuit or transformer) or a loss of a single component without fault:

  Not to exceed 20% for more than 20 cycles at any bus

  Not to exceed 25% at any bus
- 3-phase faults with normal clearing resulting in the loss of two or more components (generator, transmission circuit or transformer)
- SLG fault with delayed clearing resulted in the loss of one or more components:

  Not to exceed 20% for more than 40 cycles at any bus

  Not to exceed 30% at any bus

The duration of the transient voltage dip excludes the duration of the fault. The transient voltage dip criteria will not be applied to three-phase faults followed by stuck breaker conditions unless the determined impact is extremely widespread.

The voltages at all buses in the Entergy system (115 kV and above) were monitored during each of the fault cases as appropriate. A slow voltage recovery was observed following Faults 1a, 2a, 3a and 10a. Faults 1a, 2a and 3a involve a 3 phase stuck-breaker (IPO) fault at G. Gulf 500 kV and loss of one (1) 500 kV transmission line connected to G. Gulf 500 kV substation at a time. As these faults are 3 Phase stuck breaker faults the voltage dip criteria are not applicable. The plots for voltages in the local area following Faults 1a, 2a 3a and 10a are shown in Figure III-6 through Figure III-9.

No violations of the transient voltage dip criteria were observed among simulated faults.

Plots of relevant parameters (machine angles and speed, the PID-203, G.GULF UNIT#1, bus voltages and frequency, etc) are shown in Appendix A.E.

