Impact Re-Study
For
Generation Interconnection
Request
GEN-2006-014

SPP Tariff Studies
(#GEN-2006-014)

January, 2008

Executive Summary

Southwest Power Pool has performed this Impact Re-Study for the purpose of interconnecting 300 MW of wind generation within the control area of Missouri Public Utilities (d/b/a Aquila Networks – Missouri Public Service) (MIPU) located in Atchison County, Missouri. The proposed method of interconnection is a new 161 kV ring-bus switching station to be located on the existing Maryville – Midway 161 kV transmission line, owned by MIPU. The proposed in-service date is May 31, 2008. This Impact Re-Study was caused by a change in status of two prior queued projects.

Power flow analysis has indicated that for the powerflow cases studied, it is possible to interconnect the 300 MW of generation with transmission system reinforcements within the local transmission system. In order to maintain acceptable reactive power compensation, the customer will be required to pay for the installation of a combined total of at least 75 Mvar of 34.5 kV capacitor bank(s) to be installed in the Customer's collector substation.

The requirement to interconnect the 300 MW of wind generation on the existing Maryville – Midway 161 kV transmission line consists of constructing a new 161 kV three-breaker ring-bus switching station with terminals to Midway, Maryville and the Customer Generating Facility. The new station will be constructed and maintained by MIPU.

The total minimum cost for building the required facilities for this 300 MW of generation is $3,500,000 and is detailed in the Facility Study for this request that was posted in July, 2007. Network constraints in the Associated Electric Cooperatives, Inc. (AECI), Kansas City Power & Light (KCPL), MIPU and Westar Energy (WERE) transmission systems that were identified are shown in Table 3. These Network constraints will have to be verified with a Transmission Service Request (TSR) and associated studies. Network Constraints are in the local area of the new generation when this generation is sunk throughout the SPP footprint for the Energy Resource (ER) Interconnection request. With a defined source and sink in a Transmission Service Request, this list of Network Constraints will be refined and expanded to account for all Network Upgrade requirements. This cost does not include building the 161 kV line from the Customer 161/34.5 kV collector substation into the point of interconnection. This cost also does not include the Customer's 161/34.5 kV collector substation or the 34.5 kV, 75 Mvar capacitor bank(s).

In Table 4, a value of Available Transfer Capability (ATC) associated with each overloaded facility is included. These values may be used by the Customer for future analyses including the determination of lower generation capacity levels that may be installed. When transmission service associated with this interconnection is evaluated, the loading of the facilities listed in this table may be greater due to higher priority reservations. If the loading of a facility is higher, the level of ATC will be lower.

A transient stability analysis conducted for this generation interconnection request found that the wind farm will stay on line and the transmission system will remain stable for all studied contingencies. This analysis was based on the assumption that the wind farm will be using General Electric 1.5 MW wind turbines with the manufacturer's LVRT II package for low voltage ride through. The wind farm, while using these GE wind turbines with the LVRT II package will meet FERC Order 661A low voltage ride through provisions.

There are several other proposed generation additions in the general area of the Customer's facility. It was assumed in this preliminary analysis that not all of these other projects within the AECI and KCPL control areas will be in service. Those previously queued projects that have advanced to nearly complete phases were included in this Impact Study. In the event that another request for a generation interconnection with a higher priority withdraws, then this request may have to be re-evaluated to determine the local Network Constraints.

The required interconnection costs listed in Tables 1 and 2 and other upgrades associated with Network Constraints do not include all costs associated with the deliverability of the energy to final customers. These costs are determined by separate studies if the Customer submits a Transmission Service Request through Southwest Power Pool's OASIS.

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Introduction

Southwest Power Pool has performed this Impact Re-Study for the purpose of interconnecting 300 MW of wind generation within the control area of Missouri Public Utilities (d/b/a Aquila Networks – Missouri Public Service) (MIPU) located in Atchison County, Missouri. The proposed method of interconnection is a new 161 kV ring-bus switching station to be located on the existing Maryville – Midway 161 kV transmission line, owned by MIPU. The proposed in-service date is May 31, 2008. This Impact Re-Study was caused by a change in status of two prior queued projects.

Interconnection Facilities

The primary objective of this study is to identify the system problems associated with connecting the plant to the area transmission system. The Feasibility and other subsequent Interconnection Studies are designed to identify attachment facilities, Network Upgrades and other Direct Assignment Facilities needed to accept power into the grid at the interconnection receipt point.

The requirements for interconnection of the 300 MW consist of constructing a new 161 kV three-breaker ring-bus switching station on the existing Maryville – Midway 161 kV transmission line, owned by MIPU. This substation will be constructed and maintained by MIPU. A preliminary one-line drawing of the interconnection facilities are shown in Figure 1.

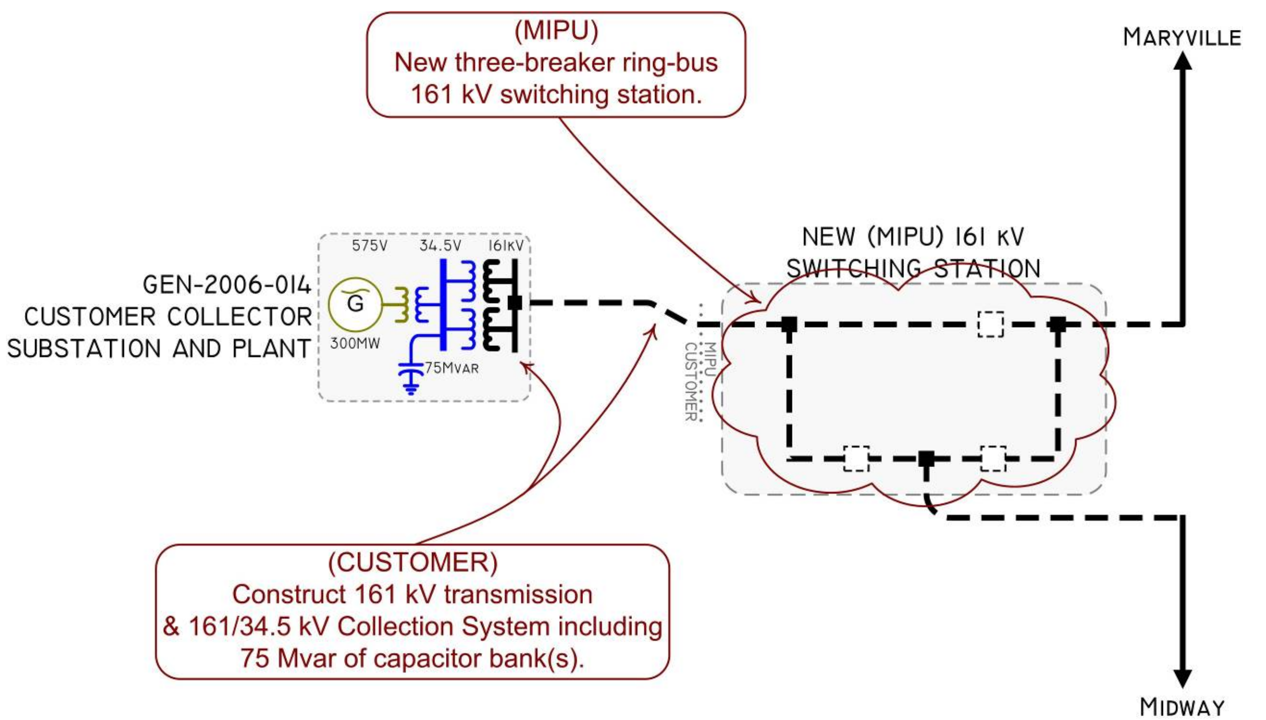


Figure 1: Proposed Method of Interconnection

(Final design to be determined)

Interconnection Estimated Costs

The minimum cost for adding a new breaker and terminating the transmission line serving GEN-2006-014 facilities is estimated at $3,500,000. These costs are detailed in the Facility Study for this request posted in July, 2007. This cost does not include building the Customer's 161 kV transmission line extending from the point of interconnection to serve its 161/34.5 kV collection facilities. This cost also does not include the Customer's 161/34.5 kV collector substation or the 75 Mvar of capacitor bank(s), all of which should be determined by the Customer. The Customer is responsible for these 161 kV – 34.5 kV facilities up to the point of interconnection. Other Network Constraints in the Associated Electric Cooperatives, Inc. (AECI), Kansas City Power & Light (KCPL), MIPU and Westar Energy (WERE) transmission systems that were identified are shown in Table 3.

These costs do not include any cost that might be associated with short circuit study results or dynamic stability study results. These costs will be determined when and if a System Impact Study is conducted.

Table 1: Direct Assignment Facilities

FACILITY	ESTIMATED COST (2007 DOLLARS)
CUSTOMER – (1) 161 kV transmission line from Customer collector substation to the new three-breaker ring-bus station located on the Maryville – Midway 161 kV transmission line.	*
MIPU – Termination and interconnection of CUSTOMER 161 kV transmission line into the new 161 kV three-breaker ring bus.	*
CUSTOMER – (1) 161/34.5 kV Customer collector substation facilities.	*
CUSTOMER – 34.5 kV, 75 Mvar capacitor bank(s) to be installed in the Customer 161/34.5 kV collector substation.	*
CUSTOMER – Right-of-Way for all Customer facilities.	*
TOTAL	*****

* *Estimates of cost to be determined.*

Table 2: Required Interconnection Network Upgrade Facilities

FACILITY	ESTIMATED COST (2007 DOLLARS)
MIPU – (1) 161 kV three-breaker ring-bus switching station for GEN-2006-014 located on the Maryville – Midway 161 kV transmission line. Station to include breakers, switches, control relaying, high speed communications, metering and related equipment and all related structures.	$3,500,000
TOTAL	*****

* *Estimates of cost to be determined.*

Powerflow Analysis

A powerflow analysis was conducted for the facility using modified versions of the 2008, 2009, and 2012 summer and winter peak models, and the 2017 summer peak model. The output of the Customer's facility was offset in each model by a reduction in output of existing online SPP generation. This method allows the request to be studied as an Energy Resource (ER) Interconnection request. The proposed in-service date of the generation is May 31, 2008. The available seasonal models used were through the 2017 Summer Peak of which is the end of the current SPP planning horizon.

