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Phase III-IV Field Test Report
Prepared by the SERC EC Generator Standard Field Test Task Force
June 15, 2007

BACKGROUND

The purpose of this report is to document the activities of the SERC EC Generator Standard Field Test Task Force in the NERC Field Tests of proposed Reliability Standards for MOD-026 (Verification of Models and Data for Generator Excitation System Functions); MOD-027 (Verification of Generator Unit Frequency Response); PRC-019 (Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection); and PRC-024 (Generator Performance During Frequency and Voltage Excursions).

SERC EC GSFT-TF members include representatives from the US Army Corps of Engineers-Mobile District (USACE), Dominion, Entergy, SCE&G, and Southern. In support of the Field Test activities by SERC member Generator and Transmission Owners, the GSFT-TF developed the following Field Test Guidelines and Reporting Forms:

1) SERC Field Test Guidelines – Verification of Models and Data for Generator Excitation System Functions - NERC Reliability Standards MOD-026; [SERC MOD-026 Field Test Guideline Rev 1 (1-11-07).doc]

2) MOD-026 SERC Field Test Reporting form; [SERC MOD-026 Field Test Reporting Form Rev 0 (1-11-07).doc]

3) SERC Field Test Guidelines – Verification of Generator Unit Frequency Response – NERC Draft Reliability Standard MOD-027; SERC MOD-027 Field Test Guideline Rev 0 (3-2-07).doc

4) MOD-027 SERC Field Test Reporting Form; SERC MOD-027 Field Test Reporting Form Rev 0 (4-17-07).doc

5) SERC Field Test Guidelines – Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection; SERC PRC-019 Field Test Guideline Rev 0 (8-28-06).doc

6) PRC-019 SERC Field Test Reporting Form; SERC PRC-019 Field Test Reporting Form Rev 1 (11-2-06).doc

7) SERC Field Test Guidelines – Generator Performance during Frequency and Voltage Excursions; SERC PRC-024 Field Test Guidelines Rev 0 (3-2-07).doc

8) Generator Owner PRC-024 SERC Field Test Reporting Form; SERC PRC-024 GO Field Test Reporting Form Draft 0 (3-13-07).doc

9) Transmission Owner PRC-024 SERC Field Test Reporting Form; SERC PRC-024 TO Field Test Reporting Form Draft 0 (3-13-07).doc

The purpose of the aforementioned Field Test Guidelines and Reporting Forms are to provide assistance to the SERC volunteer members that conducted the Field Tests. As such, the documents do not contain content that constitutes a requirement on any SERC entity.

Following is Field Test background information specific to each proposed Reliability Standard:

MOD-026-1: Verification of Models and Data for Generator Excitation System

Generation Owner entities within SERC that participated in this field test include the USACE-Mobile District, Dominion, SCE&G, and Southern. Though the current version of the proposed Reliability Standard does not include applicability to Transmission Owners, TO entities within SERC that participated include the USACE-Mobile District, Dominion, Entergy, and Southern. All of these entities were also represented on the GSFT-TF. Therefore, all were extremely knowledgeable regarding the GSFT-TF developed Field Test Guidelines and Reporting Forms. Even before the start of the Field Test, SERC had approved the Supplement which called for the open step in voltage testing and subsequent excitation model verification over a multi year phase in period. As such, all of the entities had either planned or had performed some exciter model verifications in the past.

MOD-027-1: Verification of Generator Unit Frequency Response

Generation Owner entities within SERC that participated in this field test include the USACE-Mobile District, Dominion, Entergy, SCE&G, and Southern. Though the current version of the proposed Reliability Standard does not include applicability to Transmission Owners, TO entities within SERC that participated include Dominion, Entergy, and Southern. All of these entities were also represented on the GSFT-TF. Therefore, all were extremely knowledgeable regarding the GSFT-TF developed Field Test Guidelines and Reporting Forms.

As documented in the Field Test Guidelines, the GSFT-TF attempted to utilize an event based approach to Validate unit frequency response for a sample number of generators. While it is known that WECC has developed and utilize this type of approach, it has not been previously utilized in SERC. A significant part of the effort was spent finding an appropriate software tool to re-create the frequency event and validate the models. Generator response data for two specific frequency excursion events were compared to unit frequency responses predicted by the unit's speed / load control dynamic models.

PRC-019-1: Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection

Generation Owner entities within SERC that participated in this field test include the USACE-Mobile District, Dominion, Entergy, and Southern. All of these entities were also represented on the GSFT-TF. Therefore, all were extremely knowledgeable of the GSFT-TF developed Field Test Guidelines and Reporting Forms. Though not obligated through any RRO or NERC requirements, Southern Company Generation has been performing generator coordination studies for a few years. The other entities had not recently conducted these coordination studies until this Field Test. As such, they had to implement through significant start up processes.

PRC-024-1: Generator Performance during Frequency and Voltage Excursions

Generation Owner entities within SERC that participated in this field test include Dominion, Southern, and USACE-Mobile District. All of these entities were also represented on the GSFT-TF. Therefore, all were extremely knowledgeable regarding the GSFT-TF developed Field Test Guidelines and Reporting Forms. As part of SERC UFLS studies, efforts have been made in the past to identify units with under frequency turbine protection that would not coordinate with UFLS relays. There has been some limited investigation of low voltage ride through (LVRT) capabilities of units in SERC. Draft frequency excursion and LVRT curves have been drafted and discussed in SERC groups, with the intent of adding them to SERC Supplements in support of Planning Standards. However, the efforts were put on hold with the abolishment of the Planning Standards. Therefore, before these Field Test activities, there has been little formal investigation of unit ride through capability for frequency and voltage excursions within SERC.

EXECUTIVE SUMMARY

MOD-026-1: Verification of Models and Data for Generator Excitation System

The GSFT-TF developed Field Test Guidelines that addresses each of the proposed NERC Reliability Standard Requirements in MOD-026-1. Two SERC Generator Owner entities actually performed the activities detailed in the completed SERC Field Test Guidelines (Attachment 1), while 2 utilized outside consultants to address some of the Requirements. The GSFT-TF believes these activities would constitute compliance with the proposed MOD-026-1 NERC Reliability Standard as currently drafted.

Four Generator Owners, and the associated Transmission Planning entities, within SERC participated in the Field Test of MOD-026. One Generator Owner and Transmission Planning entity have been performing the Open Step in Voltage tests and subsequent exciter model verification for a number of years. Prior to the Field Tests, the other entities had limited experience. Two entities relied on consultants to perform the Open Step in Voltage test, either as part of unit start up activities, or through a specific contract for excitation system model verification. It should be noted that most entities will require the use of consultants to perform these tests and the model validations due to a lack of in-house expertise. It was observed that using consultants is expensive, roughly $20,000 to 30,000 for one unit.

Open Step in Voltage tests are performed when the unit is at synchronous speed but at no load (i.e., functionally, the generator breaker is open). Therefore, it is best performed when the generator is coming off-line or is about to be put on-line. Thus, scheduling of these tests can be problematic.

Satisfactorily completing the requirements in draft Reliability Standard MOD-026-1 does improve the accuracy of the exciter models used in dynamic simulations. But it is noted that the effort required to verify the exciter model with the Open Step in Voltage tests can be laborious and time consuming. While the major dynamic simulation software vendors do have a number of exciter models in their library, it is becoming commonplace for Generator Owners to execute partial excitation system change outs. For example, conversion of a rotating field excitation system from an analog voltage regulator to a static voltage regulator results in an hybrid system that does not fit well with any standard library models. Significant effort, including requests for additional unit data from generator manufacturers, resulting in required use of an exponentially more complicated exciter model was required to obtain good model verification.

It is difficult to accurately project the cost, time, and level of benefits for all applicable entities in the region to implement the procedures to verify excitation system and PSS models. The current amount of actual generating plant capability in Commercial Operation in SERC approaches 260 GW. The GSFT-TF recommends that all units below 75 MVA or interconnected at voltages less than 100 kV should be exempt from the model verification requirements. Also, rigorous configuration control processes and sister units philosophy should be allowed so that model verification efforts can potentially be applicable to multiple units. Assuming the Reliability Standard is developed with reasonable exemption criteria, and allowances for configuration control / sister unit philosophies, the SERC GSFT-TF would recommend a 7 year phase in period (Effective date 2 years after adoption, then 20% per year for 5 years).

As marked up by the GSFT-TF in the redline versions of the current draft of MOD-026 (MOD-026_Draft for Field Test (GSFT-TF revised 5-3-07).doc), the GSFT also recommends:

1) A list of acceptable models be maintained, along with a procedure for revising the list of acceptable models (must be available in the major dynamic simulation software libraries).
2) Additional specificity regarding PSS commissioning tests.

MOD-027-1: Verification of Generator Unit Frequency Response

The GSFT-TF developed Field Test Guidelines that addresses each of the proposed NERC Reliability Standard Requirements in MOD-027-1. Five SERC Generator Owner entities attempted to perform the activities detailed in the completed SERC Field Test Guidelines. Upon inspection of captured event data for both the frequency excursion events, one of the Generator Owners found that none of his units were in an operating state conducive to responding to under frequency events (i.e., units were motoring). The other Generator Owners were able to identify multiple units in a proper operating state for further analysis and completion of all the Requirements as detailed proposed MOD-027-1. While dependent on the operating state of units during frequency events which are subsequently analyzed, the GSFT-TF believes these activities would constitute compliance with the proposed MOD-027-1 NERC Reliability Standard as currently drafted.

Until the Field Test, there have been few dedicated efforts to verify unit speed load control systems. Because of the large number of generators in SERC, the GSFT-TF determined that an event based methodology, similar to that utilized by WECC, was clearly the most practical course to pursue. However, selection of a tool to perform the simulations to replicate actual frequency excursion events was difficult. Software packages conducive to control system block diagram construction and code generation were evaluated. However, to utilize these packages, each type of speed load control system model to be verified would have to be constructed and tested.

At least one dynamic simulation software package contains a “playback” feature, which forces frequency and voltage signatures that can be manipulated to replicate what was recorded during actual transmission system events. The simulated frequency excursions are then applied to the unit frequency response models so that the resulting MW response predicted by the frequency response models could be compared to the actual captured unit MW response

event data. Unfortunately, that capability does not exist for the dynamic simulation software package used by the vast majority of Transmission Planners in SERC.

Despite the absence of a “playback feature”, the tool chosen for this Field Test effort was the dynamic simulation software package utilized in SERC. The GSFT-TF developed a small 3 bus loadflow, with a dominant “Eastern Interconnection” machine and the test machine. Source code altering the mechanical power of the dominant machine was developed to force the dominant machine to slow down relative to 60 hertz and create a simulated transmission system frequency to approximately replicate the actual recorded transmission system frequency. The resulting unit MW versus time output produced by the test machine unit frequency response model was compared to the actual unit MW versus time output captured by the event data. Further details can be found in SERC MOD-027 Field Test Reporting Form Rev 0 (4-17-07).doc.

The GSFT-TF volunteer entities investigated multiple models for two separate frequency excursion events. In some cases, good correlation between the event data and model data was not obtained. The field test concluded before issues regarding the poor correlation could be resolved. Once the poor correlations are resolved, the end result will be closer correlation between the models and the actual performance of the installed equipment.

The Field Test was a successful proof of concept exercise. However, the processes would require additional development before becoming a “production grade” activity that would be expected for compliance with an approved NERC Reliability Standard. Following are a list of specific issues that would need to be addressed before it is practical for unit frequency response model verifications be required per an enforceable NERC Reliability Standard:

1) A process would need to be set up to identify frequency excursion events which meet minimum criteria for verifying unit speed load governor systems, and subsequently communicate this information to the appropriate parties.
2) A significant number of units are not equipped with event recording equipment with sufficient resolution, triggering capabilities (if not inherently continuous) and/or data retention. Also, some plants do not have individual recording equipment for each unit (example, CC plants often sum their MW output into one transducer or meter)
3) A tool needs to be developed that can be utilized by the entities responsible for verifying the unit speed load models. While SERC utilized dynamic simulation software predominately used by almost all SERC members with a small loadflow along with flecs code unique to each frequency excursion event. The process was cumbersome and required user expertise in dynamic simulation. It did not exactly replicate the transmission system frequency and the models MW output often had high frequency oscillations associated with numeric instability (note – we were advised by the software vendor to alter the frequency filter, but this resulted in limited positive impact). In summary, the process is not “production grade”.
4) Staged events, at least in the Eastern Interconnection, are impractical. It will probably take significant calendar time before enough events would occur to capture most of the non-exempt units on-line but far enough below maximum power output for governor response to be observed. The GSFT-TF recommends that all units below 75 MVA or interconnected at voltages less than 100 kV should be exempt from the model verification requirements. Also, rigorous configuration control processes should be allowed as a means to demonstrate that validated unit responses are unchanged.

Working through these issues will take considerable time and effort. Therefore, the GSFT-TF recommends that drafting efforts on this standard be delayed until such time as adequate tools be developed and made available.

However, if draft Reliability Standard MOD-027-1 continues through the drafting process and is ultimately successfully balloted, the effective date should be delayed for 2 years, with the requirements phased in over at 20% per year over the next 5 years.

PRC-019-1: Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection

The GSFT-TF developed Field Test Guidelines that addresses each of the proposed NERC Reliability Standard Requirements in PRC-019-1. Five SERC Generator Owners actually performed the activities detailed in the completed SERC Field Test Guidelines. The GSFT-TF believes these activities would constitute compliance with the proposed PRC-019-1 NERC Reliability Standard as currently drafted.

One Generator Owner has been performing these unit coordination studies a number of years. Out of roughly 65 generating units reviewed, only one case of marginal coordination was identified. Prior to the Field Tests, the other entities had limited experience. The other Generator Owners initiated new processes, utilizing the Field Test Guidelines for direction. In all cases, the Generator Owners reported significant startup costs in both manpower and capital costs. Selection of tools, and obtaining equipment limit characteristics from vendors proved to be manpower intensive. No miscoordinations were identified by the other entities participating in this field test. The GSFT-TF estimates this could cost as much as $16 million to meet these requirements for all the applicable generating units in the SERC region. However, even with the high costs the GSFT-TF agrees that this is a beneficial standard.

The GSFT-TF discussed and noted that it may be difficult to obtain start-up test data on older generators, and that re-performing those tests would be a high cost and significant effort. The GSFT-TF agreed that there should be an exemption for older generators. Other GSFT-TF comments, as detailed in the referenced “Redlined” standard, include:

1) In addition to older generators, all units below 75 MVA or interconnected at voltages less than 100 kV should generally be exempt
2) The prime mover limit should be removed as a required plot characteristic – it hardly ever refers to a true physical limit. It is more appropriate to relate this to the MW capability determined in MOD-024.
3) The requirement to plot additional limits that restrict the MW or Mvar capability should be removed as this is an ambiguous requirement
4) The Generator Owner should retain the latest coordination study and provide it to the Compliance Monitor upon request.

The GSFT-TF agrees that this standard should be phased in at 20% per year.

PRC-024-1: Generator Performance during Frequency and Voltage Excursions

The GSFT-TF developed Field Test Guidelines that addresses each of the proposed NERC Reliability Standard Requirements in PRC-024-1. Three SERC entities, consisting of three GOs and two TOs, attempted to perform the activities detailed in the completed SERC Field Test Guidelines.

The task of determining coordination with the SERC draft frequency excursion curve shown in the PRC-024 Field Test Guidelines was a relatively simple task. Coordination of this curve with UFLS relays has been accomplished in past and an ongoing SERC UFLS study. Ignoring tool startup costs, coordination with generator turbine under frequency protective relays was also relatively simple for two of the GOs. The other GO reported that they have plant procedures in place to manually trip the unit if the frequency drops below thresholds which do not coordinate with the SERC draft frequency excursion curve. The GO went on to state that upon further review, they could alter their plant procedures to coordinate with the draft frequency excursion curve without compromising the unit.

The task of determining coordination with the SERC draft LVRT curve was a more daunting task. Plant auxiliary UV relays did not pose a risk of operating for the SERC draft LVRT characteristic. Utilizing steady state techniques with some simplifying assumptions, such as relaxation of steady state Mvar limits, suggested that generator back up impedance relays would not be able to ride through this characteristic. However, one TO utilized dynamic simulations to approximately create the LVRT characteristic through a small bus dynamic case and found that the back up impedance relay would not be expected to operate for the LVRT excursion. The reason why the steady state evaluation produced an incorrect solution was due to the inherent absence of the exciter time constants and exciter ceiling limits.

Based on reviewing the dynamic simulations, the LVRT characteristic should be changed from fault clearing time until one second should be raised from 0.4 to 0.5 per unit. This is required to provide adequate margin from unit transient instability.

The GSFT-TF understands that in order for Transmission Planners to be able to design UF and/or UV safety net schemes, assumptions regarding the UF and LVRT have to be made. Therefore, there is a reliability need to assess the expected ride through capability of units. However, the draft Reliability Standard as written does not address all of the plant systems that could be limiting factors in ride through capability. The GOs have serious concerns regarding the LVRT capability of systems required for operation of generating plants. Coordination of unit protection systems with the LVRT requirements alone will not guarantee the unit will always remain on-line. For example, Boiler Control Systems, systems unique to Nuclear Power Plants, and station service loads will impact ride through capability. The GOs believe that due to the complexity of these systems it is not possible to ensure a generating plant can survive every event. These topics are discussed in more detail in Attachment 6,

The issue of ride through characteristics for generators, especially LVRT, is evolving throughout the industry. The GSFT-TF experience in the field test shows that additional work is required before an effective NERC Reliability Standard can be developed. The GSFT-TF recommends that a process be put in place for additional research into these areas.

ATTACHMENTS

1. **GSFT-TF Documents**
2. **Standard Redlines**
3. **MOD-026 Test Results**
4. **MOD-027 Test Results**
5. **PRC-019 Test Results**
6. **PRC-024 Test Results**

Attachment 1
GSFT-TF Documents

- **SERC MOD-026 Field Test Guideline Rev 1 (1-11-07).doc**
- **SERC MOD-026 Field Test Reporting Form Rev 0 (1-11-07).doc**
- **SERC MOD-027 Field Test Guideline Rev 0 (3-2-07).doc**
- **SERC MOD-027 Field Test Reporting Form Rev 0 (4-17-07).doc**
- **SERC PRC-019 Field Test Reporting Form Rev 1 (11-2-06).doc**
- **SERC PRC-019 Field Test Guideline Rev 0 (8-28-06).doc**
- **SERC PRC-024 Field Test Guidelines Rev 0 (3-2-07).doc**
- **SERC PRC-024 GO Field Test Reporting Form Draft 0 (3-13-07).doc**
- **SERC PRC-024 TO Field Test Reporting Form Draft 0 (3-13-07).doc**

SERC Field Test Guidelines

Verification of Models and Data for Generator Excitation System Functions

NERC Reliability Standard
MOD-026

SERC Reliability Corporation

Revision History

Revision	Date	Comments
0	October 10, 2006	GSFT-TF finalized SERC MOD-026-1 Guideline for Field Test purposes.
1	January 11, 2007	Revised Attachment 2

Responsible SERC Subgroup & Region Review Group

The Generator Standard Field Test Task Force (GSFT-TF) has been tasked by the Engineering Committee to develop these field test guidelines and to provide assistance to SERC volunteer members. Responsible SERC Subgroup(s) and the Regional Review Group would be assigned only after the successful ballot and NERC B.O.T adoption of draft NERC Reliability Standard MOD-026.

Review and Re-Certification Requirements

Not applicable until the successful ballot and NERC B.O.T adoption of draft NERC Reliability Standard MOD-026.

Effective Dates:

Not applicable until the successful ballot and NERC B.O.T adoption of draft NERC Reliability Standard MOD-026.

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List of Attachments

Attachment 1: NERC Reliability Standard MOD-026
Attachment 2: Excitation System Questionnaire

I. Introduction/ Purpose

In order to effectively evaluate the electric system's performance, the accuracy of data for the interconnected transmission network and the associated generating equipment is critical. Accordingly, valid data reflecting generator excitation systems are essential for performing planning and operating studies to assess or evaluate the reliability of the electric system.

This SERC field test guideline for the NERC Reliability Standards MOD-026 is intended to:

1) Provide guidance for SERC Generator Owners/Operators to address verification of generator excitation system, power system stabilizers models, and excitation limit controls.
2) Document the GSFT-TF recommended exemption criteria and sister unit philosophy.
3) Document the GSFT-TF recommended Configuration Controls.

II. Definitions

1. **Confirm (–ed, –ation) –** To assure that plant or equipment conditions (including control settings) that would impact previously provided data has not changed.

2. **Exempt Generation –** Generator(s) that meets the exemption criteria for a particular Validation/test requirement.

3. **Validate (-dated, -dation)** – To establish the accuracy of data used to model electrical equipment. Validation may be achieved through simulation, operating data, field readings, engineering evaluations or reviews, use of manufacturer data, commissioning data, performance tracking, and/or testing where appropriate.

4. **Verify (Verification)** – To establish through Validation or Confirmation.

5. **Standard Model (or Model) –** A model included with the Power System Simulator, Power Technologies, Inc. (PSS/E) dynamic simulation software. Many Institute of Electrical and Electronics Engineers, Inc. (IEEE) models are included in the standard PSS/E models. Complete model information includes both the name of the Standard Model and the value of each parameter.

III. Requirements/Expectations

A. Generator Exemption Criteria [*Ref.MOD-026, R1.1*]

In order to maximize the efficiency of generator testing, it is prudent to exempt generators that are believed to have less significant impact on the reliability of the bulk electric system from data Validation requirements. The exemption criteria specified by these guidelines are based on both the operating voltage of the bulk power system to which the generator is interconnected, and the MVA rating of the generator. When referring to the MVA rating of the generator, at facilities where multiple machines and/or prime movers are required for normal unit operation, the MVA rating refers to the total MVA capacity of the facility. Examples of this include combined cycle or cross compound units.

As documented in the NERC Glossary of Terms, the NERC Board of Trustees approved a definition for the bulk electric system on February 8, 2005 as follows:

> "As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition."

Therefore, for generators interconnected to a power system operated at a voltage of less than 100 kV, Validation is not required. Inasmuch as possible, models and model parameters should be based on the most accurate information available from sources such as the manufacturer, calibration and maintenance records and field inspection (i.e., estimated parameters).

Generators with a nameplate rating less than or equal to 75 MVA or that are not connected to the bulk power system are exempt.

Table 1 summarizes the Generator Exemption Criteria.

Generator Interconnected kV or MVA Size	Validated Models & Data Required
< 100 kV	No
≥ 100kV & ≤ 75 MVA	No
≥100kV & > 75 MVA	Yes

Table 1: Generator Exemption Criteria

B. Sister Unit/Equipment Validation Guidelines

Some units have equipment with the same characteristics such that they respond the same as equipment of other units. If it can be demonstrated that the units, equipment, or systems have identical designs, identical major components and identical significant control system settings, then the units can be considered sisters in regard to that equipment or system. In those situations, an assumption can be made for a sister unit by Validating the excitation system (and PSS system as appropriate) model for one (sample) unit. Equipment or systems that do not impact the equipment or system to be Validated need not be identical. Units that are sisters in one regard may not be sisters for other equipment or systems to be Validated. Documentation must exist to demonstrate that the information about the sample unit can be applied to a sister unit. In future Validations, a different sister unit shall be selected to eventually verify that the sister approach was valid.

C. Configuration Controls

The Generator Owner shall implement a program intended to ensure the condition of the excitation controls (Automatic Voltage Regulator, Limiters, and Power System Stabilizer) remains consistent with the state of the equipment when the latest model Verification was performed. This will normally be performed during a major generator outage, or when setting changes are implemented. [Ref.MOD-026, R1.4.6]

There are several programmatic alternatives that are considered adequate for assuring the generator excitation system models accurately reflect the response of the field equipment. The alternatives are:

1. Periodically repeating the baseline testing and simulation comparisons to assure the model parameters submitted for dynamic simulations are accurate.
2. With the appropriate data collection equipment and excitation system modeling expertise available, the generator owner may want to Validate the model by alternate means.
3. If analog control equipment owners regularly calibrate their controls and have documented excitation system parameters at the time of the baseline test, then future calibration activities can be conducted with the goal of maintaining excitation system parameters in the as-modeled state. This assures and documents that the excitation system modeling parameters are still consistent with the Validated baseline model parameters.
4. For digital excitation systems , once baseline parameters are established through testing, future Validation activities shall consist of ensuring any components that may drift (such as A/D converters) are properly calibrated and ensuring the control system parameters have not changed from the baseline data.
5. In general, hybrid excitation systems (excitation systems that contain both analog and digital subsystems), should be treated as analog control systems.

D. Excitation System Classification:

The generator owner shall provide the Planning Authority and/or Transmission Planner the following excitation system classification information (see Attachment 2) [*Ref.MOD-026, R1.4.1*]:

1. Manufacturer and Type of Excitation System. Examples of excitation system types are static, brushless, alternator rectifier, motor driven dc exciters, etc
2. Manufacturer and Type of Voltage Regulator.

E. Regulator and Excitation Control Systems

1. General Requirements *[Ref.MOD-026, R1.4.2]*

a) The Generator Owner shall provide an appropriate automatic voltage regulator and excitation system Standard Model and associated parameters. The Transmission Planner shall provide assistance in selection and Validation of this Standard Excitation Model[1].

b) The Generator Owner shall provide reactive current or line drop compensation settings where applicable. *[Ref.MOD-026, R1.4.4]*

c) The Generator Owner shall provide open circuit step test data necessary for Validation of the model for the excitation control system.

d) The Transmission Planner will perform a simulation of the open circuit test using the modeling data provided in sections a, b, and c above to verify the generator excitation system model.

e) Due to nuclear licensing requirements and concerns, Transmission Planners and Generator Owners shall coordinate any required studies, assessment, and / or testing of the generator excitation systems that could adversely impact the capacity and/or the capability of the nuclear plant off-site sources and nuclear plant safety.

2. Specific Requirements *[Ref.MOD-026, R1.2]*

a) Validation Process

Adequate Validation requires a baseline model to be established in conjunction with an Open Circuit Step Response (OCSR) test. (Note: Data from an OCSR test itself does not constitute the model, but can be used to adjust the model parameters until the simulation results closely match the OCSR response.) This test consists of collecting data (for data points, see below) on the generator performance during transients when a step in the voltage reference is introduced.

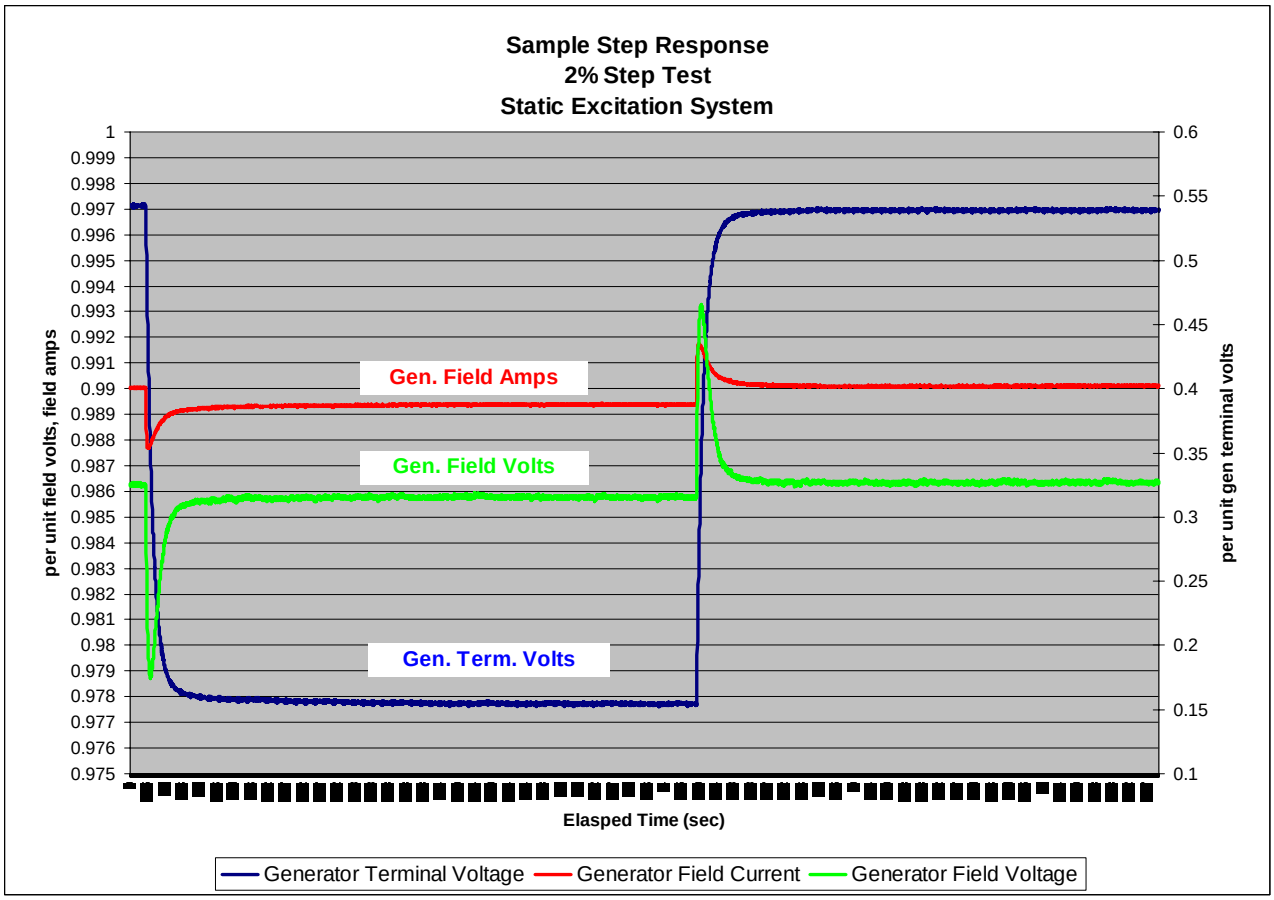
[1] Many times, dynamic simulation software manufacturers wait until a model is approved by IEEE before including it within the library of models provided with the software. Therefore, there can be a significant time lapse between installation/use of something that requires a model and the availability of a Standard Model. Until such time as new models are added to the Transmission Planners' model library, a Standard Model that most closely approximates the actual response shall be used. User Defined Models are usually complicated and troublesome to incorporate into the regional and interregional dynamics databases, and therefore they shall only be used in extraordinary situations

Good correlation between the model and the OCSR test must be achieved. Otherwise, the model along with other variables that affect exciter response must be re-examined.

b) Data Points Required for Validation Tests *[Ref.MOD-026, R1.4.5]*
The following data points shall be monitored for Validation. If signal transducer outputs are used for data collection, any time lags introduced by the transducer must be accounted for in the model Validation process. Otherwise, the response of the transducer output may be inappropriate for model Validation. The test parameters are:

1.) Generator Voltage
2.) Field Voltage (Generator and/or Exciter as appropriate)
3.) Field Current (Generator and/or Exciter as appropriate)
4.) Step input (for voltage step test)

Note, the magnitude of the step input (generally expressed as a percentage of the generator voltage) shall be stated, but shall be no less than 1%. See sample test data below. Some recording equipment allows both graphical and tabular data formats. These data collection systems are preferred since one can visually see the results and can use the tabular data for comparison with simulated results to aid in the validation process.