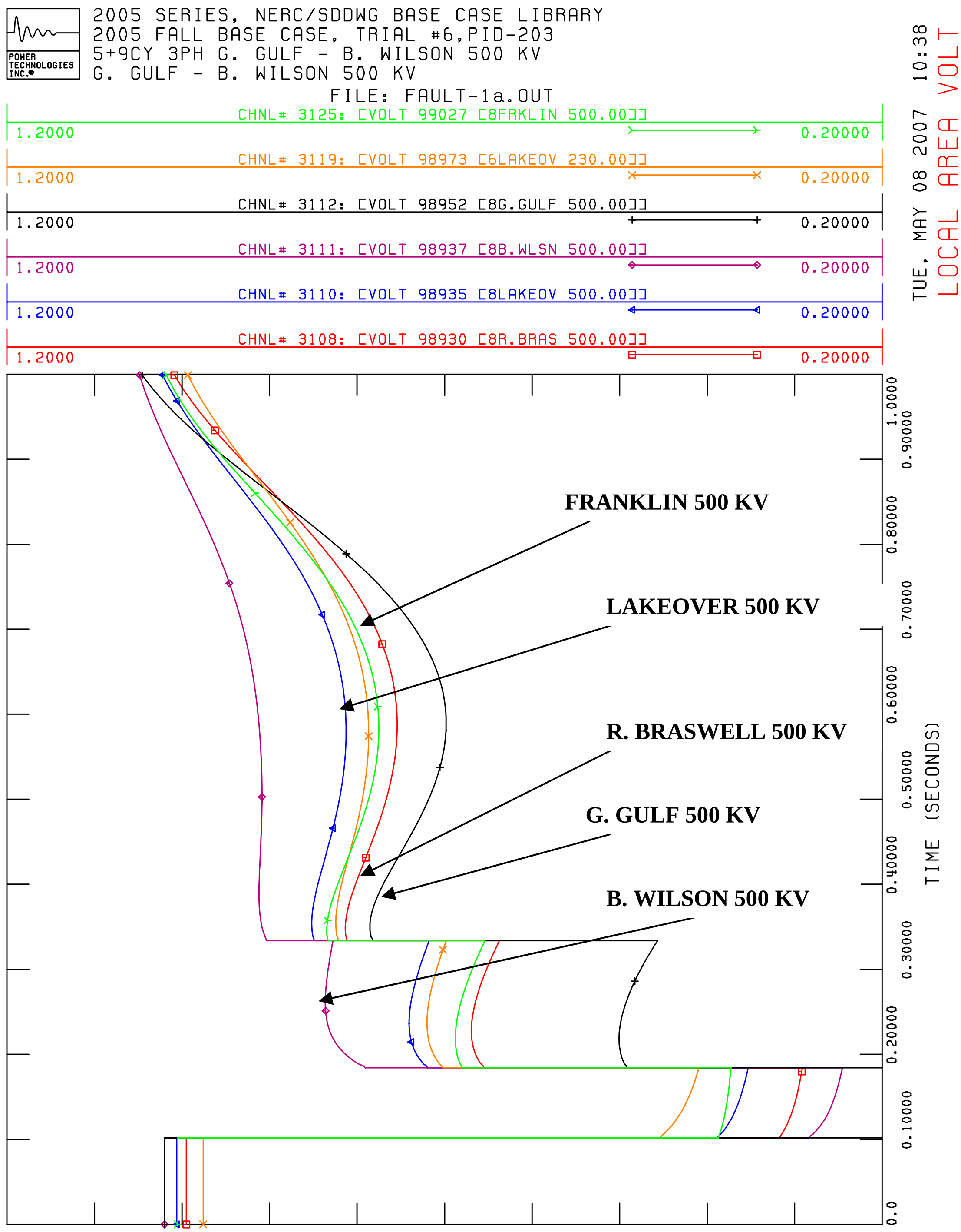


Figure III-6: Local area voltages following Fault-1a with PID-203

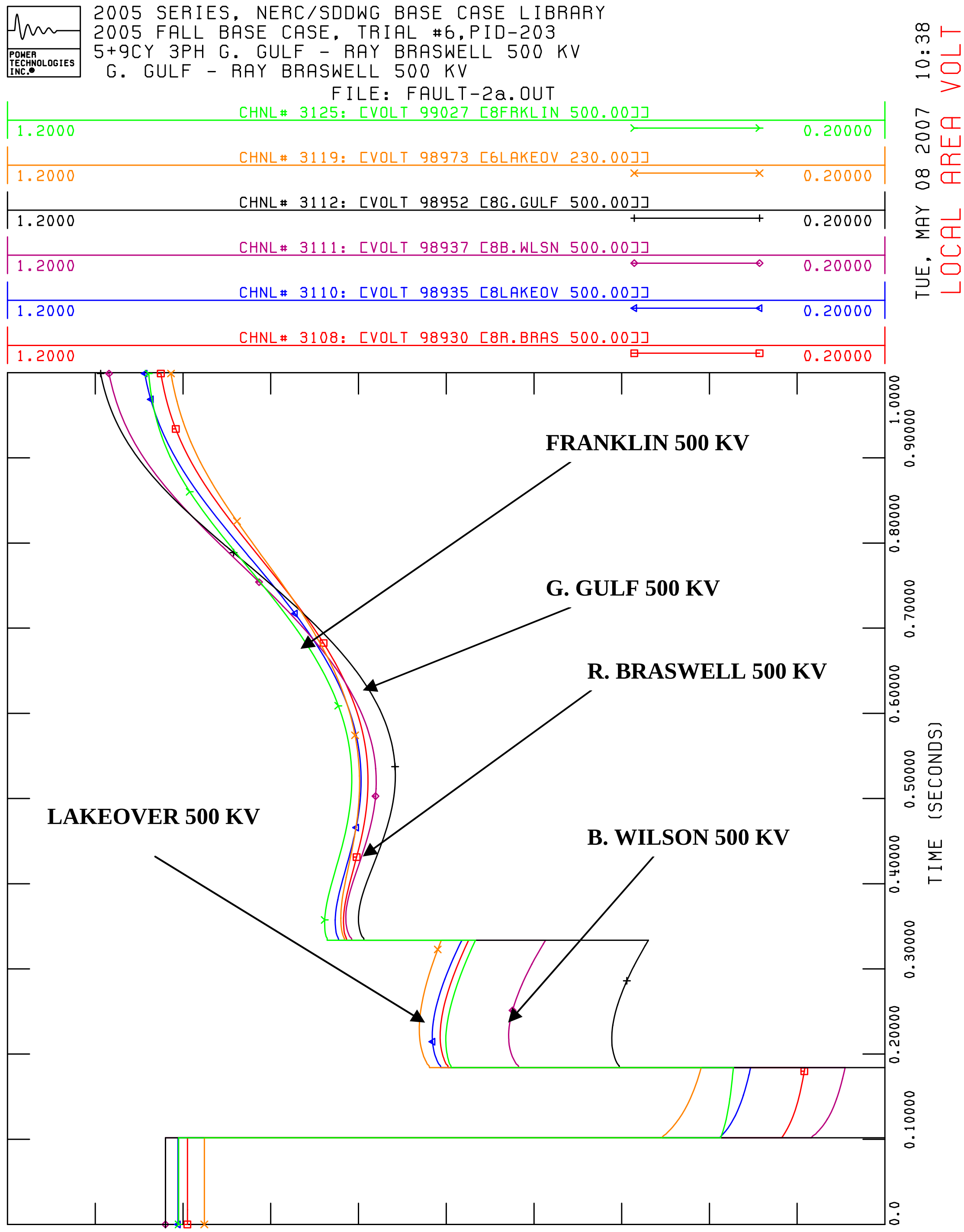


Figure III-7: Local area voltages following Fault-2a with PID-203

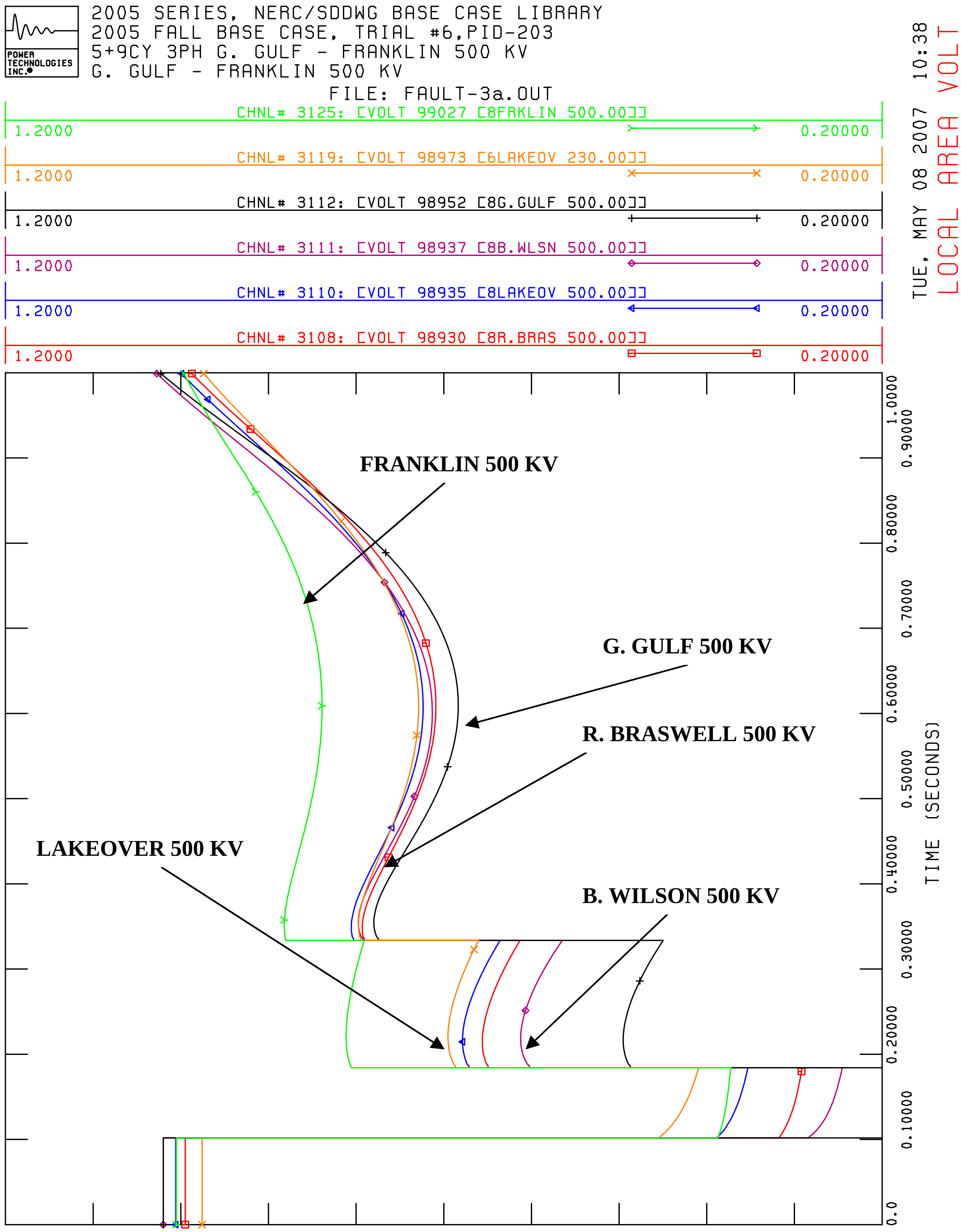


Figure III-8: Local area voltages following Fault-3a with PID-203

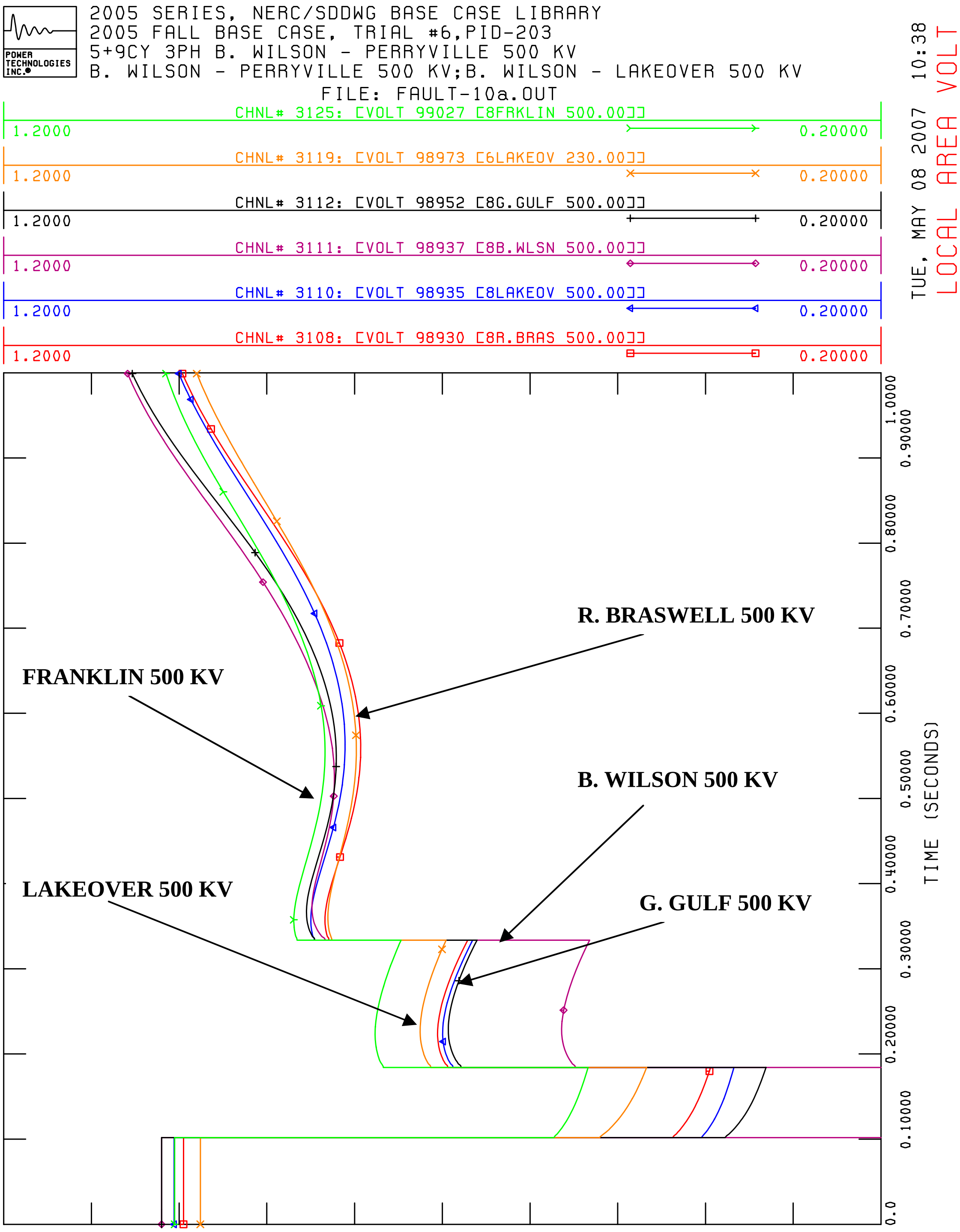


Figure III-9: Local area voltages following Fault-10a with PID-203

In summary, when considering the new PID-203 (1522 MW) generation at the G. GULF 500 kV bus, all the simulated faults are stable. No violations of the voltage dip criteria were observed. This meets Entergy's performance criteria when the PID-203 plant is in-service.

Due to restructuring of the utility industry, there has been a large increase of merchant generation activity on the Entergy system. These generators are equipped with modern exciters that have a high gain and a fast response to enhance transient stability. However, these fast response exciters, if used without stabilizers, can lead to oscillatory instability affecting local or regional reliability. This problem is exacerbated particularly in areas where there is a large amount of generation with limited transmission available for exporting power. Stability studies carried out at Entergy have validated this concern. Furthermore, based on the understanding of operational problems experienced in the WECC area over the last several years and the opinion of leading experts in the stability area, Power System Stabilizers (PSS) are an effective and a low cost means of mitigating dynamic stability problems. In particular, PSS cost can be low if it is included in power plant procurement specifications.

Therefore, as a pre-emptive measure, Entergy requires all merchant generation intending to interconnect to its transmission system to install PSS on their respective units. Please refer to Appendix A-I for Entergy's Policy Statement on PSS Requirements.

APPENDIX A.A DATA PROVIDED BY CUSTOMER

A.A.1 LARGE GENERATING FACILITY DATA

UNIT RATINGS

kVA 1,933,000 °F 115 Voltage 27 kV/500 kV
Power Factor 0.9
Speed (RPM) 1800 Connection Wye
Short Circuit Ratio 0.5 Frequency, Hertz 60
Stator Amperes at Rated kVA 41,334 Field Volts 685
Max Turbine MW 1657 °F < 40

COMBINED TURBINE-GENERATOR-EXCITER INERTIA DATA

Inertia Constant, H = 4.84 to 6 kW sec/kVA
Moment-of-Inertia, WR^2 = 12,500,000 to 15,500,000 lb. ft.^{2}

REACTANCE DATA (PER UNIT-RATED KVA)

		DIRECT AXIS		QUADRATURE AXIS
Synchronous – saturated	X_{dv}	2.06	X_{qv}	1.94
Synchronous – unsaturated	X_{di}	2.06	X_{qi}	1.94
Transient – saturated	X'_{dv}	0.305	X'_{qv}	0.55
Transient – unsaturated	X'_{di}	0.365	X'_{qi}	0.55
Subtransient – saturated	X''_{dv}	0.21	X''_{qv}	0.21
Subtransient – unsaturated	X''_{di}	0.28	X''_{qi}	0.28
Negative Sequence – saturated	$X2_v$	0.21		
Negative Sequence – unsaturated	$X2_i$	0.28		
Zero Sequence – saturated	$X0_v$	0.2		
Zero Sequence – unsaturated	$X0_i$	0.2		
Leakage Reactance	Xl_m	0.225		

FIELD TIME CONSTANT DATA (SEC)

Open Circuit	T'_{do}	11.3	T'_{qo}	0.53
Three-Phase Short Circuit Transient	T'_{d3}	1.51	T'_{q}	0.15
Line to Line Short Circuit Transient	T'_{d2}	2.56		
Line to Neutral Short Circuit Transient	T'_{d1}	3.27		
Short Circuit Subtransient	T''_{d}	0.026	T''_{q}	0.026
Open Circuit Subtransient	T''_{do}	0.038	T''_{qo}	0.068

ARMATURE TIME CONSTANT DATA (SEC)

Three Phase Short Circuit	T_{a3}	0.28
Line to Line Short Circuit	T_{a2}	0.28
Line to Neutral Short Circuit	T_{a1}	0.23

NOTE: If requested information is not applicable, indicate by marking "N/A."

MW CAPABILITY AND PLANT CONFIGURATION
LARGE GENERATING FACILITY DATA

ARMATURE WINDING RESISTANCE DATA (PER UNIT)

Positive	R_1	0.0037
Negative	R_2	0.0171
Zero	R_0	0.0023

Rotor Short Time Thermal Capacity I_2^2t = 5.0
Field Current at Rated kVA, Armature Voltage and PF = 6,386 amps
Field Current at Rated kVA and Armature Voltage, 0 PF = 10,267 amps
Three Phase Armature Winding Capacitance = 1.3564 microfarad
Field Winding Resistance = 0.1091 ohms 125 °C
Armature Winding Resistance (Per Phase) = 0.0009 ohms 100 °C

CURVES

Provide Saturation, Vee, Reactive Capability, Capacity Temperature Correction curves. Designate normal and emergency Hydrogen Pressure operating range for multiple curves.

See attached documents:

"Attachment D Saturation Curves.pdf"
"Attachment E Vee Curves.pdf"
"Attachment F Reactive Capability Curves.pdf"

Capacity Temperature Correction curves are not required because this unit is base load rated at worst case conditions (cold liquid 37 deg C and 46 deg C cold gas) and unit operation is not ambient following.

GENERATOR STEP-UP TRANSFORMER DATA RATINGS

Capacity Self-cooled / Maximum Nameplate
1,200,000 / 2,000,000 kVA

Voltage Ratio (Generator Side/System side/Tertiary)
27 / 525 / kV

Winding Connections (Low V/High V/Tertiary V (Delta or Wye))
Delta / Wye /

Fixed Taps Available 5 @ 2.5% set size (nominal ± 5%)

Present Tap Setting Nominal tap setting, 525 kV

IMPEDANCE

Positive Z_1 (on 2,000 MVA base) 14 % 100 X/R

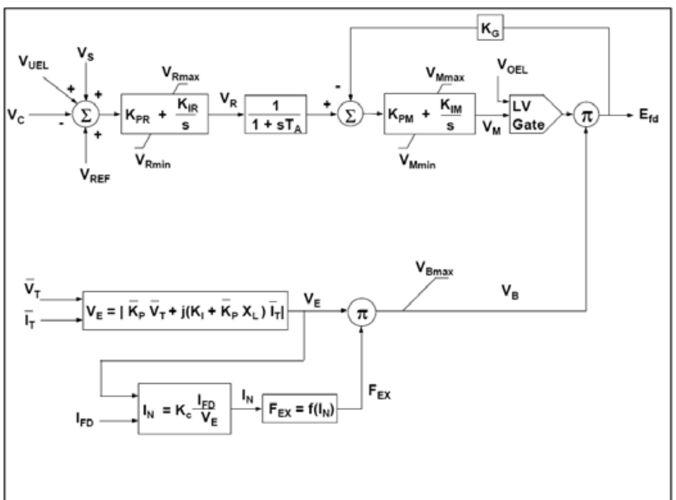
Zero Z_0 (on 2,000 MVA base) 14 % 100 X/R

EXCITATION SYSTEM DATA

Identify appropriate IEEE model block diagram of excitation system and power system stabilizer (PSS) for computer representation in power system stability simulations and the corresponding excitation system and PSS constants for use in the model.

SIZE A | DWG NO | SH 2 | REV

Customer	ESBWR			
unit				
Generator				
Design	ESBWR01A	LSTG	8/28/2006	
MVA Rating	1933		KV Rating	27
RPM	1800		PF	0.90
SCR	0.50		H2PSI	75
Volts DC	750		RFG at 100 C	0.1015
AFAG amps	1732		AFFL amps	6857
EX2100 Busfed Exciter Model Parameters				
IEEE ST4B Model Format		Exciter Nominal Response at rated input		2.29
TR	0		KC	0.30
KPR	2.66		KIR	2.66
VRMAX	1.00		VRMIN	-0.80
TA	0.01		KG	0
KPM	1.00		KIM	0
VMMAX	1.00		VMIMIN	-0.80
KP	7.53		KI	0
VBMAX	9.41		XL	0



"Computer Models for Representation of Digital-Based Excitation Systems", IEEE Trans. EC, Vol. 11, No. 3, September 1996, pp 607-615.