Following current practice, this analysis was conducted assuming that previous queued requests in the immediate area of this interconnect request were in service. The analysis of the Customer's project indicates that, given the requested generation level of 300 MW and location, additional criteria violations will occur on the existing AECI, KCPL, MIPU and WERE transmission systems under steady state and contingency conditions in the peak seasons. Table 3 lists these overloaded facilities.

In Table 4, a value of Available Transfer Capability (ATC) associated with each overloaded facility is included. These values may be used by the Customer to determine lower generation capacity levels that may be installed. When transmission service associated with this interconnection is evaluated, the loading of the facilities listed in this table may be greater due to higher priority reservations. When a facility is overloaded for more than one contingency, only the highest loading on the facility for each season is included in the table.

In order to maintain a zero reactive power flow exchanged at the point of interconnection, additional reactive compensation is required. The Customer will be required to install a combined total of 75 Mvar of capacitor bank(s) in the Customer's 161/34.5 kV collector substation on the 34.5 kV bus. Dynamic Stability studies performed as part of the System Impact Study will provide additional guidance as to whether the reactive compensation can be static or a portion must be dynamic (such as a SVC or STATCOM). It is possible that an SVC or STATCOM device will be required at the Customer facility because of FERC Order 661A Low Voltage Ride-Through Provisions (LVRT) which went into effect January 1, 2006. FERC Order 661A orders that wind farms stay on-line for 3-phase faults at the point of interconnection even if that requires the installation of a SVC or STATCOM device.

There are several other proposed generation additions in the general area of the Customer's facility. Some of the local projects that were previously queued were assumed to be in service in this Impact Study. Not all local projects that were previously queued and have advanced to nearly complete phases were included in this Impact Study.

Powerflow Analysis Methodology

The Southwest Power Pool (SPP) criteria states that: "The transmission system of the SPP region shall be planned and constructed so that the contingencies as set forth in the Criteria will meet the applicable NERC Planning Standards for System Adequacy and Security – Transmission System Table I hereafter referred to as NERC Table I) and its applicable standards and measurements".

Using the created models and the ACCC function of PSS\E, single contingencies in portions or all of the modeled control areas of Sunflower Electric Power Corporation (SUNC), Missouri Public Service (MIPU), Westar Energy (WERE), Kansas City Power & Light (KCPL), West Plains (WEPL), Midwest Energy (MIDW), Oklahoma Gas and Electric OKGE, American Electric Power West (AEPW), Grand River Dam Authority (GRDA), Southwestern Public Service Company (SPS), Western Farmers Electric Cooperative (WFEC) and other control areas were applied and the resulting scenarios analyzed. This satisfies the 'more probable' contingency testing criteria mandated by NERC and the SPP criteria.

Powerflow Results

Table 3: Network Constraints

AREA	OVERLOADED ELEMENT
AECI	FAIRPORT - OSBORN 161KV CKT 1
KCPL/MIPU	ALABAMA - NASHUA 161KV CKT 1
KCPL/MIPU	HAWTHORN - ST JOE 345KV CKT 1
KCPL/MIPU	HAWTHORN (HAWT 20) 345/161/13.8KV TRANSFORMER CKT 20
KCPL/MIPU	ST JOE - IATAN 345KV CKT 1
MIPU	ALABAMA - LAKE ROAD 161KV CKT 1
MIPU	HALLMARK - RITCHFIELD 161KV CKT 1
MIPU	IATAN - STRANGER CREEK 161KV CKT 1
MIPU	IATAN - STRANGER CREEK 345KV CKT 1
MIPU	SIBLEY - RITCHFIELD 161KV CKT 1
WERE	WEST JUNCTION CITY - WEST JUNCTION CITY JUNCTION (EAST) 115KV CKT 1
WERE	NORTH AMERICAN PHILIPS JUNCTION (SOUTH) - WEST MCPHERSON 115KV CKT 1
AECI	Associated Electric Cooperative, Inc.
KCPL	Kansas City Power and Light
MIPU	Missouri Public Service
WERE	Westar Energy

Table 4: Contingency Analysis

SEASON	OVERLOADED ELEMENT	RATING (MVA)	LOADING (%)	ATC (MW)	CONTINGENCY
08SP	ALABAMA - LAKE ROAD 161KV CKT 1	153	131	0	IATAN - STRANGER CREEK 345KV CKT 1
08SP	ALABAMA - NASHUA 161KV CKT 1	153	121	0	IATAN - STRANGER CREEK 345KV CKT 1
08SP	G06-14 161.00 – MARYVILLE 161KV CKT 1	182	155	164	G06-14 161.00 - MIDWAY 161KV CKT 1
08SP	G06-14 161.00 - MIDWAY 161KV CKT 1	182	151	196	G06-14 161.00 – MARYVILLE 161KV CKT 1
08SP	MIDWAY - ST JOE 161KV CKT 1	182	142	204	G06-14 161.00 – MARYVILLE 161KV CKT 1
08SP	NORTH AMERICAN PHILIPS JUNCTION (SOUTH) - WEST MCPHERSON 115KV CKT 1	68	103	242	EAST MCPHERSON - SUMMIT 230KV CKT 1
08SP	ALABAMA - LAKE ROAD 161KV CKT 1	153	102	255	HAWTHORN (GEN542951 5)
08SP	WEST JUNCTION CITY - WEST JUNCTION CITY JUNCTION (EAST) 115KV CKT 1	194	100	280	JEFFERY ENERGY CENTER - SUMMIT 345KV CKT 1
08WP	G06-14 161.00 – MARYVILLE 161KV CKT 1	182	156	156	G06-14 161.00 - MIDWAY 161KV CKT 1
08WP	G06-14 161.00 - MIDWAY 161KV CKT 1	182	152	195	G06-14 161.00 – MARYVILLE 161KV CKT 1
08WP	MIDWAY - ST JOE 161KV CKT 1	182	144	202	G06-14 161.00 – MARYVILLE 161KV CKT 1
09SP	ALABAMA - LAKE ROAD 161KV CKT 1	153	123	0	HAWTHORN - ST JOE 345KV CKT 1
09SP	ALABAMA - NASHUA 161KV CKT 1	153	113	53	HAWTHORN - ST JOE 345KV CKT 1
09SP	G06-14 161.00 – MARYVILLE 161KV CKT 1	182	156	165	G06-14 161.00 - MIDWAY 161KV CKT 1
09SP	G06-14 161.00 - MIDWAY 161KV CKT 1	182	152	193	G06-14 161.00 – MARYVILLE 161KV CKT 1
09SP	MIDWAY - ST JOE 161KV CKT 1	182	144	199	G06-14 161.00 – MARYVILLE 161KV CKT 1
09WP	ALABAMA - LAKE ROAD 161KV CKT 1	153	100	295	HAWTHORN - ST JOE 345KV CKT 1
09WP	G06-14 161.00 – MARYVILLE 161KV CKT 1	182	156	165	G06-14 161.00 - MIDWAY 161KV CKT 1
09WP	G06-14 161.00 - MIDWAY 161KV CKT 1	182	152	193	G06-14 161.00 – MARYVILLE 161KV CKT 1
09WP	MIDWAY - ST JOE 161KV CKT 1	182	144	199	G06-14 161.00 – MARYVILLE 161KV CKT 1
12SP	ALABAMA - LAKE ROAD 161KV CKT 1	153	147	0	HAWTHORN - ST JOE 345KV CKT 1
12SP	ALABAMA - NASHUA 161KV CKT 1	153	136	0	HAWTHORN - ST JOE 345KV CKT 1
12SP	HAWTHORN - ST JOE 345KV CKT 1	1138	118	0	SPP-KCPL-02B: IATAN - STRANGER CREEK 345KV CKT 1, ALABAMA - LAKE ROAD 161KV CKT 1
12SP	HAWTHORN (HAWT 20) 345/161/13.8KV TRANSFORMER CKT 20	550	106	0	SPP-KCPL-02B: IATAN - STRANGER CREEK 345KV CKT 1, ALABAMA - LAKE ROAD 161KV CKT 1
12SP	FAIRPORT - OSBORN 161KV CKT 1	227	107	123	SPP-KCPL-02B: IATAN - STRANGER CREEK 345KV CKT 1, ALABAMA - LAKE ROAD 161KV CKT 1

TABLE 4: Contingency Analysis (continued)