Sample Step Response
2% Step Test
Static Excitation System
per unit field volts, field amps
per unit gen terminal volts
Gen. Field Amps
Gen. Field Volts
Gen. Term. Volts
Elasped Time (sec)
Generator Terminal Voltage
Generator Field Current
Generator Field Voltage

F. Power System Stabilizers

1. General Requirements *[Ref.MOD-026, R1.4.6]*

All units that have commissioned Power System Stabilizers (PSS) must submit a Validated Standard Model. The Standard Model will normally be Confirmed during a major outage, or when setting changes are implemented. *[Ref.MOD-026, R1.3]*

2. Specific Requirements *[Ref.MOD-026, R1.2]*

a) Units commissioning new PSSs will supply the Transmission Planner applicable test results provided upon commissioning. This includes results of the Gain Margin test, Phase Compensation test, and on-line step in voltage tests with and without the PSS in service.

b) Units that have previously commissioned PSSs will supply the Transmission Planner applicable test results provided from the initial commissioning, if available, including the results of the Gain Margin test, Phase Compensation test, and on-line step in voltage tests with and without the PSS in service. If the aforementioned tests are not available, the Transmission Planner may grant the Generator Owner the option of providing a PSS tuning study report along with field verification of the exciter and PSS settings.

c) Where appropriate, the Standard Model data can be described by block diagrams and/or tables, based on standard IEEE or PSS/E type models.

d) The Phase Compensation Test must include a gain and phase shift Bode plot for the excitation system with and without the stabilizer. Each Bode plot must be formatted as follows:

1) Semi-log type chart
2) Gain magnitude expressed in decibels
3) Phase shift expressed in degrees
4) Frequency expressed in Hertz, typically 0.01 – 5.0 Hz log scale

G. Excitation Limit Controls

1. General Requirements *[Ref.MOD-026, R1.3]*

a) Data concerning excitation limit controls must be submitted for all units. Updated data must be submitted to the Planning Authority and/or Transmission Planner each time changes are made that could affect the limits (such as upgrades and replacements). This data shall be Confirmed during a major generator outage, or when setting changes are implemented.

b) For new or refurbished systems, design data obtained from the vendor and submitted at the time of requisition is sufficient until such time as more accurate data (from commissioning/acceptance testing) can be obtained and submitted to the Transmission Planner.

2. Specific Requirements *[Ref.MOD-026, R1.2 & R1.4.3]*

a) Verification of setpoints may be performed for most of the regulator systems with the generator shutdown by providing simulated inputs (such as PT and CT) of the appropriate magnitude and phase angle and assuring that the regulator responds appropriately when the limit is reached.

b) Underexcition Limiter setpoints could also be checked by lowering excitation with the unit on line until the limiter prevents any further decrease in excitation.

c) If data is retrievable, calibration or maintenance data such as field measurements may be used to calculate limiter characteristics instead of a separate test.

Attachment 1

NERC Reliability Standard MOD-026

A. Introduction

1. **Title:** **Verification of Models and Data for Generator Excitation System Functions**

2. **Number:** MOD-026-1

3. **Purpose:** To ensure accurate information on generator excitation system functions (including voltage regulator controls, limiters, compensators, and power system stabilizers, if applicable) is available for models used to assess Bulk Electric System reliability.

4. **Applicability**

   4.1. Regional Reliability Organization.

   4.2. Generator Owner.

5. **Proposed Effective Date:** To be determined.

B. Requirements

R1. The Regional Reliability Organization shall establish and maintain procedures to address verification of models and data associated with generator excitation system functions including voltage regulator controls, limiters, compensators, and power system stabilizers. These procedures shall include the following:

R1.1. Generating unit exemption criteria including documentation of those units that are exempt from a portion or all of these procedures.

R1.2. Acceptable methods for model and data verification, including any applicable conditions under which the data should be verified. Such methods can include use of manufacturer data, commissioning data, performance tracking, engineering analysis, field verification of equipment settings, testing, simulation and comparison with test results or disturbance monitoring data, etc.

R1.3. Periodicity and schedule of verification and reporting, including a list of report recipients, schedules associated with field changes to existing units, and refurbished units.

R1.4. Information to be reported related to generator excitation system functions:

R1.4.1. Verified manufacturer and type of excitation system/voltage regulator control system (for example, static, brushless, rotating, etc.).

R1.4.2. Verified model for each excitation system/voltage regulator control system with associated gains, time constants, and limits.

R1.4.3. Verified static set points for under and over excitation limiters.

R1.4.4. Verified line drop compensator settings.

R1.4.5. Open circuit test response data showing generator field voltage and generator terminal voltage (exciter field voltage and current data for brushless units).

R1.4.6. Verified model for each power system stabilizer with associated gains, time constants, and limits.

R1.4.7. Confirmation that the verification was conducted with the voltage regulator in the automatic voltage control mode

R1.4.8. Method of verification used.

R1.4.9. Date of verification.

R2. The Regional Reliability Organization shall provide its generator excitation system data verification and reporting procedures, and any changes to those procedures, to the Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners affected by the procedure within 30 calendar days of the approval.

R3. The Generator Owner shall follow its Regional Reliability Organization's procedures for verifying and reporting its models and data associated with generator excitation system functions per MOD-026 R1.

C. Measures

M1. The Regional Reliability Organization shall have available for inspection a procedure for the verification and reporting of models and data associated with its generator excitation system functions in accordance with MOD-026 R1.

M2. The Regional Reliability Organization shall have evidence that its procedure for verification and reporting of generator excitation system data, and any revisions to that procedure were provided to affected Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners within 30 calendar days of approval.

M3. The Generator Owner shall have evidence it provided verification of the models and data associated with its generator excitation system functions, consistent with the Regional Reliability Organization procedure.

Attachment 2

Reporting Form

Excitation Systems Controls

1. **Unit Name:** _____
2. **Company:** _____
3. **Date:** _____
4. **Submitter:** _____
5. **Phone No.** _____

1. Exciter Information:

Manufacturer: _____

Type of Excitation System:

- ☐ Static
- ☐ Brushless
- ☐ Alternator Rectifier
- ☐ Motor Driven dc exciter
- ☐ Shaft Driven dc exciter

2. Voltage Regulator Information:

Manufacturer: _____

Type of Voltage Regulator:

- ☐ Analog
- ☐ Digital
- ☐ Other(describe)
- ☐

3. Does unit have a commissioned Power System Stabilizer (PSS):

Yes_____ No____

If the answer is yes,

Manufacturer: _____

Type of PSS:

- ☐ Single input (delta speed/frequency type)
- ☐ Dual input (integral of accelerating power)
- ☐ Other(describe)
- ☐

Attachment 2

Reporting Form

Excitation Systems Controls

4. Provide the open circuit test data (plots), appropriate voltage regulator and excitation system Standard Model and associated parameters, and documentation/plots showing good correlation between model simulation and OCSR test results.

5. If the unit is equipped with a commissioned PSS, provide the data required in III.F.2.

6. Provide the data required in III.G.2 on Excitation Limit Controls.

MOD-026 SERC Field Test Reporting Form

The purpose of this form is to provide a consistent report format for field testing results after using the SERC Field Test Guideline "Verification of Models and Data for Generator Excitation System Functions". Documentation of the test results will provide feedback showing that the field test was successful and/or will help to enhance the test guideline.

Use the attached SERC Field Test Guideline "Verification of Models and Data for Generator Excitation System Functions" to perform the test (engineering study). Complete one (1) report form for each unit tested.

Provide the following information:

1. How long did it take to perform an Open Circuit Step Response (OCSR) test and collect the relevant data (generator voltage, field voltage and field current) in order to validate the exciter model?
   - Pre-Test Planning & Preparation : _____ Hours
   - Setup of Test Equipment: _____ Hours
   - Time to Prepare Unit for Test: _____ Hours
   - Performance of Test and Data Collection: _____ Hours
2. How long did it take to analyze the test data and get a good correlation between exciter model and the OCSR test? _____ Hours
3. Was a good correlation between the exciter model and the OCSR test obtained? (Yes or No)

   If no please attach additional information as appropriate.
4. What was the magnitude of the step input applied? _____
5. List any material costs associated with this testing.
   _____
   _____
6. Were set points (overexcitation and underexcitation) verified on the voltage regulator (Yes or No). If no, please attach additional information as appropriate.
7. Please list any suggested changes to the guideline?
   _____
   _____
   _____
8. Provide a completed Attachment # 2 to the SERC Field Test Guidelines for Verification of Models and Data for Generator Excitation System Functions (MOD-026).
9. Name of the person completing the form:_____ Phone Number_____ Company Name_____

Send the completed report form, plots, models and documentation to **phuntley@serc1.org**

draft

SERC Field Test Guideline

Verification of Generator Unit Frequency Response

NERC Draft Reliability Standard MOD-027

Revision History

Revision	Date	Comments
0	March 2, 2007	GSFT-TF finalized SERC MOD-027-1 Guideline for Field Test purposes.

Responsible SERC Subgroup & Region Review Group

The Generator Standard Field Test Task Force (GSFT-TF) has been tasked by the Engineering Committee to develop these field test guidelines and to provide assistance to SERC volunteer members. Responsible SERC Subgroup(s) and the Regional Review Group would be assigned only after the successful ballot and NERC B.O.T adoption of draft NERC Reliability Standard MOD-027.

Review and Re-Certification Requirements

Not applicable until the successful ballot and NERC B.O.T adoption of draft NERC Reliability Standard MOD-027.

Effective Dates – Not Applicable:

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List of Attachments

Attachment 1: Draft NERC Reliability Standard MOD-027
Attachment 2: Sample Reporting Form: Turbine and Governor (Speed/Load) Controls Questionnaire
Attachment 3: Definitions of Unit Frequency Response

I. Introduction

In order to effectively evaluate the electric system's performance, the accuracy of data for the interconnected transmission network and the associated generating equipment is critical. This document addresses one such item, generating unit frequency response and associated model data. For dynamic planning and operating studies with a time frame of 0 to 60 seconds, unit frequency response of hydro and conventional fossil steam generating units is primarily influenced by the turbine governor system. Thus, valid models for these type units should focus on the governor system. For combustion turbine based generation (CTs and Combined Cycle), unit frequency response for 0 to 60 seconds can be influenced by both the governor system, if active for frequency control, and other plant control systems such as combustion turbine firing temperature controls, etc. Thus, the development of valid models for these units may require additional control functions. Nuclear generating units typically do not provide a frequency response since their governor systems are generally inactive or insensitive regarding frequency control. If this is the case, the development of valid models for those units is not necessary.

This SERC field test guideline for the NERC Reliability Standards MOD-027 is intended to:

1) Provide guidance for SERC Transmission Planners and Generator Owners/Operators to address verification of generator unit frequency response.
2) Document the GSFT-TF recommended exemption criteria and sister unit philosophy.
3) Document the GSFT-TF recommended Configuration Controls.

After this field test has been completed, and if MOD-027 Reliability Standard is approved and implemented, the GSFT-TF recommends that SERC develop a regional procedure identifying future events for which data should be collected and evaluated by SERC members.

II. Definitions

1. **Confirm (–ed, –ation) –** To assure that plant or equipment conditions (including control settings) that would impact previously provided data has not changed.

2. **Exempt Generation –** Generator(s) that meets the exemption criteria for a particular Validation/test requirement.

3. **Validate (-dated, -dation)** – To establish the accuracy of data used to model electrical equipment. Validation may be achieved through simulation,

operating data, field readings, engineering evaluations or reviews, use of manufacturer data, commissioning data, performance tracking, and/or testing where appropriate.

4. **Verify (Verification)** – To establish through Validation or Confirmation.

5. **Standard Model (or Model) –** A model included with the Power System Simulator, Power Technologies, Inc. (PSS/E) dynamic simulation software. Many Institute of Electrical and Electronics Engineers, Inc. (IEEE) models are included in the standard PSS/E models. Complete model information includes both the name of the Standard Model and the value of each parameter.

III. Requirements/Expectations

A. Generator Exemption Criteria [Ref.MOD-027, R1.2]

In order to maximize the use of resources, it is prudent to exempt generators that are believed to have less significant impact on the reliability of the bulk electric system from data Validation requirements. The exemption criteria specified by these guidelines are based on both the operating voltage of the bulk power system to which the generator is interconnected, and the MVA rating of the generator. When referring to the MVA rating of the generator, at facilities where multiple machines and/or prime movers are required for normal unit operation, the MVA rating refers to the total MVA capacity of the facility. Examples of this include combined cycle or cross compound units.

As documented in the NERC Glossary of Terms, the NERC Board of Trustees approved a definition for the bulk electric system on February 8, 2005 as follows:

> "As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition."

Therefore, for generators interconnected to a power system operated at a voltage of less than 100 kV, Validation is not required. Inasmuch as possible, models and model parameters should be based on the most accurate information available from sources such as the manufacturer, calibration and

maintenance records, field inspection (i.e., estimated parameters), and event data.

Generators with a nameplate rating less than or equal to 75 MVA or that are not connected to the bulk power system are exempt. Table 1 summarizes the Generator Exemption Criteria.

Table 1:

Generator Interconnected kV or MVA Size	Validated Models & Data Required
< 100 kV	No
≥ 100kV & ≤ 75 MVA	No
≥100kV & > 75 MVA	Yes

Generator Exemption Criteria

B. Sister Unit/Equipment Validation Guidelines

Some units have equipment with the same characteristics such that they respond the same as equipment of other units. If it can be demonstrated that the units, equipment, or systems have identical designs, identical major components and identical significant control system settings, then the units can be considered sisters in regard to that equipment or system. In those situations, an assumption can be made for a sister unit by Validating the unit frequency response model for one (sample) unit. Equipment or systems that do not impact the equipment or system to be Validated need not be identical. Units that are sisters in one regard may not be sisters for other equipment or

systems to be Validated. Documentation must exist to demonstrate that the information about the sample unit can be applied to a sister unit. In future Validations, a different sister unit shall be selected to eventually verify that the sister approach was valid.

C. Configuration Controls

The Generator Owner shall implement a program intended to insure the condition of the unit frequency response system (speed / load control system) remains consistent with the state of the equipment when the latest model Validation was performed. This will normally be performed during a major generator outage, or when setting changes are implemented. [Ref.MOD-027, R1.3]

Turbine-Generator speed/load governor systems consist of:

1) a speed signal from the TG
2) a speed load governor controller
3) mechanical (usually hydraulic) actuators and valves (or gates on hydro units)

In general, the speed signal and mechanical portion of the system are not modified unless the overall governor system is being modified. Thus, Configuration Controls do not apply to these two subsystems. The speed load governor controller may vary widely between units due to vintage, retrofit or component modification and thus is the primary focus in the Configuration Controls. The following addresses the key aspects of a Configuration Controls program for the speed load governor controller portion of the system. In cases where the controller is being replaced, the speed/load governor system should be treated like a new governor.

1. Periodically repeating the event based model Validation described in Section D.2 (post-mortem simulation of specific event(s) using dynamics models to validate turbine governor and associated control systems parameters) to assure the existing model parameters for dynamic simulations are accurate.

2. Due to their design, the response of a Mechanical Hydraulic Control (MHC) system is not easily adjustable and thus if properly maintained (replacement of deteriorated components), it is not subject to appreciable performance changes. Thus, no specific Configuration Controls process is necessary.

3. For analog based governor controllers (Electro Hydraulic Control - EHC systems), the Configuration Controls process should consist of a maintenance program that includes regular calibration of the controller to

conform to baseline data (typically previous calibration data) that was used in the previously governor model Validation process described in Section D.2

4. For digital based governor controllers (Digital Electro Hydraulic - DEH systems), the Configuration Controls process should consist of a maintenance program that includes regular calibration of any components that are subject to drift (such as A/D converters) and verification that the configuration files are the same as those utilized in the original Validation activities.

These activities should assure and document that the unit frequency response system modeling parameters are still consistent with the validated baseline model parameters.

D. Turbine and Governor (Speed/Load) Controls [Ref. MOD-027, R1]

1. General Requirements

a) Generator Owners will submit to their Transmission Planner an appropriate speed/load control system Standard Model with associated parameters (based on the most accurate information available from sources such as the manufacturer, calibration and maintenance records, field inspection, operating data and engineering evaluations or reviews) and the Attachment 2 reporting form for each generating unit. The Generator Owner and the Transmission Planner may need to coordinate to determine which Standard Model to use. (Ref.MOD-027, R1.5.1)

b) As detailed in D.2., an event based approach to Validate generator unit frequency response will be utilized.

c) For each new or modified speed/load control system, a Standard Model (based on as-built parameter information available from the vendor) must be submitted in addition to the Attachment 2 questionnaire. The model based on this design data is sufficient until more accurate data (from event analysis or commissioning/acceptance testing) can be obtained and submitted to the Transmission Planner. The Generator Owner and the Transmission Planner may need to coordinate to determine which Standard Model applies and/or what data should be provided. (Ref.MOD-027, R1.4)

d) If there are typical operating modes that have different control parameters, a model must be provided for each mode.

e) Standard Models and/or parameters must be Validated each time

changes are made that could affect the model such as upgrades and replacements or Confirmed at least every five years. (Ref.MOD-027, R1.4)

f) SERC shall provide its frequency response verification and reporting procedures, and any changes to those procedures, to the Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners affected by the procedures within 30 days of approval. (Ref.MOD-027, R2)

g) The Generator Owner and Transmission Planners shall follow the SERC procedure for verifying and reporting its generator unit frequency response. (Ref.MOD-027, R3)

2. Specific Requirements

An event based approach will be utilized to Validate unit frequency response for each applicable generator. Generator response data for specific frequency excursion event(s) will be compared to the unit frequency response predicted by the Standard Models. Validation of the unit frequency response system is achieved by adjusting (if necessary) the turbine governor and associated control systems parameters[1] in the Standard Model until good correlation with the captured event(s) data is obtained. [Ref.MOD-027, R1.3]

a) Speed/load control system response must be Validated with underfrequency event data. In order for event data to be suitable for Validation, the data must

- Record generator electric power and local system frequency
- Record a frequency drop to 59.96 Hz or below (resolution 0.01 Hz)
- Have a generator power resolution of 1% of the generator Continuous Capability
- Record data every 4 to 6 seconds, or more frequently
- Record data for at least 60 seconds, or more depending on the timeframe of the response

b) Generator event data required is unit MW output versus time. This data may be obtained from SCADA systems, data loggers, excitation/governor event capturing systems, dedicated monitoring systems or test instrumentation.

[1] As reference see Pereira, Undrill, Kosterev, Davies and Patterson, "A New Thermal Governor Modeling Approach in the WECC," IEEE Trans. Power Syst., vol 18, pp 819-829, May 2003 and other documents located on the WECC website for the Modeling and Validation Work Group (MVWG) at http://www.wecc.biz/committees/PCC/TSS/MVWG/documents/index.html

c) PSS/E dynamic simulation software will be used by SERC for the NERC Field Test activity of Validating the generator's speed/load control models:

1. A loadflow consisting of a large (MVA) unit representing Eastern Interconnection (EI), a large EI load, the unit whose speed/load model is to be Validated, and any other transmission system elements required to replicate the event will be modeled. The loadflow is expected to have ten or less buses.
2. Transmission system frequency versus time event data will be examined as part of the validation process
3. After creating the dynamic "snap" but before compiling and linking the dynamics executable, "flecs" code will be inserted in the "conec" file. The code will alter the mechanical power of the large EI machine. The result is that the large EI machine will speed up or slow down accordingly, thus changing system frequency to reasonably match the event data.
4. The resulting unit MW versus time output produced by the model will be compared to the actual unit MW versus time output captured by the event data. If good correlation[2] is obtained, Validation of the model is complete. If good correlation is not obtained, the following courses of action should be considered:
   i. Modify the parameters of the unit's existing speed/load model and repeat the Validation process.
   ii. A new model with new parameters could be developed.
   iii. The Generator Owner could investigate why good correlation was not obtained, which could result in refining the unit's frequency response controls
5. Care should be taken to consider more than one frequency excursion event before implementing an updated model into the dynamics database.

d) When Validating the generator power output response of an event simulation with actual recorded event data, the response time to be modeled should be 60 seconds, regardless of unit type. If compromises have to be made in the selection of model parameters, there should be emphasis on selecting parameters that best replicate the generator power output response during the first 30 seconds of the event. (Ref.MOD-027, R1.1).

e) It is recognized by the GSFT-TF that other stand alone software programs could be used to replicate a transmission system frequency

[2] As part of the field test activities efforts will be made to quantify "good correlation."

excursion and subsequently Validate generator unit speed/load control models. The GSFT-TF investigated and determined that PSLF ™, EMTP ™, and MAT LAB ™ software programs could be used for this activity. Therefore, upon the successful ballot and NERC B.O.T and FERC adoption of draft NERC Reliability Standard MOD-027, the GSFT-TF would advise SERC that the aforementioned and other commercially available software tools could be utilized to fulfill the applicable NERC requirements.

f) Reporting

A record of the most recent Validation including information specified in NERC Reliability Standard MOD-027-1 R1.5.1 – R.1.5.4 on each generator shall be maintained by the Validating party and reported to SERC or NERC within 30 days of the request. (Ref.MOD-027, R1.4, R1.5.1 - R1.5.4)

g) Examples

Attachment 3 refers to several types of turbine - governor controllers.

Attachment 1

A. Introduction

1. Title: **Verification of Generator Unit Frequency Response**

2. Number: MOD-027-1

3. Purpose: To provide verification of generator unit frequency response (other than Automatic Generation Control) for use in models for reliability studies.

4. Applicability

4.1. Regional Reliability Organization.

4.2. Generator Owner.

5. Proposed Effective Date: To be Determined.

B. Requirements

R1. The Regional Reliability Organization shall establish and maintain procedures to address verification of generator unit frequency response. These procedures shall include the following:

R1.1. Response time to be modeled, e.g. up to 30 seconds for steam units, up to 45 seconds for hydro units, etc.

R1.2. Generating unit exemption criteria including documentation of those units that are exempt from a portion or all of these procedures.

R1.3. Acceptable methods for model and data verification, including any applicable conditions under which the data should be verified. Such methods can include use of manufacturer data, commissioning data, performance tracking, engineering analysis, field verification of equipment settings, testing, simulation and comparison with test results or disturbance monitoring data, etc.

R1.4. Periodicity and schedule of verification and reporting, including a list of report recipients, schedules associated with field changes to existing units, and refurbished units.

R1.5. Information to be reported related to generator unit frequency response:

R1.5.1. Verified manufacturer and type of speed governor controls.

R1.5.2. Verified model for each speed governor control with any associated deadband, gains, time constants, and limits (e.g., maximum valve opening velocity, maximum capability of the turbine, etc.).

R1.5.3. Verified frequency response data of the unit, considering additional plant controls that affect the response of the unit (blocked or nonfunctioning governors or modes of operation that limit frequency response).

R1.5.4. Method of verification and conditions of the verification including status of controls.

R2. The Regional Reliability Organization shall provide its frequency response verification and reporting procedures, and any changes to those procedures, to the Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners affected by the procedures within 30 calendar days of the approval.

R3. The Generator Owner shall follow its Regional Reliability Organization's procedure for verifying and reporting its generator unit frequency response per MOD-027 R1.

Attachment 1

C. Measures

M1. The Regional Reliability Organization shall have available for inspection a procedure for verifying and reporting generator unit frequency response in accordance with MOD-027 R1.

M2. The Regional Reliability Organization shall have evidence that its procedure, and any revisions to that procedure, for verification and reporting generator unit frequency response was provided to affected Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners within 30 calendar days of approval.

M3. The Generator Owner shall have evidence it provided verification of the models and data associated with generator unit frequency response, consistent with the Regional Reliability Organization procedure.

Attachment 2

Sample Reporting Form

Turbine and Governor (Speed/Load) Controls Questionnaire

1. **Unit Name:** _____
2. **Company:** _____
3. **Date:** _____
4. **Submitter:** _____
5. **Phone No.** _____

Governor Information:

Identify general type of governor control:

- ☐ Mechanical hydraulic (MHC)
- ☐ Analog electro-hydraulic (EHC)
- ☐ Digital electro-hydraulic (DEH)
- ☐ _____

Check type of governor model submitted:

- ☐ PTI Standard Model with As built parameters
- ☐ PTI Standard Model with Estimated Parameters
- ☐ PTI Standard Model with Parameters derived from event(s) based Validation(s)

Droop Setting (%): _____

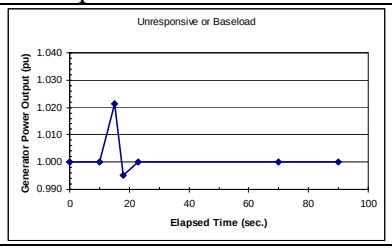
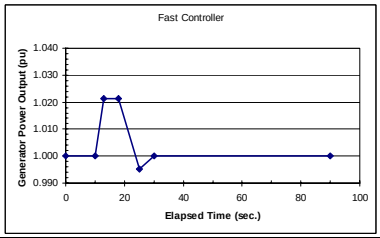
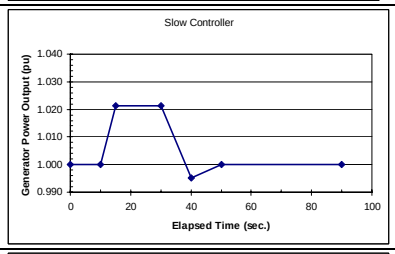
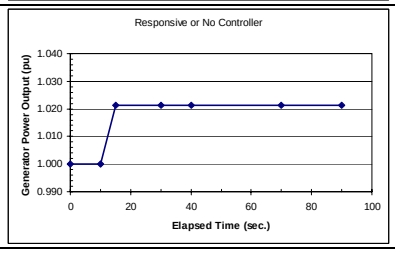
Attachment 3

Definitions of Unit Frequency Response

Steam units may operate in several modes, but for modeling these three will be considered:

Baseload –	Operating at or near maximum output
Setpoint Control –	Operating such that other controls will override automatic action of the governor. Typically the setpoint is related to load and temperature limits.
Responsive –	Operating with typical governor control without other automatic override controls.

Based on the above information and the diagram below, the type of turbine – governor response for thermal units is defined:

	Thermal		Examples†
	Type UC	Unresponsive, baseload unit (very quickly returns to near baseload after an initial response)	
	Type FC	Fast controller, shorter response (quickly returns to near baseload)	
	Type SC	Slow controller, longer response (responds for a short time, then returns to near baseload)	
	Type NC	No controller, responsive	

† Just to illustrate what each type may look like, some example charts are given. The event is assumed to occur at 10 seconds and a hypothetical change in generator output is depicted.

Gas turbine units are divided into two categories:

	Gas	
	Type GL	with load controller
	Type GN	no load controller

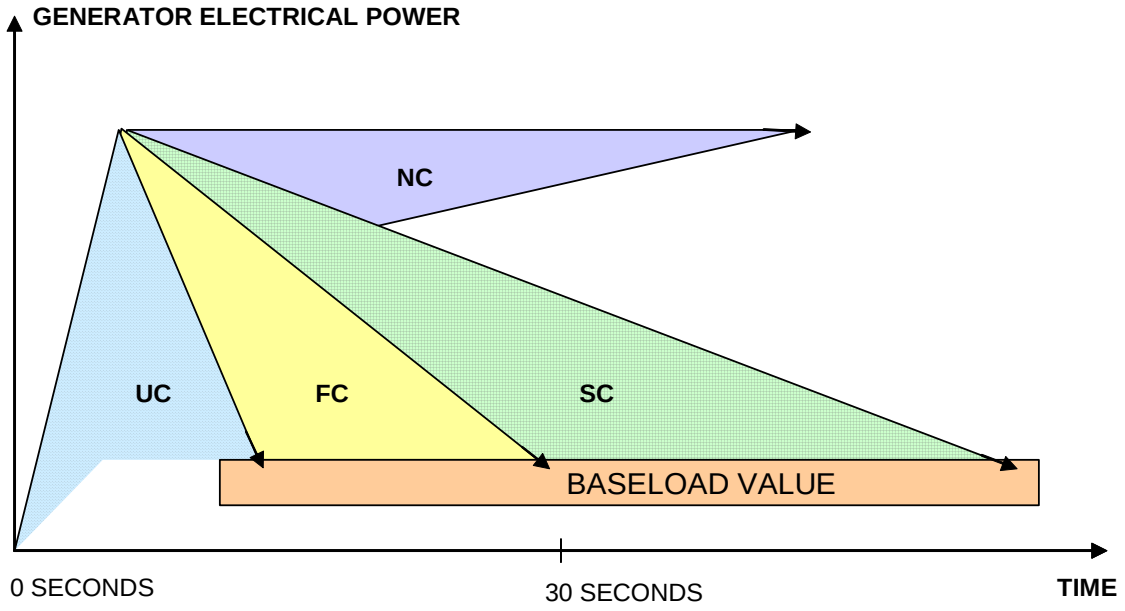


Figure A3-1, General characteristics of each type of turbine – governor response

MOD-027 SERC Field Test Reporting Form

The purpose of this form is to provide a consistent report format for field testing results after using the SERC Field Test Guideline "Verification of Generator Unit Frequency Response". Documentation of the test results will provide feedback showing that the field test was successful and/or will help to enhance the test guideline.

Use the attached SERC Field Test Guideline "Verification of Generator Unit Frequency Response" to perform the test (engineering study). Complete one (1) report form for each unit tested.

Provide the following information:

1. Is there a maintenance management program in place for the turbine speed load governor control system (analog and/or digital based)? (Yes or No)
   - If yes, what is the maintenance interval? (months)
2. Is there a configuration management program in place for the turbine speed load governor control system (analog and/or digital based)? (Yes or No)
3. Was good correlation between the generator output (MW vs. time) and the model obtained? (Yes or No)

   3. A. **If yes:** (Use additional pages if needed to explain.)
   - How long did it take to obtain the generator output data? (hours)
   - How long did it take to set up the model to simulate this event? (hours)
   - How long did it take to compare the generator output data to the model? (hours)
   - Did the model parameters or type need to be changed?

   3. B. **If No:**
   - Use additional pages to explain.
4. List any material costs associated with this study.
5. Please list any suggested changes to the guideline?
6. Provide a completed Attachment # 2 to the SERC Field Test Guidelines for Verification of Generator Unit Frequency Response (MOD-027).
7. Name of the person completing the form: Phone Number:

   Company Name:

Send the completed report form and supporting documentation electronically to: phuntley@serc1.org.

draft

SERC Field Test Guideline

Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection

NERC Reliability Standard PRC-019

SERC Reliability Corporation

Revision History

Revision	Date	Comments
0	August 28, 2006	GSFT-TF finalized SERC PRC-019-1 Guideline for Field Test purposes.

Responsible SERC Subgroup & Region Review Group

The Generator Standard Field Test Task Force (GSFT-TF) has been tasked by the Engineering Committee to develop these field test guidelines and to provide assistance to SERC volunteer members. Responsible SERC Subgroup(s) and the Regional Review Group would be assigned only after the successful ballot and NERC B.O.T adoption of draft NERC Reliability Standard PRC-019.

Review and Re-Certification Requirements

Not applicable until the successful ballot and NERC B.O.T adoption of draft NERC Reliability Standard PRC-019.

Effective Dates:

Not applicable until the successful ballot and NERC B.O.T adoption of draft NERC Reliability Standard PRC-019.

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Attachment 2: Example – Over Excitation Capability Coordination
Attachment 3: Example – Generator Field Over Excitation Limiter/Protection Coordination
Attachment 4: Example – Volts/Hertz Coordination
Attachment 5: Example – Under Excitation Capability Coordination
Attachment 6: Example – Circle and Radius Equations

I. Introduction

This SERC field test guideline for the NERC Reliability Standards PRC-019 is intended to:

1) Provide guidance for SERC Generator Owners/Operators in conducting studies to show coordination of generator voltage regulator controls with unit capabilities and protection as specified by the NERC Reliability Standards (Section IIIA).
2) Document the GSFT-TF recommended exemption criteria (Section IIIA) and sister unit philosophy (Section IIIB).