GENERAL ELECTRIC COMPANY	SIZE	CAGE CODE	DWG NO	
GE Power Generation — SCHENECTADY, NY	A			
DRAWN ZEEKY BUKHALA 2006/09/13				
ISSUED	SCALE		SHEET	2

SIZE	DWG NO	SH	REV
A		3	

TR	AC sensor time constant
KPR	AVR proportional gain
KIR	AVR integral gain
VRMAX	Maximum AVR Output
VRMIN	Minimum AVR output
TA	AVR time constant
KG	Field voltage feedback gain
KPM	Inner loop proportional gain
KIM	Inner loop integral gain
VMMAX	Maximum inner loop output
VMIMIN	Minimum inner loop output
VBMAX	Maximum source voltage
KP	Potential source constant
KI	Current source constant
XL	Source leakage reactance
KC	Rectifier loading factor
VS	Stabilizing input
VOEL	Over Excitation limit input
VUEL	Under excitation limit input
VC	Compensated terminal voltage
VREF	Terminal voltage setpoint
EFD	Field voltage
IFD	Field current
VT	Terminal voltage
IT	Terminal current

GENERAL ELECTRIC COMPANY

GE Power Generation SCHENECTADY, NY

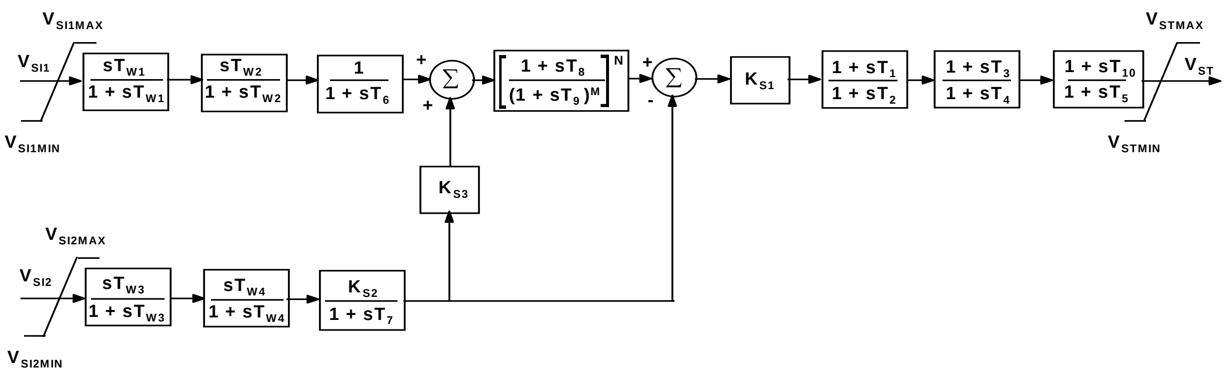
SIZE	CAGE CODE	DWG NO
A		

DRAWN ZEEKY BUKHALA 2006/09/13

ISSUED

SCALE		SHEET 3

TYPICAL EX2100 Power System Stabilizer (PSS)
IPS504229



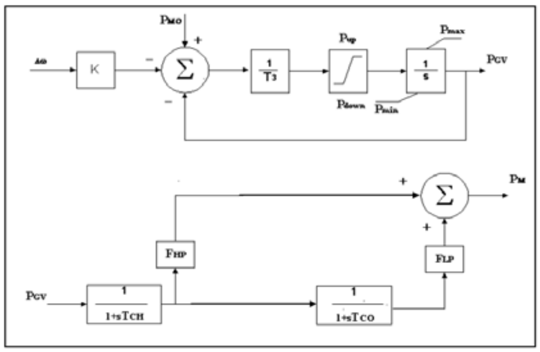
Ref. IEEE 421.5-1992 Type PSS2A
Note: Parameters shown with ranges give the typical or useful ranges
actual setting ranges are usually much wider.
VSI1 = speed input VSI2 = electrical power input
VSI1max, VSI1min - input #1 limits +/- 0.08 pu (fixed)
VSI2max, VSI2min - input #2 limits +/- 1.25 pu (fixed)
*T1 = lead #1 0.15 (range 0.1 - 2.0 sec) *T2 = lag #1 0.03 (range 0.01 - 1.0 sec)
*T3 = lead #2 0.15 (range 0.1 - 2.0 sec) *T4 = lag #2 0.03 (range 0.01 - 1.0 sec)
T5 = lag #3 0.0 (fixed not used in GE design) can be used if there are three lead lags
or for equivalent torsional filter time constant which may be required for some units
(determined by studies)
T6 = 0.0 (fixed) T7 = TW 2.0 sec (range 2 - 15 sec)
T8 = 0.5 sec (fixed) T9 = 0.1 sec (fixed)
T10 = Lag #3 = 0.0 (fixed not used in GE design)
N = 1 (fixed) M = 5 (fixed)
*KS1 = PSS gain = 4 - (range 3 - 20 typical)
KS2 = 0.167 to 0.207 = TW/(2H) - where H = combined turbine-gen. Inertia constant estimated
KS3 = 1.0
VSTmax = (range 0.05 to 0.1) VSTmin = (range -0.05 to -0.1)
TW1 = TW see note on T7 above TW2 = TW see note on T7 above
TW3 = TW see note on T7 above TW4 = 0.0 (fixed)
* Note:Lead/Lags and Gain must be Determined by Studies
HCS 10-05-06

GOVERNOR SYSTEM DATA

Identify appropriate IEEE model block diagram of governor system for computer representation in power system stability simulations and the corresponding governor system constants for use in the model.

Values listed are approximate for N2R Type ST

Turbine Governor Model



Description	Value	Units
Gain/Regulation(K)	20	NA
Gov Servo Constant(T3)	0.15	sec
Servo rate limit-opening(Pup)	0.012 **	(pu/sec)
Servo rate limit-closing(Pdown)	- 0.012 **	(pu/sec)
Upper power limit(Pmax)	1	(pu)
Lower power limit(Pmin)	0	(pu)
Steam chest and inlet piping delay(Tch)	0.5 #	(sec)
Crossaround, MSR and LP Bowl delay(Tco)	0.35	(sec)
HP turbine power fraction(FHP)	0.34	NA
LP turbine power fraction(FLP)	0.66	NA

$\Delta\omega$ = deviation in turbine speed
P_{MO} = inital per unit mechanical power
P_{GV} = per unit mechanical power at control valves
P_M = mechanical power

this time delay does not include piping ahead of main stop valves.

** constant is highly dependent on position of valves. Value given is for the small scale incremental power change(+/- 2% change) around the normal operation point of "valves wide open". Full stroke change rates are in the neighborhood of 0.83 pu/sec. With valves wide open drop in turbine speed will result in no additional power.

7/26/2006 - Rev PrelimSDP

A.A.2 DATA USED IN STABILITY MODEL

Load Flow Models

The **PID-203** plant equipment data are listed in Appendix A-A. No other elements were added to the Entergy system.

Stability Models

The **PID-203** plant equipment stability model data are listed in Appendix A-A. The resulting PSS/E model data is a follows:

Loadflow data in Stability Models

```
0,   100.00          / PSS/E-29.4    MON, APR 09 2007  13:44
2005 SERIES, NERC/SDDWG BASE CASE LIBRARY
2005 FALL BASE CASE, TRIAL #6,PID-203
98982,'PID-203 ',  27.0000,2,     0.000,     0.000, 151, 151,0.99999,  22.1462,   1
0 / END OF BUS DATA, BEGIN LOAD DATA
0 / END OF LOAD DATA, BEGIN GENERATOR DATA
98982,'3 ',  1612.000,   485.323,   842.000,  -603.000,1.02000,98952,  1933.000,
0.00000,   0.28000,   0.00000,   0.00000,1.00000,1,  100.0,  1612.000,     0.000,
1,1.0000
0 / END OF GENERATOR DATA, BEGIN BRANCH DATA
0 / END OF BRANCH DATA, BEGIN TRANSFORMER DATA
98952,98982,    0,'1 ',2,2,1,   0.00000,   0.00000,2,'        ',1,   1,1.0000
   0.00140,   0.14000, 2000.00
525.000, 525.000,   0.000, 2000.00, 2000.00, 2000.00, 0,     0,551.2500,498.7500,
1.05000, 0.95000,   5, 0, 0.00000, 0.00000
27.0000,  27.000
0 / END OF TRANSFORMER DATA, BEGIN AREA DATA
 151,99343,    56.000,     5.000,'EES     '
0 / END OF AREA DATA, BEGIN TWO-TERMINAL DC DATA
0 / END OF TWO-TERMINAL DC DATA, BEGIN VSC DC LINE DATA
0 / END OF VSC DC LINE DATA, BEGIN SWITCHED SHUNT DATA
0 / END OF SWITCHED SHUNT DATA, BEGIN IMPEDANCE CORRECTION DATA
0 / END OF IMPEDANCE CORRECTION DATA, BEGIN MULTI-TERMINAL DC DATA
0 / END OF MULTI-TERMINAL DC DATA, BEGIN MULTI-SECTION LINE DATA
0 / END OF MULTI-SECTION LINE DATA, BEGIN ZONE DATA
 151,'EMICEN  '
0 / END OF ZONE DATA, BEGIN INTER-AREA TRANSFER DATA
0 / END OF INTER-AREA TRANSFER DATA, BEGIN OWNER DATA
   1,'APC     '
0 / END OF OWNER DATA, BEGIN FACTS DEVICE DATA
0 / END OF FACTS DEVICE DATA
```

Dynamics data in Stability Models

```
      PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E      MON, APR 09 2007  13:44
 2005 SERIES, NERC/SDDWG BASE CASE LIBRARY
 2005 FALL BASE CASE, TRIAL #6,PID-203

 PLANT MODELS

 REPORT FOR ALL MODELS                         BUS 98982 [PID-203 27.000] MODELS


 ** GENROU **  BUS X-- NAME --X BASEKV MC    C O N S     S T A T E S
            98982     PID-203  27.000 3   80914-80927   31007-31012

            MBASE     Z S O R C E         X T R A N       GENTAP
           1933.0  0.00000+J 0.28000  0.00000+J 0.00000  1.00000

  T'D0 T''D0  T'Q0 T''Q0     H   DAMP   XD     XQ     X'D    X'Q   X''D    XL
 11.30 0.038  0.53 0.068   4.84  0.00 2.0600 1.9400 0.3650 0.5500 0.2800 0.2250

                                S(1.0)  S(1.2)
                                0.3750  1.1000


 ** PSS2A **   BUS X-- NAME --X BASEKV MC    C O N S     S T A T E S     V A R S      I C
O N S
            98982     PID-203  27.000 3   80928-80944   31013-31028    4009-4012
1296-1301

                   IC1 REMBUS1     IC2 REMBUS2       M       N
                    1       0       3       0       5       1

      TW1      TW2      T6       TW3      TW4      T7       KS2      KS3
     2.000    2.000    0.000    2.000    0.000    2.000    0.207    1.000

      T8       T9       KS1      T1       T2       T3       T4      VSTMAX   VSTMIN
     0.500    0.100    4.000    0.150    0.030    0.150    0.030    0.100   -0.100


 ** ESST4B **  BUS X-- NAME --X BASEKV MC    C O N S     S T A T E S
            98982     PID-203  27.000 3   80945-80961   31029-31032

    TR    KPR     KIR     VRMAX    VRMIN    TA     KPM     KIM    VMMAX   VMMIN
   0.000   2.660   2.660   1.000  -0.800   0.010   1.000   0.000   1.000  -0.800

            KG      KP      KI   VBMAX     KC      XL    THETAP
          0.000   7.530   0.000   9.410   0.300  0.0000   0.000


 ** IEEEG1 **  BUS X-- NAME --X BASEKV MC    C O N S     S T A T E S     V A R S
            98982 PID-203      27.000 3   80962-80981   31033-31038    4013-4014

     K      T1      T2      T3     UO      UC    PMAX   PMIN     T4      K1
   20.00   0.000   0.000   0.150  0.120  -0.120 0.8500 0.0000   0.500   0.340

    K2      T5      K3      K4      T6      K5      K6      T7      K7      K8
  0.000   0.350   0.660   0.000   0.000   0.000   0.000   0.000   0.000   0.000
```

APPENDIX A.B Stability Issues in the Western Region of the Entergy System Due to Independent Power Generation

Introduction

The WOTAB (West of the Atchafalaya Basin) Area in defined as Entergy's systems in Southwestern Louisiana, and Southeastern Texas. The WOTAB area is a major load center for the Entergy System. The load to generation ratio requires a significant amount of power to be imported into the WOTAB area. However, because of the influx of new generating projects proposed for the area, it is likely that by the year 2003 this area may turn into a significant exporter of power. There have been a significant number of requests for interconnection studies to evaluate the potential interconnection of new generating facilities in the WOTAB area. It is anticipated that by 2003 there may be approximately 4000 – 6000 MW of new merchant generation within the WOTAB area.

Entergy's transmission system was planned, designed and built to serve approximately 5000 – 6000 MW of native and network loads in the WOTAB area. The addition of a significant amount of merchant generation will result in the export of power out of the WOTAB area. A high level of export power has the potential to create major problems, such as voltage and dynamic stability. The main objective of this study is to establish an estimated power export limit for the WOTAB area based on stability criteria.

Signing an interconnection agreement provides the generator the right to interconnection to the transmission system, but does not provide it any right to move its power onto or over the transmission system. The right to use the transmission system to transmit power can only be obtained by submitting a transmission request for service pursuant to Entergy's FERC-approved transmission tariff. Solutions to stability problems to increase export limits, such as construction of 500 kV line, have very long lead-times and tend to be very expensive.