SEASON	OVERLOADED ELEMENT	RATING (MVA)	LOADING (%)	ATC (MW)	CONTINGENCY
12SP	IATAN - STRANGER CREEK 345KV CKT 1	1195	104	145	SPP-KCPL-01A: LAKE ROAD - ALABAMA 161KV CKT 1, HAWTHORN - ST. JOE 161KV CKT 1
12SP	G06-14 161.00 – MARYVILLE 161KV CKT 1	182	157	159	G06-14 161.00 - MIDWAY 161KV CKT 1
12SP	G06-14 161.00 - MIDWAY 161KV CKT 1	182	156	191	G06-14 161.00 – MARYVILLE 161KV CKT 1
12SP	MIDWAY - ST JOE 161KV CKT 1	182	146	198	G06-14 161.00 – MARYVILLE 161KV CKT 1
12SP	IATAN - STRANGER CREEK 161KV CKT 1	335	112	258	IATAN - STRANGER CREEK 345KV CKT 1
12WP	ALABAMA - LAKE ROAD 161KV CKT 1	153	163	0	IATAN - STRANGER CREEK 345KV CKT 1
12WP	ALABAMA - NASHUA 161KV CKT 1	153	153	0	IATAN - STRANGER CREEK 345KV CKT 1
12WP	ST JOE - IATAN 345KV CKT 1	1073	141	0	SPP-KCPL-02B: IATAN - STRANGER CREEK 345KV CKT 1, ALABAMA - LAKE ROAD 161KV CKT 1
12WP	G06-14 161.00 – MARYVILLE 161KV CKT 1	182	156	165	G06-14 161.00 - MIDWAY 161KV CKT 1
12WP	G06-14 161.00 - MIDWAY 161KV CKT 1	182	152	193	G06-14 161.00 – MARYVILLE 161KV CKT 1
12WP	MIDWAY - ST JOE 161KV CKT 1	182	144	199	G06-14 161.00 – MARYVILLE 161KV CKT 1
17SP	ALABAMA - LAKE ROAD 161KV CKT 1	153	186	0	IATAN - STRANGER CREEK 345KV CKT 1
17SP	ALABAMA - NASHUA 161KV CKT 1	153	173	0	IATAN - STRANGER CREEK 345KV CKT 1
17SP	ST JOE - IATAN 345KV CKT 1	1073	145	0	SPP-KCPL-02B: IATAN - STRANGER CREEK 345KV CKT 1, ALABAMA - LAKE ROAD 161KV CKT 1
17SP	SIBLEY - RITCHFIELD 161KV CKT 1	223	115	0	SPP-KCPL-02B: IATAN - STRANGER CREEK 345KV CKT 1, ALABAMA - LAKE ROAD 161KV CKT 1
17SP	HALLMARK - RITCHFIELD 161KV CKT 1	223	110	0	SPP-KCPL-02B: IATAN - STRANGER CREEK 345KV CKT 1, ALABAMA - LAKE ROAD 161KV CKT 1
17SP	HAWTHORN (HAWT 20) 345/161/13.8KV TRANSFORMER CKT 20	550	104	128	SPP-KCPL-02B: IATAN - STRANGER CREEK 345KV CKT 1, ALABAMA - LAKE ROAD 161KV CKT 1
17SP	G06-14 161.00 – MARYVILLE 161KV CKT 1	182	156	165	G06-14 161.00 - MIDWAY 161KV CKT 1
17SP	G06-14 161.00 - MIDWAY 161KV CKT 1	182	152	193	G06-14 161.00 – MARYVILLE 161KV CKT 1
17SP	MIDWAY - ST JOE 161KV CKT 1	182	144	199	G06-14 161.00 – MARYVILLE 161KV CKT 1
17SP	HAWTHORN - ST JOE 345KV CKT 1	1138	102	237	SPP-KCPL-02B: IATAN - STRANGER CREEK 345KV CKT 1, ALABAMA - LAKE ROAD 161KV CKT 1

Note: When transmission service associated with this interconnection is evaluated, the loading of the facilities listed in this table may be greater due to higher priority reservations. If the loading of a facility is higher, the level of ATC will be lower.

Stability Analysis

The following stability definition was applied in this study:

"Power system stability is defined as that condition in which the differences of the angular positions of synchronous machine rotors become constant following normally an aperiodic system disturbance."

Additionally, the new wind generator is required to stay on-line following normally cleared faults at the Point of Interconnection (POI).

The stability analysis was performed by using PSS/E Power System Simulator Version 29.5. Both three-phase and single-phase line faults were simulated. The synchronous machine rotor angles were monitored as well as the stability of the asynchronous machines.

Modeling of the Wind Plant Generator in the Powerflow

The Customer generation facility consists of two hundred GE 1.5 MW WTGs capable of producing up to 300 MW. The generator will be connected through two 161/34.5kV transformers and individual 34.5kV/600V step up transformers. Further details are found in Impact Study for Generation Interconnection Request GEN-2006-014 dated February 2007.

Modeling of the Wind Plant Generator in Dynamics

Equivalents for the wind turbine and generator step-up (GSU) transformer in the load flow case were modeled. For the stability simulations, the GE 1.5 MW WTGs were modeled using the provided GE 1.5 MW wind turbine dynamic model set.

The wind turbine generators were studied to have the manufacturer's second tier LVRT II package for ride-through capability for voltage and frequency. It was determined this LVRT package was necessary for the wind turbines to meet FERC Order #661A provisions for low voltage ride through (LVRT). Further details are found in Impact Study for Generation Interconnection Request GEN-2006-014 dated February 2007.

Stability Simulation Contingencies

Eighteen (18) contingencies were considered for the transient stability simulations. These contingencies are shown in Table 5.

The single phase faults were simulated by applying the fault impedance to the positive sequence network to represent the effect of the negative and zero sequence networks on the positive sequence network. The fault impedance was determined by using PSS/E to give a positive sequence voltage at the fault location of approximately 60% of the pre-fault value.

Table 5: Stability Simulation Contingencies

Contingency Number	Contingency Name	Description
1	FLT_1_3PH	3 phase fault on the Wind Farm (572) - Maryville (59251) 161kV line, near the wind farm. a. Apply fault at the Wind Farm. b. Clear fault after 5 cycles by tripping the line from the Wind Farm - Maryville c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
2	FLT_2_1PH	Single phase fault and sequence like Cont. No. 1
3	FLT_3_3PH	3 phase fault on the Wind Farm (572) - Midway (59252) 161kV line, near the wind farm. a. Apply fault at the Wind Farm. b. Clear fault after 5 cycles by tripping the line from the Wind Farm - Midway c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
4	FLT_4_1PH	Single phase fault and sequence like Cont. No. 3
5	FLT_5_3PH	3 phase fault on the Maryville (59251) to AECI Maryville (96097) 161kV line, near Maryville. a. Apply fault at the Maryville. b. Clear fault after 5 cycles by tripping the line from Maryville- AECI Maryville c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
6	FLT_6_1PH	Single phase fault and sequence like Cont. No. 5
7	FLT_7_3PH	3 phase fault on the Maryville (59251) to Clarinda (63826) 161kV line, near Maryville. a. Apply fault at Maryville. b. Clear fault after 5 cycles by tripping the line from Maryville-Clarinda c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
8	FLT_8_1PH	Single phase fault and sequence like Cont. No. 7
9	FLT_9_3PH	3 phase fault on the AECI Maryville (96097) to AECI Nodaway (96104) 161kV line, near AECI Maryville. a. Apply fault at the AECI Maryville. b. Clear fault after 5 cycles by tripping the line from AECI Maryville- Nodaway c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
10	FLT_10_1PH	Single phase fault and sequence like Cont. No. 9

Contingency Number	Contingency Name	Description
11	FLT_11_3PH	3 phase fault on the AECI Maryville (96097) to Creston (66560) 161kV line, near AECI Maryville. a. Apply fault at the AECI Maryville. b. Clear fault after 5 cycles by tripping the line from AECI Maryville- Creston c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
12	FLT_12_1PH	Single phase fault and sequence like Cont. No. 11
13	FLT_13_3PH	3 phase fault on the Midway (59252) – St. Joseph (59253) 161kV line, near the Midway. a. Apply fault at the Midway. b. Clear fault after 5 cycles by tripping the line from the Midway – St. Joe c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
14	FLT_14_1PH	Single phase fault and sequence like Cont. No. 13
15	FLT_15_3PH	3 phase fault on a St. Joe 345/161kV autotransformer a. Apply fault at St. Joe 345kV (59199). b. Clear fault after 5 cycles by tripping the auto c. No reclose
16	FLT_16_1PH	Single phase fault and sequence like Cont. No. 15
17	FLT_17_3PH	3 phase fault on the Fairport – AECI PQ wind farm 161kV bus at Fairport (96076) a. Apply fault at Fairport (96076). b. Clear fault after 5 cycles b tripping the line from Fairport to AECI Wind Farm c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
18	FLT_18_1PH	Single phase fault and sequence like Cont. No. 17

Prior Queue Projects

The two base cases were modified to include prior queued projects. All the prior queued projects in this study are shown in Table 6. The power generated by the Customer's generation facility and the previously queued projects is dispatched into the SPP footprint. Simulations were carried out on the cases with the added generation for a no-disturbance run of 16 seconds to verify the numerical stability of the model. All cases were confirmed to be stable.

Table 6: Prior Queue Projects

Project	MW
AECI #1	50
AECI #2	50
AECI #3	50
AECI #4	400
AECI #5	400

Stability Results

The results of the stability analysis are summarized in Table 3. The results indicate that for all contingencies simulated, GEN-2006-014 and the transmission system remained stable for both seasons. None of the prior queued wind farms tripped off-line during the simulations. Selected stability plots are shown in the appendices. All plots are available on request. Simulations were run for minimum 10 seconds duration to confirm proper machine damping.