II. Definitions

1. **Generator Capability Curve –**A graphical presentation of data that illustrates the thermal limits of the combined real and reactive power capability of the generator at the specified terminal voltage.
2. **Additional Definitions to be added as needed.**

III. Requirements/Expectations

A. **Generator Exemption Criteria** [*Ref.PRC-019, R2.*]

In order to maximize the use of resources, it is prudent to exempt generators that are believed to have less significant impact on the reliability of the bulk electric system from maintaining rigorous documentation of generator control and protective relay coordination study results. The exemption criteria specified by this guideline are based on both the operating voltage of the bulk power system to which the generator is interconnected, and the MVA rating of the generator. When referring to the MVA rating of the generator, at facilities where multiple machines and/or prime movers are required for normal unit operation, the MVA rating refers to the total MVA capacity of the facility. Examples of this include combined cycle or cross compound units.

As documented in the NERC Glossary of Terms, the NERC Board of Trustees approved a definition for the bulk electric system on February 8, 2005 as follows:

> "As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition."

Therefore, for generators interconnected to a power system operated at a voltage of less than 100 kV, a documented study demonstrating the coordination of generator voltage regulator controls with unit capabilities and protection is not required.

Generators with a nameplate rating less than or equal to 75 MVA or that are not connected to the bulk power system are exempt.

Table 1 summarizes the Generator Exemption Criteria.

Generator Interconnected kV or MVA Size	Study Documentation of Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection Required
< 100 kV	No
> 100kV & ≤ 75 MVA	No
>100kV & > 75 MVA	Yes

Table 1: Generation Exemption Criteria

B. Sister Unit/Equipment Verification Guidelines

If it can be demonstrated that the generators, voltage regulator and exciters along with their control and protection system equipment and settings are all identical, then the units can be considered sisters units. In those situations, an assumption can be made for a sister unit by coordinating the generator voltage regulator controls with unit capabilities and protection for one (sample) unit. Documentation must exist to demonstrate that the information about the sample unit can be applied to a sister unit.

C. Requirements [*Ref. PRC-019, R2.1*]

1. Generator owner/operator to develop (or retrieve from generator manufacturer) the Generator Capability Curve for each non-exempt generating unit. This curve shall include specification of nominal voltage, ambient air or cooling temperature, or hydrogen pressure as appropriate. [*Ref. PRC-019, R2.1.1*]

2. Generator owner/operator to show on the Generator Capability Curve and other appropriate curves (plots) that the coordination of the generator voltage regulator controls and limit functions are coordinated with the generator's capabilities and protective relays. The completed curves (plots) should show the following as appropriate (See Attachments 2 through 5):

    a) Steady state over-excitation and under excitation limiter control characteristics. [*Ref. PRC-019, R2.1.2*]

    b) Power output limit of the unit, as verified per MOD-024. [*Ref. PRC-019, R2.1.3*]

    c) Other factors that could limit megawatt or megavar capability. [*Ref. PRC-019, R2.1.4*] Example: generator step-up transformer MVA rating, generator rotor with shorted turn, steady state transmission and station auxiliary bus voltage limits, etc.

    d) Loss of excitation relay / field protection relay characteristics [*Ref. PRC-019, R2.1.5*]

    e) Coordination of the volts per hertz protection system(s), including limiters, relating to the generator, generator step-up transformer, normal station service transformer. [*Ref. PRC-019, R2.1.6*]

Attachment 1

A. Introduction

1. Title: Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection

2. Number: PRC-019-1

3. Purpose: Ensure generator voltage regulator controls and limit functions are coordinated with the generator's capabilities and protective relays.

4. Applicability

4.1. Regional Reliability Organization.

4.2. Generator Owner.

5. Proposed Effective Dates: To be determined:

One year beyond Board of Trustee adoption for Requirement 1

Two years beyond Board of Trustee adoption 1st 20% compliant with Requirement 2 and Requirement 3

Three years beyond Board of Trustee adoption 2nd 20% compliant with R2, R3

Four years beyond Board of Trustee adoption 3rd 20% compliant with R2, R3

Five years beyond Board of Trustee adoption 4th 20% compliant with R2, R3

Six years beyond Board of Trustee adoption 5th 20% compliant with R2, R3

B. Requirements

R1. The Regional Reliability Organization shall establish and maintain criteria for exemptions to any of the Generator Owner requirements in R2.

R2. Unless exempted by the Regional Reliability Organization in accordance with R1, the Generator Owner shall have study results that show it verified that its generator voltage regulator controls and limit functions are coordinated with the generator's capabilities and protective relays. This study shall include the following:

R2.1. Plots, or data that could be plotted for the following:

R2.1.1. Generator capability curve, including specification of nominal voltage, ambient air or cooling temperature, or hydrogen pressure.

R2.1.2. Steady state over-excitation limiter and under-excitation limiter control characteristics.

R2.1.3. MW limit of the prime mover.

R2.1.4. Any other limit that could restrict the megawatt or megavar capability.

R2.1.5. Loss of excitation / field protective relay characteristics.

R2.1.6. Volts-per-hertz protection settings including volts-per-hertz limiters in the automatic voltage regulator.

R3. The Generator Owner shall have the information in R2.1.1 through R2.1.6 available to show to the Regional Reliability Organization upon request (within 30 calendar days).

C. Measures

M1. The Regional Reliability Organization shall, within 30 calendar days of a request, provide to Generator Owners its exemption criteria defined in accordance with R1.

M2. The Generator Owner shall have evidence it showed the Regional Reliability Organization the information identified in R2.1 through R2.1.6 within 30 calendar days of a request.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

NERC for the Regional Reliability Organization.

Regional Reliability Organization for Generator Owners.

1.2. Compliance Monitoring Period and Reset Timeframe

The compliance reset period is one calendar year.

1.3. Data Retention

The Generator Owner shall retain all current information needed to show coordination. The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Regional Reliability Organization and Generator Owner shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance

2.1. Level 1: The Regional Reliability Organization did not provide the exemption criteria in accordance with R1.

2.2. Level 2: The Generator Owner information on coordination of the generator voltage regulator controls and limit functions does not address one of the requirements identified in accordance with R2.1.1 through R2.1.6.

2.3. Level 3: Not applicable.

2.4. Level 4: The Generator Owner information on coordination of the generator voltage regulator controls and limit functions does not address two or more of the requirements identified in accordance with R2.1.1 through R2.1.6.

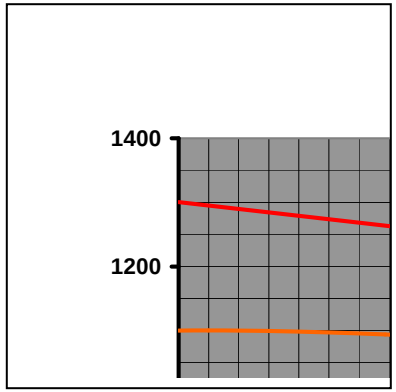
E. Regional Differences

None identified.

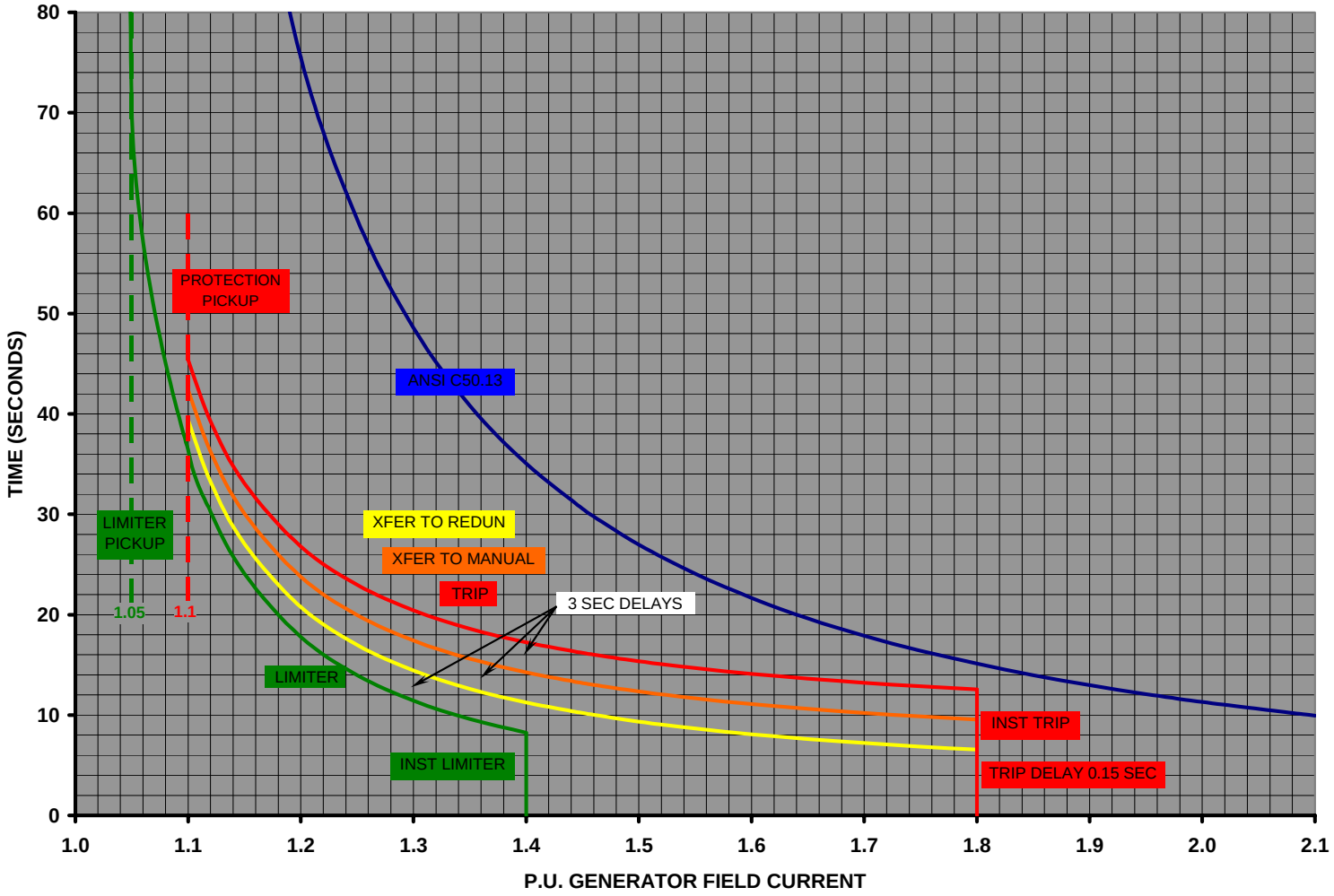
a. Version History

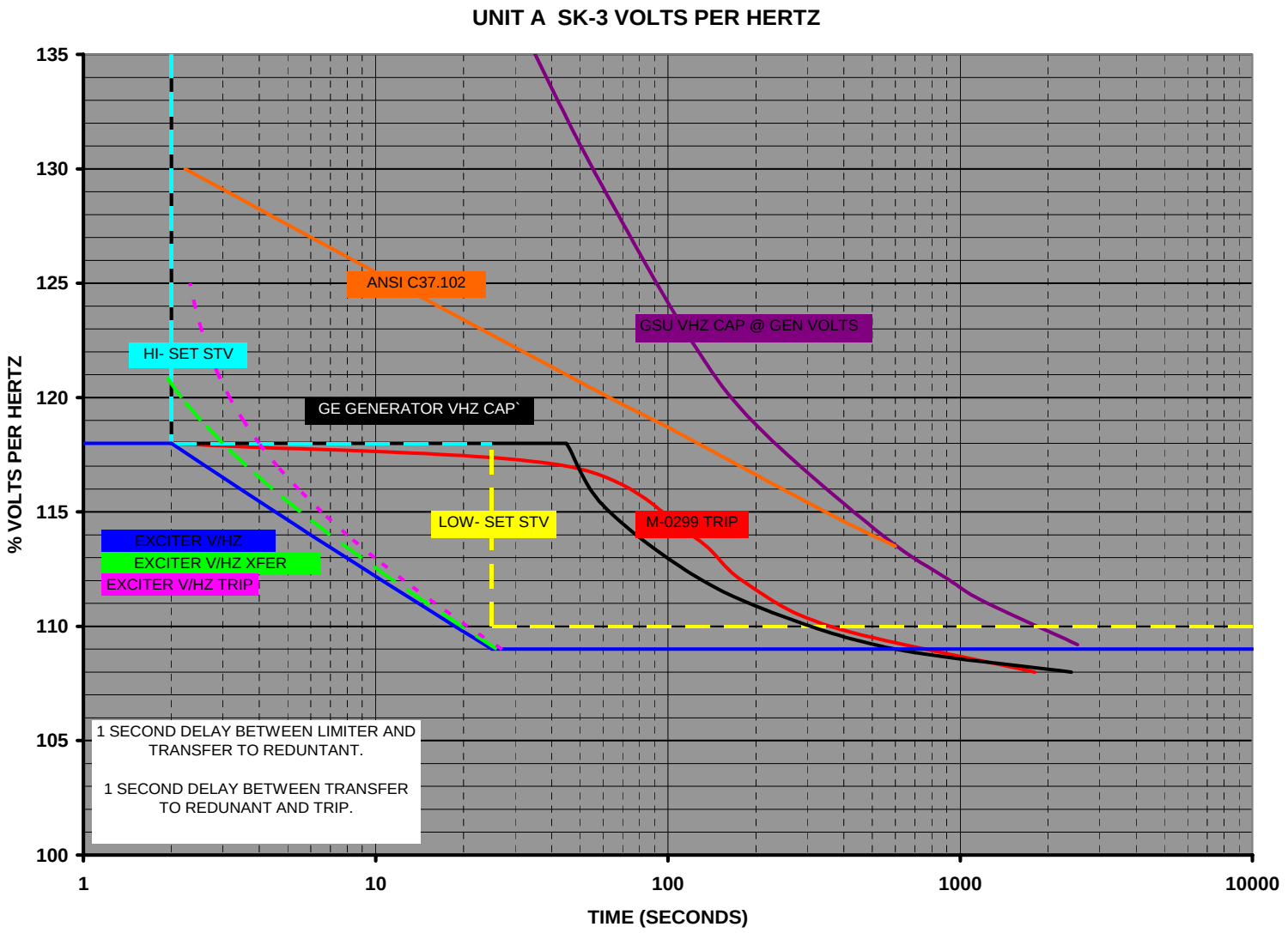
Version	Date	Action	Change Tracking

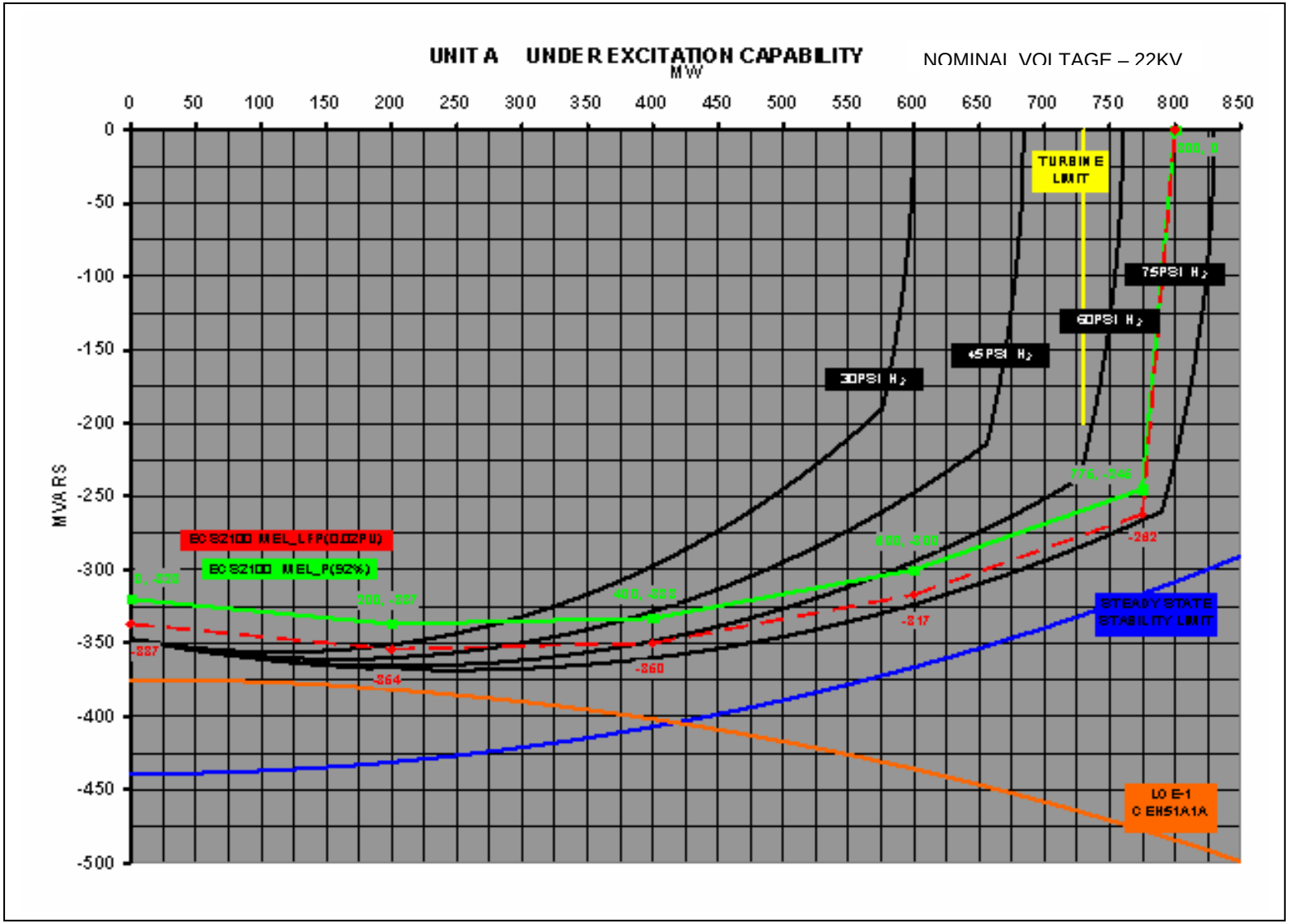
Attachment 2



UNIT A SK-2 GENERATOR FIELD OVER EXCITATION LIMITER/PROTECTION




UNIT A SK-3 VOLTS PER HERTZ
% VOLTS PER HERTZ
TIME (SECONDS)
135
130
125
120
115
110
105
100
1
10
100
1000
10000
ANSI C37.102
GSU VHZ CAP @ GEN VOLTS
HI- SET STV
GE GENERATOR VHZ CAP`
LOW- SET STV
M-0299 TRIP
EXCITER V/HZ
EXCITER V/HZ XFER
EXCITER V/HZ TRIP
1 SECOND DELAY BETWEEN LIMITER AND TRANSFER TO REDUNTANT.
1 SECOND DELAY BETWEEN TRANSFER TO REDUNANT AND TRIP.


UNIT A UNDER EXCITATION CAPABILITY
NOMINAL VOLTAGE – 22KV
MW
MVARS
0
50
100
150
200
250
300
350
400
450
500
550
600
650
700
750
800
850
-50
-100
-150
-200
-250
-300
-350
-400
-450
-500
TURBINE LIMIT
75PSI H2
60PSI H2
45PSI H2
30PSI H2
ECS2100 MEL_LFP(0.002PU)
ECS2100 MEL_P(92%)
0, -330
200, -287
400, -333
600, -308
776, -246
800, 0
-287
-364
-360
-317
-282
STEADY STATE STABILITY LIMIT
LO E-1
C EH51A1A

Attachment 6

Circle and Radius Equations

Equations used to plot the different segments of the Generator Capability Curve.

CENTER AND RADIUS OF CIRCLE GIVEN THREE POINTS $(X_1\ Y_1)$ $(X_2\ Y_2)$ $(X_3\ Y_3)$

$$AX^2 + CY^2 + BXY + DX + EY + F = 0$$

WHERE: A = C and B = 0

COMPLETING THE SQUARE:

$$A\left(X + \frac{D}{2A}\right)^2 + A\left(Y + \frac{E}{2A}\right)^2 + F - \frac{D^2 + E^2}{4A} = 0$$

STANDARD CIRCLE EQN.

$$(X - H)^2 + (Y - K)^2 = R^2$$

CENTER COORDINATES: $X_C = -\frac{D}{2A}$ $\quad Y_C = -\frac{E}{2A}$

RADIUS LENGTH: $R = \sqrt{\frac{D^2 + E^2}{4A^2} - \frac{F}{A}}$

$$A = \begin{vmatrix} X_1 & Y_1 & 1 \\ X_2 & Y_2 & 1 \\ X_3 & Y_3 & 1 \end{vmatrix} \qquad D = -\begin{vmatrix} (X_1^2 + Y_1^2) & Y_1 & 1 \\ (X_2^2 + Y_2^2) & Y_2 & 1 \\ (X_3^2 + Y_3^2) & Y_3 & 1 \end{vmatrix}$$

$$E = \begin{vmatrix} (X_1^2 + Y_1^2) & X_1 & 1 \\ (X_2^2 + Y_2^2) & X_2 & 1 \\ (X_3^2 + Y_3^2) & X_3 & 1 \end{vmatrix} \qquad F = -\begin{vmatrix} (X_1^2 + Y_1^2) & X_1 & Y_1 \\ (X_2^2 + Y_2^2) & X_2 & Y_2 \\ (X_3^2 + Y_3^2) & X_3 & Y_3 \end{vmatrix}$$

SERC PRC-019 Field Test Reporting Form

The purpose of this form is to provide a consistent report format for field testing results after using the SERC Field Test Guideline "Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection". Documentation of the test results (this field test may actually be considered an engineering study) will provide feedback showing that the field test was successful and/or will help to enhance the test guideline.

Use the SERC Field Test Guideline "Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection" to perform the test (engineering study). It is suggested that a newer, more modern generating unit be used for the test, to verify the coordination of more different types of protection relay systems (versus an older unit that may not have as many generator protection relays). Complete one (1) report form for each unit tested (studied).

Provide the following information:

1. How long did it take to assemble (bring together) the technical data (generator capability curve(s), voltage regulator settings, protective relay settings, etc.) needed to perform the engineering study? _____ Hours
2. What methodology / tools were used to perform the coordination studies?
   - ☐ Computerized coordination curves
   - ☐ Manual coordination curves
   - ☐ Combination (computerized / manual)
3. How many man-hours did it take to develop the methodology / tools? _____
4. How long did it take to analyze the technical information and draw the curves (plots)? _____ Hours
5. List any material costs associated with this study.
   _____
   _____
6. Were the voltage regulator settings and the protective relay settings coordinated with the generator capability curve (as found)? _____ (Yes or No)
7. If not, list the devices that needed configuration changes:
   _____
   _____
8. Please list any suggested changes to the guideline or Draft NERC Reliability standard?
   _____
   _____
9. Provide the completed curves (plots). Remove all references that would identify the unit (company, station, and unit names, etc)
10. Name of person completing form: _____ Phone number _____

    Company name _____

Send the completed report form and coordination curves electronically to: phuntley@serc1.org.

SERC Field Test Guidelines

Generator Performance During Frequency and Voltage Excursions

NERC Draft Reliability Standards PRC-024

DRAFT

SERC Reliability Corporation

Revision History

Revision	Date	Comments
0	March 2, 2007	GSFT-TF finalized SERC PRC-024-1 Guideline for Field Test purposes.

Responsible SERC Subgroup & Region Review Group

The Generator Standard Field Test Task Force (GSFT-TF) has been tasked by the Engineering Committee to develop these field test guidelines and to provide assistance to SERC volunteer members. Responsible SERC Subgroup(s) and Region Review Group would be assigned only after the successful ballot and NERC B.O.T adoption of draft NERC Reliability Standard PRC-024.

Review and Re-Certification Requirements

Not applicable until the successful ballot and NERC B.O.T adoption of draft NERC Reliability Standard PRC-024.

Effective Dates – Not Applicable:

DRAFT

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List of Attachments

Attachment 1: Draft NERC Reliability Standard PRC-024

I. Introduction

In order to effectively evaluate the electric system's performance, Transmission Planners make implicit or explicit assumptions regarding the ability of generators to remain on-line during frequency and voltage excursions. The validity of these assumptions are critical for planning and operating studies of the reliability of the electric system. These assumptions are especially critical for studies used to develop "safety-net" schemes such as Under Frequency Load Shedding (UFLS) and Under Voltage Load Shedding (UVLS). Incorrect assumptions regarding the ability of generators to remain on-line would lead to ineffective or suboptimal load shedding schemes.

This SERC field test guideline for the NERC Reliability Standards PRC-024 is intended to:

1) Provide guidance for SERC Generator Owners to address verification of the capability of generators to remain connected to the electrical grid during defined system frequency and voltage excursions.
2) Provide guidance for SERC Generator and Transmission Owners to:
    a. Address coordination between the generator under frequency protection and SERC's UFLS program.
    b. Address coordination of generator protection with transmission protection systems.
3) Document the GSFT-TF recommended exemption criteria, variance requests, and sister unit philosophy.

It is recognized that any effort to verify the capability of generators to remain connected during defined system frequency and voltage excursions does not constitute a guarantee by the Generator Owner. There are systems in a generation plant where practical means are not readily available to determine how they would respond to the frequency and voltage excursion, and/or if a trip of these systems would subsequently cause an immediate or delayed generator trip. These systems include, but are not limited to, Boiler Control Systems, Adjustable Speed Drives, and station auxiliary loads (motor performance due to undervoltage or underfrequency, and loss of load due to dropout of unlatched contactors).

Therefore, the GSFT-TF is recommending for these field test activities a verification process meant to uncover protection system coordination issues that would almost certainly lead to a generator tripping if exposed to the defined frequency or voltage excursion. As such, the likelihood of the generator remaining on-line during the defined frequency or voltage excursion would be increased and lend some additional validity to study assumptions made by Transmission Planners.

II. Definitions

1. **Exempt Generation –** Generator(s) that meets the exemption criteria for a particular

requirement.

2. **Low Voltage Ride Through (LVRT) Capability** – the ability of a generator to remain on-line when subjected to a defined transmission system voltage excursion.
3. **Variance** – a deviation in the established RRO requirement for a generator to remain on-line during system frequency and/or voltage excursion.

III. Requirements/Expectations

A. Generator Exemption Criteria [*Ref. PRC-024, R3*]

It is prudent to exempt small generators that, if they are unable to stay on-line for certain frequency and voltage excursions, would be expected to have an insignificant impact on the reliability of the bulk electric system. Therefore, generators interconnected to a power system operated at a voltage of less than 100 kV or having a nameplate rating of less than or equal to 75 MVA are exempt from complying with SERC's requirements for generators to remain connected during the defined frequency and voltage excursions. On a case by case basis the Transmission Planner may identify certain generators that are less than 75 MVA, but have a significant impact on transmission voltage security, and cannot be exempted from the low voltage ride-through requirements.

B. Variance Procedures [*Ref. PRC-024, R4*]

It is recognized that efforts to ensure coordination between generator protection systems and the Region's defined voltage and frequency excursion could result in identification of generators who have systems that will be unable to achieve coordination. In those instances, the Generator Owner can request a Variance from SERC. SERC, the Generator Owner, and the Transmission Owner will then work together to determine if the requested Variance would adversely impact bulk power system reliability. In no instances should any protection or control scheme setting be endorsed that exposes a generating unit to damage.

C. Requirements for Generators to Remain Connected During System Frequency and Voltage Excursions

1. Frequency Excursion Requirements

a) To ensure coordination with under-frequency load shed (UFLS) schemes, generator protection schemes are expected to be set such that the generator would remain on-line when subjected to the frequency excursion curve defined in Figure 1 [*Ref. PRC-024, R1*] .

b) The process of determining coordination with the frequency excursion curve defined in Figure 1 assumes that the corresponding transmission system voltage remains within scheduled limits.

c) The Generator Owner can demonstrate coordination with transmission system UFLS schemes through the development of a coordination curve (reference Figure 2).

d) If generator protection schemes are set such that the generator would not be expected to stay on line for the frequency excursion curve shown in Figure 1, the Generator Owner should investigate if the schemes can be relaxed without exposing the generator to potential damage. This could include consultation with the Original Equipment Manufacturer. If the protection schemes cannot be adjusted such that the generator would stay on line for the frequency excursion shown in Figure 1, the Generator Owner should request a Variance (reference Section B).

e) To reasonably assure the generators capability to remain on-line during the frequency excursion defined in Figure 1, expected performance of the following systems should be evaluated:

(1) Turbine Generator protection
Specific protective relays that should be checked for coordination with the frequency excursion defined in Figure 1 include turbine frequency protection and volts per hertz.

(2) Nuclear Power Plant Systems
Systems that are both unique to Nuclear power plant systems and are potentially sensitive to under frequency excursions should be checked for coordination with the frequency excursion defined in Figure 1. These systems include Reactor Coolant Pumps for PWRs and Reactor Recirc Pumps for BWRs.

f) To ensure coordination with generator turbine underfrequency protection schemes, UFLS schemes are expected to be designed to initiate load shed for frequency excursions which are less severe than the curve defined in Figure 1. In order to show the coordination, the Transmission Owner is required to develop a coordination curve – an example is shown in Figure 3. This activity should occur at the same time that the UFLS scheme review of the set points and timing is conducted per NERC Reliability Standard PRC-006 R.1.4.1. [*Ref. PRC-024, R2.1.*]

2. Voltage Excursion Requirements

a) To ensure the interconnected transmission system is planned appropriately per the requirements in TPL-001 through TPL-004, generator protection schemes are expected to be set such that the generator would have sufficient LVRT capability to remain on-line when subjected to the voltage excursion curve defined in Figure 4 [*Ref. PRC-024, R1*]

b) The process of determining coordination with the voltage excursion curve

defined in Figure 4 assumes that the corresponding transmission system frequency remains at 60 Hertz.

c) The SERC under-voltage excursion curve, shown in Figure 4, is defined at the generator's highside transmission bus. Note that the time at Voltage 0 in Figure 4 would typically be dictated by transient stability limits. If the LVRT Capability of the generator corresponds to a Voltage 0 time which is less than the transient stability limit, the Generator Owner should work with the Transmission Owner to determine if any additional action is required.

d) The technical drivers dictating the flat and then gradual recovery to 80% within 2 seconds depicted on the generator LVRT curve in Figure 4 include:

(1) Captured event data verify that fault activity resulting in similar voltage signatures as depicted in Figure 4 have occurred in SERC as a result of fault activity.
(2) In order to design secure UVLS safety net schemes, SERC utilities have installed UVLS schemes with logic to trip load include time delays from approximately 1 to just beyond 2.0 seconds. Thus, a minimum LVRT of 2.0 seconds is required.
(3) Detailed dynamic simulations consistently confirm that the transmission system does not have to be significantly further stressed to transition from a delayed voltage recovery of 2 second at the highside of generation plants to a "no recovery" wide area fast voltage collapse scenario. Therefore, if critical generation units trip before UVLS schemes can operate, the transmission system will have exposure to credible wide area voltage collapse scenarios that may or may not be contained to a control area.

e) To reasonably assure the generators LVRT Capability to withstand the voltage excursion defined in Figure 4, expected response to the voltage excursion by the following systems should be evaluated:

(1) Station Service Bus Under Voltage Relays
All station service under voltage relays which protect buses and/or individual loads that contain known loads critical to the generator remaining on-line should coordinate with the under-voltage excursion curve depicted in Figure 4.
(2) Generator Under Voltage Relays
The settings of any generator under voltage relay should coordinate with the under-voltage excursion curve depicted in Figure 4.
(3) Loss of Field and/or Power Potential Source Exciter PPT Secondary Relaying
The setting of any loss of field and/or power potential source exciter PPT secondary relay(s) should be checked for coordination with the under-voltage excursion curve depicted in Figure 4.
(4) Generator Backup relays (Overcurrent and/or Distance)

Suggested screening method for Generator Backup Distance relay: 1) Note the time delay. 2) Note the per unit voltage at the time delay noted in Step 1. 3) Calculate the corresponding impedance seen by the relay. Note that an increase in per unit voltage can generally be assumed on the low side of the generator GSU.