Entergy believes that it is important to post this study publicly on its OASIS site so that entities that have already executed interconnection agreements, as well as entities that are proposing to site new generation within the WOTAB area, can incorporate this information into their decision-making process.

Analysis

In order to establish stability limits from the WOTAB area, all merchant generating]that have signed an interconnection agreement were dispatched at their maximum capability along with the native generation in the area. In order to accommodate this export and simulate a worst case scenario, generation was reduced in the northern part of the Entergy System.

In this analysis the export limits were determined without the addition of any Power System Stabilizers (PSSs). However, sensitivity studies were conducted to determine the impact of stabilizers. If voltage stability limits were found to be lower than the dynamic stability limits, they were captured in this analysis.

One important assumption made in this study was to ignore thermal limitations. Thermal issues will be addressed as part of Transmission Service Request as they are based on source to sink information and generation dispatch within the WOTAB area.

The two cases analyzed in this study are as follows:

1. Base case with no merchant generation
2. Base case with merchant generation

Voltage stability analysis was performed for the pre-contingency condition and contingencies on four critical lines: Hartburg-Mt. Olive 500 kV, Richard–Webre 500 kV, Nelson–Richard 500 kV, and Grimes–Crockett 345 kV lines. As part of the voltage stability analysis, PV curves were developed in order to determine the maximum power that can be exported from the WOTAB area without experiencing voltage decline or voltage collapse. Entergy's guideline on voltage decline states that voltage at any station should not fall below 0.92 pu of nominal system voltage on single contingency.

Transient stability analysis was performed by applying a 3 phase to ground fault on the lines mentioned earlier. The fault clearing time was assumed to be 5 cycles for 500 kV and 345 kV lines and 6 cycles for the 230 kV lines. The transient stability plots show the machine angle as a function of time and indicate whether machine is stable and well damped, transiently unstable or dynamically unstable. A three percent damping criteria was used to screen the damping problem.

Results

Case 1 – Base Case with no Merchant Generation

No voltage stability problems were identified in this case. The transient stability plots in Figures 1 and 2 for a three-phase fault on the Hartburg – Mt.Olive 500 kV and Richard – Webre 500 kV lines show that the machines are stable and well damped.

Case 2 – Base case with Merchant Generation

A. Voltage Stability Analysis

The voltage stability plot or PV Curve for this case is shown in Figure 3. The X-axis of this plot is the power export level from the WOTAB area corresponding to the pre-contingency condition and the contingency of the four critical lines described earlier. The Y-axis represents the voltage at the Cane River 115 kV bus in the North Louisiana area. This station is representative of the voltage collapse occurring in that area. From the PV plot it can be observed that the most limiting contingency from the point of view of export from the area is the Hartburg – Mt. Olive 500 kV line. Based on the voltage decline guideline, the export limit from the area on the contingency of Hartburg-Mt. Olive line is 2100 MW. Figure 3 also shows that voltage collapse will eventually occur at about 3300 MW.

B. Transient/Dynamic Stability Analysis

The transient stability simulations were performed with the assumption that there are no Power System Stabilizers (PSS) installed on the proposed merchant generating units. The maximum export under this condition where the units are marginally damped was determined to be approximately 2700 MW. The stability plot for this simulation is shown in Figure 4. It was determined that export limits can be improved by adding PSS to the merchant generation. Henceforth, it will be a requirement that all new units in the area be equipped with stabilizers.

Conclusions:

The West of the Atchafalaya Basin (WOTAB) area can experience a voltage and dynamic stability problem if a significant amount of new merchant generation is operating in the area by year 2003. The export limit from this area is determined to be 2700 MW based on dynamic stability and 2100 MW based on voltage decline. As this area can experience dynamic problems beyond a certain export limit it will be mandatory for all IPPs in the area to install PSS on their units. Any *further* increase in the export level may require major upgrades, such as construction of 500 kV transmission lines.
The thermal limits were not evaluated in this study because they are source and sink specific and based on the generation dispatch. These limits will be evaluated when transmission service is requested and a System Impact Study is conducted.

APPENDIX A.C POLICY STATEMENT/GUIDELINES FOR POWER SYSTEM STABILIZER ON THE ENTERGY SYSTEM

Background:

A Power System Stabilizer (PSS) is an electronic feedback control that is a part of the excitation system control for generating units. The PSS acts to modulate the generator field voltage to damp the Power System oscillation.

Due to restructuring of the utility industry, there has been a significant amount of merchant generation activity on the Entergy system. These generators are typically equipped with modern exciters that have a high gain and a fast response to enhance transient stability. However, these fast response exciters, if used without stabilizers, can lead to oscillatory instability affecting local or regional reliability. This problem is exacerbated particularly in areas where there is a large amount of generation with limited transmission available for exporting power.

Stability studies carried out at Entergy have validated this concern. Furthermore, based on the understanding of operational problems experienced in the WSCC area over the last several years and the opinion of leading experts in the stability area, PSS are an effective and a low cost means of mitigating dynamic stability problems. In particular, PSS cost can be low if it is included in power plant procurement specifications.

Therefore, as a pre-emptive measure, Entergy requires all new generation (including affiliates and qualifying facilities) intending to interconnect to its transmission system to install PSS on their respective units.

The following guidelines shall be followed for PSS installation:

- PSS shall be installed on all new synchronous generators (50 MVA and larger) connecting to the transmission system that were put into service after January 1, 2000.

- PSS shall be installed on synchronous generators (50 MVA and larger) installed before January 1, 2000 subject to confirmation by Entergy that these units are good candidates for PSS and installing PSS on these units will enhance stability in the region. The decision to install PSS on a specific unit will be based on the effectiveness of the PSS in controlling oscillations, the suitability of the excitation system, and cost of retrofitting.

- In areas where a dynamic stability problem has not been explicitly identified, all synchronous generators (50 MVA and larger) will still be required to install stabilizers. However, in such cases the tuning will not be required and the stabilizer may remain disconnected until further advised by Entergy.

- Need for testing and tuning of PSS on units requesting transmission service from areas where stability problem has not been explicitly identified will be determined on an as-needed basis as part of transmission service study.

- The plants are responsible for testing and tuning of exciter and stabilizer controls for optimum performance and providing PSS model and data for use with PSS/E stability program.

- PSS equipment shall be tested and calibrated in conjunction with automatic voltage regulation (AVR) testing and calibration at-least every five years in accordance with the NERC Compliance Criteria on Generator Testing. PSS re-calibration must be performed if AVR parameters are modified.

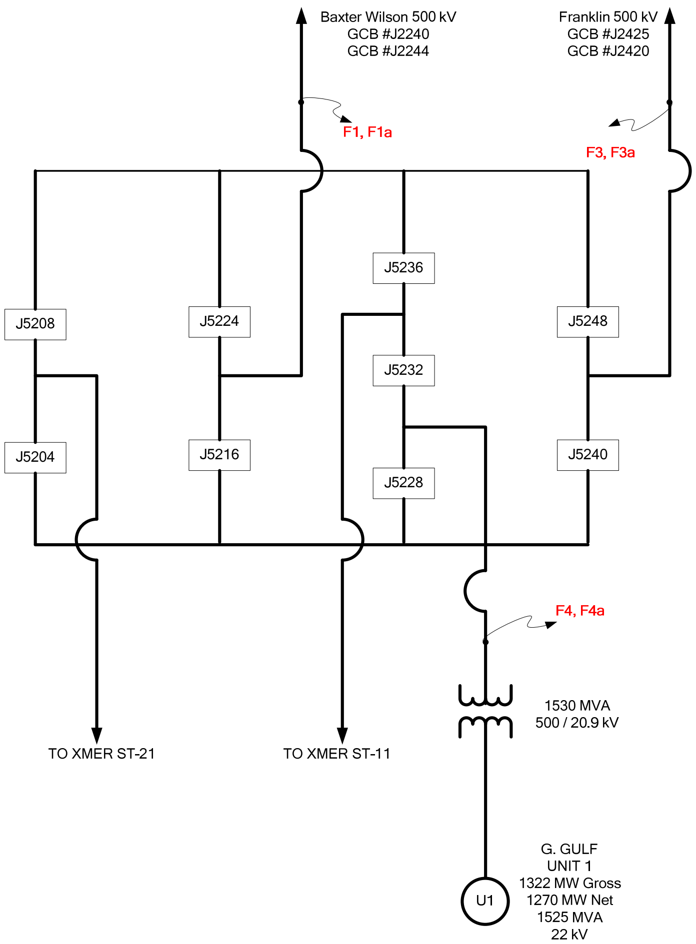
- The PSS equipment to be installed is required to be of the Delta-P-omega type.

References:

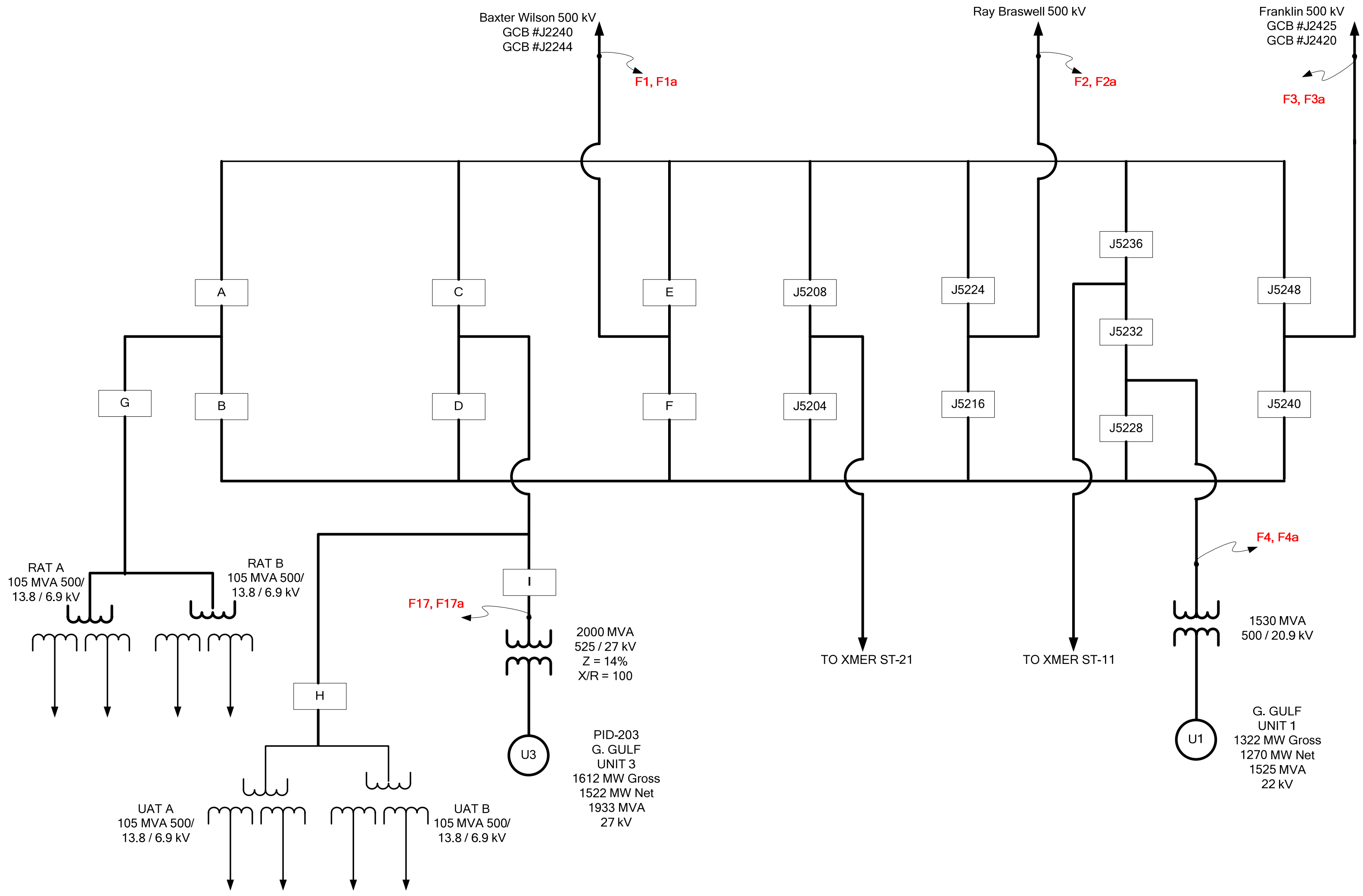
WOTAB Area Stability Study for the Entergy System
WSCC Draft Policy Statement on Power System Stabilizers
PSEC Application Notes: Power System Stabilizer helps need plant stability margins for Simple Cycle and Combined Cycle Power Plants