Table 7: Stability Results

Contingency Name	2008 Winter Peak	2012 Summer Peak
FLT_1_3PH	STABLE	STABLE
FLT_2_1PH	STABLE	STABLE
FLT_3_3PH	STABLE	STABLE
FLT_4_1PH	STABLE	STABLE
FLT_5_3PH	STABLE	STABLE
FLT_6_1PH	STABLE	STABLE
FLT_7_3PH	STABLE	STABLE
FLT_8_1PH	STABLE	STABLE
FLT_9_3PH	STABLE	STABLE
FLT_10_1PH	STABLE	STABLE
FLT_11_3PH	STABLE	STABLE
FLT_12_1PH	STABLE	STABLE
FLT_13_3PH	STABLE	STABLE
FLT_14_1PH	STABLE	STABLE
FLT_15_3PH	STABLE	STABLE
FLT_16_1PH	STABLE	STABLE
FLT_17_3PH	STABLE	STABLE
FLT_18_1PH	STABLE	STABLE

Conclusion

Due to a change in status of some prior queued projects, SPP undertook this Re-Study of the Impact Study for GEN-2006-014. The minimum costs of interconnecting the Customer's interconnection request are estimated at $3,500,000 for Direct Assignment Facilities and Network Upgrades and are given in the Facility Study for this request posted in July, 2007. At this time, the cost estimates for other Direct Assignment facilities including those in Tables 1 and 2 have not been defined by the Customer. In addition to the Customer's proposed interconnection facilities, the Customer will be responsible for installing a total of 75 Mvar of capacitor bank(s) in the Customer's substation for reactive support. As stated earlier, some but not all of the local projects that were previously queued are assumed to be in service in this Impact Study. These costs exclude upgrades of other transmission facilities that were listed in Table 3 of which are Network Constraints.

In Table 4, a value of Available Transfer Capability (ATC) associated with each overloaded facility is included. These values may be used by the Customer to determine lower generation capacity levels that may be installed. When transmission service associated with this interconnection is evaluated, the loading of the facilities listed in this table may be greater due to higher priority reservations. When a facility is overloaded for more than one contingency, only the highest loading on the facility for each season is included in the table.

The Transient Stability analysis was performed again as part of this Impact Study. The Transient Stability analysis determined that GEN-2006-014, with the studied General Electric 1.5MW wind turbines with the manufacturer's LVRTII low voltage ride through package, will stay on line and the transmission system will remain stable for all studied contingencies. With the LVRTII low voltage ride through package, GEN-2006-014 will be able to meet FERC Order #661A provisions for low voltage ride through.

The required interconnection costs listed in Tables 1 and 2 and other upgrades associated with Network Constraints do not include all costs associated with the deliverability of the energy to final customers. These costs are determined by separate studies if the Customer submits a Transmission Service Request through Southwest Power Pool's OASIS.

Appendix A: Point of Interconnection Area Map

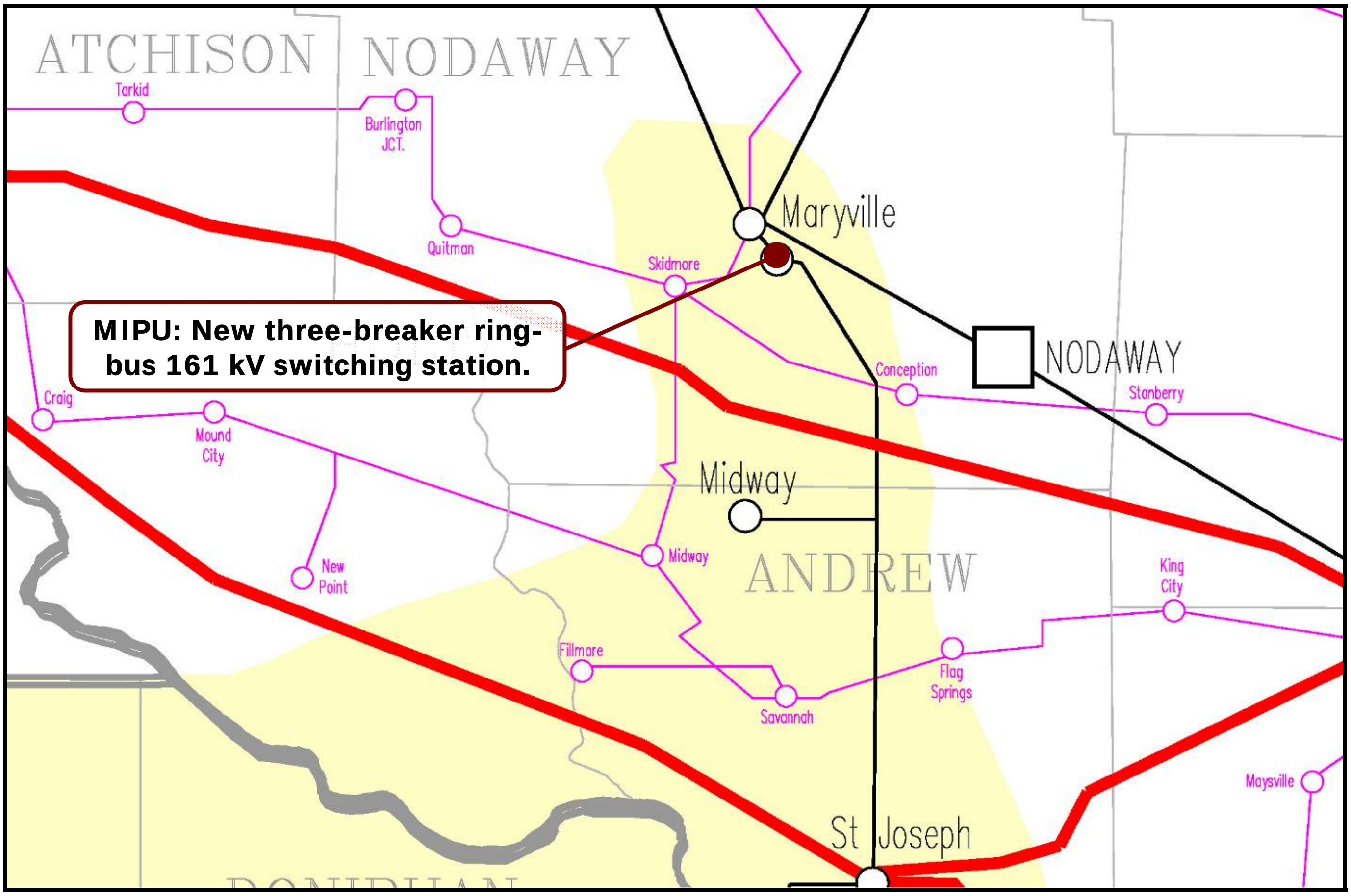


Figure 2: Point of Interconnection Area Map

Appendix B: Selected Stability Plots

2007 Winter Peak Stability Plots

NOTE: All plots available upon request.