(5) Nuclear Power Plant Loss of Offsite Power Relays.

f) If generators are unable to withstand the under-voltage excursion shown in Figure 4, the Generator Owner should investigate the possibility of increasing the LVRT Capability of the Generators. If the voltage excursion withstand capability cannot be adjusted such that the generator would be expected to remain on line for the under-voltage excursion shown in Figure 4, the Generator Owner should request a Variance (reference Section B).

g) To ensure coordination between generator unit and transmission protection, the Transmission Owner and the Generator Owner should exchange relay setting information and develop coordination plots. These coordination plots should depict generator back-up protection and transmission system back-up protection, including UVLS protection, as appropriate. [Ref. PRC-024, R2.2]

3. SERC Documentation Requirements

a) SERC shall provide documentation of its excursion requirements, exemptions, and variance procedure to the Transmission Owners and Generator Owners within its Region within 30 calendar days of approval. [Ref. PRC-024, R5]

b) SERC shall, at least every five years, review and, as necessary, update its requirements, exemption criteria, and variance procedure. [Ref. PRC-024, R6]

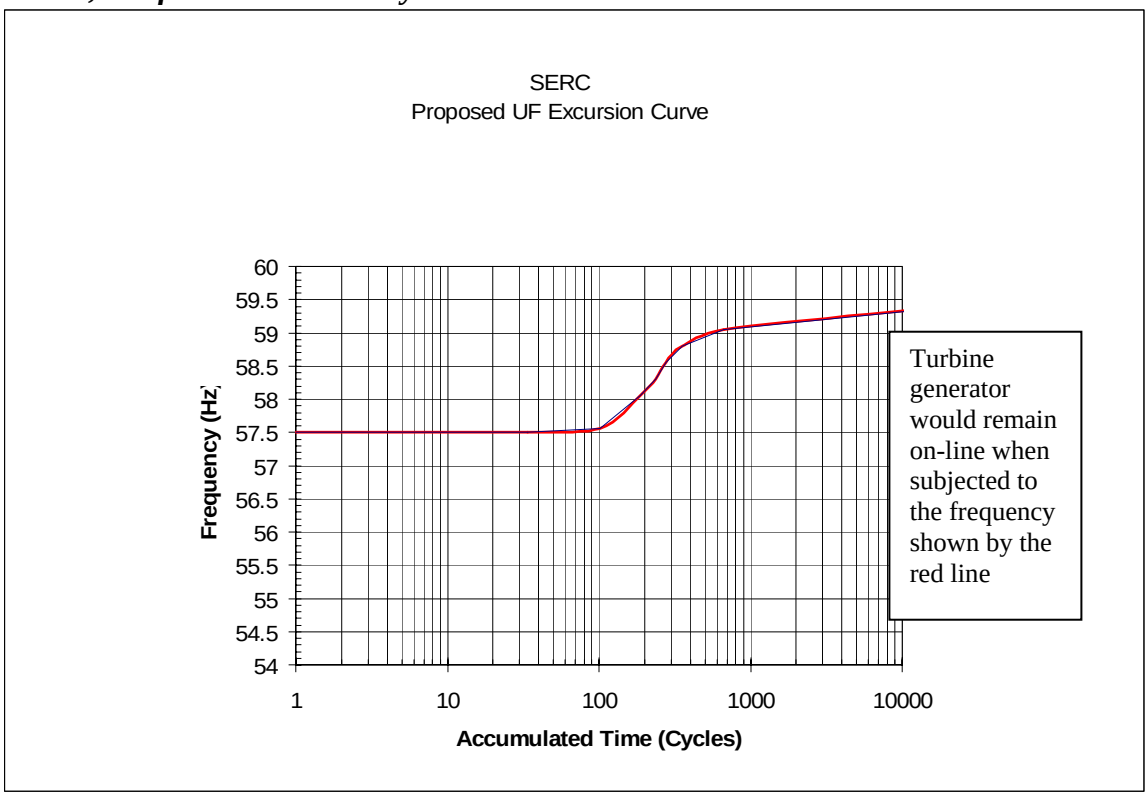
SERC
Proposed UF Excursion Curve
Frequency (Hz)
60
59.5
59
58.5
58
57.5
57
56.5
56
55.5
55
54.5
54
1
10
100
1000
10000
Accumulated Time (Cycles)
Turbine generator would remain on-line when subjected to the frequency shown by the red line

Figure 1

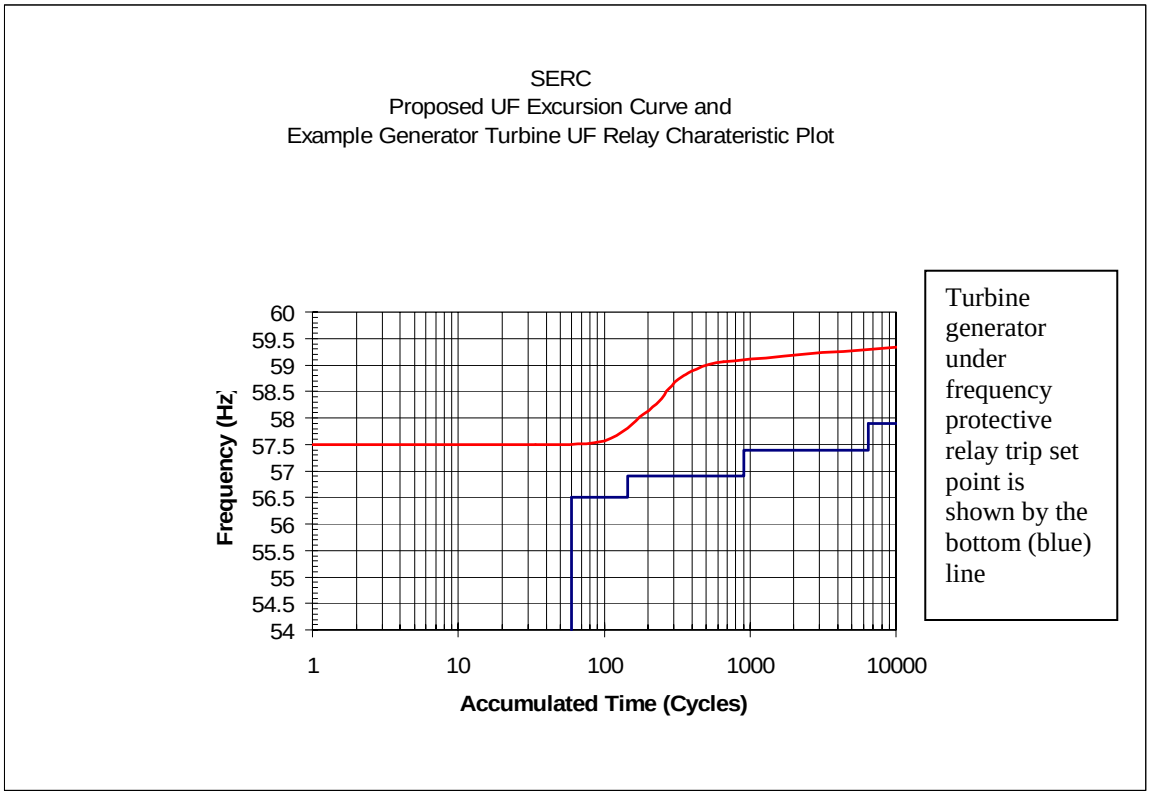
SERC
Proposed UF Excursion Curve and
Example Generator Turbine UF Relay Charateristic Plot
Frequency (Hz)
60
59.5
59
58.5
58
57.5
57
56.5
56
55.5
55
54.5
54
1
10
100
1000
10000
Accumulated Time (Cycles)
Turbine generator under frequency protective relay trip set point is shown by the bottom (blue) line

Figure 2

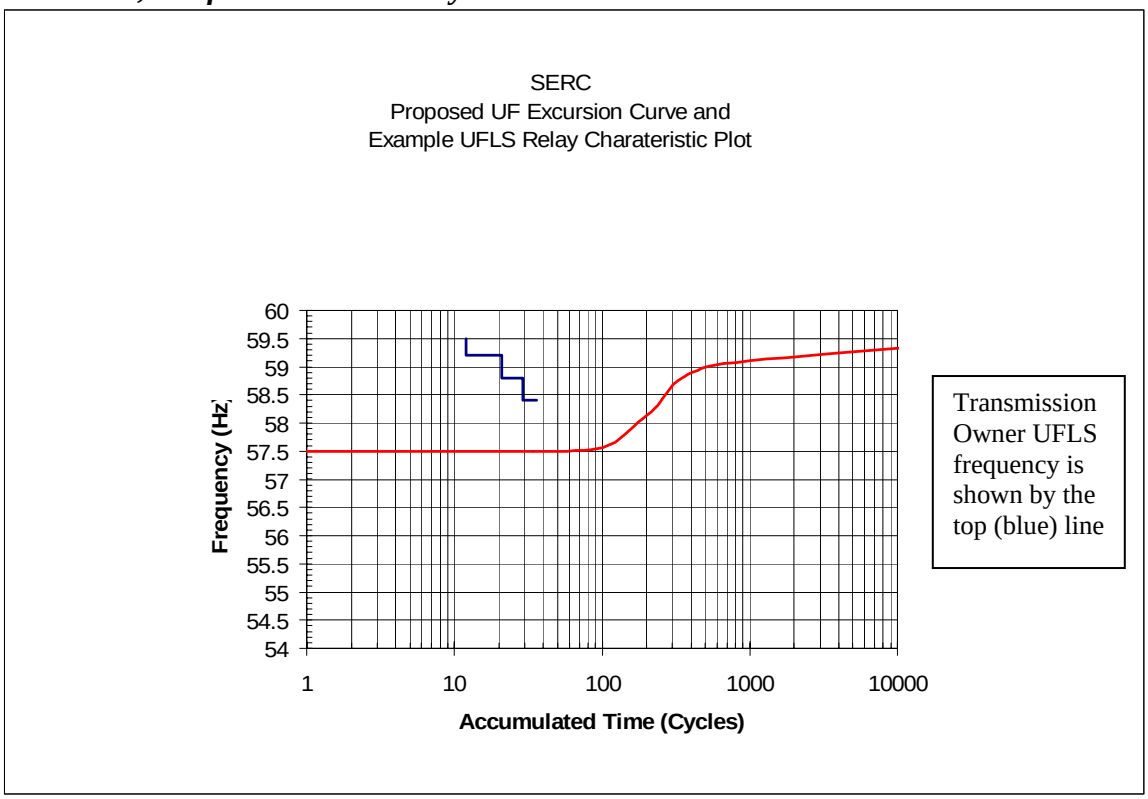
SERC
Proposed UF Excursion Curve and
Example UFLS Relay Charateristic Plot
Frequency (Hz)
60
59.5
59
58.5
58
57.5
57
56.5
56
55.5
55
54.5
54
1
10
100
1000
10000
Accumulated Time (Cycles)
Transmission Owner UFLS frequency is shown by the top (blue) line

Figure 3

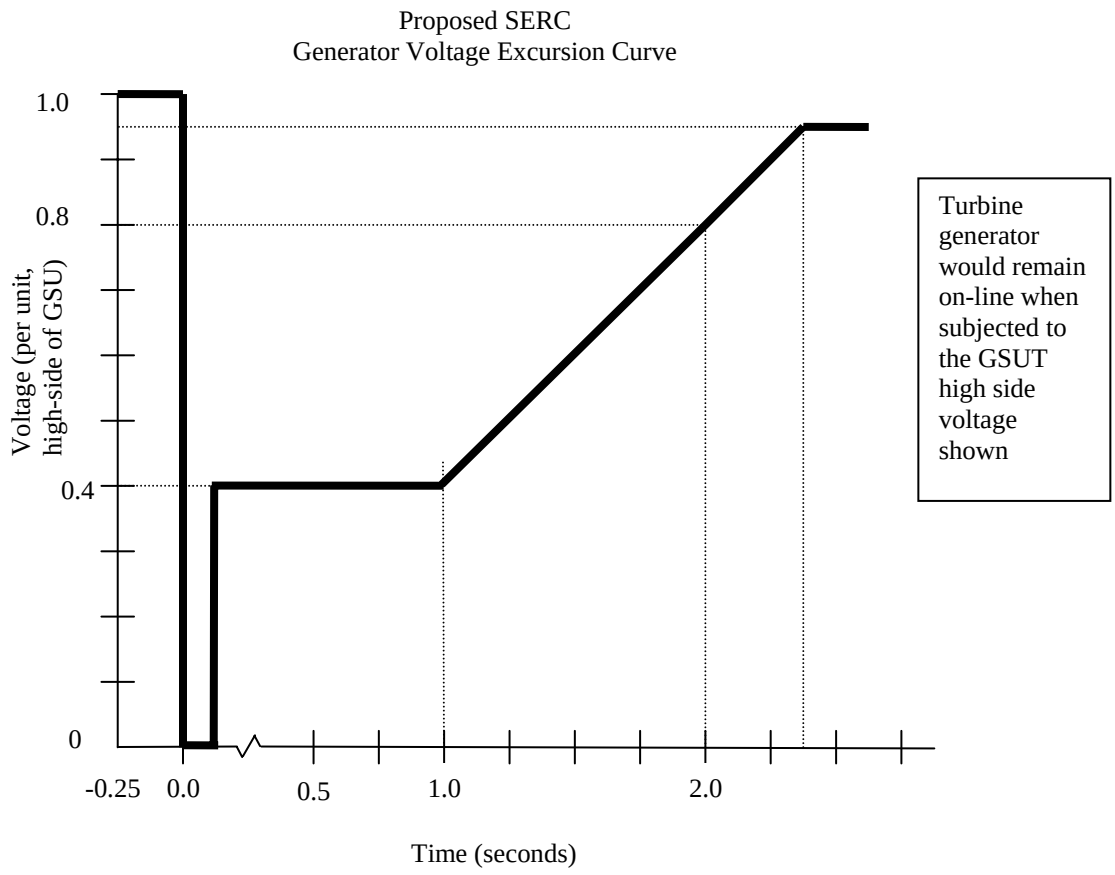
Proposed SERC
Generator Voltage Excursion Curve
1.0
0.8
0.4
0
Voltage (per unit, high-side of GSU)
-0.25
0.0
0.5
1.0
2.0
Time (seconds)
Turbine generator would remain on-line when subjected to the GSUT high side voltage shown

Figure 4

Attachment 1

A. Introduction

1. Title: **Generator Performance During Frequency and Voltage Excursions**

2. Number: PRC-024-1

3. Purpose: To ensure that generators remain connected to the electrical grid during voltage and frequency excursions and are not normally tripped manually or by preset protection schemes during frequency and voltage excursions.

4. Applicability

4.1. Regional Reliability Organizations.

4.2. Generator Owners.

4.3. Transmission Owners.

5. Proposed Effective Dates: To be determined:

Requirement 1 through Requirement 6 – One year beyond Board of Trustee adoption

Requirement 7 – Two years beyond Board of Trustee adoption

B. Requirements

R1. The Regional Reliability Organization shall establish requirements for generators to remain connected during system frequency and voltage excursions expressed as a function of:

R1.1. Time duration in seconds or cycles.

R1.2. Amplitude or magnitude of the excursion.

R1.3. Relationship between time and amplitude or magnitude.

R2. The Regional Reliability Organization shall establish and maintain requirements for generators to remain connected during frequency and voltage excursions. These requirements shall include:

R2.1. Coordination between the generator under frequency protection and the regional Under Frequency Load Shedding (UFLS) program.

R2.2. Coordination of generator protection, including back-up protection, with transmission Protection Systems.

R3. The Regional Reliability Organization shall establish and maintain criteria for exemptions to any of the regional requirements established in accordance with R1 and R2.

R4. The Regional Reliability Organization shall establish and maintain a procedure for handling variances (i.e., different criteria or methods) from the Regional Reliability Organization‘s requirements established in R1 and R2, including steps for requesting and approving such variances.

R5. The Regional Reliability Organization shall provide documentation of its excursion requirements, exemptions, and variance procedure to the Transmission Owners and Generator Owners within its Region within 30 calendar days of approval.

R6. The Regional Reliability Organization shall, at least every five years, review and, as necessary, update its requirements, exemption criteria, and variance procedure.

R7. Generator Owners and Transmission Owners shall comply with the regional requirements for coordination of generator protection defined in R2 and any approved variances.

Attachment 1

A. Measures

M1. The Regional Reliability Organization shall, within 30 calendar days of a request, provide NERC with its requirements, exemption criteria, and variance procedure for generators to withstand excursions in voltage and frequency.

M2. The Regional Reliability Organization shall have evidence it provided the requirements, criteria and procedures to the Transmission Owners and Generator Owners within its Region within 30 calendar days of approval.

M3. The Regional Reliability Organization shall have evidence it reviewed and updated its requirements, criteria and procedures as required in R6.

M4. Generator Owners and Transmission Owners shall, within 30 calendar days of a request, provide the Regional Reliability Organization with documentation that it met the regional requirements for coordination of generator protection defined in R1 and R2 and any approved regional variances.

Generator Owner PRC-024 SERC Field Test Reporting Form

The purpose of this form is to provide a consistent report format for field testing results after using the SERC Field Test Guideline "Generator Performance During Frequency and Voltage Excursions". Documentation of the test results will provide feedback showing that the field test was successful and/or will help to enhance the test guideline.

Use the attached SERC Field Test Guideline "Generator Performance During Frequency and Voltage Excursions" to perform the applicable engineering studies. Complete one (1) report form for each unit tested.

Provide the following information:

1. How long did it take to assemble (bring together) the technical data needed to plot the expected unit frequency withstand capability? Hours
2. If frequency excursion plots were created, what methodology / tools were used to construct the frequency excursion coordination plots?

   ☐ Computerized coordination curves

   ☐ Manual coordination curves

   ☐ Combination (computerized / manual)
3. If frequency excursion plots were not created, please explain the methodology used to demonstrate coordination with the draft SERC frequency excursion characteristic.
4. How many man-hours did it take to develop the methodology / tools?
5. Did the results indicate that the generator would be expected to remain on line for the draft SERC frequency Characteristic? ☐Yes ☐ No

   If no please attach additional information as appropriate.
6. How long did it take to analyze the technical information and draw the frequency curves (plots)? Hours
7. List any material costs associated with the generator frequency withstand capability portion of this field test.
8. How long did it take to assemble (bring together) the technical data needed to plot the expected Low Voltage Ride Through (LVRT) capability? Hours
9. If LVRT plots were created, what methodology / tools were used to construct the frequency excursion coordination plots?

   ☐ Computerized coordination curves

   ☐ Manual coordination curves

   ☐ Combination (computerized / manual)
10. If LVRT plots were not created, please explain the methodology used to demonstrate coordination with the draft SERC LVRT characteristic.
11. How many man-hours did it take to develop the methodology / tools?

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Generator Owner PRC-024 SERC Field Test Reporting Form

12. Did the results indicate that the generator would be expected to remain on line for the draft LVRT characteristic? ☐Yes ☐ No

    If no please attach additional information as appropriate.

13. How long did it take to analyze the technical information and draw the LVRT curves (plots)? Hours

14. List any material costs associated with the generator LVRT capability portion of this field test.

15. Please list any suggested changes to the guideline or the draft NERC Reliability Standard.

16. Provide the completed curves (plots) and other applicable documentation. Remove all references that would identify the unit (company, station, and unit names, etc)

17. Name of the person completing the form: Phone Number Company Name

Send the completed report form, plots, models and documentation to
phuntley@serc1.org

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Transmission Owner PRC-024 SERC Field Test Reporting Form

The purpose of this form is to provide a consistent report format for field testing results after using the SERC Field Test Guideline "Generator Performance During Frequency and Voltage Excursions". Documentation of the test results will provide feedback showing that the field test was successful and/or will help to enhance the test guideline.

Use the attached SERC Field Test Guideline "Generator Performance During Frequency and Voltage Excursions" to perform the applicable engineering studies. Complete one (1) report form for each unit tested.

Provide the following information:

1. How long did it take to assemble (bring together) the technical data needed to plot the UFLS characteristics? Hours
2. If frequency plots were created, what methodology / tools were used to construct the frequency coordination plots?

   ☐ Computerized coordination curves

   ☐ Manual coordination curves

   ☐ Combination (computerized / manual)
3. If frequency plots were not created, please explain the methodology used to demonstrate coordination with the draft SERC frequency excursion characteristic.
4. How many man-hours did it take to develop the methodology / tools?
5. Did the results indicate the UFLS characteristic coordinates with the draft SERC frequency Characteristic? ☐Yes ☐ No

   If no please attach additional information as appropriate.
6. How long did it take to analyze the technical information and draw the frequency curves (plots)? Hours
7. List any material costs associated with the generator frequency withstand capability portion of this field test.
8. How long did it take to assemble (bring together) the technical data needed to plot the transmission system backup protection characteristic applicable for the draft SERC LVRT curve? Hours
9. If LVRT plots were created, what methodology / tools were used to construct the frequency excursion coordination plots?

   ☐ Computerized coordination curves

   ☐ Manual coordination curves

   ☐ Combination (computerized / manual)
10. If LVRT plots were not created, please explain the methodology used to demonstrate coordination with the draft SERC LVRT characteristic and associated generator backup relay characteristics.
11. How many man-hours did it take to develop the methodology / tools?

DRAFT

Transmission Owner PRC-024 SERC Field Test Reporting Form

12. Did the results indicate coordination with the draft LVRT characteristic? ☐Yes ☐ No

    If no please attach additional information as appropriate.

13. How long did it take to analyze the technical information and draw the LVRT curves (plots)? Hours

14. List any material costs associated with the transmission LVRT capability portion of this field test.

15. Please list any suggested changes to the guideline or the draft NERC Reliability Standard.

16. Provide the completed curves (plots) and other applicable documentation. Remove all references that would identify the unit (company, station, and unit names, etc)

17. Name of the person completing the form: Phone Number Company Name

Send the completed report form, plots, models and documentation to **phuntley@serc1.org**

DRAFT

Attachment 2
Standard Redlines

- **MOD-026_Draft for Field Test (GSFT-TF revised 5-3-07).doc**
- **MOD-027_Draft for Field Test (GSFT-TF revised 5-3-07).doc**
- **PRC-019_Draft for Field Test (GSFT-TF revised 5-3-07).doc**

A. Introduction

1. Title: **Verification of Models and Data for Generator Excitation System Functions**

2. Number: MOD-026-1

3. Purpose: To ensure accurate information on generator excitation system functions (including voltage regulator controls, limiters, compensators, and power system stabilizers, if applicable) is available for models used to assess Bulk Electric System reliability.

4. Applicability

4.1. Regional Reliability Organization.

4.2. Generator Owner

4.3. Transmission Planner.

5. Proposed Effective Date: ~~To be determined.~~ The effective date should be delayed for 2 years, then phased in over at 20% per year over the next 5 years.

B. Requirements

R1. The Regional Reliability Organization shall establish and maintain procedures to address verification of models and data associated with generator excitation system functions including voltage regulator controls, limiters, compensators, and power system stabilizers. These procedures shall include the following:

R1.1. Generating unit exemption criteria ~~including documentation of those units that are exempt from a portion or all of these procedures~~. [exempt generators 75 MVA or less or generators not directly connected to the 100kV system through their step-up transformer.]

R1.2. Acceptable methods for model and data verification, including any applicable conditions under which the data should be verified. Such methods can include use of manufacturer data, commissioning data, performance tracking, engineering analysis, field verification of equipment settings, testing, simulation and comparison with test results or disturbance monitoring data, etc.

R1.3. A list of acceptable models to be used and procedures for revising the list of acceptable models.

~~**R1.3.**~~**R1.4.** Periodicity and schedule of verification and reporting, including a list of report recipients, schedules associated with field changes to existing units, and refurbished units.

~~**R1.4.**~~**R1.5.** Information to be reported related to generator excitation system functions:

~~**R1.4.1.**~~**R1.5.1.** Verified manufacturer and type of excitation system/voltage regulator control system (for example, static, brushless, rotating, etc.).

~~**R1.4.2.**~~**R1.5.2.** Verified model for each excitation system/voltage regulator control system with associated gains, time constants, and limits.

~~**R1.4.3.**~~**R1.5.3.** Verified static set points for under and over excitation limiters.

~~**R1.4.4.**~~**R1.5.4.** Verified line drop compensator settings.

~~**R1.4.5.**~~**R1.5.5.** Open circuit test response data showing generator field voltage and generator terminal voltage (exciter field voltage and current data for brushless units).

Draft

~~**R1.4.6.**~~**R1.5.6.** Verified model for each power system stabilizer with associated gains, time constants, and limits. Generator owners commissioning new PSSs will supply the Transmission Planner applicable test results provided upon commissioning. This includes results of the Gain Margin test, Phase Compensation test, and on-line step in voltage tests with and without the PSS in service.

~~**R1.4.7.**Confirmation that the verification was conducted with the voltage regulator in the automatic voltage control mode~~

~~**R1.4.8.**~~**R1.5.7.** Method of verification used.

~~**R1.4.9.**~~**R1.5.8.** Date of verification.

R2. The Regional Reliability Organization shall provide its generator excitation system data verification and reporting procedures, and any changes to those procedures, to the Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners affected by the procedure within 30 calendar days of the approval.

R3. The Generator Owner shall follow its Regional Reliability Organization's procedures for verifying and reporting its models and data associated with generator excitation system functions per MOD-026 R1.

C. Measures

M1. The Regional Reliability Organization shall have available for inspection a procedure for the verification and reporting of models and data associated with its generator excitation system functions in accordance with MOD-026 R1.

M2. The Regional Reliability Organization shall have evidence that its procedure for verification and reporting of generator excitation system data, and any revisions to that procedure were provided to affected Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners within 30 calendar days of approval.

M3. The Generator Owner shall have evidence it provided verification of the models and data associated with its generator excitation system functions, consistent with the Regional Reliability Organization procedure.

Draft

A. Introduction

1. **Title:** **Verification of Generator Unit Frequency Response**

2. **Number:** MOD-027-1

3. **Purpose:** To provide verification of generator unit frequency response (other than Automatic Generation Control) for use in models for reliability studies.

4. **Applicability**

   4.1. Regional Reliability Organization.

   4.2. Generator Owner.

   4.3. Transmission Planner

5. **Proposed Effective Date:** To be Determined. Because of the need to develop new tools and methods to capture and analyze the results and time required to validate each generator, the effective date should be delayed for 2 years, then phased in over at 20% per year over the next 5 years.

B. Requirements

R1. The Regional Reliability Organization shall establish and maintain procedures to address verification of generator unit frequency response. These procedures shall include the following:

R1.1. Response time to be modeled, ~~e.g. up to~~at least 60~~30~~ seconds ~~for steam units, up to 45 seconds for hydro units, etc~~.

R1.2. Generating unit exemption criteria ~~including documentation of those units that are exempt from a portion or all of these procedures~~. [exempt generators 75 MVA or less or generators not directly connected to the 100kV system through their step-up transformer.]

R1.3. Acceptable methods for model and data verification, including any applicable conditions under which the data should be verified. Such methods can include use of manufacturer data, commissioning data, performance tracking, engineering analysis, field verification of equipment settings, testing, simulation and comparison with test results or disturbance monitoring data, etc. [Standard should include, but not be limited to, an event based methodology as specified in section III.D.2 of the SERC Field Test Guideline for Verification of Generator Unit Frequency Response (draft NERC Reliability Standard MOD-027).]

R1.4. Periodicity and schedule of verification and reporting, including a list of report recipients, schedules associated with field changes to existing units, and refurbished units.[Standard should allow documented configuration controls as a means of ensuring validated unit response remains applicable]

R1.5. Information to be reported related to generator unit frequency response:

~~**R1.5.1.**Verified manufacturer and type of speed governor controls.~~

~~**R1.5.2.**~~**R1.5.1.** Verified model for each speed governor control ~~with any associated deadband, gains, time constants, and limits (e.g., maximum valve opening velocity, maximum capability of the turbine, etc.)~~.

~~R1.5.3.~~R1.5.2. Verified frequency response data of the unit, considering additional plant controls that affect the response of the unit (blocked or nonfunctioning governors or modes of operation that limit frequency response).

~~R1.5.4.~~R1.5.3. Method of verification and conditions of the verification including status of controls.

R2. The Regional Reliability Organization shall provide its frequency response verification and reporting procedures, and any changes to those procedures, to the Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners affected by the procedures within 30 calendar days of the approval.

R3. The Generator Owner shall follow its Regional Reliability Organization's procedure for verifying and reporting its generator unit frequency response per MOD-027 R1.

C. Measures

M1. The Regional Reliability Organization shall have available for inspection a procedure for verifying and reporting generator unit frequency response in accordance with MOD-027 R1.

M2. The Regional Reliability Organization shall have evidence that its procedure, and any revisions to that procedure, for verification and reporting generator unit frequency response was provided to affected Generator Owners, Generator Operators, Transmission Operators, Planning Authorities, and Transmission Planners within 30 calendar days of approval.

M3. The Generator Owner shall have evidence it provided verification of the models and data associated with generator unit frequency response, consistent with the Regional Reliability Organization procedure.

Draft

A. Introduction

1. **Title:** **Coordination of Generator Voltage Regulator Controls with ~~Unit~~ Generator Capabilities and Protection**

2. **Number:** PRC-019-1

3. **Purpose:** Ensure generator voltage regulator controls and limit functions are coordinated with the generator's capabilities and protective relays.

4. **Applicability**

   4.1. Regional Reliability Organization.

   4.2. Generator Owner.

5. **Proposed Effective Dates:** To be determined:

   One year beyond Board of Trustee adoption for Requirement 1

   Two years beyond Board of Trustee adoption 1st 20% compliant with Requirement 2 and Requirement 3

   Three years beyond Board of Trustee adoption 2nd 20% compliant with R2, R3

   Four years beyond Board of Trustee adoption 3rd 20% compliant with R2, R3

   Five years beyond Board of Trustee adoption 4th 20% compliant with R2, R3

   Six years beyond Board of Trustee adoption 5th 20% compliant with R2, R3

B. Requirements

R1. The Regional Reliability Organization shall establish and maintain criteria for exemptions to any of the Generator Owner requirements in R2. [exempt generators 75 MVA or less or generators not directly connected to the 100kV system through their step-up transformer.]

R2. Unless exempted by the Regional Reliability Organization in accordance with R1, the Generator Owner shall have study results that show it verified that its generator voltage regulator controls and limit functions are coordinated with the generator's capabilities and protective relays. This study shall include the following:

R2.1. Plots~~, or data that could be plotted for~~ to show the following, if applicable:

R2.1.1. Generator capability curve, including specification of nominal voltage, ambient air or cooling temperature, or hydrogen pressure.

R2.1.2. Steady state over-excitation limiter and under-excitation limiter control characteristics.

R2.1.3. Verified MW ~~limit of the prime mover~~capability of the generating unit [as developed in MOD-024].

R2.1.4. ~~Any other limit that could restrict the megawatt or megavar capability~~**.**

R2.1.5. Loss of excitation / field protective relay characteristics.

R2.1.6. Volts-per-hertz protection settings including volts-per-hertz limiters in the automatic voltage regulator.

R3. The Generator Owner shall have the information in R2.1.1 through R2.1.6 available to show to the Regional Reliability Organization upon request (within 30 calendar days).

Draft

C. Measures

M1. The Regional Reliability Organization shall, within 30 calendar days of a request, provide to Generator Owners its exemption criteria defined in accordance with R1.

M2. The Generator Owner shall have evidence it ~~showed the Regional Reliability Organization the information~~performed the studies identified in R2.1 through R2.1.6 within 30 calendar days of a request.