APPENDIX A.D SUBSTATION CONFIGURATION WITH AND WITHOUT PID-203

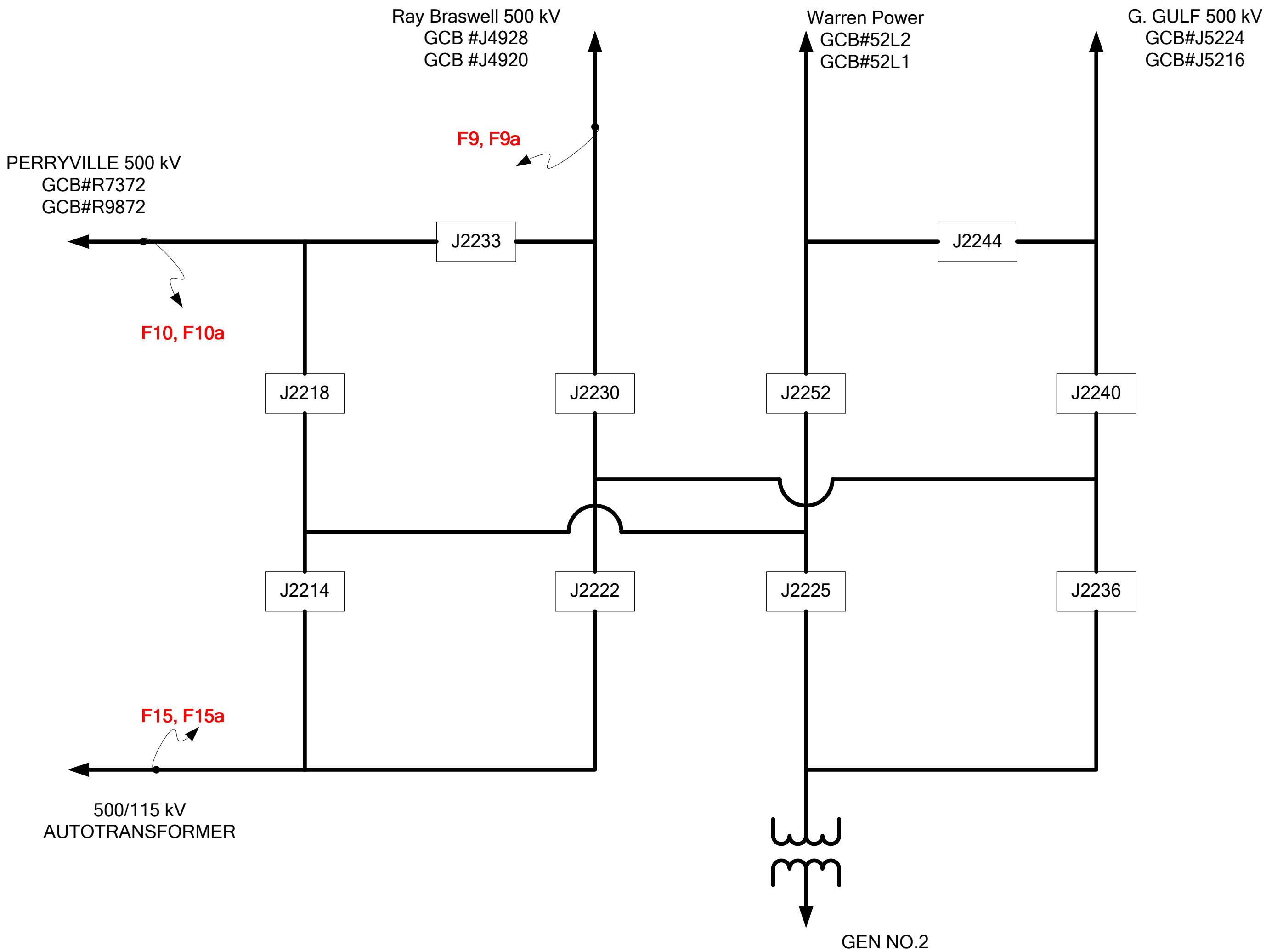
Bus configuration for G. Gulf 500 kV substation PRE-PID-203



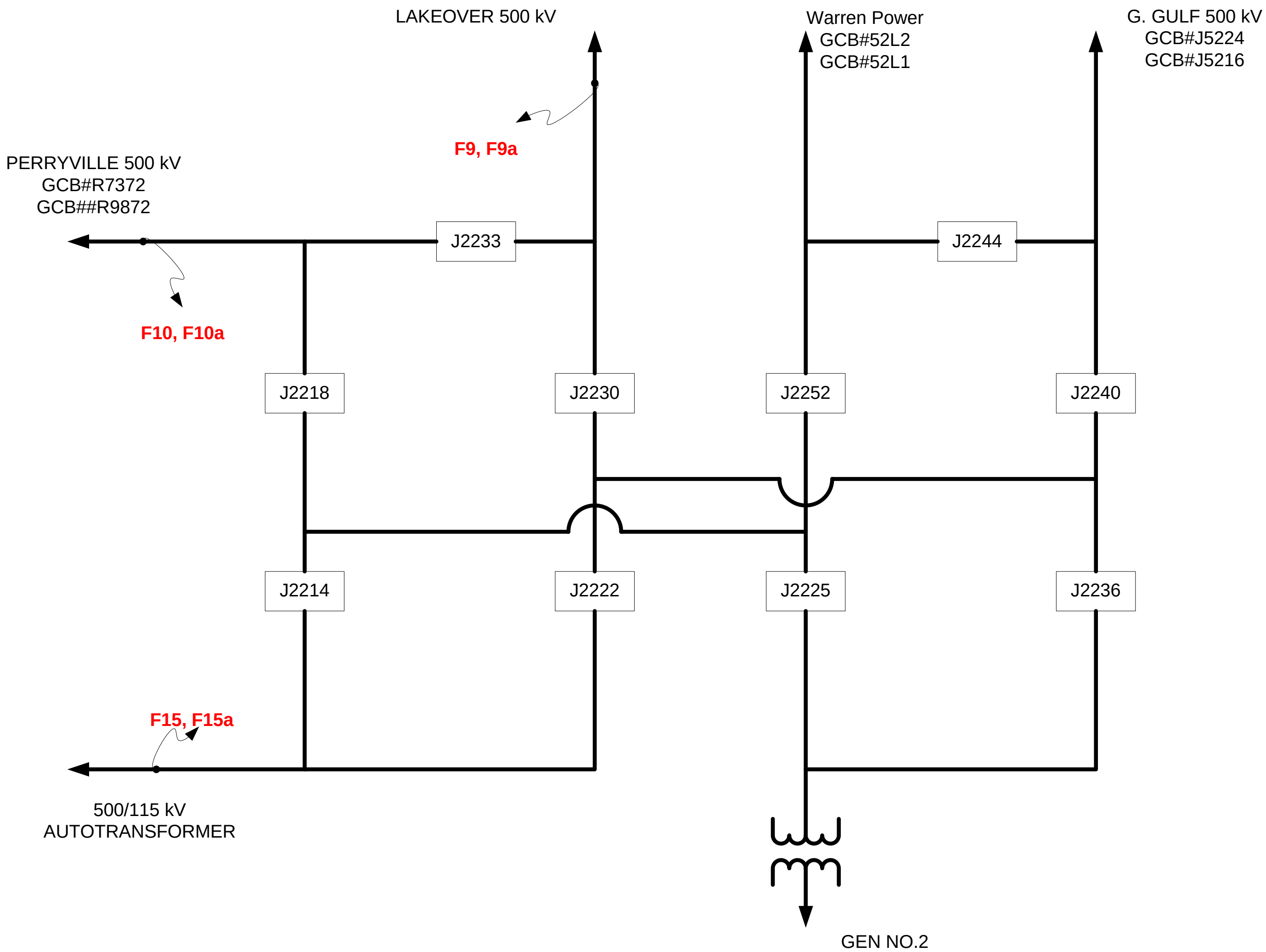
Bus configuration for G. Gulf 500 kV substation POST-PID-203



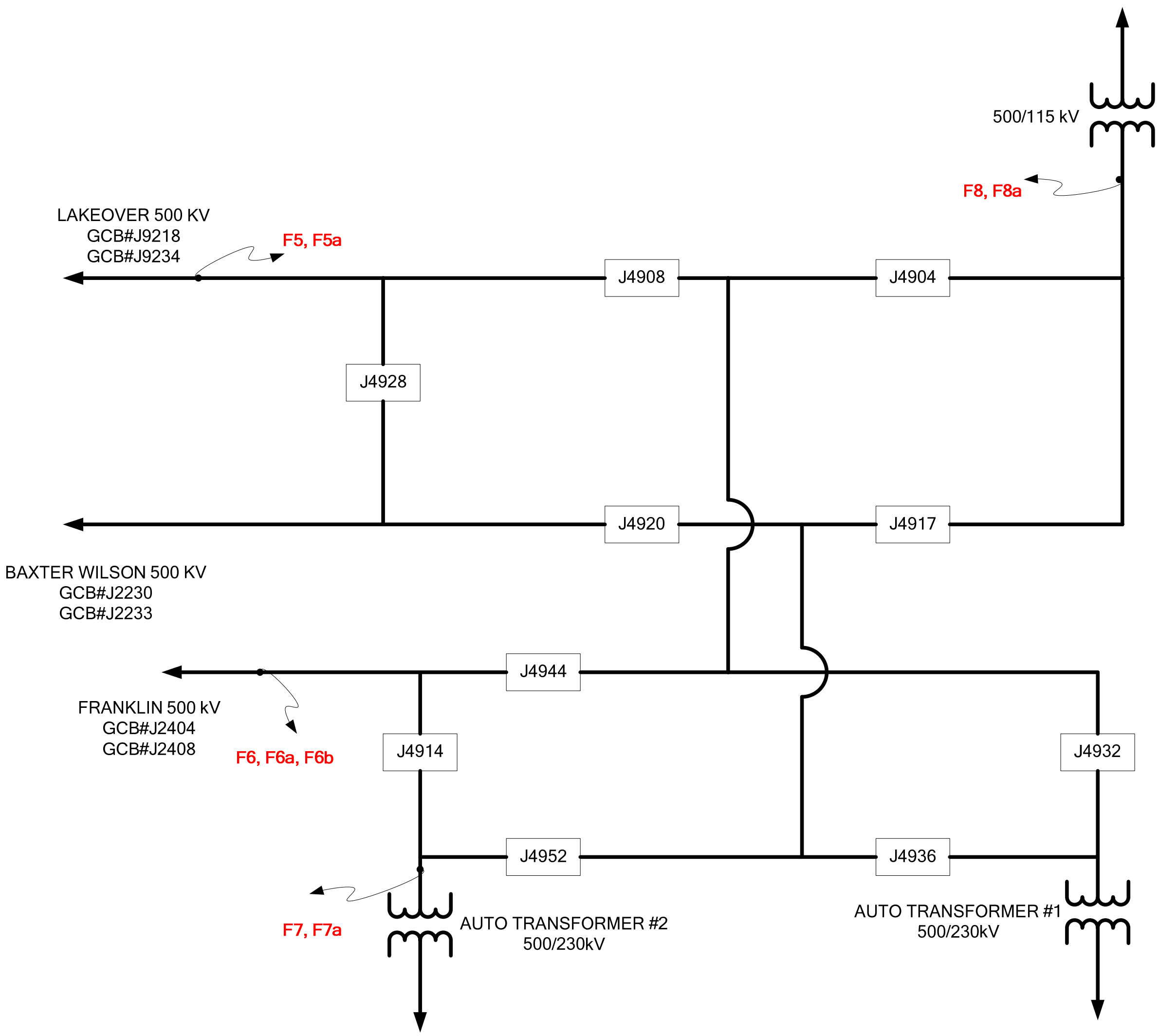
Bus configuration for B. Wilson 500 kV substation PRE-PID-203