Figure 3: 2007 Winter Peak Season - FLT_1_3PH

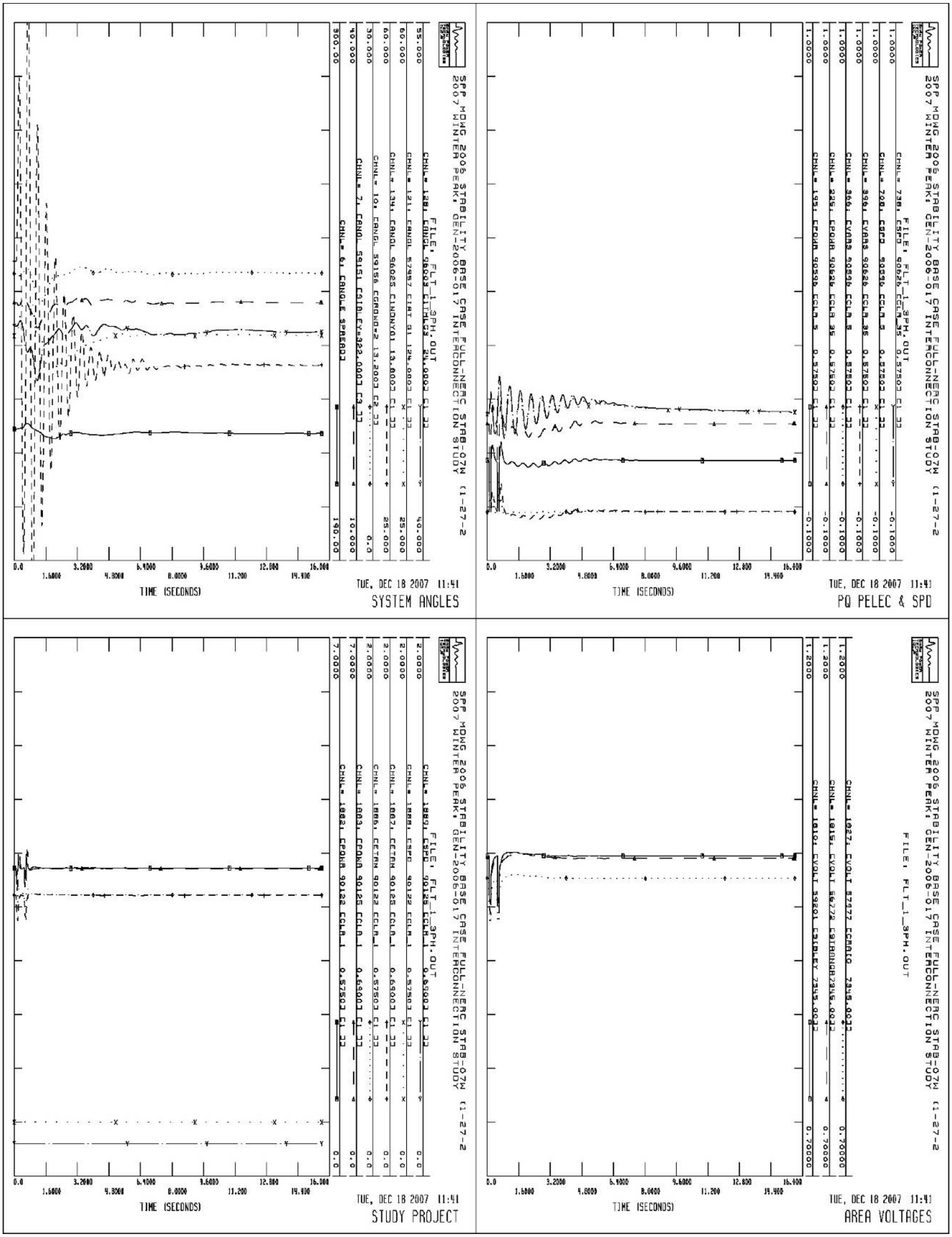


Figure 4: 2007 Winter Peak Season - FLT_2_1PH

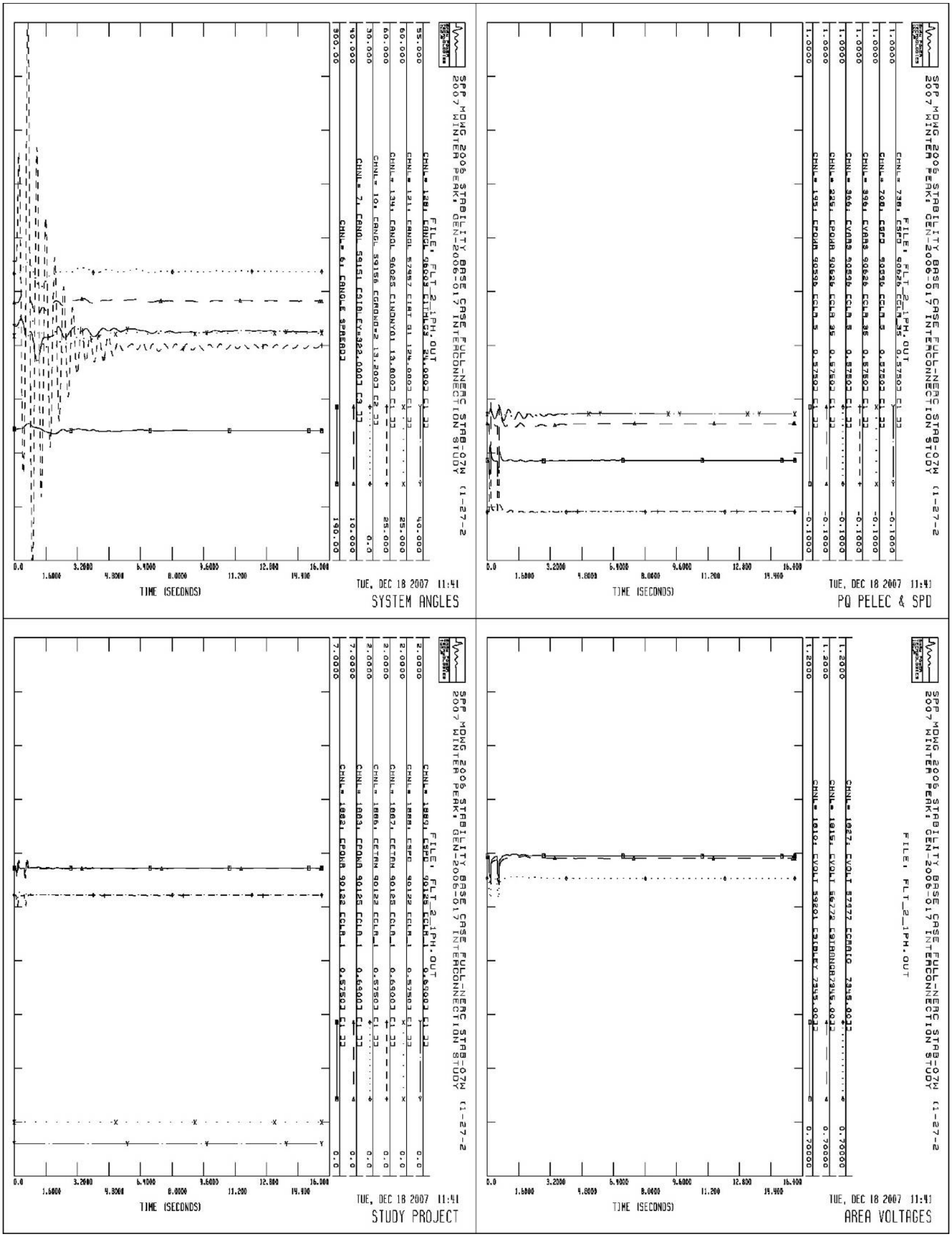


Figure 5: 2007 Winter Peak Season - FLT_3_3PH

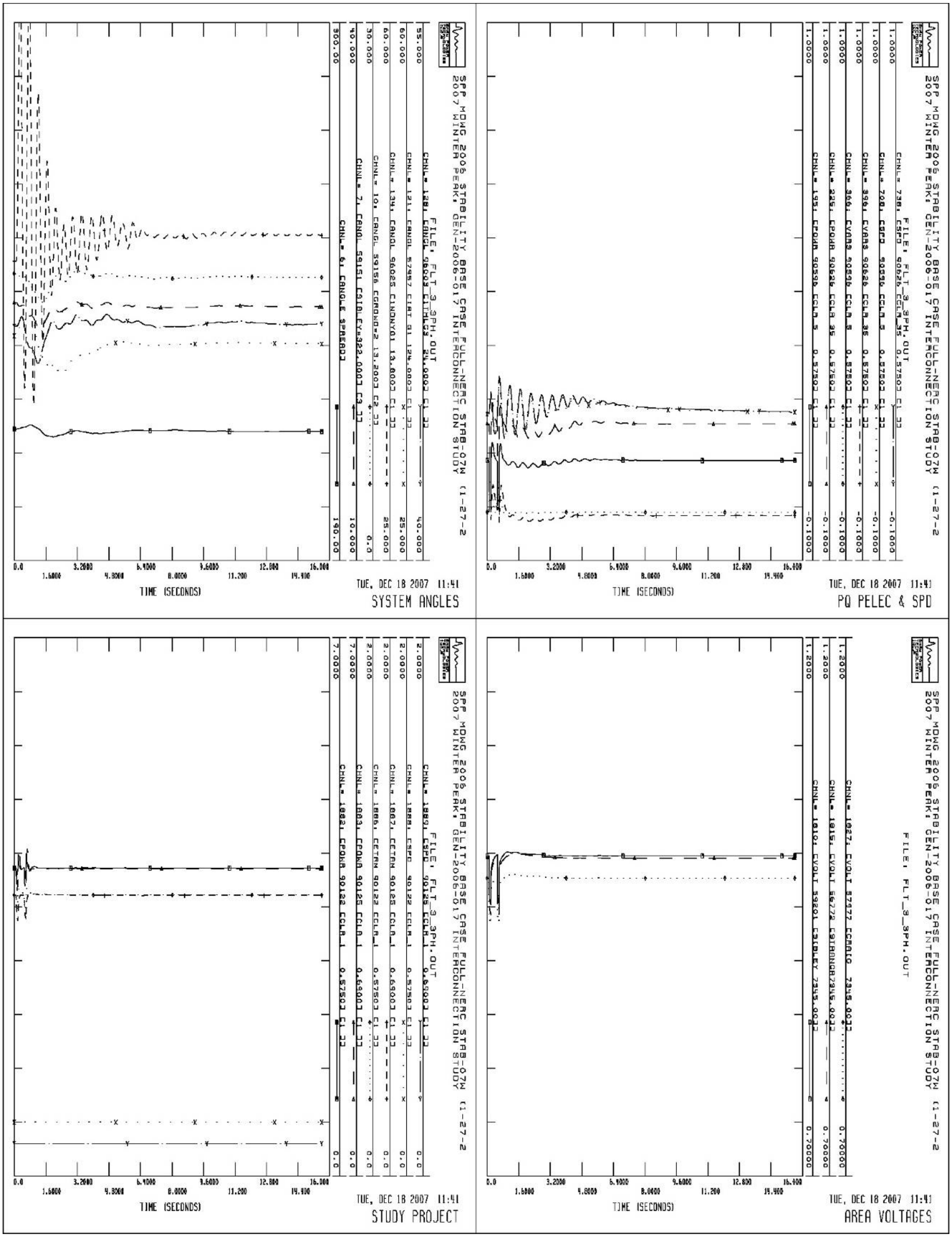


Figure 6: 2007 Winter Peak Season - FLT_7_3PH