Draft

Attachment 3
MOD-026 Test Results

- **SERC MOD-026 Field Test Reporting Form - COE 6-8-2007.pdf**
- **MOD-026 Reporting Form Dominion.pdf**
- **serc mod-026 field test reporting form rev 0 (1-11-07)(Completed).doc**
- **SERC MOD-026 Reporting form - Attachment 2.doc**
- **SCG Sample MOD 026 Field Test Reporting Form.doc**
- **gs5 2pct step 29 Jan 2007.JPG**
- **SCG Excitation System Model.ppt**

MOD-026 SERC Field Test Reporting Form

The purpose of this form is to provide a consistent report format for field testing results after using the SERC Field Test Guideline "Verification of Models and Data for Generator Excitation System Functions". Documentation of the test results will provide feedback showing that the field test was successful and/or will help to enhance the test guideline.

Use the attached SERC Field Test Guideline "Verification of Models and Data for Generator Excitation System Functions" to perform the test (engineering study). Complete one (1) report form for each unit tested.

Provide the following information:

1. How long did it take to perform an Open Circuit Step Response (OCSR) test and collect the relevant data (generator voltage, field voltage and field current) in order to validate the exciter model?
   - Pre-Test Planning & Preparation : ____Unknown____ Hours
   - Setup of Test Equipment: ___8_____ Hours
   - Time to Prepare Unit for Test: ___1_____ Hours
   - Performance of Test and Data Collection: ____1____ Hours

Note: The subject testing was performed by an outside contractor. The above numbers are only observed estimates of the contractor time in each area.

2. How long did it take to analyze the test data and get a good correlation between exciter model and the OCSR test? __Unknown __ Hours

Note: The subject testing and data analysis was performed by an outside contractor.

3. Was a good correlation between the exciter model and the OCSR test obtained? (**Yes** or No)

   If no please attach additional information as appropriate.

4. What was the magnitude of the step input applied? _____2 %_____

5. List any material costs associated with this testing. __Currently our organization does not have all of the test equipment, software and testing experience needed to perform the testing and data analysis required by this proposed standard. All testing, data collection and analysis for this field test was performed by an outside contract at a cost of approximately $20, 000.

   _____
   _____

6. Were set points (overexcitation and underexcitation) verified on the voltage regulator (**Yes** or No). If no, please attach additional information as appropriate.

7. Please list any suggested changes to the guideline?

   _____
   _____
   _____

draft

MOD-026 SERC Field Test Reporting Form

8. Provide a completed Attachment # 2 to the SERC Field Test Guidelines for Verification of Models and Data for Generator Excitation System Functions (MOD-026). Attached.
9. Name of the person completing the form:_David Williams_ Phone Number_706.643.0313_____ Company Name_Corps of Engineers – Mobile District_____

Send the completed report form, plots, models and documentation to **phuntley@serc1.org**

draft

Attachment 2

Reporting Form

Excitation Systems Controls

1. **Unit Name: ___Hydro Unit - X_____**
2. **Company: ____Corps of Engineers _____**
3. **Date: _____June 4, 2007_____**
4. **Submitter: ____David Williams__ _____**
5. **Phone No. _____706.643.0313_____**

1. Exciter Information:

Manufacturer: __ABB Inc. _____

Type of Excitation System:

- [X] Static
- [ ] Brushless
- [ ] Alternator Rectifier
- [ ] Motor Driven dc exciter
- [ ] Shaft Driven dc exciter

2. Voltage Regulator Information:

Manufacturer: __ABB Inc. _____

Type of Voltage Regulator:

- [ ] Analog
- [X] Digital
- [ ] Other(describe)
- [ ]

3. Does unit have a commissioned Power System Stabilizer (PSS):

Yes__X___ No____

If the answer is yes,

Manufacturer: __ABB Inc. _____

Type of PSS:

- [ ] Single input (delta speed/frequency type)
- [X] Dual input (integral of accelerating power)
- [ ] Other(describe)
- [ ]

Attachment 2

Reporting Form

Excitation Systems Controls

4. Provide the open circuit test data (plots), appropriate voltage regulator and excitation system Standard Model and associated parameters, and documentation/plots showing good correlation between model simulation and OCSR test results.

   See APPENDIX A and B.

5. If the unit is equipped with a commissioned PSS, provide the data required in III.F.2.

   See APPENDIX A and B.

6. Provide the data required in III.G.2 on Excitation Limit Controls.

   See APPENDIX C.

APPENDIX A: MODELS AND RATINGS

A1. Ratings

Ratings		Value	Units
Generator Base Power	Sbase	131.579	MVA
Generator Base Voltage	Ebase	13.8	kV
Rated Speed	rpm	163.6	rpm
power factor	pf	0.95	
Rated MVA and pf Field Current	ifdrated	750	
Base Air-Gap Line Field Current	ifdbase	382	A
Base Air-Gap Line Field Voltage	efdbase	145	V
Field Winding Resistance	rfdbase	0.38	ohms
Field Winding Base Temperature	rfd temp	75	C

A2. Generator Model

GENSAL: Salient Pole Generator Model

Description	Parameter	Value	Units
D-Axis O.C. Transient Time Constant	T'do (>0)	8	sec
D-Axis O.C. Sub-Transient Time Constant	T"do (>0)	0.05	sec
Q-Axis O.C. Sub-Transient Time Constant	T"qo (>0)	0.05	sec
Inertia	H	5.1	pu
Speed Damping	D	0	pu
D-Axis Synchronous Reactance	Xd	0.992	pu
Q-Axis Synchronous Reactance	Xq	0.65	pu
D-Axis Transient Reactance	X'd	0.3	pu
D-Axis/Q-Axis Sub-Transient Reactance	X"d = X"q	0.2	pu
Leakage Reactance	Xl	0.1	pu
Open Circuit Saturation factor	S(1.0)	0.172	pu
Open Circuit Saturation factor	S(1.2)	0.62	pu

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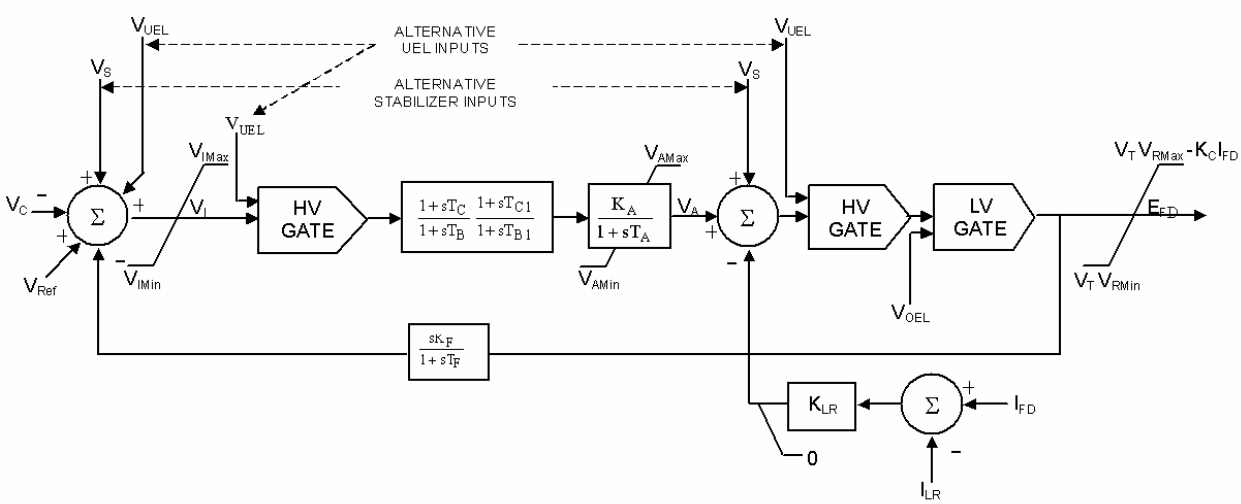
A3. Excitation System Model

IEEE Type ST1A Model

Description	Parameter	Value
Alternate UEL inputs	UEL (1,2, or 3)	1
Alternate stabilizer inputs	VOS(1 or 2)	1

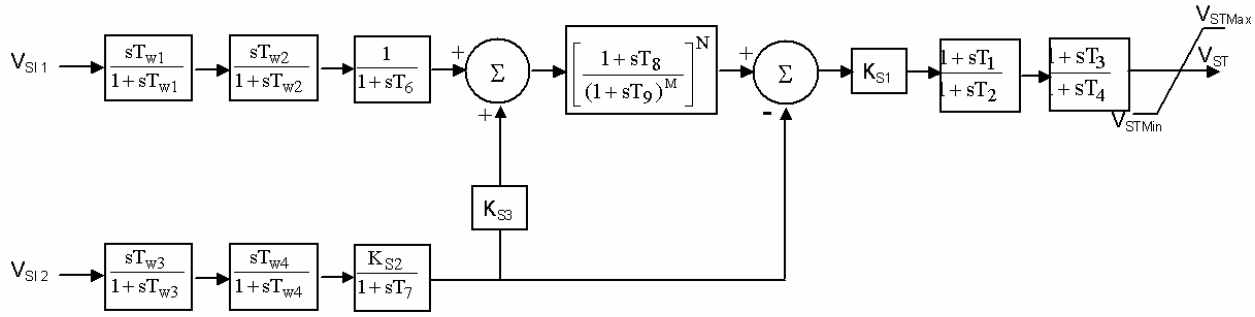
Description	Parameter	PSS OFF Value	PSS ON Value	Units
Terminal voltage transducer T.C.	Tr	0.01	0.01	sec
AVR upper limit	VIMAX	999	999	
AVR lower limit	VIMIN	-999	-999	
AVR lead time constant	TC	1	1	sec
AVR lag time constant	TB	**6**	**3.5**	sec
AVR lead time constant	TC1	0	0	sec
AVR lag time constant	TB1	0	0	sec
AVR gain	KA	**300**	**350**	
AVR time constant	TA	0	0	sec
Positive regulator output limit	VAMAX	999	999	
Negative regulator output limit	VAMIN	-999	-999	
Positive exciter output limit (ceiling)	VRMAX	3.86	3.86	
Negative exciter output limit (ceiling)	VRMIN	-3.46	-3.46	
Rectifier regulation	KC	0.046	0.046	
Exciter feedback gain	Kf	0	0	
Exciter feedback time constant	Tf (>0)	1	1	sec
Field current limiter gain	KLR	1	1	
Field current limiter setting	ILR	1.96	1.96	
Notes PSS-OFF model appropriate for open-circuit and stabilizer off conditions. **PSS-ON model appropriate for stabilizer on (normal on-line condition)**				



A4. Power System Stabilizer Model

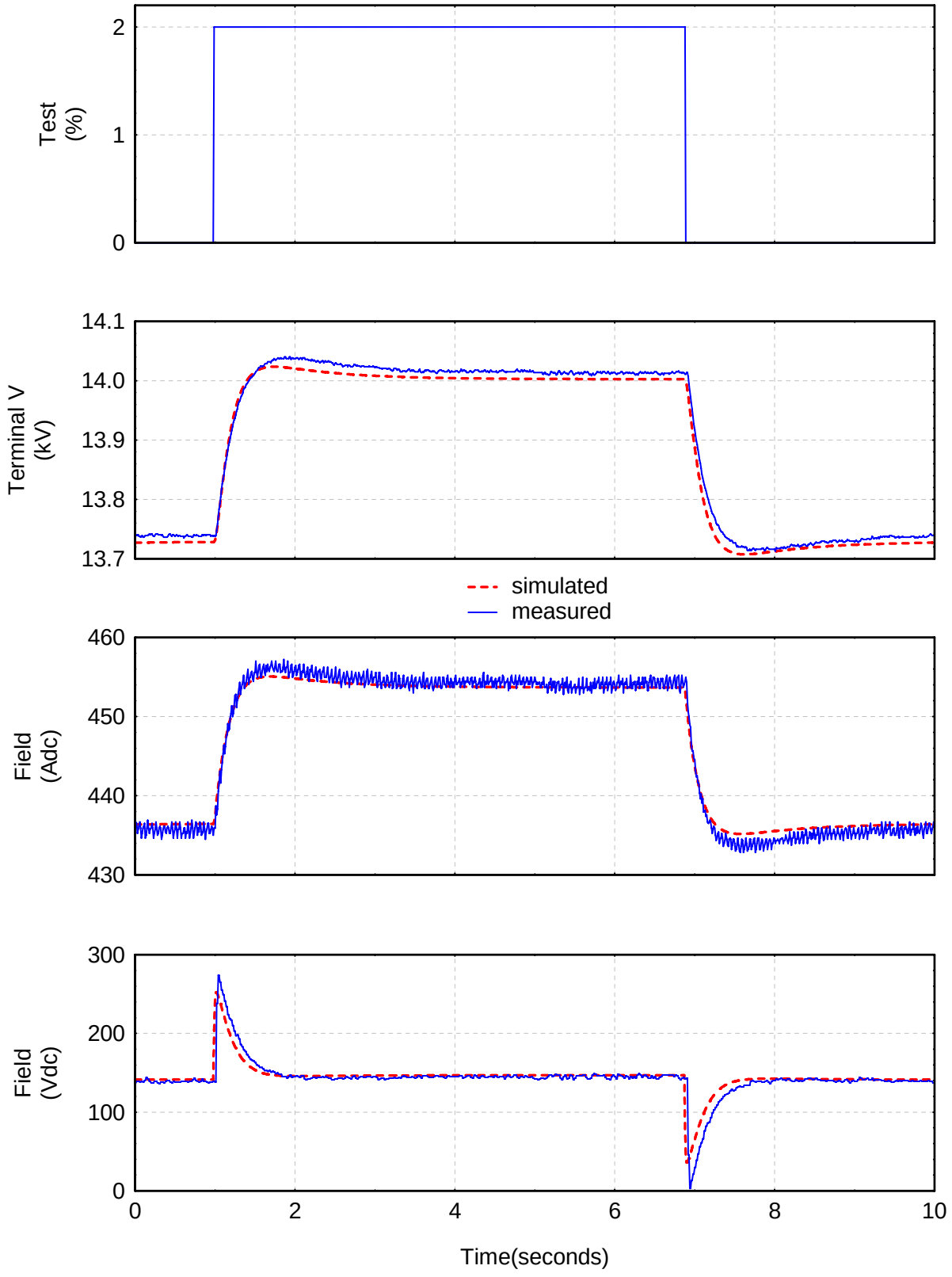
IEEE TYPE PSS2A DUAL-INPUT STABILIZER MODEL

Description	Parameter	Value	Units
First stabilizer input code	ICS1	1	Rotor speed deviation (pu)
First remote bus number	REMBUS1		
First stabilizer input code	ICS2	3	Electrical power on generator MVA base (pu)
Second remote bus number	REMBUS2		
Ramp tracking filter order	M	5	
Ramp tracking filter order	N	1	
Description	**Parameter**	**Value**	**Units**
Washout time constant	Tw1 (>0)	10	sec
Washout time constant	Tw2	10	sec
Filter time constant	T6	0	sec
Washout time constant	Tw3 (>0)	10	sec
Filter time constant	Tw4	0	sec
Washout time constant	T7	10	sec
Gain	KS2 (= T7/2H)	0.98	
Gain	KS3	1	
Ramp-tracking filter time constant	T8	0.5	sec
Ramp-tracking filter time constant	T9 (>0)	0.1	sec
Stabilizer gain	KS1	10	
Phase lead time constant	T1	0.18	sec
Phase lag time constant	T2	0.03	sec
Phase lead time constant	T3	0.12	sec
Phase lag time constant	T4	0.02	sec
Output limits	VSTMAX	0.05	pu Etref
Output limits	VSTMIN	-0.05	pu Etref
Inertia	H	5.1	MW-s/MVA
Generator Apparent Power	Sbase	131.579	MVA

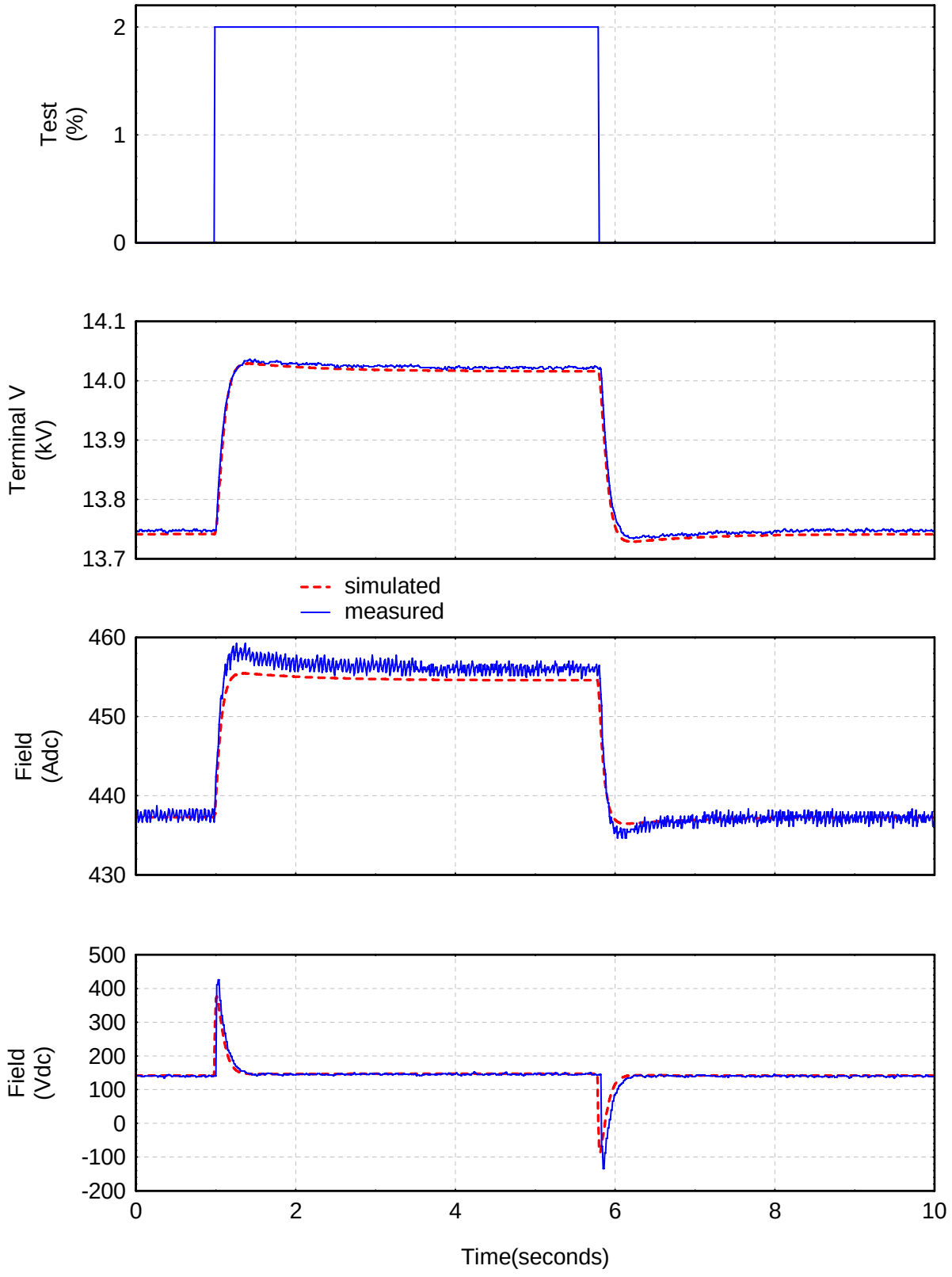


APPENDIX B: PERFORMANCE MEASUREMENTS

B3. Open Circuit Step Response, Stabilizer OFF AVR Settings



B4. Open Circuit Step Response, Stabilizer ON AVR Settings



APPENDIX C: EQUIPMENT SETTINGS

```
Parameters and Signals  04/11/2005
20:32
As Comm par Carters Unit1

202 U MACHN KV    13.80 kV
204 I MACHN KA    5.50 kA

501 U EXC V NOMINAL     272 V
502 I EXC A NOMINAL     750 A
504 U SYN V NOMINAL     430 V
515 ALPHA MIN LIMIT     15
516 ALPHA MAX LIMIT     150
517 USYN COMPENS SEL    ON
518 2DXN    5.80%

IE LIMITER: (OEL)
1301 REF1 IETH    105.00%
1302 REF2 IETH    105.00%
1303 REF1 IEMAX   160.00%
1304 REF2 IEMAX   160.00%
1305 TIME IEMAX SEL     10.0 s
1306 TC IERED MAX-TH    1.00 s
1307 TIME IE BACK INT   100.0 s
1308 not used     160.00%
1309 KOEL IE      35%

I LIMITER:
1401 REF1 I MACH TH     109.00%
1402 REF2 I MACH TH     109.00%
1403 I MACH EQUIVALENT  160.00%
1404 TIME I EQUIVALENT  10.0 s
1405 TC I MACH RED      1.00 s
1406 TIME  I BACK INT   100.0 s
1407 KOEL I  MACH 0%
1408 KUEL I  MACH 0%

PQ IEMIN LIM:     (UEL)
1501 REF0 Q(P) LIM      -50.00%
1502 REF25 Q(P) LIM     -50.00%
1503 REF50 Q(P) LIM     -40.00%
1504 REF75 Q(P) LIM     -30.00%
1505 REF100 Q(P) LIM    -18.00%
1506 KUEL Q(P) LIM      50%
1507 REF IEMIN LIM AVR  0.00%
1508 KUEL IEMIN LIM A   25%

AVR CTRL:
1901 HL REF AVR   110.00%
1902 LL REF AVR   90.00%
1903 PRESET1 REF AVR    100.00%
1904 PRESET2 REF AVR    100.00%
1905 RAMP TIME1 REF A   200.0 s
1906 RAMP TIME2 REF A   200.0 s
1907 TC FOLLOW UP AVR   10.0 s
1908 TC IMPOSED CTRL A  100.0 s
1909 Q DROOP/COMPENS    0.00%
1910 P DROOP/COMPENS    0.00%
1911 REF V/Hz LIM AVR   115.00%
1912 REF UMAX fNOM AVR  115.00%
1913 REF UMAX AVR 115.00%
1914 DELAY V/Hz LIM A   0.0 s
1915 SOFTSTART RAMP     5.0 s
1916 CEILING FACTOR A   386%

Stabilizer OFF
1917 DC GAIN AVR  300
1918 P GAIN AVR   50
1919 HF GAIN AVR  180

Stabilizer ON
1917 DC GAIN AVR  350
1918 P GAIN AVR   100
1919 HF GAIN AVR  100

1920 TA1    1.00 s
1921 TA2    1.00 s
1922 TA3    1.00 s
1923 TB1    20 ms
1924 TB2    20 ms
1925 TB3    20 ms

"AVR IN, PSS:"
2001 SEL LIM PRIORITY   OEL
2002 SEL PSS MODE ON IEEE
2003 PSS KS1      10
2004 PSS KS2      0.98
2005 PSS KS3      1
2006 PSS T1 0.18 s
2007 PSS T2 0.03 s
2008 PSS T3 0.12 s
2009 PSS T4 0.02 s
2010 PSS T7 10.00 s
2011 PSS T8 0.50 s
2012 PSS T9 0.10 s
2013 PSS TW1      10.0 s
2014 PSS TW2      10.0 s
2015 PSS TW3      10.0 s
2016 PSS TW4      0.0 s
2017 PSS N  1
2018 PSS M  5
2019 PSS P MACH MIN     10.00%
2020 not used     0.00 s
2021 not used     0.00 s
2022 Xx MACH      0.6
2023 PSS UST MAX  5.00%
2024 PSS UST MIN  -5.00%
```

MOD-026 SERC Field Test Reporting Form

The purpose of this form is to provide a consistent report format for field testing results after using the SERC Field Test Guideline "Verification of Models and Data for Generator Excitation System Functions". Documentation of the test results will provide feedback showing that the field test was successful and/or will help to enhance the test guideline.

Use the attached SERC Field Test Guideline "Verification of Models and Data for Generator Excitation System Functions" to perform the test (engineering study). Complete one (1) report form for each unit tested.

Provide the following information:

1. How long did it take to perform an Open Circuit Step Response (OCSR) test and collect the relevant data (generator voltage, field voltage and field current) in order to validate the exciter model?
   - Pre-Test Planning & Preparation : 20 Hours
   - Setup of Test Equipment: 10 Hours
   - Time to Prepare Unit for Test: 8 Hours - Fire in boiler To 3600 RPM
   - Performance of Test and Data Collection: 12 Hours - Testing performed around unit start up
2. How long did it take to analyze the test data and get a good correlation between exciter model and the OCSR test? 4 - 6 Hours
3. Was a good correlation between the exciter model and the OCSR test obtained? (Yes or No)

   If no please attach additional information as appropriate.
4. What was the magnitude of the step input applied? 1 & 2 %
5. List any material costs associated with this testing.

   _____

   _____
6. Were set points (overexcitation and underexcitation) verified on the voltage regulator (Yes or No). If no, please attach additional information as appropriate.
7. Please list any suggested changes to the guideline?

   _____

   _____

   _____
8. Provide a completed Attachment # 2 to the SERC Field Test Guidelines for Verification of Models and Data for Generator Excitation System Functions (MOD-026).
9. Name of the person completing the form:_____ Phone Number_____ Company Name_____

Send the completed report form, plots, models and documentation to

Attachment 2

Reporting Form

Excitation Systems Controls

1. **Unit Name** _____
2. **Company:** Dominion
3. **Date:** 4/
4. **Submitter:** _____
5. **Phone No.** _____

1. Exciter Information:

Manufacturer: Westinghouse

Type of Excitation System:

- [ ] Static
- [x] Brushless
- [ ] Alternator Rectifier
- [ ] Motor Driven dc exciter
- [ ] Shaft Driven dc exciter

2. Voltage Regulator Information:

Manufacturer: Westinghouse WTA 300B

Type of Voltage Regulator:

- [x] Analog
- [ ] Digital
- [ ] Other(describe)
- [ ]

3. Does unit have a commissioned Power System Stabilizer (PSS):

Yes X No____

If the answer is yes,

Manufacturer: Eaton Cutler Hammer

Type of PSS:

- [ ] Single input (delta speed/frequency type)
- [x] Dual input (integral of accelerating power)
- [ ] Other(describe)
- [ ]

MOD-026 SERC Field Test Reporting Form

The purpose of this form is to provide a consistent report format for field testing results after using the SERC Field Test Guideline "Verification of Models and Data for Generator Excitation System Functions". Documentation of the test results will provide feedback showing that the field test was successful and/or will help to enhance the test guideline.

Use the attached SERC Field Test Guideline "Verification of Models and Data for Generator Excitation System Functions" to perform the test (engineering study). Complete one (1) report form for each unit tested.

Provide the following information:

1. How long did it take to perform an Open Circuit Step Response (OCSR) test and collect the relevant data (generator voltage, field voltage and field current) in order to validate the exciter model?
   - Pre-Test Planning & Preparation : ____0.5____ Hours
   - Setup of Test Equipment: ___0.5_____ Hours
   - Time to Prepare Unit for Test: _Performed at unit startup__ Hours
   - Performance of Test and Data Collection: ___0.5_____ Hours
2. How long did it take to analyze the test data and get a good correlation between exciter model and the OCSR test? ____2____ Hours
3. Was a good correlation between the exciter model and the OCSR test obtained? (Yes or No) Yes

   If no please attach additional information as appropriate.
4. What was the magnitude of the step input applied? _____2%_____
5. List any material costs associated with this testing. ___No additional material cost. This test was performed during exciter commissioning_____
6. Were set points (overexcitation and underexcitation) verified on the voltage regulator (Yes or No). If no, please attach additional information as appropriate. Yes
7. Please list any suggested changes to the guideline?
   _____
   _____
   _____
8. Provide a completed Attachment # 2 to the SERC Field Test Guidelines for Verification of Models and Data for Generator Excitation System Functions (MOD-026).
9. Name of the person completing the form:Pat Longshore Phone Number 803-217-7490 Company Name_SC Electric & Gas__

Send the completed report form, plots, models and documentation to **phuntley@serc1.org**

draft

Attachment 2

Reporting Form

Excitation Systems Controls

1. **Unit Name:** _____
2. **Company:** _____SCE&G_____
3. **Date:** _____April 17, 2007_____
4. **Submitter:** _____Pat Longshore_____
5. **Phone No.** _____803-217-7490_____

1. Exciter Information:

Manufacturer: _____Basler_____

Type of Excitation System:

- [X] Static
- [ ] Brushless
- [ ] Alternator Rectifier
- [ ] Motor Driven dc exciter
- [ ] Shaft Driven dc exciter

2. Voltage Regulator Information:

Manufacturer: _____

Type of Voltage Regulator:

- [ ] Analog
- [X] Digital
- [ ] Other(describe)
- [ ]

3. Does unit have a commissioned Power System Stabilizer (PSS):

Yes_____ No__X__

If the answer is yes,

Manufacturer: _____

Type of PSS:

- [ ] Single input (delta speed/frequency type)
- [ ] Dual input (integral of accelerating power)
- [ ] Other(describe)
- [ ]

Attachment 2

Reporting Form

Excitation Systems Controls

4. Provide the open circuit test data (plots), appropriate voltage regulator and excitation system Standard Model and associated parameters, and documentation/plots showing good correlation between model simulation and OCSR test results.