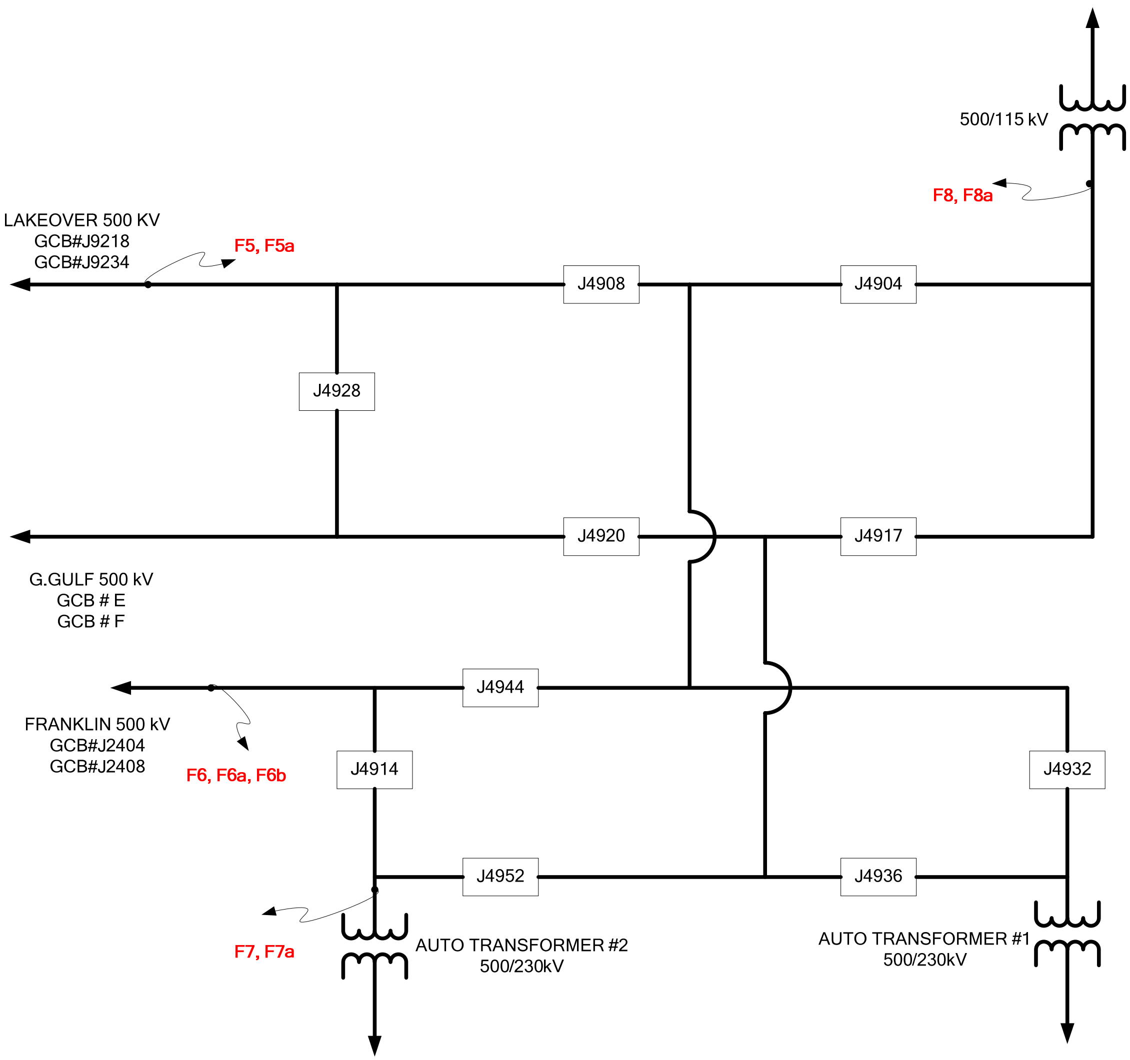
Bus configuration for B. Wilson 500 kV substation POST-PID-203



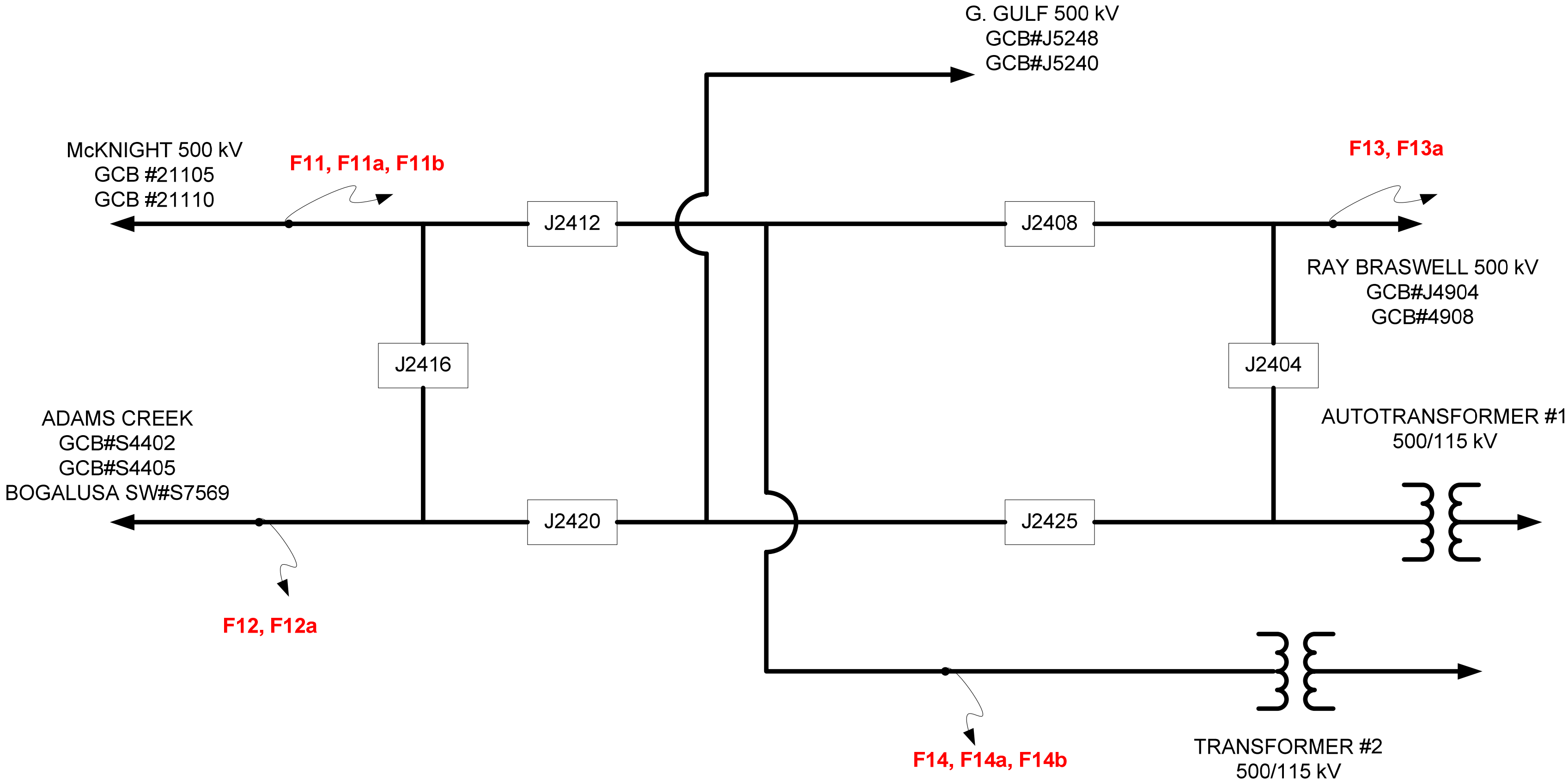
Bus configuration for Ray Braswell 500 kV substation PRE-PID-203



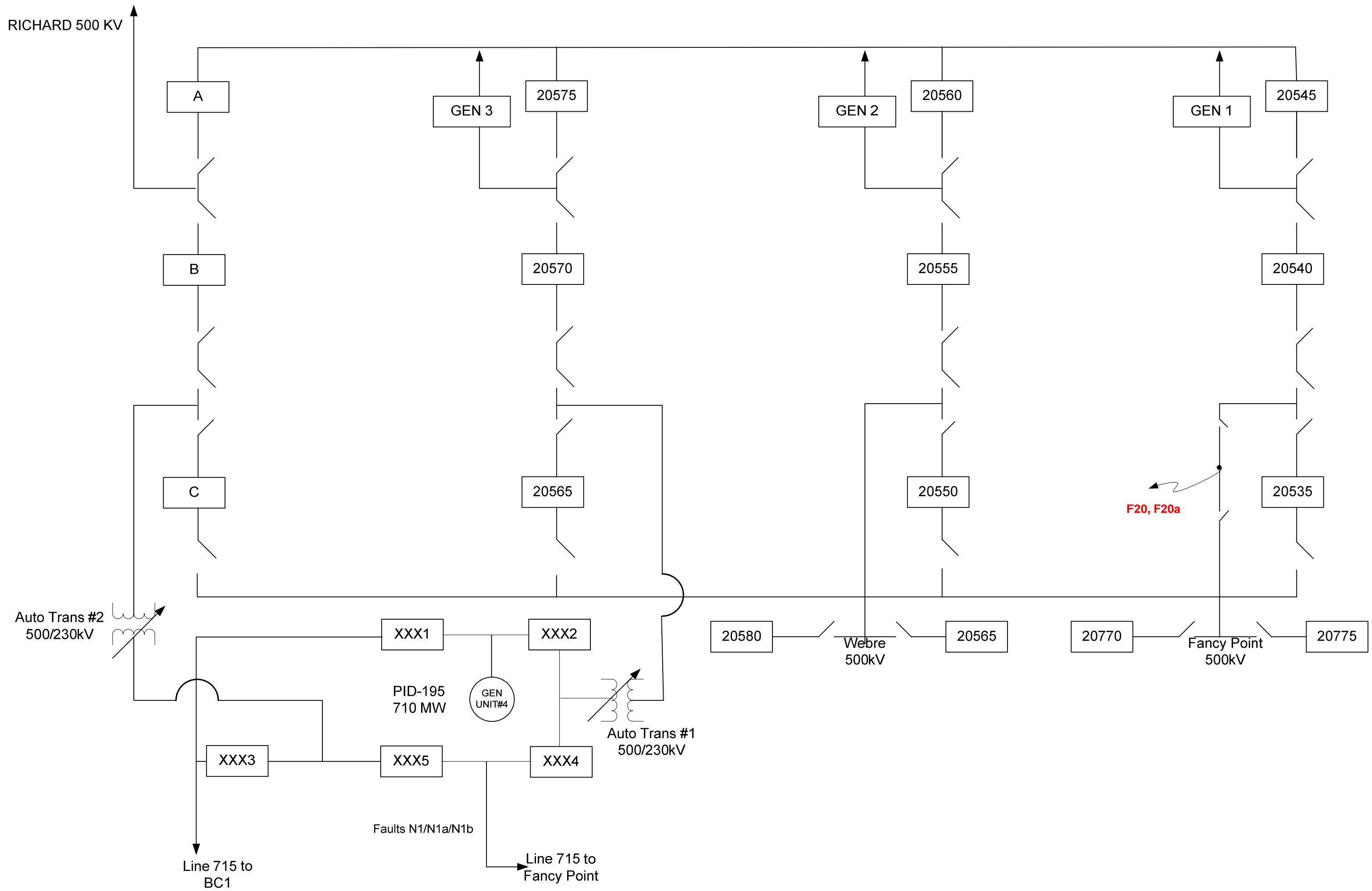
Bus configuration for Ray Braswell 500 kV substation POST-PID-203