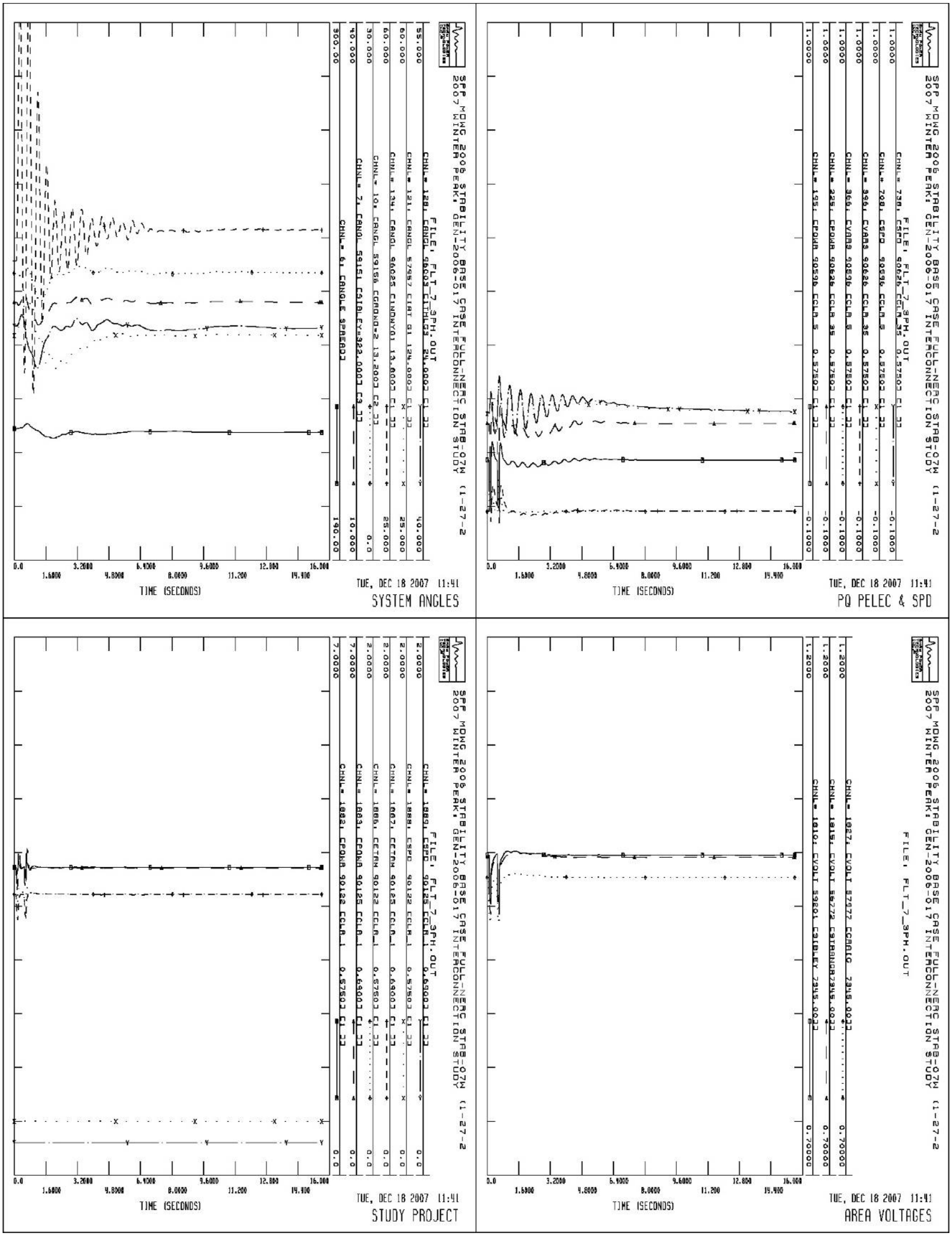


Figure 7: 2007 Winter Peak Season - FLT_8_1PH

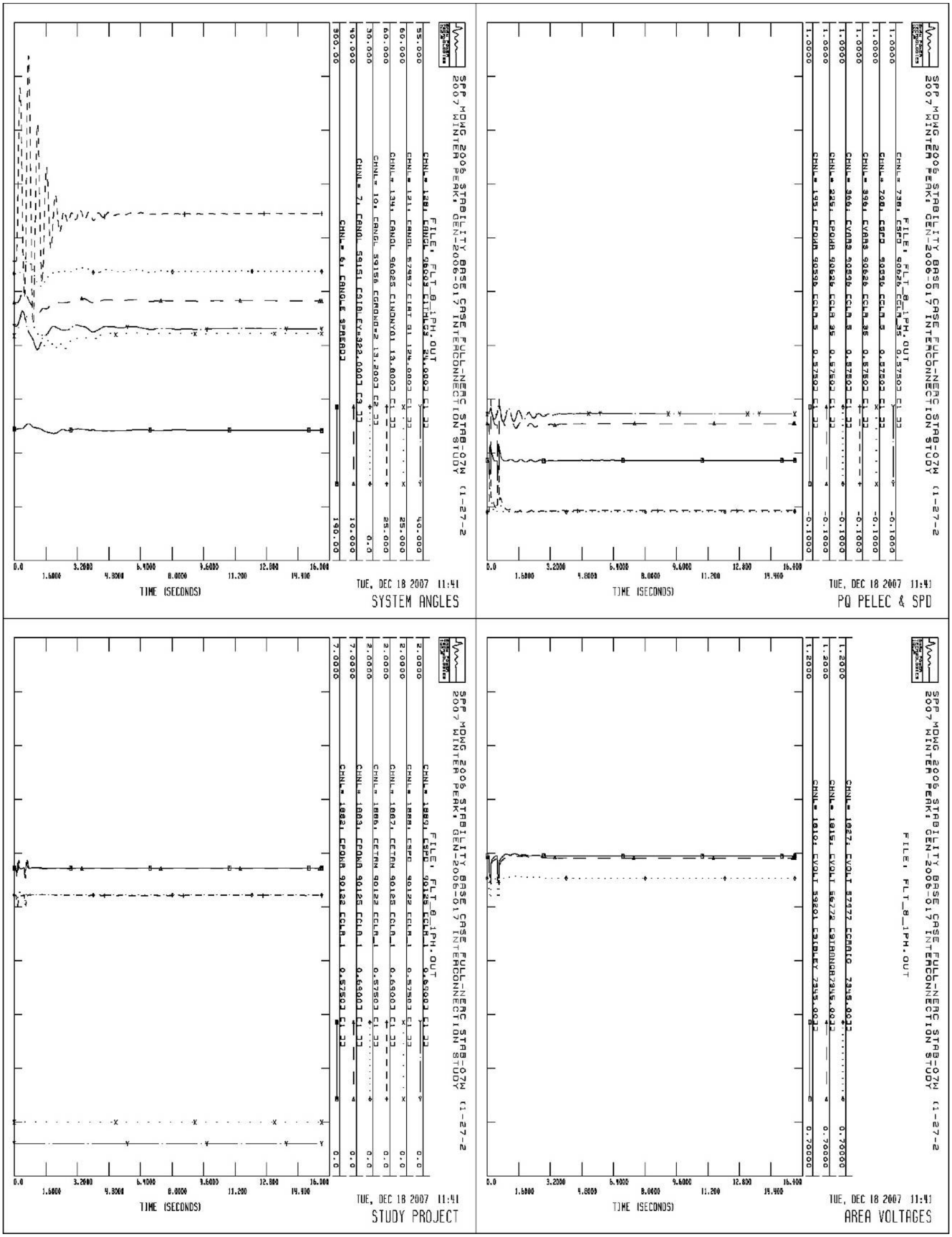
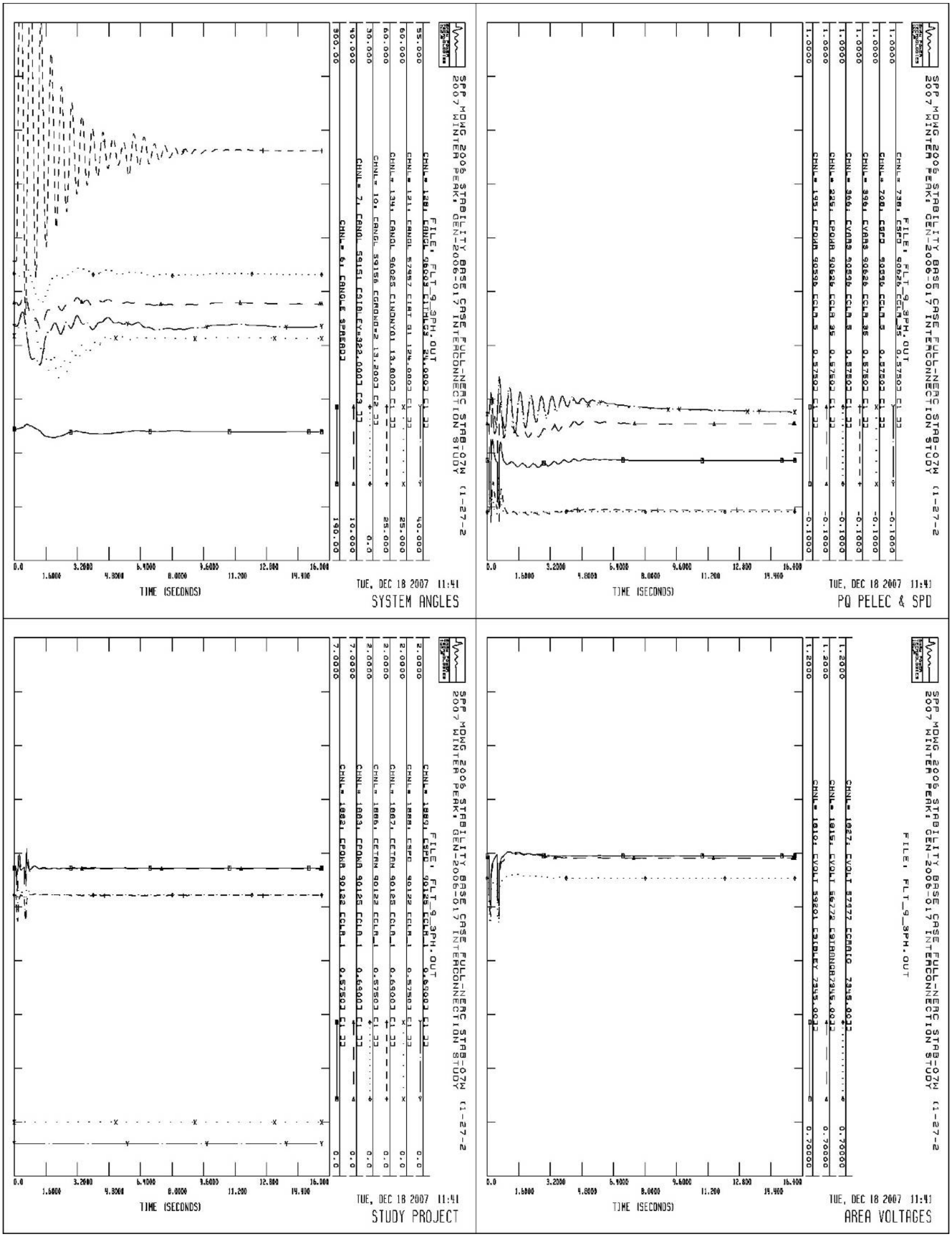


Figure 8: 2007 Winter Peak Season - FLT_9_3PH



2011 Summer Peak Stability Plots

NOTE: All plots available upon request.