5. If the unit is equipped with a commissioned PSS, provide the data required in III.F.2.

6. Provide the data required in III.G.2 on Excitation Limit Controls.

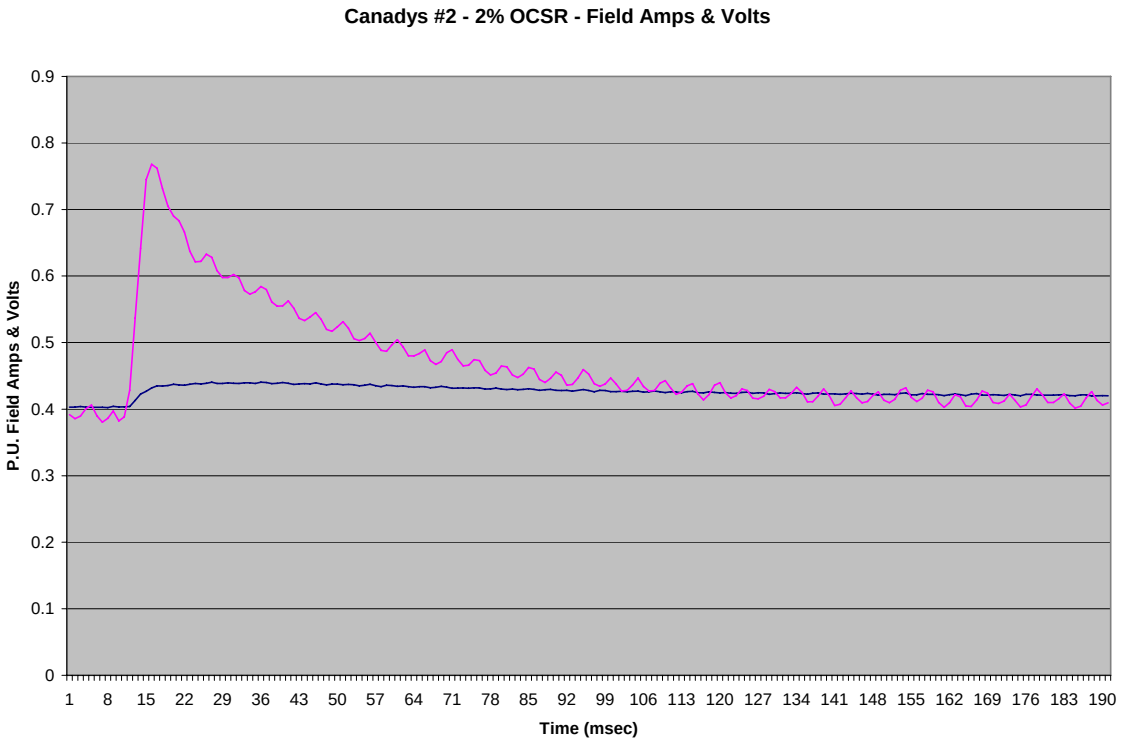
Notes:

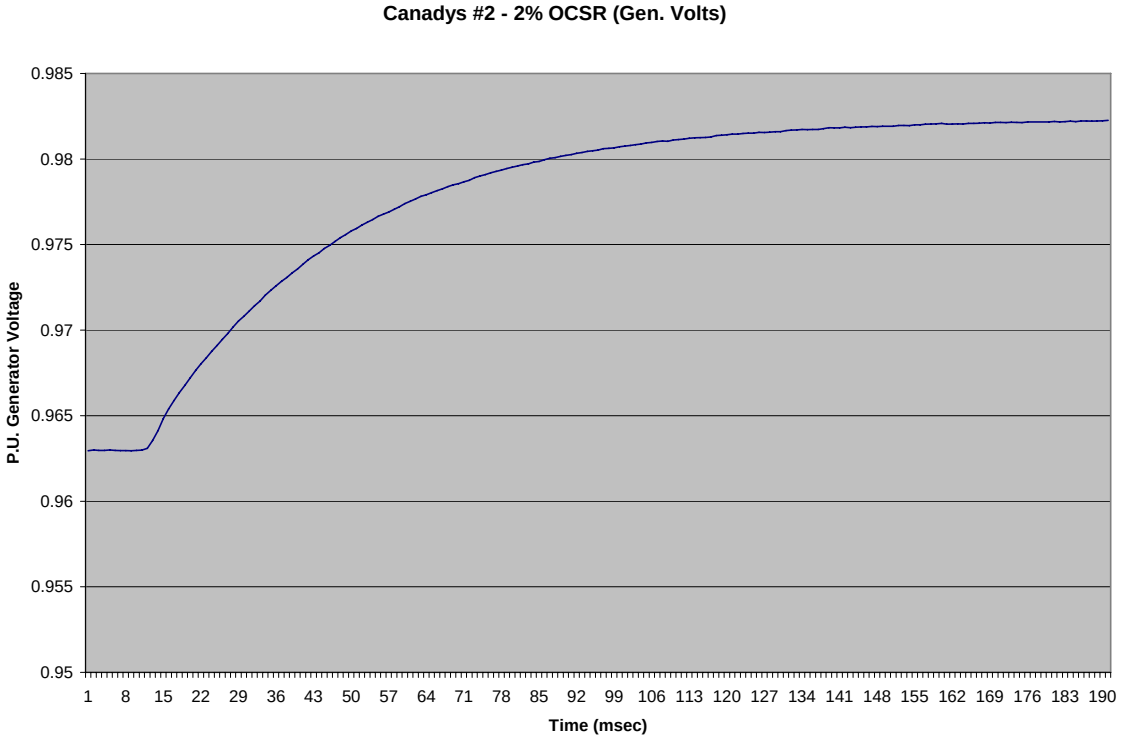
1. I obtained the IEEE exciter model from the vendor, along with the gains and constants. Our Transmission Planner (TP) performed the simulation and we did not get good correlation. The TP recommended a change to a constant and asked me to check with the Vendor. The Vendor agreed to the change and also recommended one more change to a constant. After a couple of iterations, we obtained good correlation between the model and the step response test.

Attachment 2

Reporting Form

Excitation Systems Controls

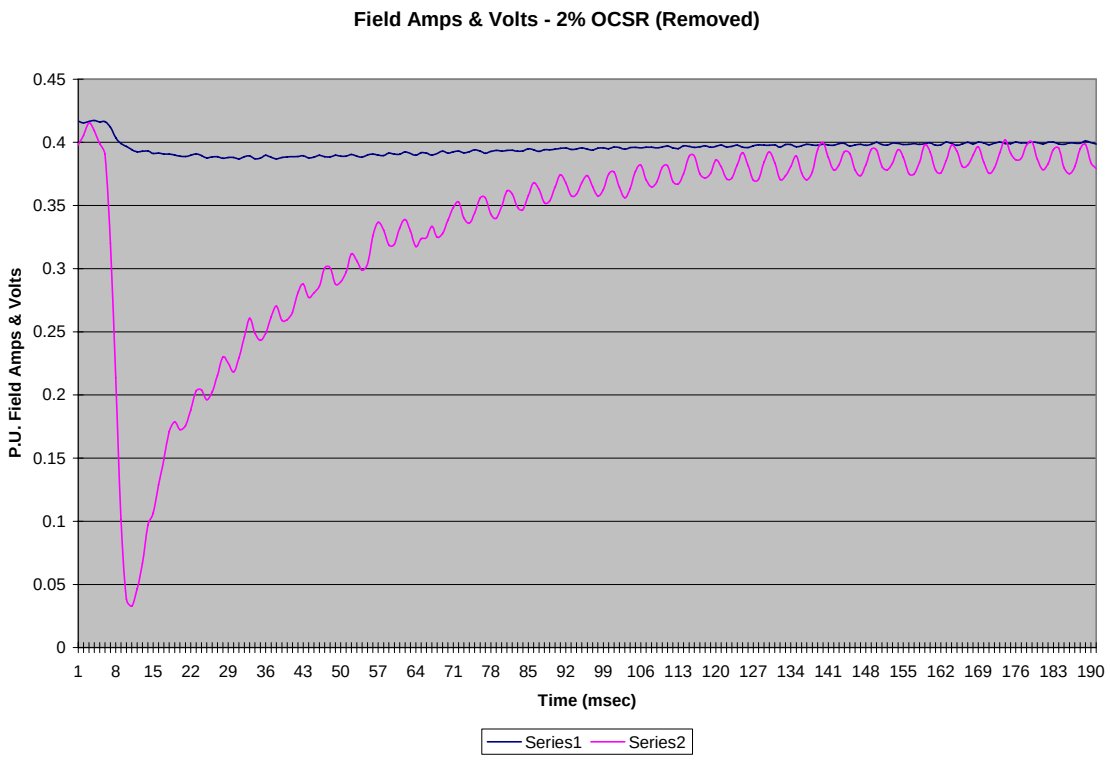


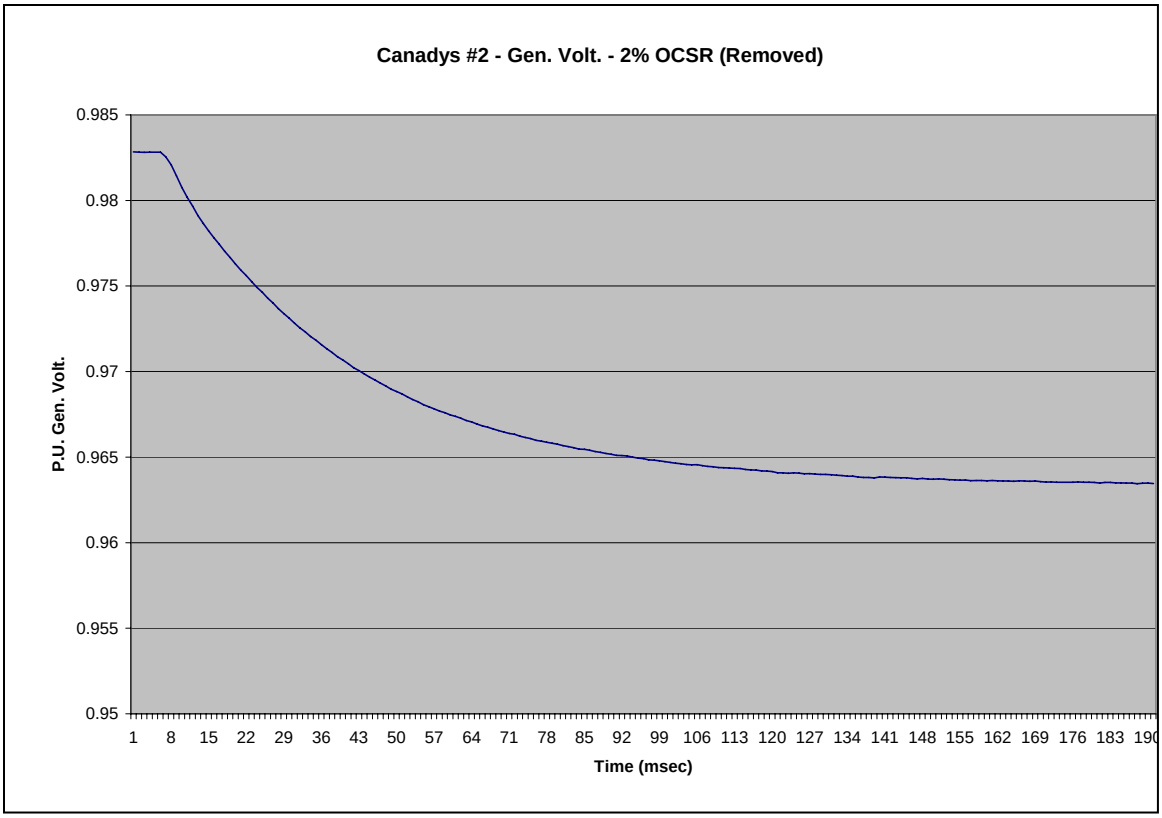


Attachment 2

Reporting Form

Excitation Systems Controls





SCG Unit
MOD-026 SERC Field Test Reporting Form

The purpose of this form is to provide a consistent report format for field testing results after using the SERC Field Test Guideline "Verification of Models and Data for Generator Excitation System Functions". Documentation of the test results will provide feedback showing that the field test was successful and/or will help to enhance the test guideline.

Use the attached SERC Field Test Guideline "Verification of Models and Data for Generator Excitation System Functions" to perform the test (engineering study). Complete one (1) report form for each unit tested.

Provide the following information:

1. How long did it take to perform an Open Circuit Step Response (OCSR) test and collect the relevant data (generator voltage, field voltage and field current) in order to validate the exciter model?
   - Pre-Test Planning & Preparation : ____1___ Hours
   - Setup of Test Equipment:_____1_____ Hours
   - Time to Prepare Unit for Test: __0.5____ Hours
   - Performance of Test and Data Collection: ___0.5___ Hours
2. How long did it take to analyze the test data and get a good correlation between exciter model and the OCSR test? ___8.0_____ Hours.
3. Was a good correlation between the exciter model and the OCSR test obtained? (**Yes** or No) The correlation of the field test data and the modeling data has been a time consume process for the subject system. We are currently finalizing the correlation by applying the IEEE AC7B model.

   If no please attach additional information as appropriate.
4. What was the magnitude of the step input applied? _2% of nominal_____
5. List any material costs associated with this testing.

   _____

   _____
6. Were set points (overexcitation and underexcitation) verified on the voltage regulator (**Yes** or No). If no, please attach additional information as appropriate.

   The set points were verified using simulated signals into the Exc. System.
7. Please list any suggested changes to the guideline?

   _____

   _____

   _____
8. Provide a completed Attachment # 2 to the SERC Field Test Guidelines for Verification of Models and Data for Generator Excitation System Functions (MOD-026). See below.

draft

SCG Unit
MOD-026 SERC Field Test Reporting Form

9. Name of the person completing the form:_Tom Higgins_____

Phone Number 205-992-7162____

Company Name_Southern Company Services_____

Send the completed report form, plots, models and documentation to **phuntley@serc1.org**

draft

SCG Unit
MOD-026 SERC Field Test Reporting Form

Attachment 2:

1. **Unit Name:** **Sample Unit**
2. **Company:** **Southern Company Generation**
3. **Date:** **06 Mar 2007**
4. **Submitter:** **William D. Shultz**
5. **Phone No.** **877-335-5753**

1. Exciter Information:

Manufacturer:

Type of Excitation System:

	Static
	Brushless
x	Alternator Rectifier
	Motor Driven dc exciter
	Shaft Driven dc exciter

2. Voltage Regulator Information:

Manufacturer:

Type of Voltage Regulator:

	Analog
x	Digital
	Other(describe)

draft

SCG Unit
MOD-026 SERC Field Test Reporting Form

Attachment 2:

3. Does unit have a commissioned Power System Stabilizer (PSS):

Yes_____ No__**x**__

If the answer is yes,

Manufacturer: _____

Type of PSS:

	Single input (delta speed/frequency type)
	Dual input (integral of accelerating power)
	Other(describe)

4. Provide the open circuit test data (plots), appropriate voltage regulator and excitation system Standard Model and associated parameters, and documentation/plots showing good correlation between model simulation and OCSR test results.

Field Test Data:

gs5 2pct step 29 Jan 2007.jpg ...

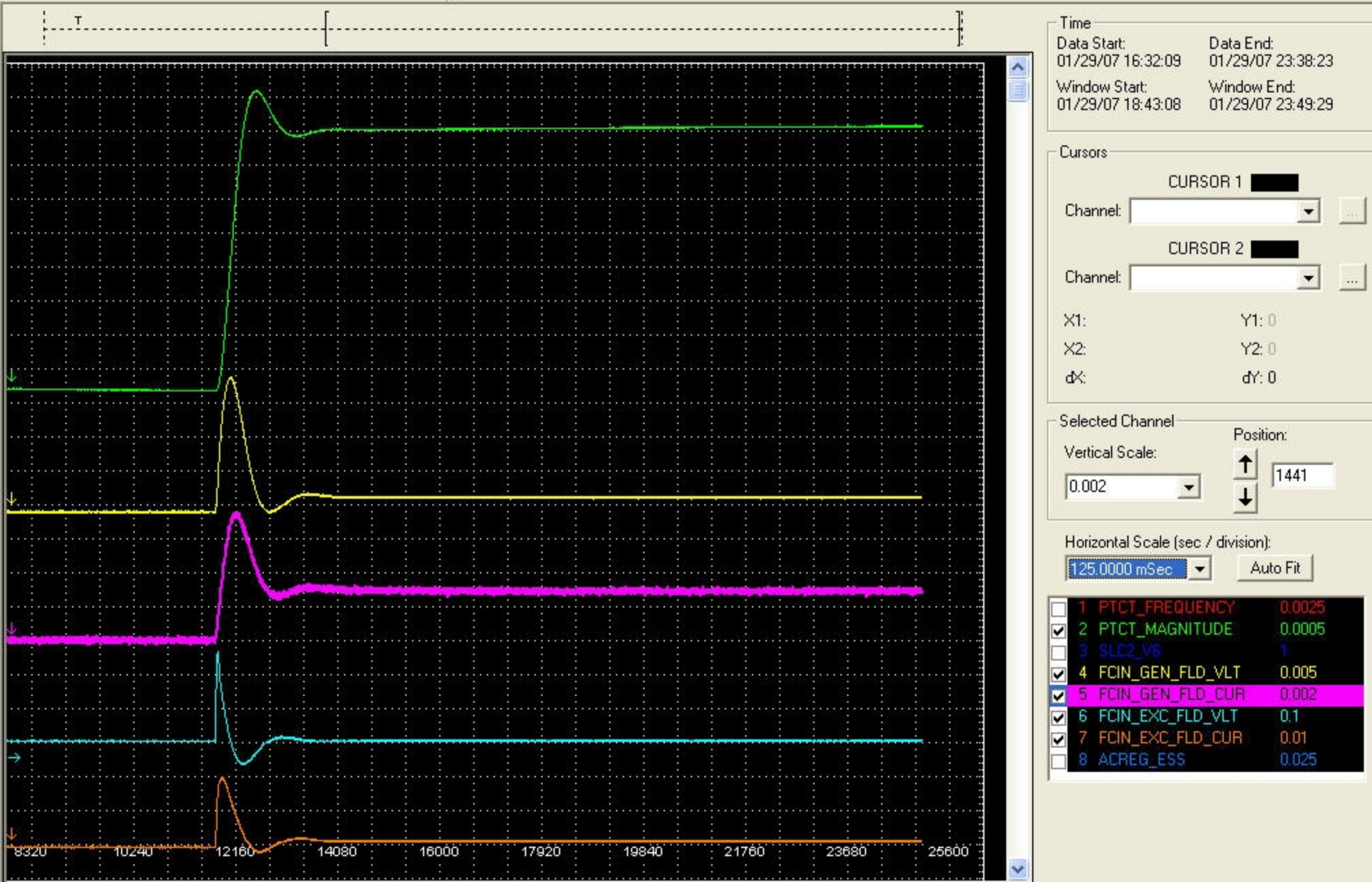
Model Validation Study Results:

SCG Sample Excitation System Mo

5. If the unit is equipped with a commissioned PSS, provide the data required in III.F.2. **N/A**

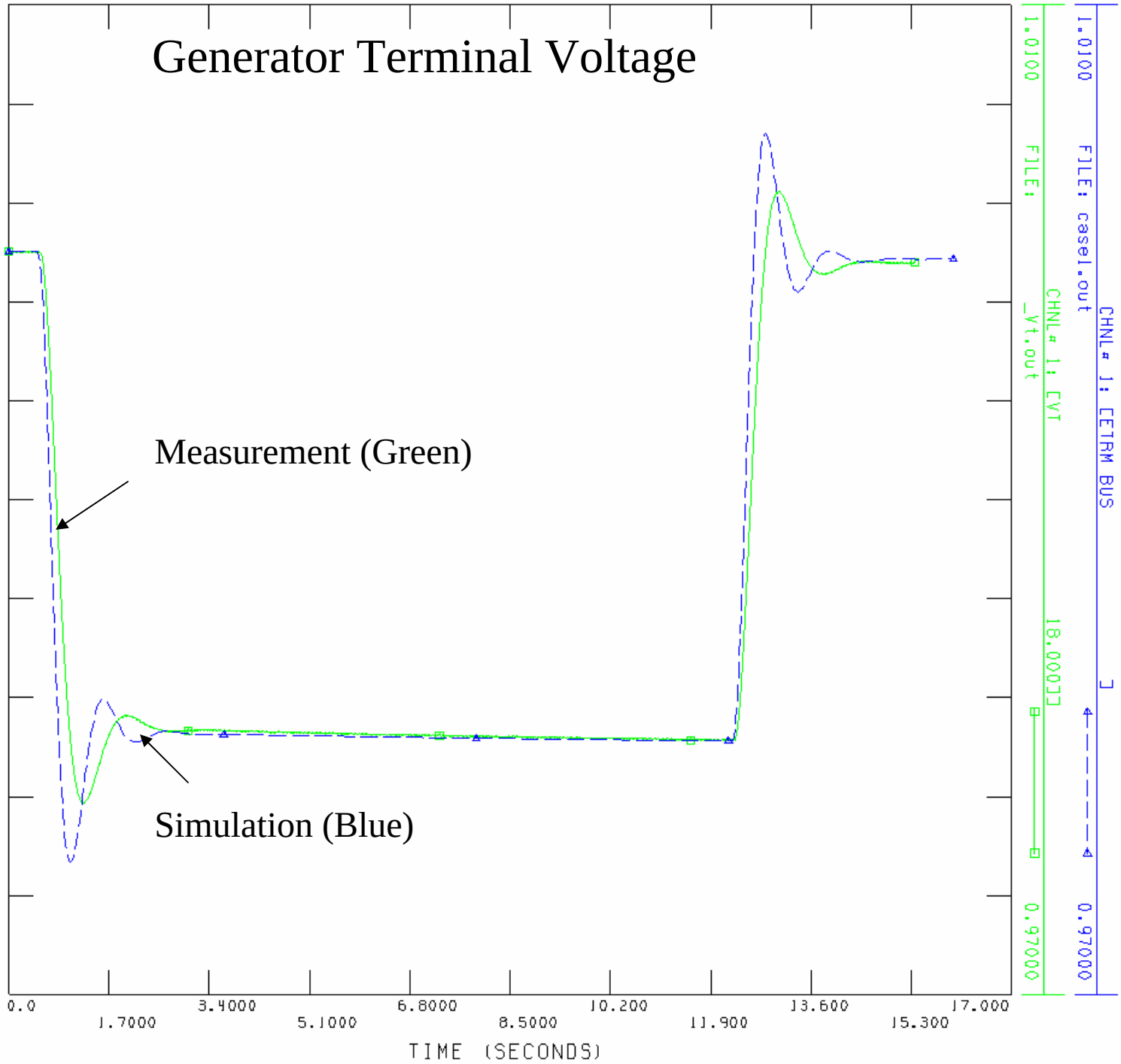
6. Provide the data required in III.G.2 on Excitation Limit Controls. Data is available upon request**. The coordination curves for this unit are contained in SCG's response to PRC-019. Actual field settings corresponded to these curves.**

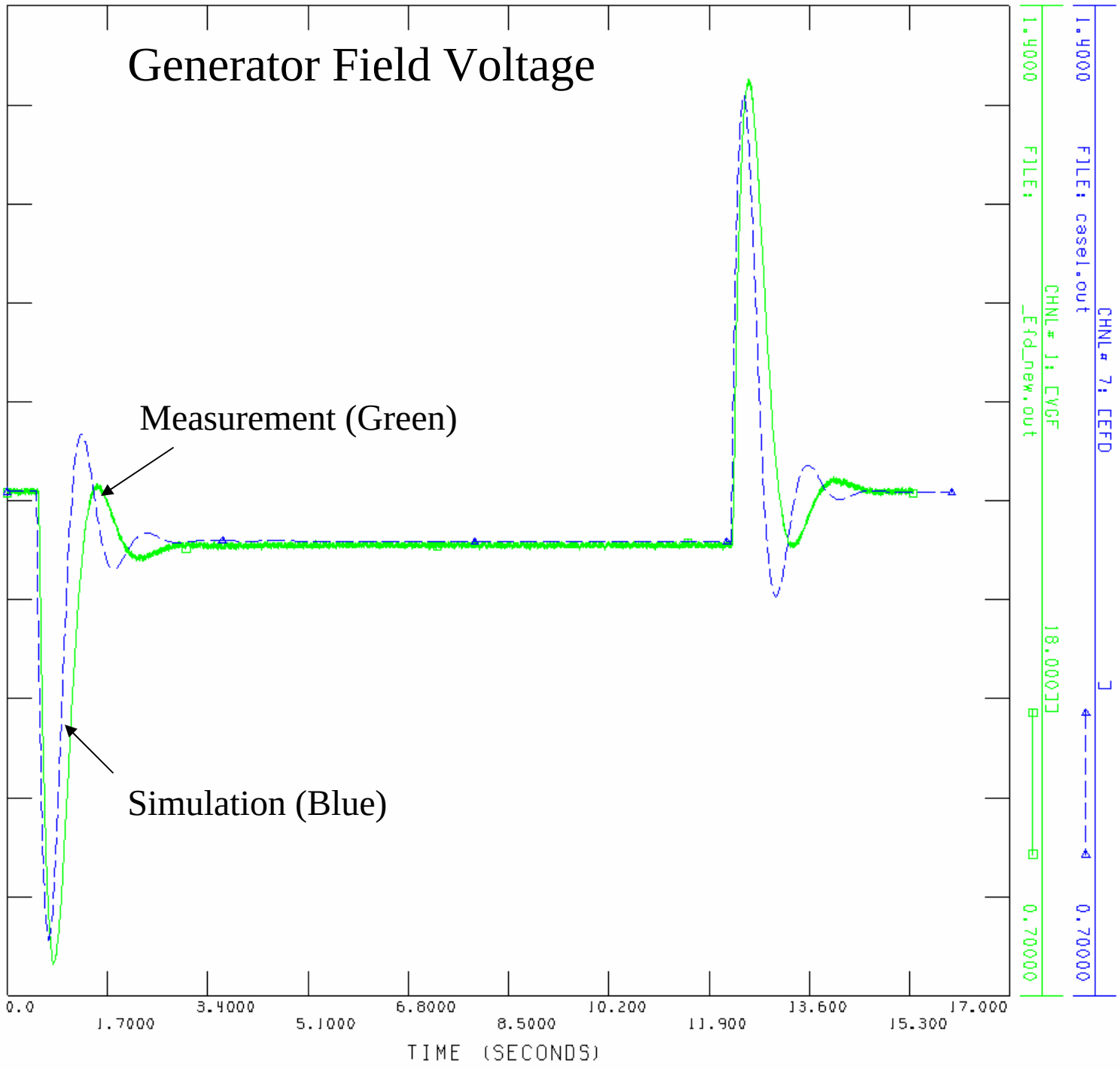
draft

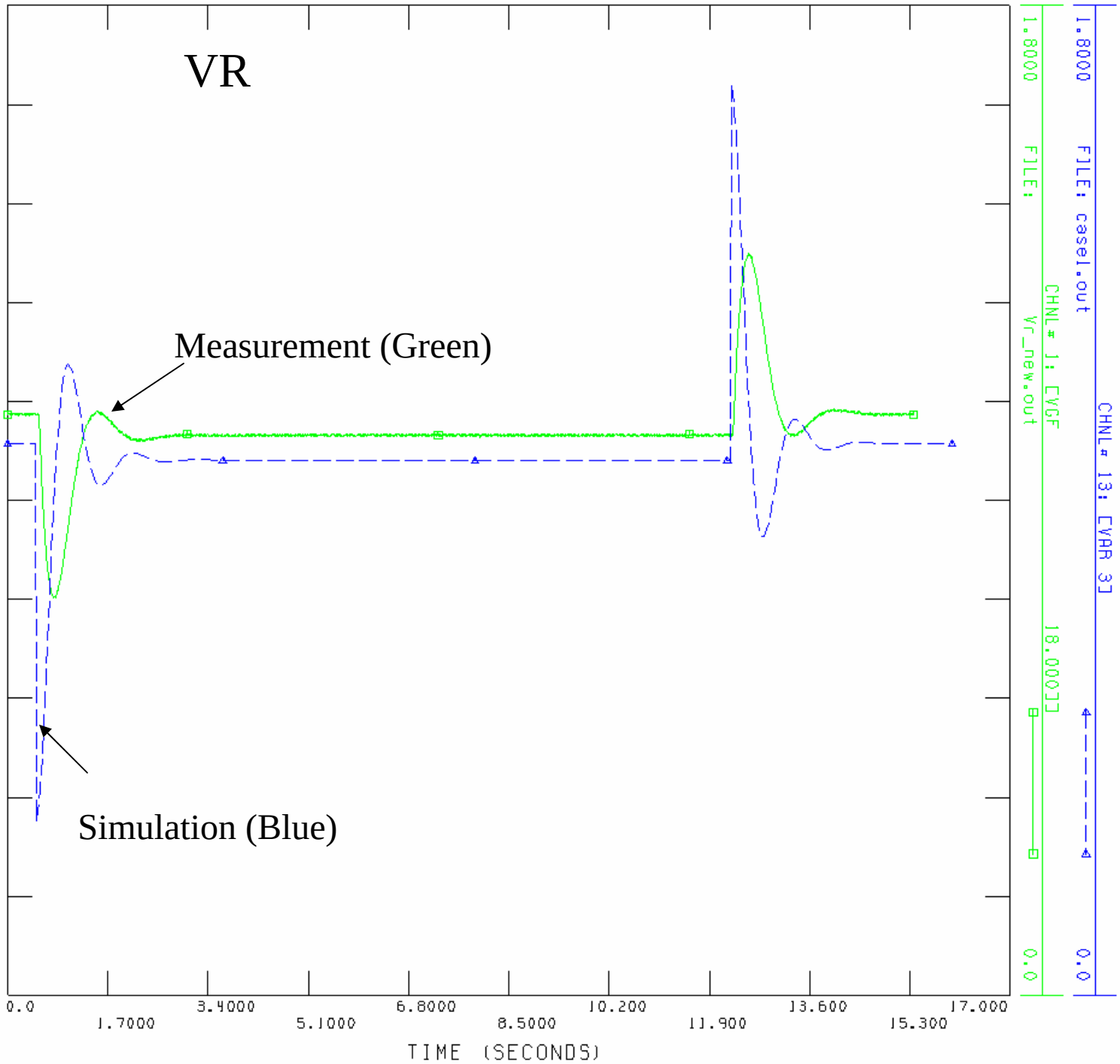

Time
Data Start:
01/29/07 16:32:09
Data End:
01/29/07 23:38:23
Window Start:
01/29/07 18:43:08
Window End:
01/29/07 23:49:29
Cursors
CURSOR 1
Channel:
CURSOR 2
Channel:
X1:
Y1: 0
X2:
Y2: 0
dX:
dY: 0
Selected Channel
Vertical Scale:
0.002
Position:
1441
Horizontal Scale (sec / division):
125.0000 mSec
Auto Fit
1 PTCT_FREQUENCY 0.0025
2 PTCT_MAGNITUDE 0.0005
3 SLC2_V6 1
4 FCIN_GEN_FLD_VLT 0.005
5 FCIN_GEN_FLD_CUR 0.002
6 FCIN_EXC_FLD_VLT 0.1
7 FCIN_EXC_FLD_CUR 0.01
8 ACREG_ESS 0.025
8320
10240
12160
14080
16000
17920
19840
21760
23680
25600

SCG Excitation System Model/Parameter Validation for Sample Unit

For SERC Field Test of MOD-026


Generator Terminal Voltage
Measurement (Green)
Simulation (Blue)
0.0
1.7000
3.4000
5.1000
6.8000
8.5000
10.200
11.900
13.600
15.300
17.000
TIME (SECONDS)
1.0100
FILE:
_Vt.out
CHNL# 1: EVT
18.0000
0.97000
1.0100
FILE: case1.out
CHNL# 1: [ETRM BUS
0.97000


Generator Field Voltage
Measurement (Green)
Simulation (Blue)
0.0
1.7000
3.4000
5.1000
6.8000
8.5000
10.200
11.900
13.600
15.300
17.000
TIME (SECONDS)
1.9000
FILE:
_Efd_new.out
CHNL# 1: [VGF
18.0000]
0.70000
1.9000
FILE: case1.out
CHNL# 7: [EFD
]
0.70000


VR
Measurement (Green)
Simulation (Blue)
0.0
1.7000
3.4000
5.1000
6.8000
8.5000
10.200
11.900
13.600
15.300
17.000
TIME (SECONDS)
1.8000
FILE:
CHNL# 1: [VGF
Vr_new.out
18.0000]
0.0
1.8000
FILE: case1.out
CHNL# 13: [VAR 3]
0.0

Attachment 4
MOD-027 Test Results

- **DVP_SERC MOD-027 Field Test Reporting Form 061207.doc**
- **DVP_SERC MOD-027 Field Test RF-Item 3B Details 061207.doc**
- **DVP_Unit A_SERC MOD-027 Attachment 2_061207.doc**
- **DVP_Unit B_SERC MOD-027 Attachment 2_061207.doc**
- **DVP_Unit C_SERC MOD-027 Attachment 2_061207.doc**
- **DVP_Unit E_SERC MOD-027 Attachment 2_061207.doc**
- **DVP_Unit F_SERC MOD-027 Attachment 2_061207.doc**
- **DVP_Unit G_SERC MOD-027 Attachment 2_061207.doc**
- **DVP_Simulation_Plots_for_Both_Events_061207.pdf**
- **SERC Nelson u4-MOD-027 Field Test Reporting Form Rev 0 (4-17-07).doc**
- **nelson u4-attachment2.doc**
- **SERC wbluff u1-MOD-027 Field Test Reporting Form Rev 0 (4-17-07).doc**
- **wbluff u1-attachment2.doc**
- **SERC wbluff u2-MOD-027 Field Test Reporting Form Rev 0 (4-17-07).doc**
- **white bluff u2-attachmnet2.doc**
- **entergy-Mod-027Simulation-Results.ppt**
- **serc mod-027 field test reporting form rev 0 (4-17-07)(Completed).doc**
- **SCG MOD-027 Field Test Reporting Form.doc**
- **SoGenUnits_Response_WansleyTrips_Sanatized_Final.ppt**

MOD-027 SERC Field Test Reporting Form

The purpose of this form is to provide a consistent report format for field testing results after using the SERC Field Test Guideline "Verification of Generator Unit Frequency Response". Documentation of the test results will provide feedback showing that the field test was successful and/or will help to enhance the test guideline.