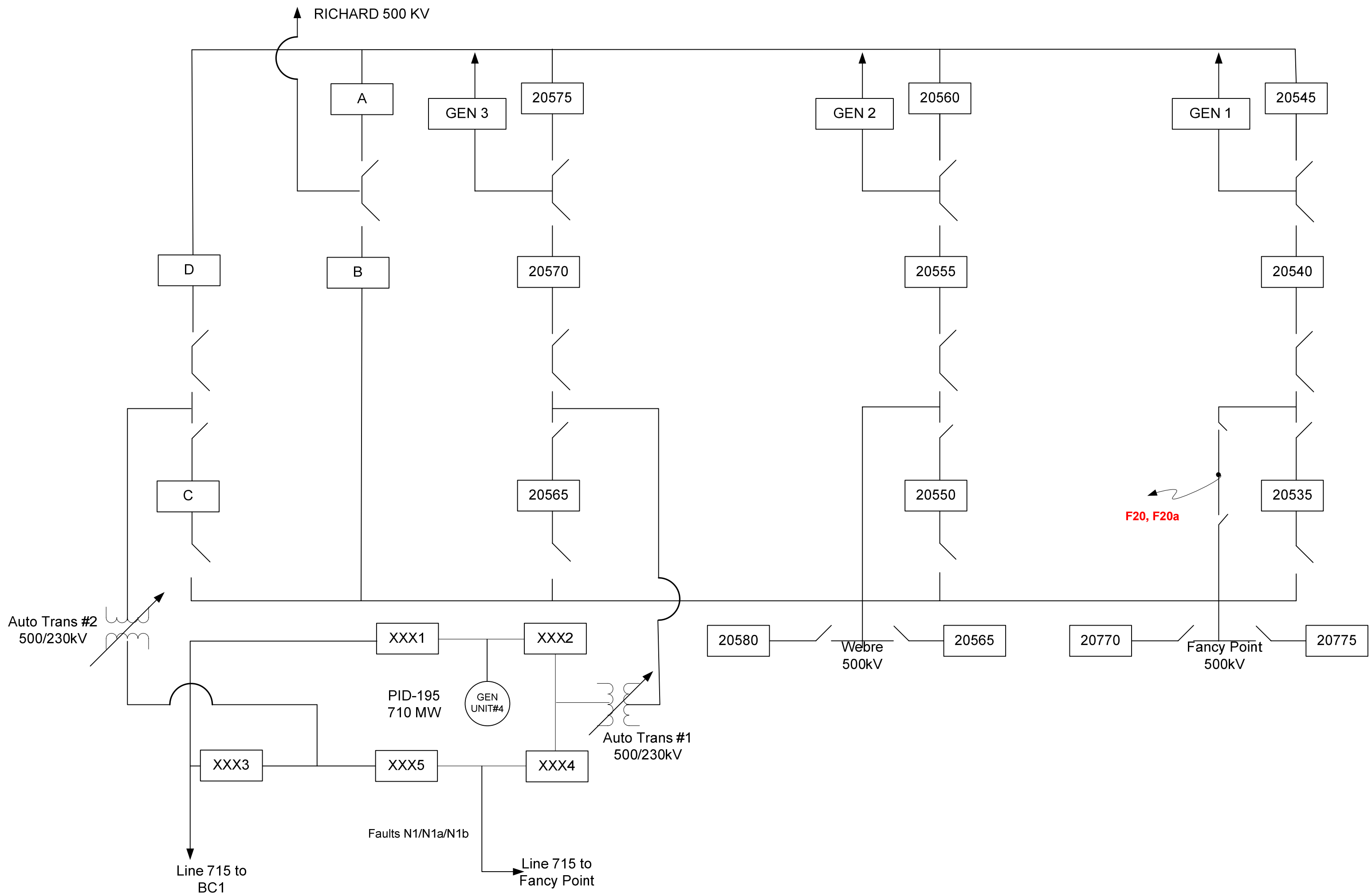
Bus configuration for Franklin 500 kV substation



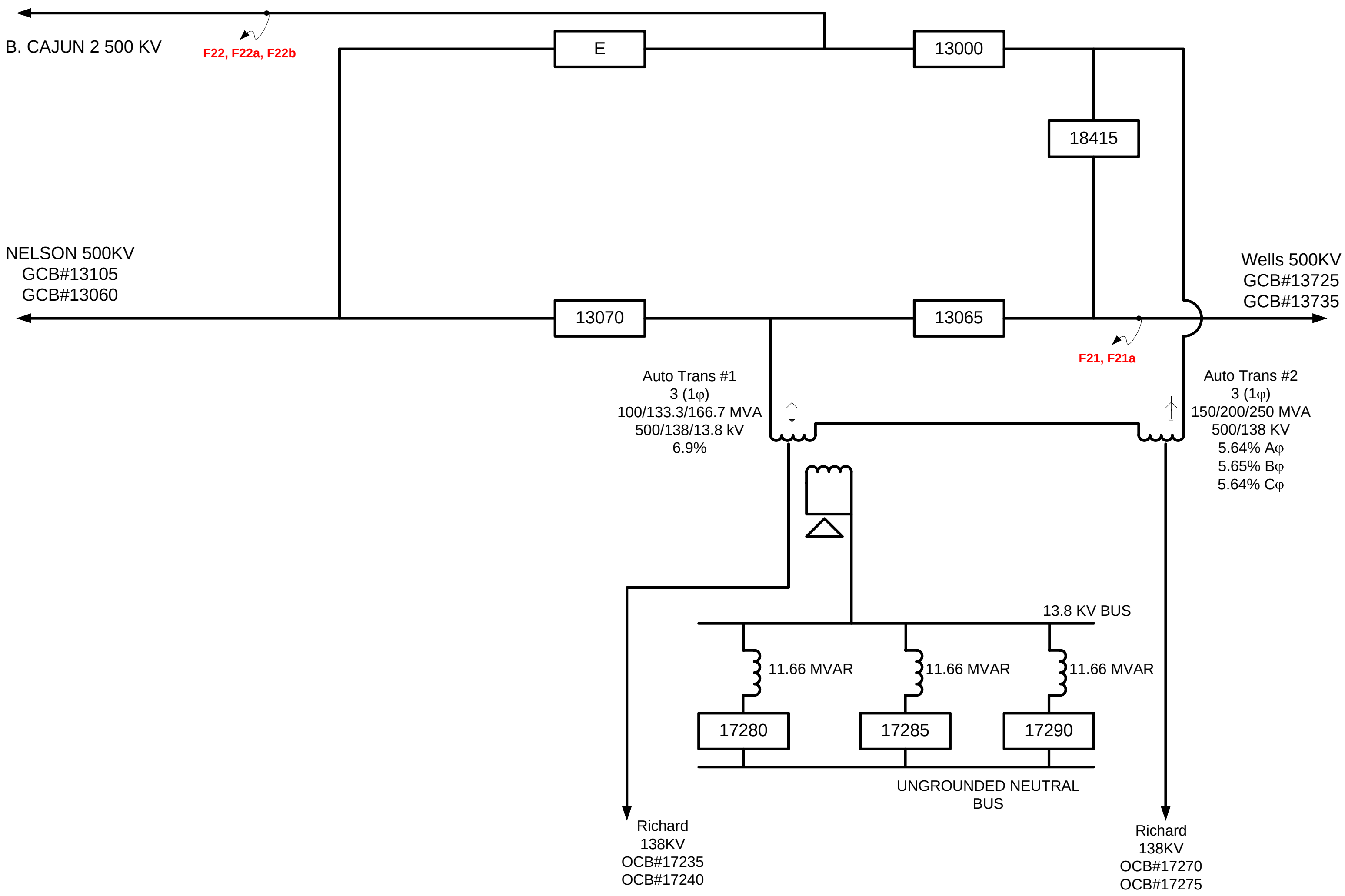
B. CAJUN 2 500 KV
(Option-1)



B. CAJUN 2 500 KV
(Option-2)



RICHARD 500 KV



APPENDIX A.E Transient Stability DATA & Plots

The Transient Stability and Data plots were removed from this report due to the size limitations. A copy of the full report can be found on the Entergy Oasis.

Section – B

Network Resource Interconnection Service

TABLE OF CONTENTS FOR SECTION –B (NRIS)

I. Introduction

A Network Resource Interconnection Services (NRIS) study was requested by PID-203 to serve 1522 MW of Entergy network load. The expected in service date for this NRIS generator is January 1, 2015. The tests were performed with only confirmed transmission reservations and existing network generators and with transmission service requests in study mode.

Two tests were performed, a deliverability to generation test and a deliverability to load test. The deliverability to generation (DFAX) test ensures that the addition of this generator will not impair the deliverability of existing network resources and units already designated as NRIS while serving network load. The deliverability to load test determines if the tested generator will reduce the import capability level to certain load pockets (Amite South, WOTAB and Western Region) on the Entergy system. A more detailed description for these two tests is described in Appendix B-A and Appendix B-B.

Also, it is understood that the NRIS status provides the Interconnection Customer with the capability to deliver the output of the Generating Facility into the Transmission System. NRIS in and of itself does not convey any right to deliver electricity to any specific customer or Point of Delivery

II. Load Flow Analysis

A. Models

The models used for this analysis were the 2012 summer and winter peak cases developed in September 2006.

The following modifications were made to the base cases to reflect the latest information available:

- Non-Firm IPPs within the local region of the study generator were turned off and other non-firm IPPs outside the local area were increased to make up the difference.
- Confirmed firm transmission reservations were modeled for the year 2015. These request are shown below.

OASIS#	PSE	POR	POD	Sink	MW	Service	Begin	End
1412068	NRG	EES	AMRN	AMRN	103	Long-Term Firm PTP	01/01/07	01/01/08
1413110	NRG	EES	LAGN	LAGN	100	Yearly Network - Designated Resources	01/01/07	01/01/09
1416650	NRG	AMRN	LAGN	LAGN	100	Yearly Network - Designated Resources	01/01/07	01/01/08
1422496	Constellation Commodities Group	EES	DENL	DENL	57	Yearly Network - Designated Resources	01/01/07	01/01/08
1424384	Constellation Commodities Group	TVA	DENL	DENL	100	Yearly Network - Designated Resources	01/01/07	01/01/08
1431165	Cargill Alliant	AMRN	SOCO	SOCO	103	Long-Term Firm PTP	01/01/08	01/01/09
1435973	Entergy Services, Inc. (EMO)	EES	EES	ENTEMO	135	Yearly Network - Designated Resources	05/01/08	05/01/10
1435323	Constellation Commodities Group	EES	EES	BENTON	74	Yearly Network - Designated Resources	04/01/07	04/01/08

- Approved transmission reliability upgrades for 2007 - 2010 were included in the base case. These upgrades can be found at Entergy's OASIS web page, http://www.entergy.com/etroasis/, under approved future projects.
- The output of Big Cajun 2 units was increased to reflect there NITS and firm point to point transfers from that unit. To do this, the output of Bayou Cove was reduced to 0MW and

Ouachita’s output was reduced from 270MW to 70. The transfer from EES to LAGN was also reduced by 200MW to 263MW.

- The load in zones 100 - 199 and 500 - 998 was reduced by 1522MW.
- All of the non-firm IPP’s were turned off.
- The output of Baxter Wilson Unit 2 was reduced to its firm level of 655MW.

Transfer analysis was performed from Grand Gulf to loads in zone 100 – 199 and 500 – 998 using MUST.

Another model was created to include all prior transmission service requests in study mode and prior NRIS interconnection generators. The prior transmission service requests that were included in this study:

OASIS #	**Customer**	**POR**	**POD**	**MW**	**Begin**	**End**
1365013	East Texas Electric Cooperative Inc.	LAGN	EES	75	3/1/2010	3/1/2045
1382405	City of North Little Rock	LAGN	DENL	60	12/1/2009	12/1/2039
1402295	SMEPA	LAGN	EES	75	6/1/2009	6/1/2029
1406786	SMEPA	EES	EES	100	4/1/2010	4/1/2040
1408199	SMEPA	EES	EES	100	4/1/2010	4/1/2040
1413255	American Electric Power Service Corp.	PUPP	CSWS	225	1/1/2007	1/1/2010
1413580	City of Conway	LAGN	CNWY	50	1/1/2011	1/1/2047
1416723	Midwest Energy	EES	EDE	50	5/1/2010	5/1/2040
1416727	Midwest Energy	EES	EDE	25	5/1/2010	5/1/2040
1416729	Midwest Energy	EES	EDE	10	5/1/2010	5/1/2040
1418968	City of West Memphis	LAGN	WMUC	15	1/1/2010	1/1/2040
1435303	East Texas Electric Cooperative Inc.	EES	EES	150	1/1/2010	1/1/2040

The NRIS interconnection generators are:

PID	Substation	MW	In Service Date
195	Big Cajun 2	710	6/1/2009
198	San Souci	700	6/1/2011

In setting up the cases, all non-firm generators serving EES load, in close proximity to the study generator were dispatched to their confirmed generation output. The generators Big Cajun2 Unit 4 and Plum Point were turned on to the amount requested in the interconnection requests, and then the transmission service requests were scheduled. The remaining generation was absorbed in Entergy’s control area 151 by first reducing the non-firm IPPs and then non-firm Entergy owned units. Loads in zones 100 -199 and 500 -998 were reduced from 24991MW to 24101MW. This allowed for turning off all non-firm generation in the model. A 1522MW transfer analysis was then simulated to zones 100 -199 and 500 -998 using MUST.

B. Contingencies and Monitored Elements

Single contingency analyses on Entergy's transmission facilities (including tie lines) 115kV and above were considered. All transmission facilities on Entergy transmission system above 100 kV were monitored.

C. Generation used for the transfer

The PID-203 generators were used as the source for the "from generation" test for deliverability.

III. Results

A. Deliverability to Generation (DFAX) Test:

The deliverability to generation (DFAX) test ensures that the addition of this generator will not impair the deliverability of existing network resources and units already designated as NRIS while serving network load. A more detailed description for these two tests is described in Appendix B-A and Appendix B-B.