Figure 9: 2011 Summer Peak Season - FLT_1_3PH

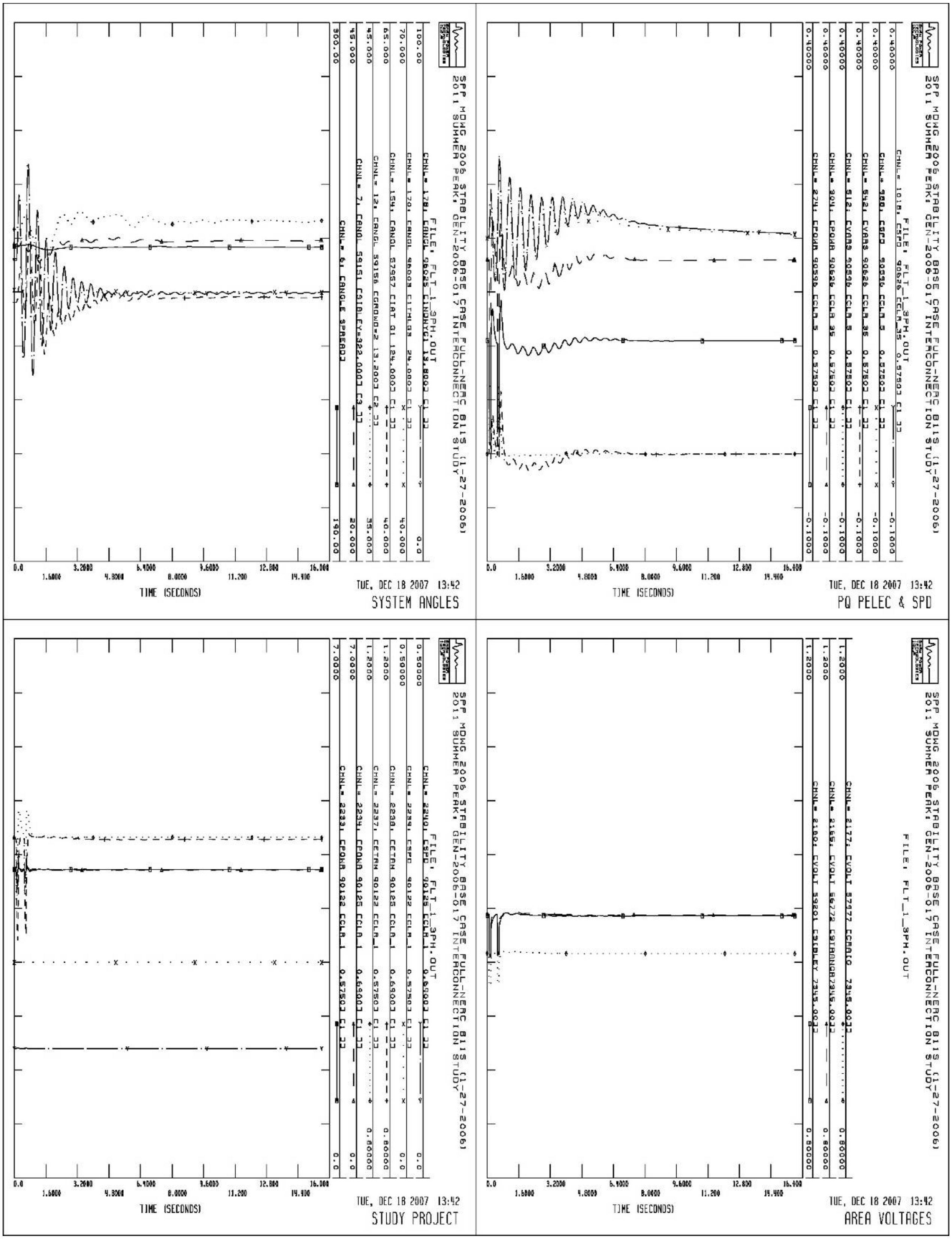


Figure 10: 2011 Summer Peak Season - FLT_2_1PH

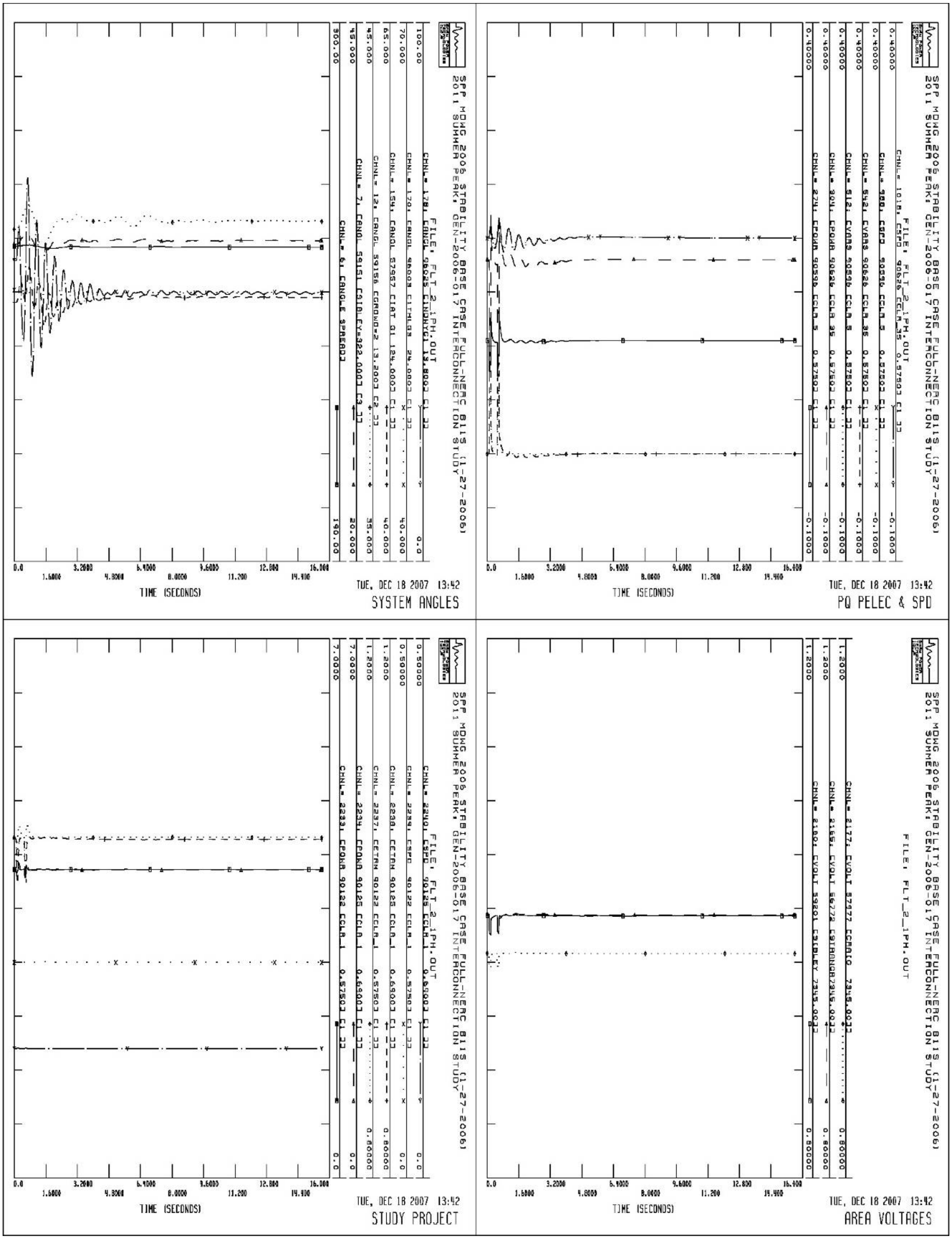


Figure 11: 2011 Summer Peak Season - FLT_3_3PH