Use the attached SERC Field Test Guideline "Verification of Generator Unit Frequency Response" to perform the test (engineering study). Complete one (1) report form for each unit tested.

Provide the following information:

1. Is there a maintenance management program in place for the turbine speed load governor control system (analog and/or digital based)? (Yes or No) No
   - If yes, what is the maintenance interval? (months)
2. Is there a configuration management program in place for the turbine speed load governor control system (analog and/or digital based)? (Yes or No) No
3. Was good correlation between the generator output (MW vs. time) and the model obtained? (Yes or No) No

   3. A. **If yes:** (Use additional pages if needed to explain.)
   - How long did it take to obtain the generator output data? (hours)
   - How long did it take to set up the model to simulate this event? (hours)
   - How long did it take to compare the generator output data to the model? (hours)
   - Did the model parameters or type need to be changed?

   3. B. **If No:**
   - Use additional pages to explain.
4. List any material costs associated with this study. None
5. Please list any suggested changes to the guideline? Most model/parameters available for the turbine-governor control systems are estimated or typical at best (this is more likely an Industry wide concern). Initially, it might be worth to have initially a couple of units field tested for the accuracy of the model/parameters. Once such field test is performed and the model and parameters are validated, then it might provide a better judgment of whether this Field Test Method provides meaningful and consistent comparison between recorded data and the simulated test results for an event or not.
6. Provide a completed Attachment # 2 to the SERC Field Test Guidelines for Verification of Generator Unit Frequency Response (MOD-027).
7. Name of the person completing the form: Kirit Doshi Phone Number: 804-819-2322
   Company Name: Dominion Virginia Power

Send the completed report form and supporting documentation electronically to: phuntley@serc1.org.

Dominion Explanation
Ref. MOD-027 SERC Field Test Reporting Form, Item 3B

The table below compares field observed readings (from SCADA/EMS data) with the simulation test results for six Dominion (F&H) units for the Wansley and the Oconee trip events. If we consider the difference within 1% of Pmax as acceptable, six instances out of total 12 matches reasonably well as far as the MW pick-up amount is concerned. Out of these six, four are for the Wansley event and two are for the Oconee event.

Field Observations Over a 60-Second Period (Maximum reading within this range used for each unit)

Dominion Unit ID	Pmax (MW)	Pre-Event Load (MW)	Max Observed Pick-up within 60 seconds (MW)	Simulated Pick-up		Difference between Pmax and Pgen	MW Diff. in Response (Simulated minus Observed)	Difference as % of Pmax
				MW	% of Pmax			
A	71	62.40	0.18	1.89	2.66	8.60	1.71	2.41
		55.38	0.96	1.88	2.65	15.62	0.92	1.30
B	118	97.48	1.45	3.29	2.79	20.52	1.84	1.56
		100.80	2.52	3.29	2.79	17.20	0.77	0.65
C	103	88.34	0.65	3.04	2.95	14.66	2.39	2.32
		79.92	2.81	3.04	2.95	23.08	0.23	0.22
D								
E	464	454.13	0.75	5.05	1.09	9.87	4.30	0.93
		457.50	0.75	3.64	0.78	6.50	2.89	0.62
F	110	81.32	1.40	2.67	2.43	28.68	1.27	1.15
		99.36	0.88	2.70	2.45	10.64	1.82	1.65
G	170	170.75	0.63	0.71	0.42	(0.75)	0.08	0.05
		169.75	1.00	1.26	0.74	0.25	0.26	0.15

Blue color readings are for Oconee event

Red color readings are for Wansley event

Note: Unit D was later deleted from the test upon finding that this unit is not expected to respond.

As for the MW versus Time comparison, below listed data indicates the recorded elapsed time in seconds from the initiation of each event for each unit to reach the maximum MW pick-up within the observed time range of 60 seconds.

	(a) Wansley Event	(b) Oconee Event
Unit A:	21	20
Unit B:	42	26
Unit C:	35	20
Unit E:	13	18
Unit F:	19	12
Unit G:	19	44

The simulated responses for most cases indicated 85 to 90 % of the total MW pick-up occur in the first 5 to 7 seconds and then gradually creep up over the next 30 to 50 seconds. Overall, the match between the field-observed responses and the simulated responses are less than satisfactory for the units tested.

This is not to say that the field test method developed is wrong. Most models/parameters available for the turbine-governor control systems are estimated or typical at best (this is more likely an Industry wide issue). Initially, it might be worth to have a couple of units field tested for the accuracy of simulation models/parameters and then evaluating this method of Field Testing may provide more accurate evaluation.

Attachment 2

Sample Reporting Form

Turbine and Governor (Speed/Load) Controls Questionnaire

1. **Unit Name: Unit A**
2. **Company: Dominion**
3. **Date: 06/12/07**
4. **Submitter: Larry Whanger**
5. **Phone No. 804-273-3576**

Governor Information:

Identify general type of governor control:

	Mechanical hydraulic (MHC)
	Analog electro-hydraulic (EHC)
x	Digital electro-hydraulic (DEH)
	_____

Check type of governor model submitted:

	PTI Standard Model with As built parameters
x	PTI Standard Model with Estimated Parameters
	PTI Standard Model with Parameters derived from event(s) based Validation(s)

Droop Setting (%): 5%

Attachment 2

Sample Reporting Form

Turbine and Governor (Speed/Load) Controls Questionnaire

1. **Unit Name: Unit B**
2. **Company: Dominion**
3. **Date: 06/12/07**
4. **Submitter: Larry Whanger**
5. **Phone No. 804-273-3576**

Governor Information:

Identify general type of governor control:

	Mechanical hydraulic (MHC)
	Analog electro-hydraulic (EHC)
x	Digital electro-hydraulic (DEH)
	_____

Check type of governor model submitted:

	PTI Standard Model with As built parameters
x	PTI Standard Model with Estimated Parameters
	PTI Standard Model with Parameters derived from event(s) based Validation(s)

Droop Setting (%): 5%

Attachment 2

Sample Reporting Form

Turbine and Governor (Speed/Load) Controls Questionnaire

1. **Unit Name: Unit C**
2. **Company: Dominion**
3. **Date: 06/12/07**
4. **Submitter: Larry Whanger**
5. **Phone No. 804-273-3576**

Governor Information:

Identify general type of governor control:

	Mechanical hydraulic (MHC)
	Analog electro-hydraulic (EHC)
x	Digital electro-hydraulic (DEH)
	_____

Check type of governor model submitted:

	PTI Standard Model with As built parameters
x	PTI Standard Model with Estimated Parameters
	PTI Standard Model with Parameters derived from event(s) based Validation(s)

Droop Setting (%): 5%

Attachment 2

Sample Reporting Form

Turbine and Governor (Speed/Load) Controls Questionnaire

1. **Unit Name: Unit E**
2. **Company: Dominion**
3. **Date: 06/12/07**
4. **Submitter: Larry Whanger**
5. **Phone No. 804-273-3576**

Governor Information:

Identify general type of governor control:

	Mechanical hydraulic (MHC)
	Analog electro-hydraulic (EHC)
x	Digital electro-hydraulic (DEH)
	_____

Check type of governor model submitted:

	PTI Standard Model with As built parameters
x	PTI Standard Model with Estimated Parameters
	PTI Standard Model with Parameters derived from event(s) based Validation(s)

Droop Setting (%): 5%

Attachment 2

Sample Reporting Form

Turbine and Governor (Speed/Load) Controls Questionnaire

1. **Unit Name: Unit F**
2. **Company: Dominion**
3. **Date: 06/12/07**
4. **Submitter: Larry Whanger**
5. **Phone No. 804-273-3576**

Governor Information:

Identify general type of governor control:

- [x] Mechanical hydraulic (MHC)
- [ ] Analog electro-hydraulic (EHC)
- [ ] Digital electro-hydraulic (DEH)
- [ ] _____

Check type of governor model submitted:

- [ ] PTI Standard Model with As built parameters
- [x] PTI Standard Model with Estimated Parameters
- [ ] PTI Standard Model with Parameters derived from event(s) based Validation(s)

Droop Setting (%): 5%

Attachment 2

Sample Reporting Form

Turbine and Governor (Speed/Load) Controls Questionnaire

1. **Unit Name: Unit G**
2. **Company: Dominion**
3. **Date: 06/12/07**
4. **Submitter: Larry Whanger**
5. **Phone No. 804-273-3576**

Governor Information:

Identify general type of governor control:

- [x] Mechanical hydraulic (MHC)
- [ ] Analog electro-hydraulic (EHC)
- [ ] Digital electro-hydraulic (DEH)
- [ ] _____

Check type of governor model submitted:

- [ ] PTI Standard Model with As built parameters
- [x] PTI Standard Model with Estimated Parameters
- [ ] PTI Standard Model with Parameters derived from event(s) based Validation(s)