Table III-1 Summary of Results of DFAX Test

Study Case	Study Case with Priors
Baxter Wilson - Grand Gulf 500kV	Baxter Wilson - Grand Gulf 500kV
Baxter Wilson - Ray Braswell 500kV	Baxter Wilson - Ray Braswell 500kV
Franklin - Grand Gulf 500kV	Franklin - Grand Gulf 500kV
Downsville - Sterlington 115kV	Webre - Wells 500kV
Webre - Wells 500kV	
Wells 500/230kV transformer	

Table III-2 DFAX Study Case Results without priors:

Limiting Element	Contingency Element	ATC(MW)
Webre - Wells 500kV	Eldorado EHV - Mount Olive 500kV	0
Wells 500/230kV transformer	Richard - Wells 500kV	0
Webre - Wells 500kV	Baxter Wilson - Perryville 500kV	0
Webre - Wells 500kV	Hartburg - Mount Olive 500kV	0
Webre - Wells 500kV	Eldorado EHV - Sterlington 500kV	0
Webre - Wells 500kV	Livonia - Wilbert 138kV	44
Webre - Wells 500kV	Baxter Wilson - Grand Gulf 500kV	245
Webre - Wells 500kV	Livonia - Line 642 Tap 138kV	263
Webre - Wells 500kV	Krotz Spring - Line 642 Tap 138kV	293
Webre - Wells 500kV	Greenwood - Terrebone 115kV	329
Webre - Wells 500kV	Grimes - Frontier 345kV	478
PPG - Verdine 230kV	Carlyss - Roy S. Nelson 230kV	663
Baxter Wilson - Ray Braswell 500kV	Franklin - Grand Gulf 500kV	764
Hartburg - Inland Orange 230kV	Cypress - Hartburg 500kV	1144
Webre - Wells 500kV	Base Case	1161
Baxter Wilson - Grand Gulf 500kV	Franklin - Grand Gulf 500kV	1334
Franklin - Grand Gulf 500kV	Baxter Wilson - Grand Gulf 500kV	1334
Downsville - Sterlington 115kV	Eldorado EHV - Sterlington 500kV	1347

Table III-3 DFAX Study Case with Priors Results:

Limiting Element	Contingency Element	ATC(MW)
PPG - Verdine 230kV	Carlyss - Roy S. Nelson 230kV	437
Baxter Wilson - Ray Braswell 500kV	Franklin - Grand Gulf 500kV	649
Webre - Wells 500kV	Big Cajun 2 - Richard 230kV	1047
Webre - Wells 500kV	Richard 500/230kV transformer	1078
Hartburg - Inland Orange 230kV	Cypress - Hartburg 500kV	1203
Baxter Wilson - Grand Gulf 500kV	Franklin - Grand Gulf 500kV	1334
Franklin - Grand Gulf 500kV	Baxter Wilson - Grand Gulf 500kV	1334
Webre - Wells 500kV	Baxter Wilson - Perryville 500kV	1337
Webre - Wells 500kV	Eldorado EHV - Mount Olive 500kV	1411

To alleviate the constrained identified in Tables III-2 & 3 a second iteration of DFAX test was performed with the following upgrades included in the model and results are listed in Table III-4 & 5:

1. Build 48 miles 500kV transmission line from Grand Gulf 500kV to Ray Braswell 500kV.
2. Remove the existing Baxter Wilson to Ray Braswell 500kV line from Ray Braswell substation, and extend this line 22 miles to Lake Over 500kV.
3. Build 56mile 500kV line from Webre 500kV to Richard 500kV

With priors, the following upgrades were needed:

1. Build 48 miles 500kV transmission line from Grand Gulf 500kV to Ray Braswell 500kV.
2. Remove the existing Baxter Wilson to Ray Braswell 500kV line from Ray Braswell substation, and extend this line 22 miles to Lake Over 500kV.
3. Add a 2nd 500/230kV transformer at the new Audubon 230kV substation connecting to Big Cajun 2 500kV substation and build 70 miles 500kV line from Big Cajun 2 500kV to Richard 500kV. This will replace the proposed NRIS upgrade at Big Cajun 2, a 230kV line from Big Cajun 2 230kV to Richard 230kV line.

Table III-4 DFAX Study Case Results without Priors:

Limiting Element	**Contingency Element**	**ATC(MW)**
PPG - Verdine 230kV	Carlyss - Roy S. Nelson 230kV	626
Hartburg - Inland Orange 230kV	Cypress - Hartburg 500kV	1027
Webre - Wells 500kV	Richard - Webre 500kV	1232

Table III-5 DFAX Study Case with Priors Results:

Limiting Element	**Contingency Element**	**ATC(MW)**
PPG - Verdine 230kV	Carlyss - Roy S. Nelson 230kV	275
Cypress 500/138kV transformer 1	Cypress 500/230kV transformer	620
Hartburg - Inland Orange 230kV	Cypress - Hartburg 500kV	1087
Webre - Wells 500kV	Big Cajun 2 - Richard 500kV	1129
Richard 500/138kV transformer 2	Roy S. Nelson - Richard 500kV	1448
Cypress 500/230kV transformer	Cypress 500/138kV transformer 1	1469

B. Deliverability to Load Test:

The deliverability to load test determines if the tested generator will reduce the import capability level to certain load pockets (Amite South, WOTAB and Western Region) on the Entergy system. A more detailed description for these two tests is described in Appendix B-A and Appendix B-B.

Amite South: Passed

WOTAB: Passed

Western Region: Passed

IV. Required Upgrades for NRIS

Preliminary Estimates of Direct Assignment of Facilities and Network Upgrades

<table>
<tr><th>Limiting Element</th><th>Planning Estimate for Upgrade</th></tr>
<tr><td>Baxter Wilson - Grand Gulf 500kV</td><td rowspan="4">With or Without Priors:
Build 48 miles 500kV from Grand Gulf to Ray Braswell, $97,000,000
Remove Baxter Wilson – Ray Braswell 500kV line from Ray Braswell and extend it 22 miles to Lake Over 500kV, $44,000,000</td></tr>
<tr><td>Baxter Wilson - Ray Braswell 500kV</td></tr>
<tr><td>Franklin - Grand Gulf 500kV</td></tr>
<tr><td>Downsville - Sterlington 115kV</td></tr>
<tr><td>Webre - Wells 500kV</td><td rowspan="2">Without Priors:
Build 56 miles 500kV line from Webre 500kV to Richard 500kV, $151,000,000

With Priors:
Build 70 miles 500kV line from Big Cajun 2 500kV to Richard 500kV, and add 2nd 500/230kV transformer at Audubon 230kV substation connecting to Big Cajun 2 500kV. $175,000,000</td></tr>
<tr><td>Wells 500/230kV transformer</td></tr>
</table>

The costs of the upgrades are planning estimates only. Detailed cost estimates, accelerated costs and solutions for the limiting elements will be provided in the facilities study.

APPENDIX B.A - Deliverability Test for Network Resource Interconnection Service Resources

1. Overview

Entergy will develop a two-part deliverability test for customers (Interconnection Customers or Network Customers) seeking to qualify a Generator as an NRIS resource: (1) a test of deliverability “from generation”, that is out of the Generator to the aggregate load connected to the Entergy Transmission system; and (2) a test of deliverability “to load” associated with sub-zones. This test will identify upgrades that are required to make the resource deliverable and to maintain that deliverability for a five year period.

1.1 The “From Generation” Test for Deliverability

In order for a Generator to be considered deliverable, it must be able to run at its maximum rated output without impairing the capability of the aggregate of previously qualified generating resources (whether qualified at the NRIS or NITS level) in the local area to support load on the system, taking into account potentially constrained transmission elements common to the Generator under test and other adjacent qualified resources. For purposes of this test, the resources displaced in order to determine if the Generator under test can run at maximum rated output should be resources located outside of the local area and having insignificant impact on the results. Existing Long-term Firm PTP Service commitments will also be maintained in this study procedure.

1.2 The “To Load” Test for Deliverability

The Generator under test running at its rated output cannot introduce flows on the system that would adversely affect the ability of the transmission system to serve load reliably in import-constrained sub-zones. Existing Long-term Firm PTP Service commitments will also be maintained in this study procedure.

1.3 Required Upgrades.

Entergy will determine what upgrades, if any, will be required for an NRIS applicant to meet deliverability requirements pursuant to Appendix B-B.

Appendix B.B – NRIS Deliverability Test

Description of Deliverability Test

Each NRIS resource will be tested for deliverability at peak load conditions, and in such a manner that the resources it displaces in the test are ones that could continue to contribute to the resource adequacy of the control area in addition to the studied resources. The study will also determine if a unit applying for NRIS service impairs the reliability of load on the system by reducing the capability of the transmission system to deliver energy to load located in import-constrained sub-zones on the grid. Through the study, any transmission upgrades necessary for the unit to meet these tests will be identified.

Deliverability Test Procedure:

The deliverability test for qualifying a generating unit as a NRIS resource is intended to ensure that 1) the generating resource being studied contributes to the reliability of the system as a whole by being able to, in conjunction with all other Network Resources on the system, deliver energy to the aggregate load on the transmission system, and 2) collectively all load on the system can still be reliably served with the inclusion of the generating resource being studied.

The tests are conducted for “peak” conditions (both a summer peak and a winter peak) for each year of the 5-year planning horizon commencing in the first year the new unit is scheduled to commence operations.

1) Deliverability of Generation

The intent of this test is to determine the deliverability of a NRIS resource to the aggregate load on the system. It is assumed in this test that all units previously qualified as NRIS and NITS resources are deliverable. In evaluating the incremental deliverability of a new resource, a test case is established. In the test case, all existing NRIS and NITS resources are dispatched at an expected level of generation (as modified by the DFAX list units as discussed below). Peak load withdrawals are also modeled as well as net imports and exports. The output from generating resources is then adjusted so as to “balance” overall load and generation. This sets the baseline for the test case in terms of total system injections and withdrawals.

Incremental to this test case, injections from the proposed new generation facility are then included, with reductions in other generation located outside of the local area made to maintain system balance.

Generator deliverability is then tested for each transmission facility. There are two steps to identify the transmission facilities to be studied and the pattern of generation on the system:

1) Identify the transmission facilities for which the generator being studied has a 3% or greater distribution factor.

2) For each such transmission facility, list all existing qualified NRIS and NITS resources having a 3% or greater distribution factor on that facility. This list of units is called the Distribution Factor or DFAX list.

For each transmission facility, the units on the DFAX list with the greatest impact are modeled as operating at 100% of their rated output in the DC load flow until, working down the DFAX list, a 20% probability of all units being available at full output is reached (e.g. for 15 generators with a Forced Outage Rate of 10%, the probability of all 15 being available at 100% of their rated output is 20.6%). Other NRIS and NITS resources on the system are modeled at a level sufficient to serve load and net interchange.

From this new baseline, if the addition of the generator being considered (coupled with the matching generation reduction on the system) results in overloads on a particular transmission facility being examined, then it is not "deliverable" under the test.

2) Deliverability to Load

The Entergy transmission system is divided into a number of import constrained sub-zones for which the import capability and reliability criteria will be examined for the purposes of testing a new NRIS resource. These sub-zones can be characterized as being areas on the Entergy transmission system for which transmission limitations restrict the import of energy necessary to supply load located in the sub-zone.

The transmission limitations will be defined by contingencies and transmission constraints on the system that are known to limit operations in each area, and the sub-zones will be defined by the generation and load busses that are impacted by the contingent transmission lines. These sub-zones may change over time as the topology of the transmission system changes or load grows in particular areas.

An acceptable level of import capability for each sub-zone will have been determined by Entergy Transmission based on their experience and modeling of joint transmission and generating unit contingencies. Typically the acceptable level of transmission import capacity into the sub-zones will be that which is limited by first-contingency conditions on the transmission system when generating units within the sub-region are experiencing an abnormal level of outages and peak loads.

The "deliverability to load" test compares the available import capability to each sub-zone that is required for the maintaining of reliable service to load within the sub-zone both with and without the new NRIS resource operating at 100% of its rated output. If the new NRIS resource does not reduce the sub-zone import capability so as to reduce the reliability of load within the sub-zone to an unacceptable level, then the deliverability to load test for the unit is satisfied. This test is conducted for a 5-year planning cycle. When the new NRIS resource fails the test, then transmission upgrades will be identified that would allow the NRIS unit to operate without degrading the sub-zone reliability to below an acceptable level.

Other Modeling Assumptions:

1) Modeling of Other Resources

Generating units outside the control of Entergy (including the network resources of others, and generating units in adjacent control areas) shall be modeled assuming "worst case" operation of the units – that is, a pattern of dispatch that reduces the sub-zone import capability, or impact the common limiting flowgates on the system to the greatest extent for the "from generation" deliverability test.

2) Must-run Units

Must-run units in the control area will be modeled as committed and operating at a level consistent with the must-run operating guidelines for the unit.

3) Base-line Transmission Model

The base-line transmission system will include all transmission upgrades approved and committed to by Entergy Transmission over the 5-year planning horizon. Transmission line ratings will be net of TRM and current CBM assumptions will be maintained.