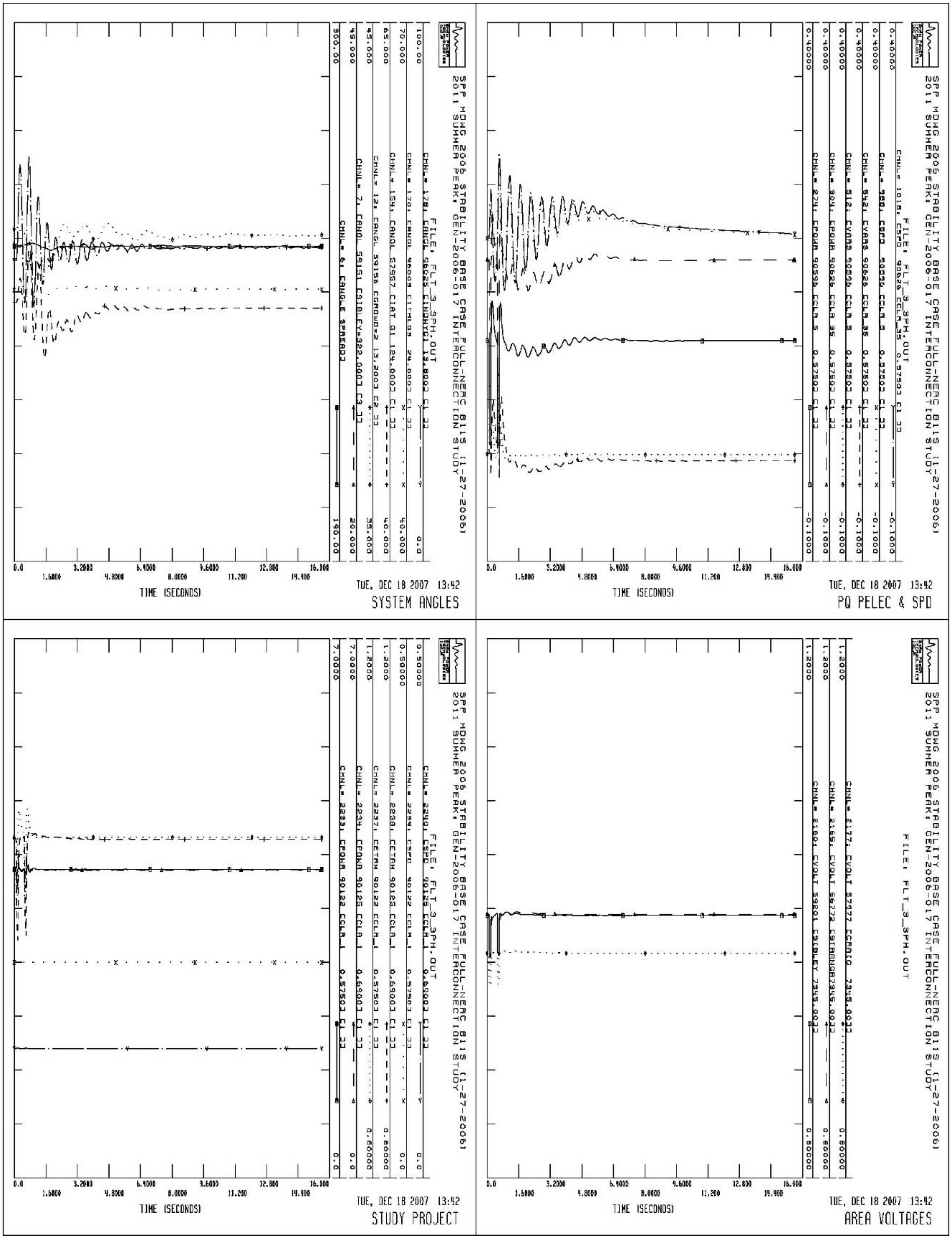


Figure 12: 2011 Summer Peak Season - FLT_7_3PH

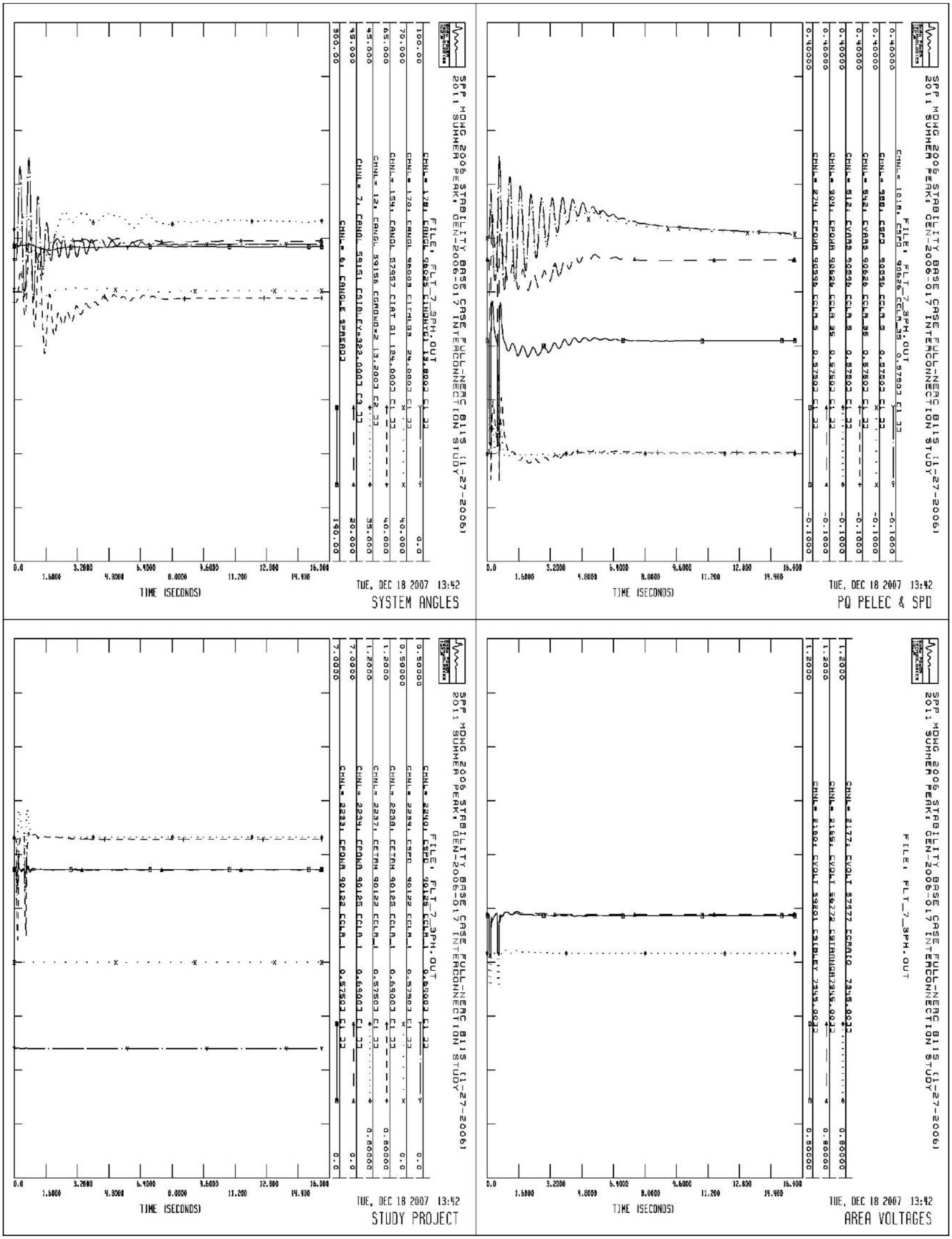


Figure 13: 2011 Summer Peak Season - FLT_8_1PH

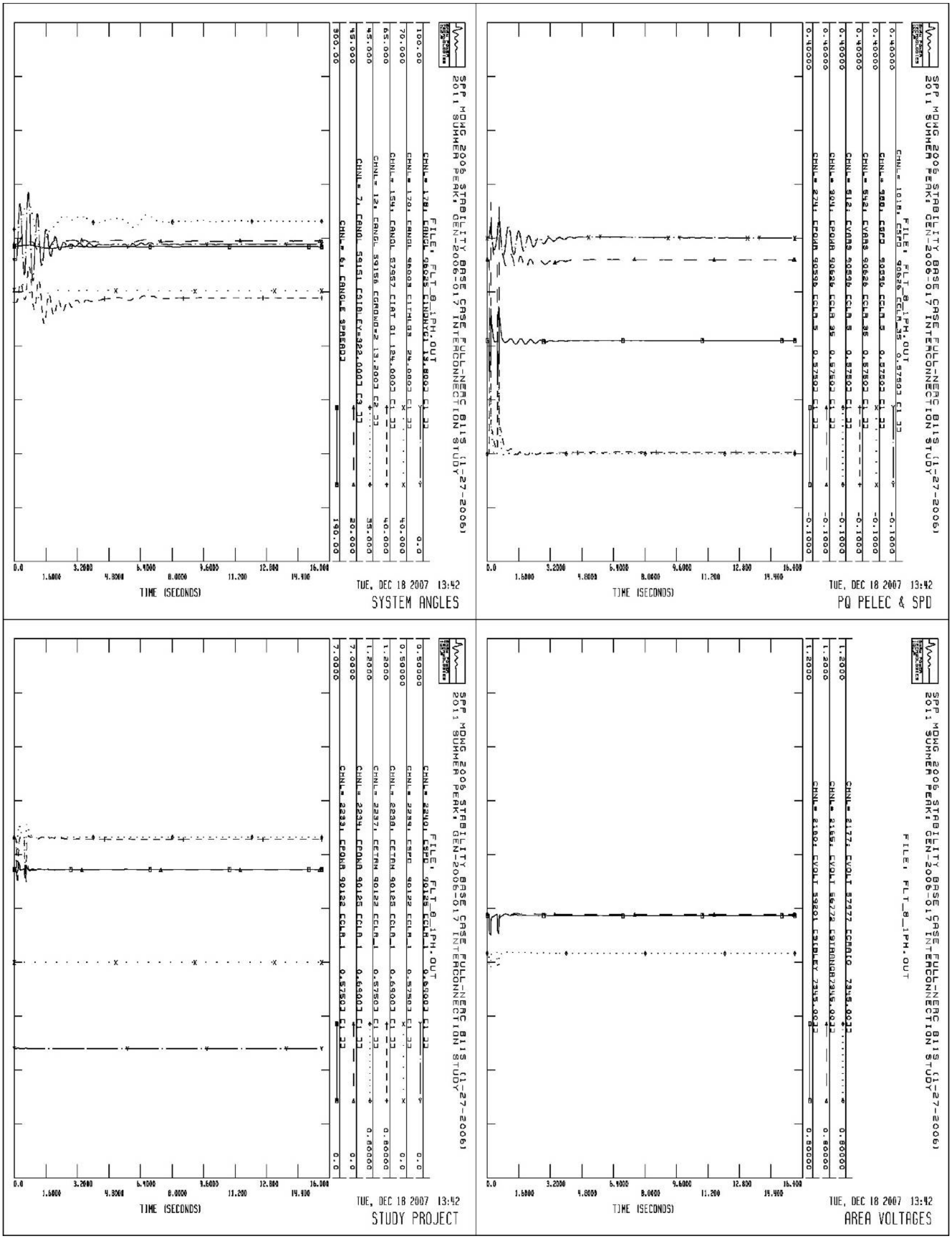


Figure 14: 2011 Summer Peak Season - FLT_9_3PH