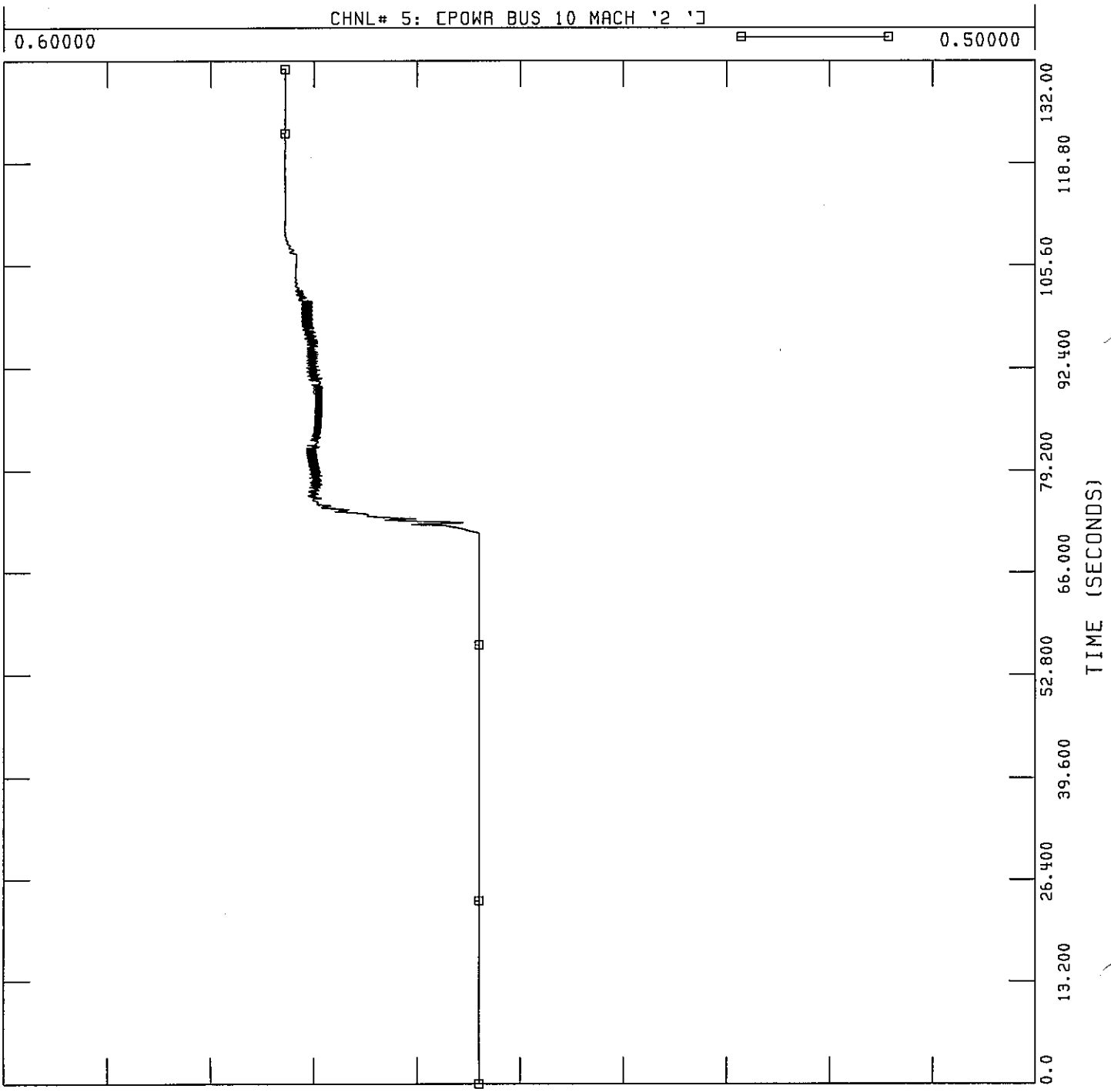
Droop Setting (%): 5%

CASE WITH [redacted] AS TEST MACHINE

FILE: C:\doshi\AAWansley\Seven\[redacted]_WanTrip.OUT

FRI, JUN 08 2007 14:38

Wansley - A

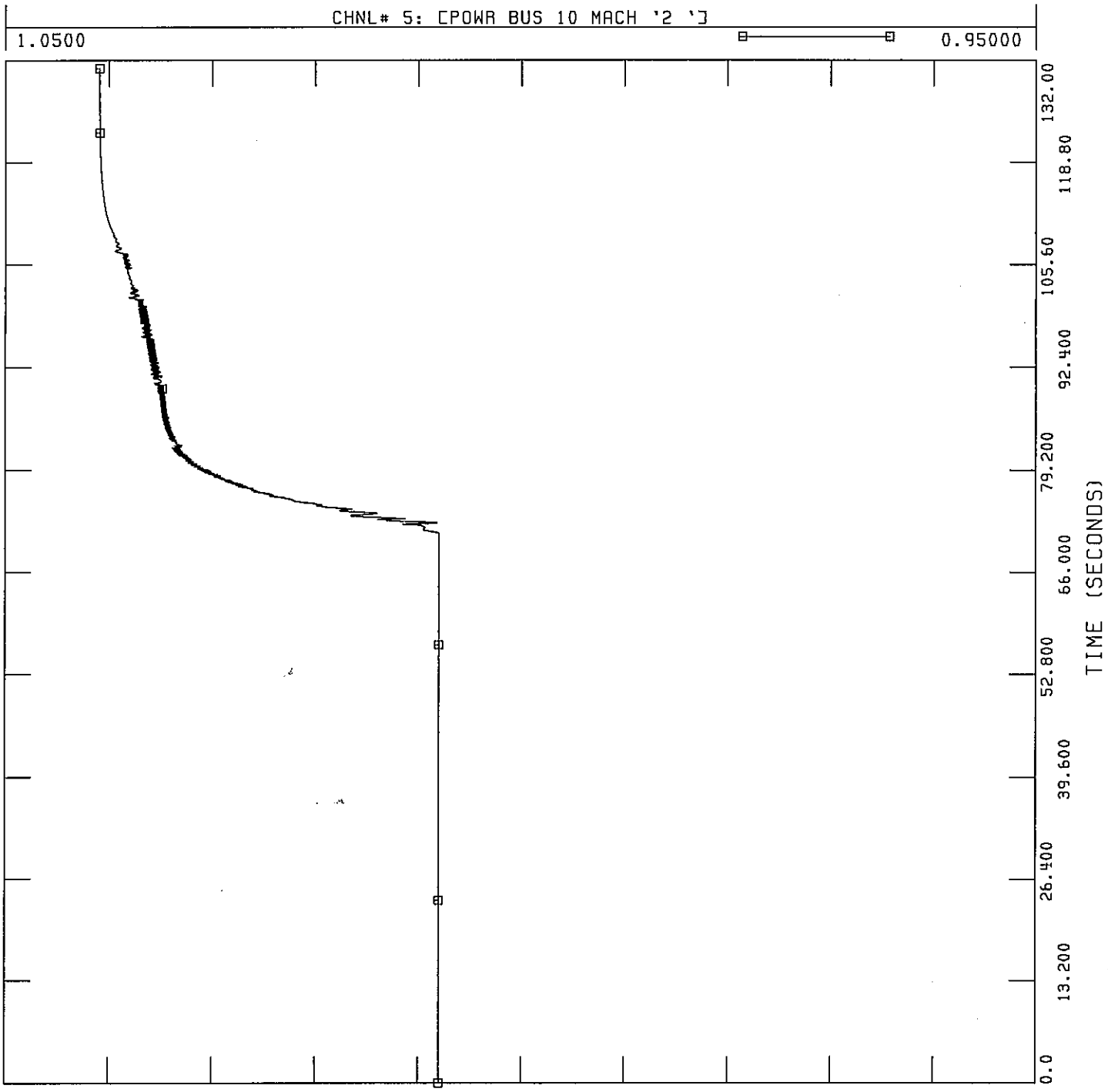


CASE WITH [redacted] AS TEST MACHINE

FILE: C:\doshi\AAWansley\Sever[redacted]_WanTrip.OUT

FRI, JUN 08 2007 14:37

Wansley - B

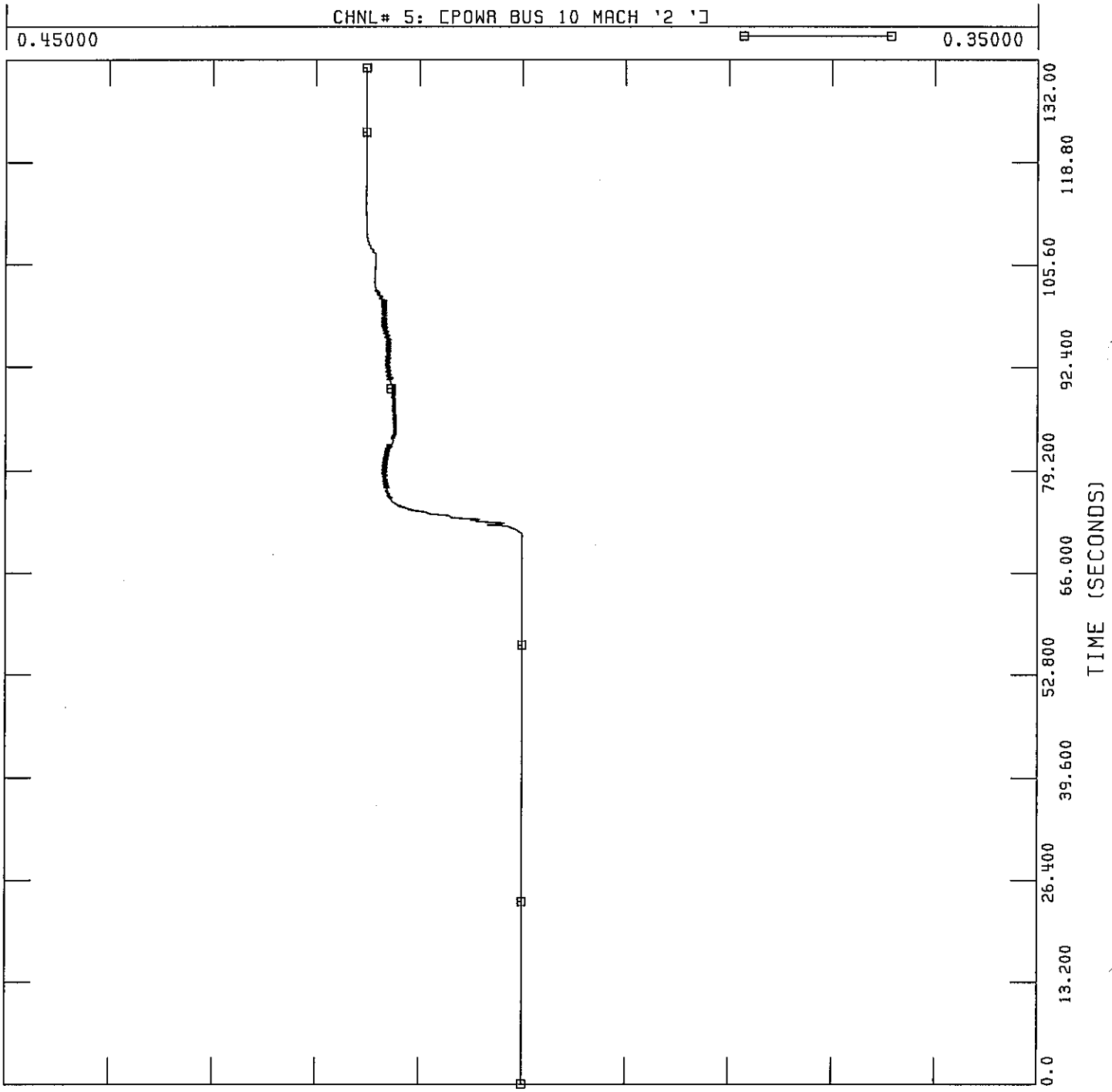


CASE WITH [redacted]AS TEST MACHINE

FILE: C:\doshi\AAWansley\Seven\[redacted]_WanTrip.OUT

FRI, JUN 08 2007 14:37

WANSLEY - C

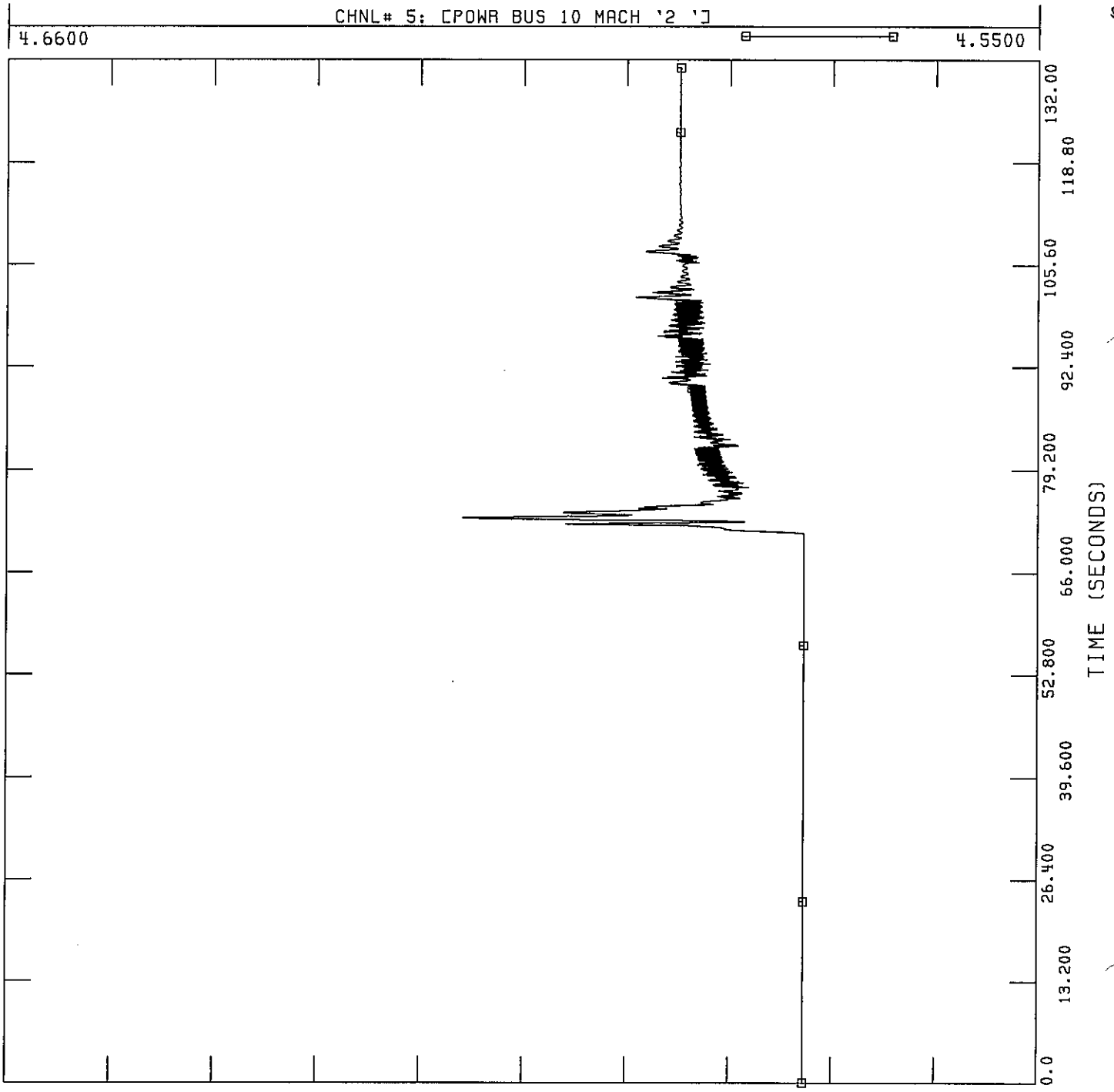


CASE WITH [redacted] AS TEST MACHINE

FILE: C:\doshi\AAWansley\Seven[redacted]_WanTrip.OUT

FRI, JUN 08 2007 14:45

WANSLEY - E

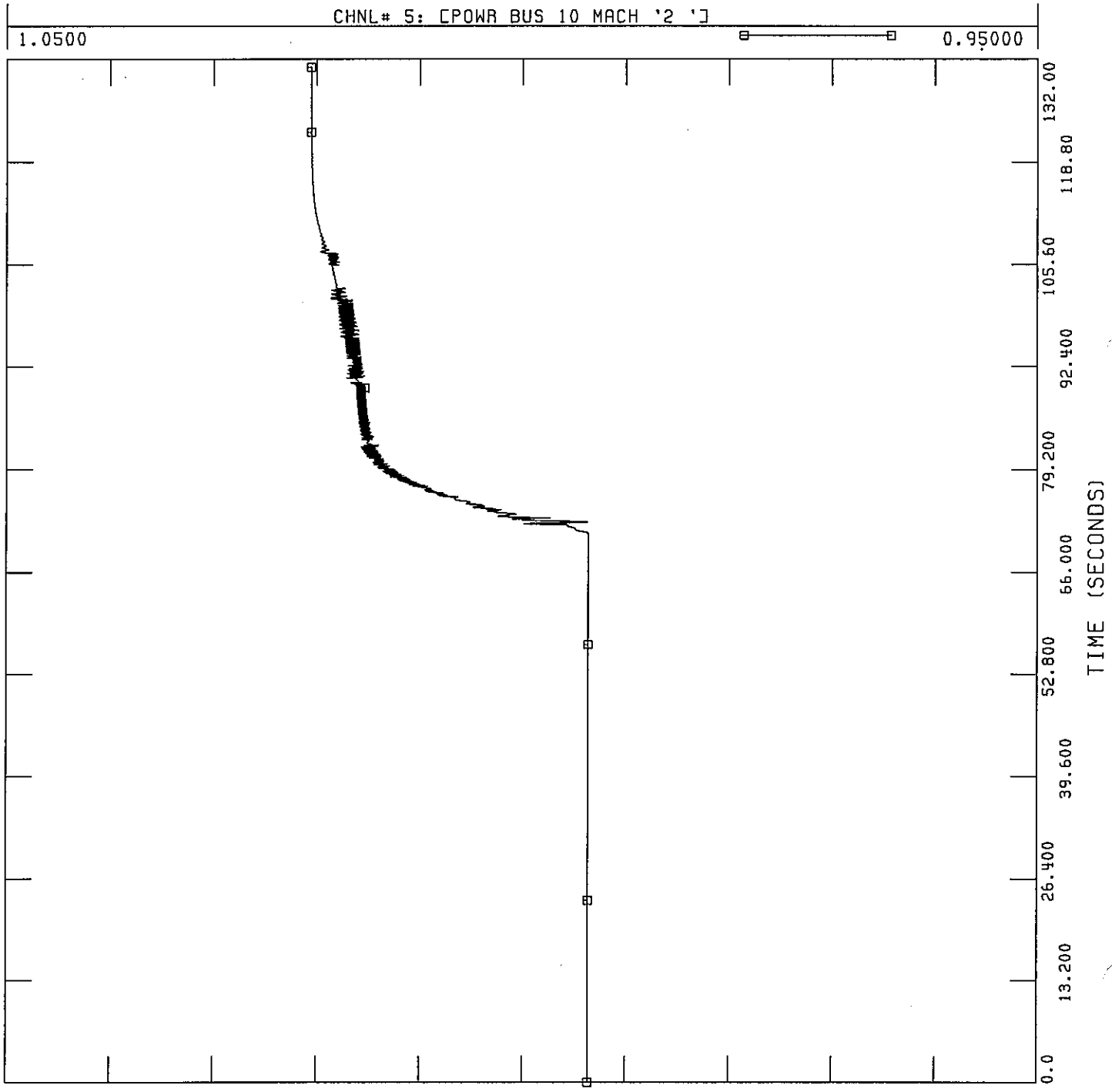


CASE WITH [redacted] AS TEST MACHINE

FILE: C:\doshi\AAWansley\Seven[redacted]anTrip.OUT

FRI, JUN 08 2007 14:29

WANSLEY - F

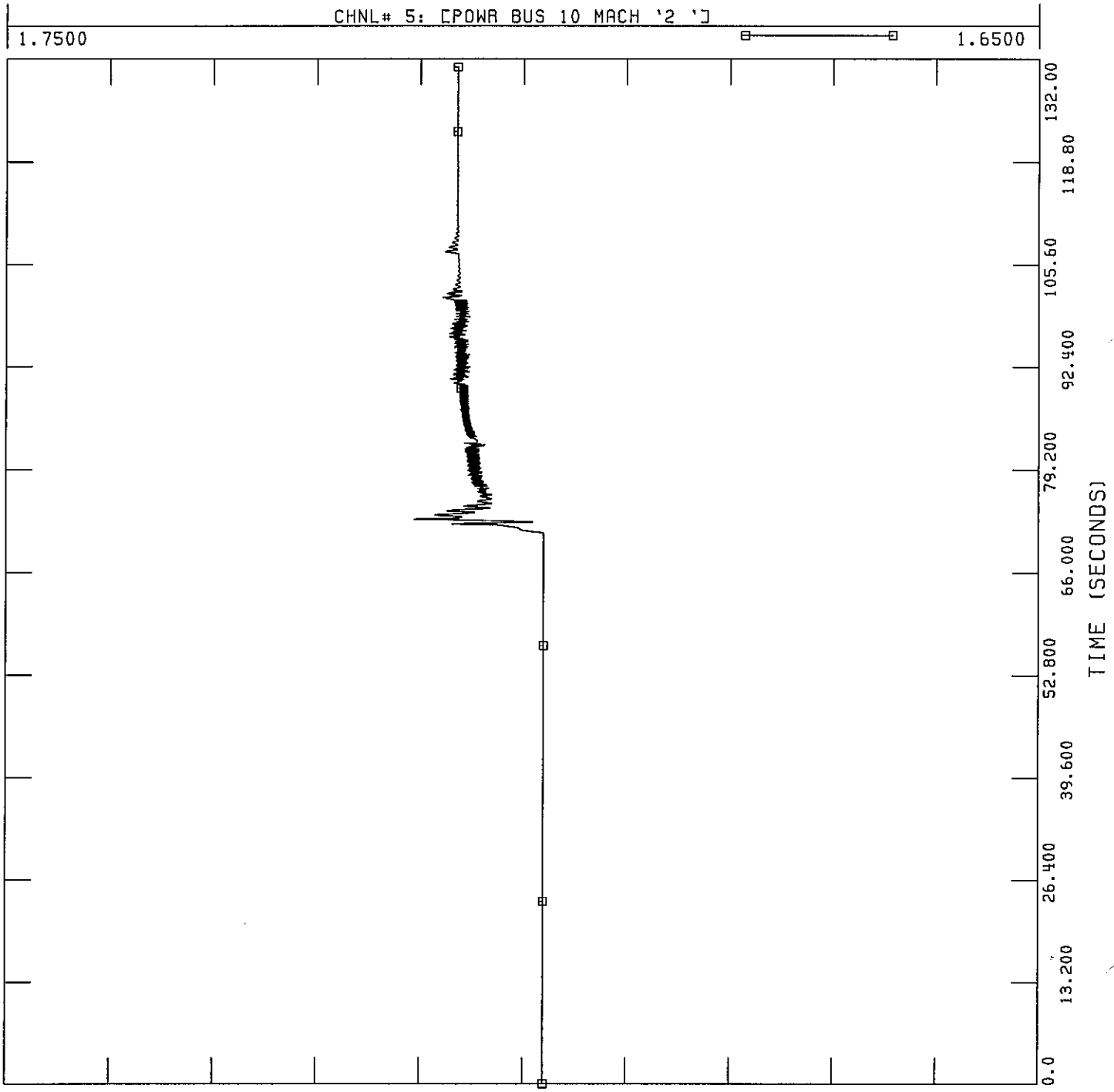


CASE WITH [redacted]AS TEST MACHINE

FILE: C:\doshi\AAWansley\Seven[redacted]WanTrip.OUT

FRI, JUN 08 2007 14:29

Wansley - G

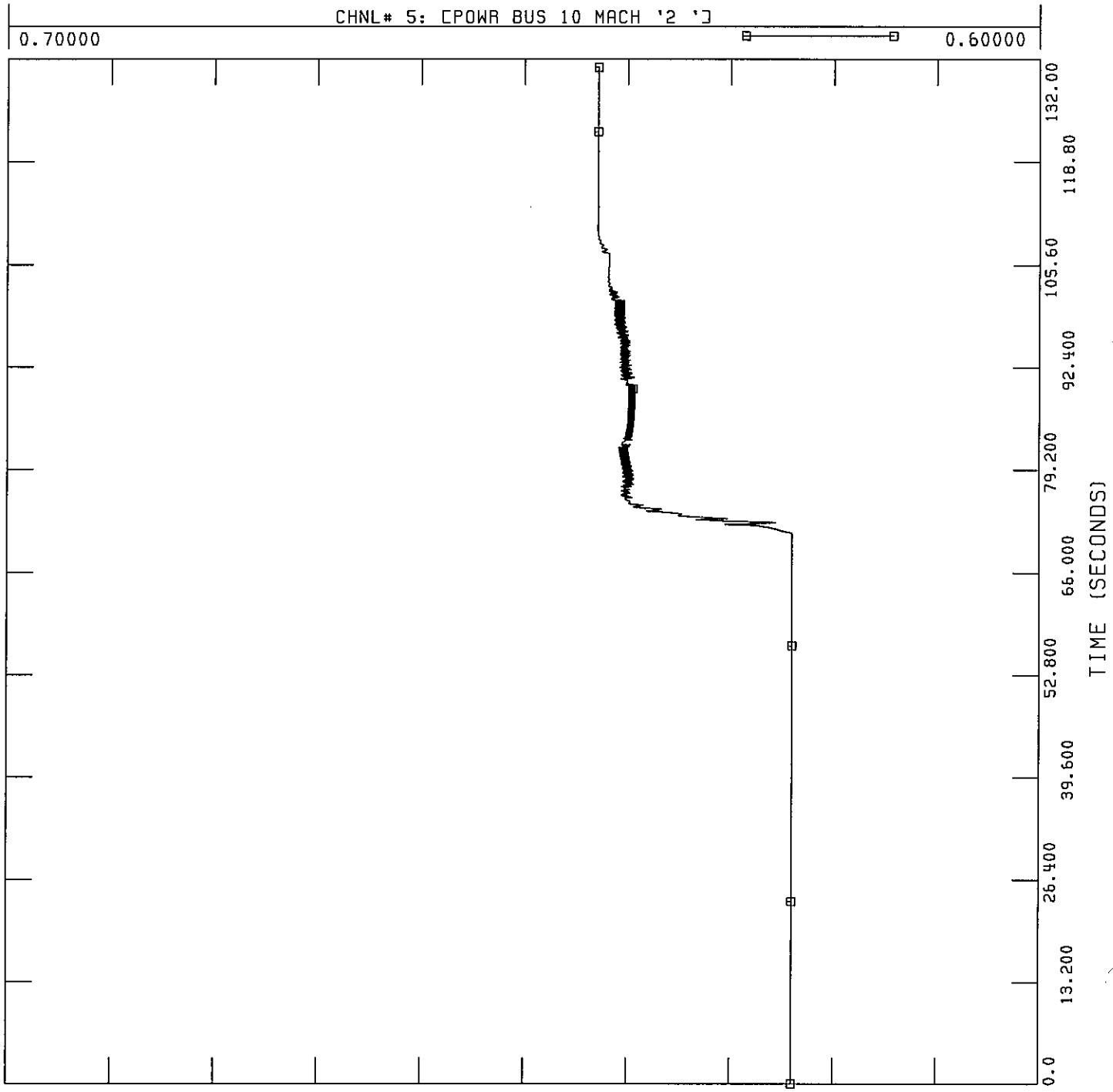


CASE WITH [redacted] AS TEST MACHINE

FILE: C:\doshi\AAOconee\Seven[redacted]_OconTrip.OUT

FRI, JUN 08 2007 14:27

Oconee - A

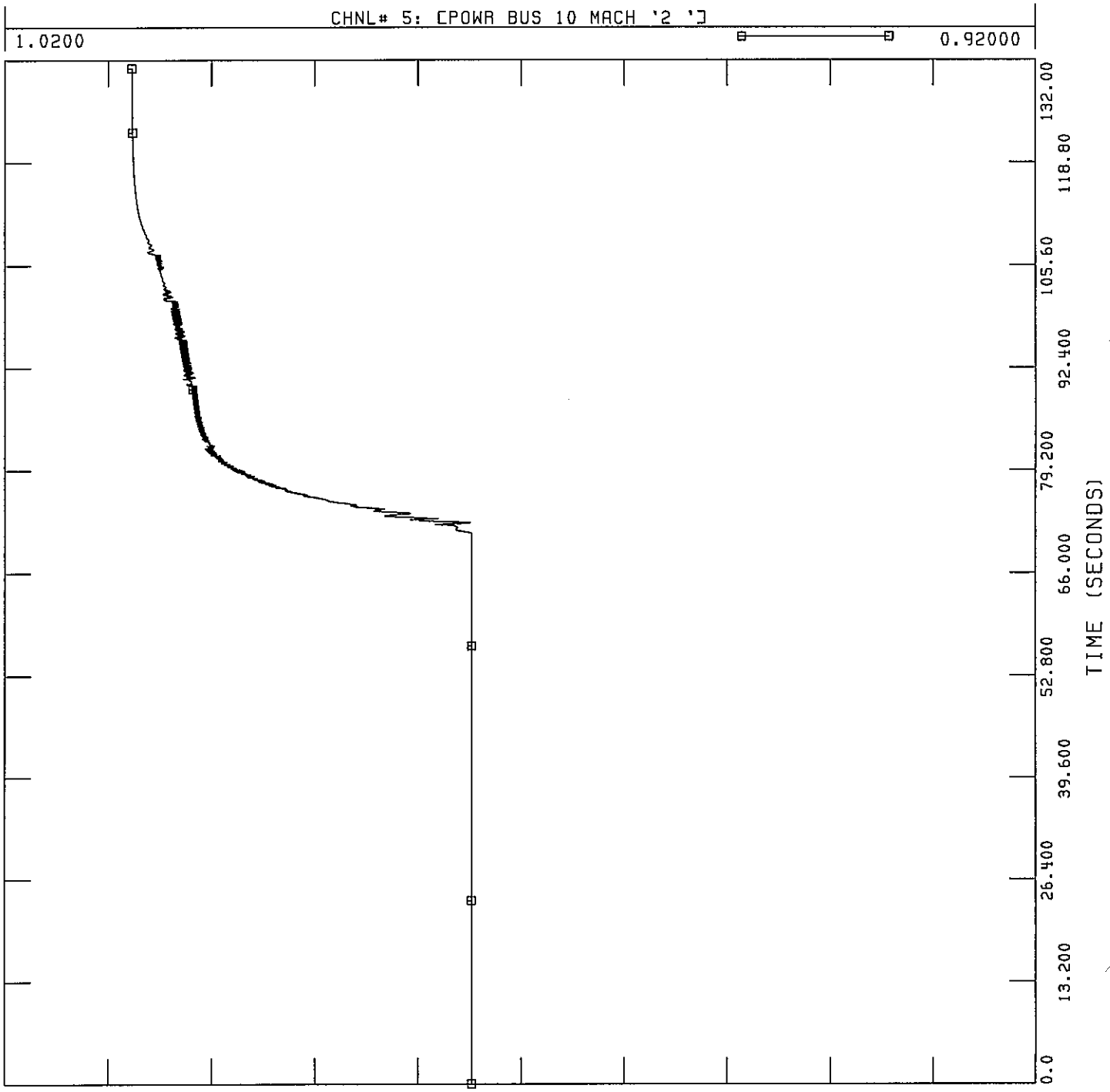


CASE WITH [redacted] AS TEST MACHINE

FILE: C:\doshi\AAOconee\Seven\[redacted]_OconTrip.OUT

FRI, JUN 08 2007 14:25

Oconee - B

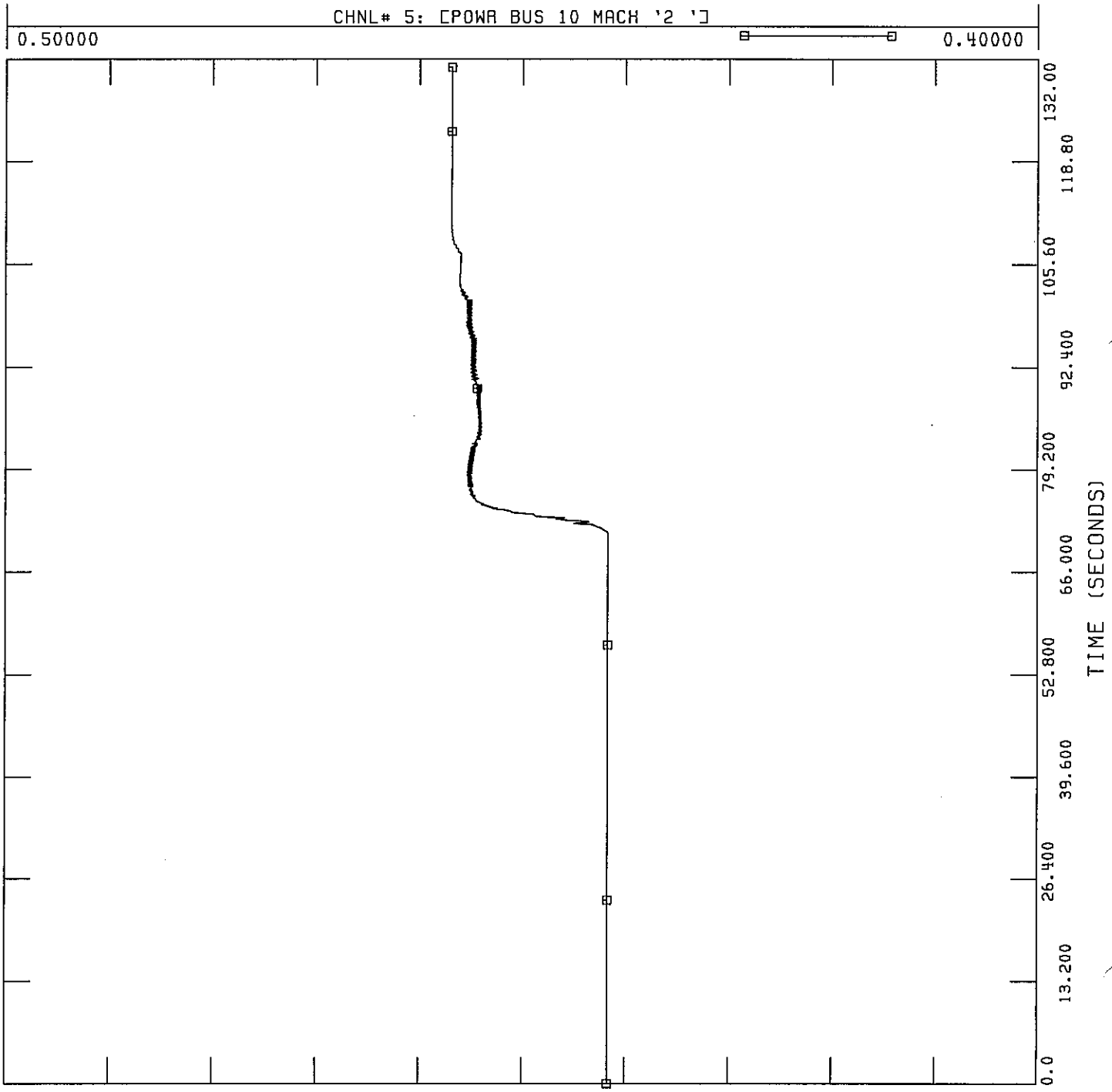


CASE WITH [redacted] 1 AS TEST MACHINE

FILE: C:\doshi\AAOconee\Seven\[redacted]_OconTrip.OUT

FRI, JUN 08 2007 14:26

OCONEE - C

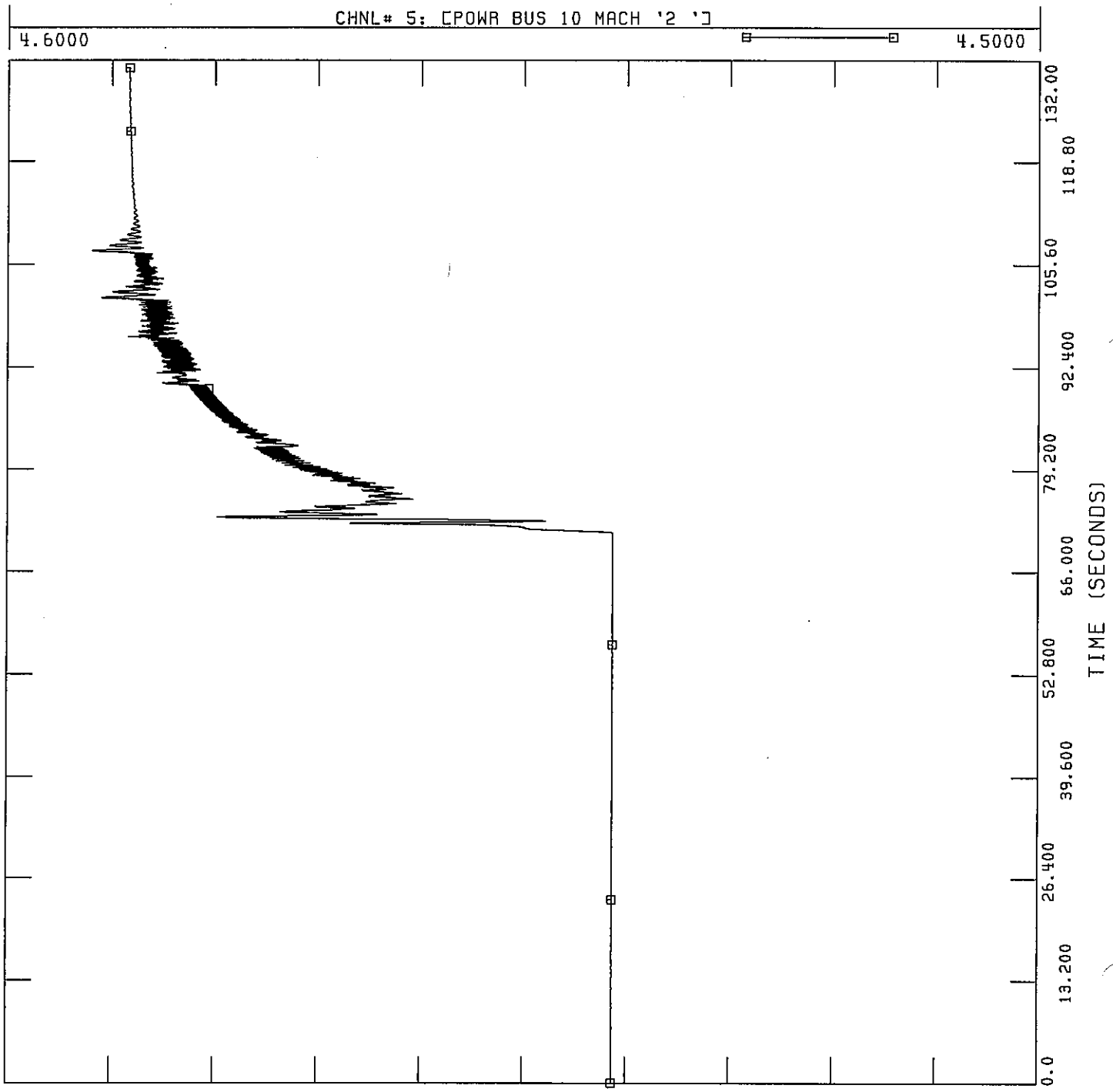


CASE WITH [redacted] AS TEST MACHINE

FILE: C:\doshi\AAOconee\Seven\[redacted]_OconTrip.OUT

FRI, JUN 08 2007 14:47

OCONEE - E

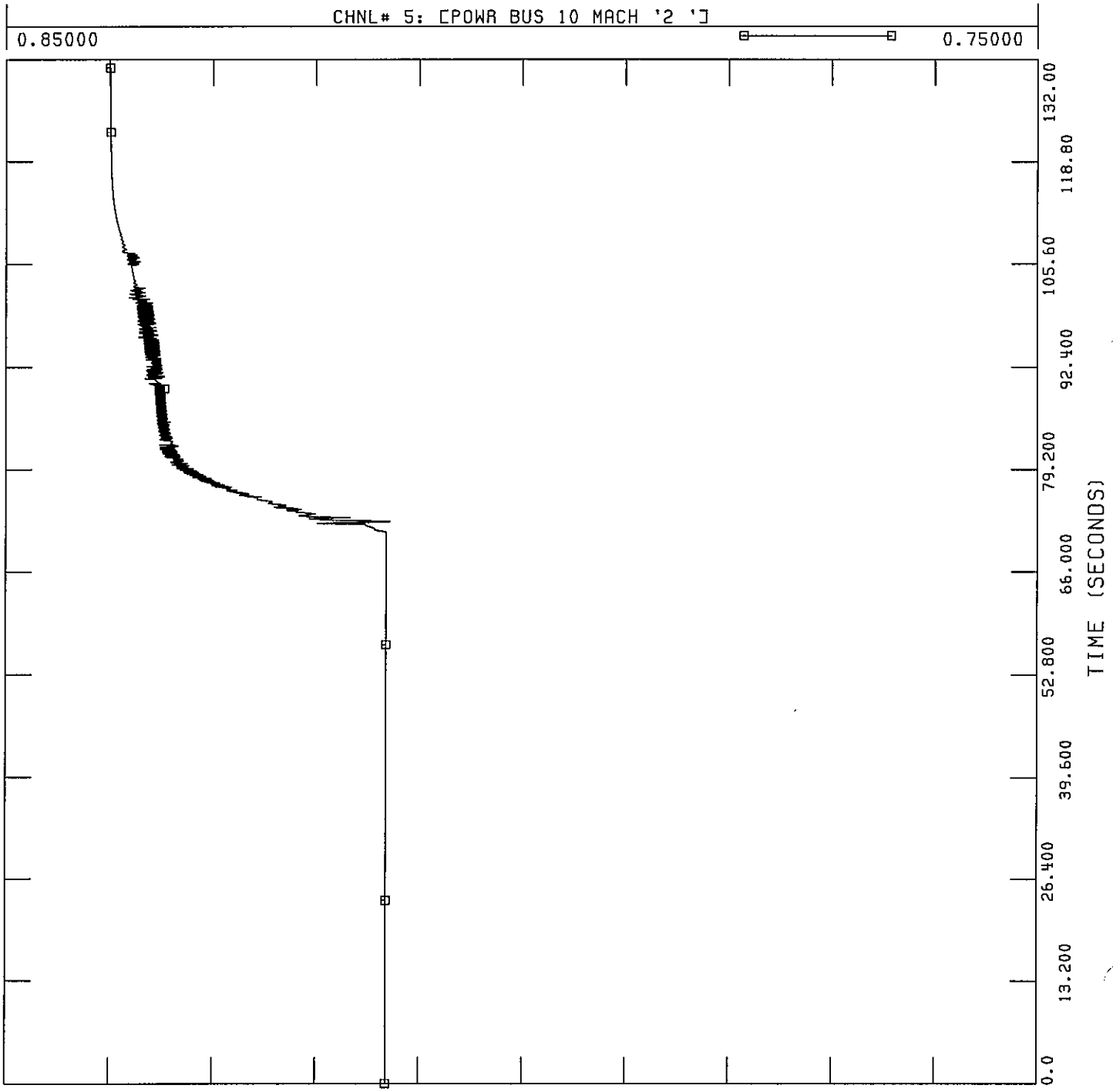


CASE WITH [redacted] AS TEST MACHINE

FILE: C:\doshi\AAOconee\Seven[redacted]OconTrip.OUT

FRI, JUN 08 2007 14:24

Oconee - F



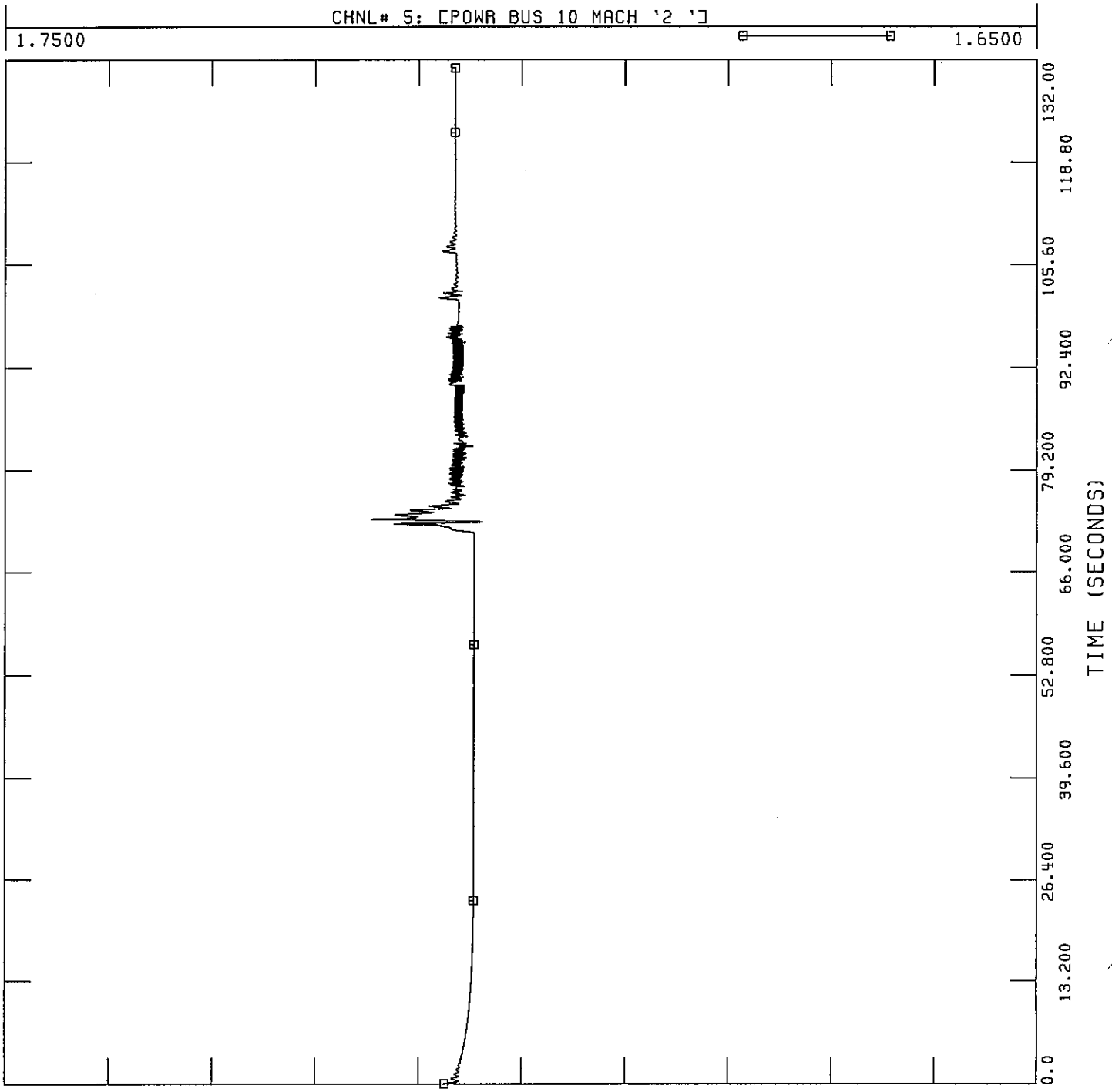
CASE WITH [redacted]S TEST MACHINE

SIEMENS POWER TECHNOLOGIES INTERNATIONAL

FILE: C:\doshi\AAOconee\Seven[redacted]OconTrip.OUT

FRI, JUN 08 2007 14:49

Oconee-G.



MOD-027 SERC Field Test Reporting Form

The purpose of this form is to provide a consistent report format for field testing results after using the SERC Field Test Guideline "Verification of Generator Unit Frequency Response". Documentation of the test results will provide feedback showing that the field test was successful and/or will help to enhance the test guideline.

Use the attached SERC Field Test Guideline "Verification of Generator Unit Frequency Response" to perform the test (engineering study). Complete one (1) report form for each unit tested.

Provide the following information:

1. Is there a maintenance management program in place for the turbine speed load governor control system (analog and/or digital based)? (Yes or No) yes
   - If yes, what is the maintenance interval? 84 (months)
2. Is there a configuration management program in place for the turbine speed load governor control system (analog and/or digital based)? (Yes or No) no
3. Was good correlation between the generator output (MW vs. time) and the model obtained? (Yes or No) Yes

   3. A. **If yes:** (Use additional pages if needed to explain.)
   - How long did it take to obtain the generator output data? 1 (hours)
   - How long did it take to set up the model to simulate this event? 3 (hours)
   - How long did it take to compare the generator output data to the model? 1 (hours)
   - Did the model parameters or type need to be changed? no

   3. B. **If No:**
   - Use additional pages to explain.
4. List any material costs associated with this study. none
5. Please list any suggested changes to the guideline? none
6. Provide a completed Attachment # 2 to the SERC Field Test Guidelines for Verification of Generator Unit Frequency Response (MOD-027).
7. Name of the person completing the form: Sujit Mandal Phone Number: 504 576 2342 Company Name: Entergy

Send the completed report form and supporting documentation electronically to: phuntley@serc1.org.

draft

Attachment 2

Sample Reporting Form

Turbine and Governor (Speed/Load) Controls Questionnaire

1. **Unit Name: _Nelson Unit 4_____**
2. **Company: _Entergy_____**
3. **Date: ___06/07/07_____**
4. **Submitter: _Sujit Mandal_____**
5. **Phone No. ___504 576 2342_____**

Governor Information:

Identify general type of governor control:

	Mechanical hydraulic (MHC)
	Analog electro-hydraulic (EHC)
x	Digital electro-hydraulic (DEH)
	_____

Check type of governor model submitted:

	PTI Standard Model with As built parameters
x	PTI Standard Model with Estimated Parameters
	PTI Standard Model with Parameters derived from event(s) based Validation(s)

Droop Setting (%): ___5_____

MOD-027 SERC Field Test Reporting Form

The purpose of this form is to provide a consistent report format for field testing results after using the SERC Field Test Guideline "Verification of Generator Unit Frequency Response". Documentation of the test results will provide feedback showing that the field test was successful and/or will help to enhance the test guideline.

Use the attached SERC Field Test Guideline "Verification of Generator Unit Frequency Response" to perform the test (engineering study). Complete one (1) report form for each unit tested.

Provide the following information:

1. Is there a maintenance management program in place for the turbine speed load governor control system (analog and/or digital based)? (Yes or No) yes
   - If yes, what is the maintenance interval? 84 (months)
2. Is there a configuration management program in place for the turbine speed load governor control system (analog and/or digital based)? (Yes or No) no
3. Was good correlation between the generator output (MW vs. time) and the model obtained? (Yes or No) Yes

   3. A. **If yes:** (Use additional pages if needed to explain.)
   - How long did it take to obtain the generator output data? 1 (hours)
   - How long did it take to set up the model to simulate this event? 3 (hours)
   - How long did it take to compare the generator output data to the model? 1 (hours)
   - Did the model parameters or type need to be changed? no

   3. B. **If No:**
   - Use additional pages to explain.
4. List any material costs associated with this study. none
5. Please list any suggested changes to the guideline? none
6. Provide a completed Attachment # 2 to the SERC Field Test Guidelines for Verification of Generator Unit Frequency Response (MOD-027).
7. Name of the person completing the form: Sujit Mandal Phone Number: 504 576 2342 Company Name: Entergy

Send the completed report form and supporting documentation electronically to: phuntley@serc1.org.

draft

Attachment 2

Sample Reporting Form

Turbine and Governor (Speed/Load) Controls Questionnaire

1. **Unit Name: _White Bluff Unit 1_____**
2. **Company: _Entergy_____**
3. **Date: ___06/07/07_____**
4. **Submitter: _Sujit Mandal_____**
5. **Phone No. ___504 576 2342_____**

Governor Information:

Identify general type of governor control:

	Mechanical hydraulic (MHC)
	Analog electro-hydraulic (EHC)
x	Digital electro-hydraulic (DEH)
	_____

Check type of governor model submitted:

	PTI Standard Model with As built parameters
x	PTI Standard Model with Estimated Parameters
	PTI Standard Model with Parameters derived from event(s) based Validation(s)

Droop Setting (%): ___5_____

MOD-027 SERC Field Test Reporting Form

The purpose of this form is to provide a consistent report format for field testing results after using the SERC Field Test Guideline "Verification of Generator Unit Frequency Response". Documentation of the test results will provide feedback showing that the field test was successful and/or will help to enhance the test guideline.

Use the attached SERC Field Test Guideline "Verification of Generator Unit Frequency Response" to perform the test (engineering study). Complete one (1) report form for each unit tested.

Provide the following information:

1. Is there a maintenance management program in place for the turbine speed load governor control system (analog and/or digital based)? (Yes or No) yes
   - If yes, what is the maintenance interval? 84 (months)
2. Is there a configuration management program in place for the turbine speed load governor control system (analog and/or digital based)? (Yes or No) no
3. Was good correlation between the generator output (MW vs. time) and the model obtained? (Yes or No) Yes

   3. A. **If yes:** (Use additional pages if needed to explain.)
   - How long did it take to obtain the generator output data? 1 (hours)
   - How long did it take to set up the model to simulate this event? 3 (hours)
   - How long did it take to compare the generator output data to the model? 1 (hours)
   - Did the model parameters or type need to be changed? no

   3. B. **If No:**
   - Use additional pages to explain.
4. List any material costs associated with this study. none
5. Please list any suggested changes to the guideline? none
6. Provide a completed Attachment # 2 to the SERC Field Test Guidelines for Verification of Generator Unit Frequency Response (MOD-027).
7. Name of the person completing the form: Sujit Mandal Phone Number: 504 576 2342 Company Name: Entergy

Send the completed report form and supporting documentation electronically to: phuntley@serc1.org.

draft

Attachment 2

Sample Reporting Form

Turbine and Governor (Speed/Load) Controls Questionnaire

1. **Unit Name: _White Bluff Unit 2_____**
2. **Company: _Entergy_____**
3. **Date: ___06/07/07_____**
4. **Submitter: _Sujit Mandal_____**
5. **Phone No. ___504 576 2342_____**

Governor Information:

Identify general type of governor control:

- [ ] Mechanical hydraulic (MHC)
- [x] Analog electro-hydraulic (EHC)
- [ ] Digital electro-hydraulic (DEH)
- [ ] _____

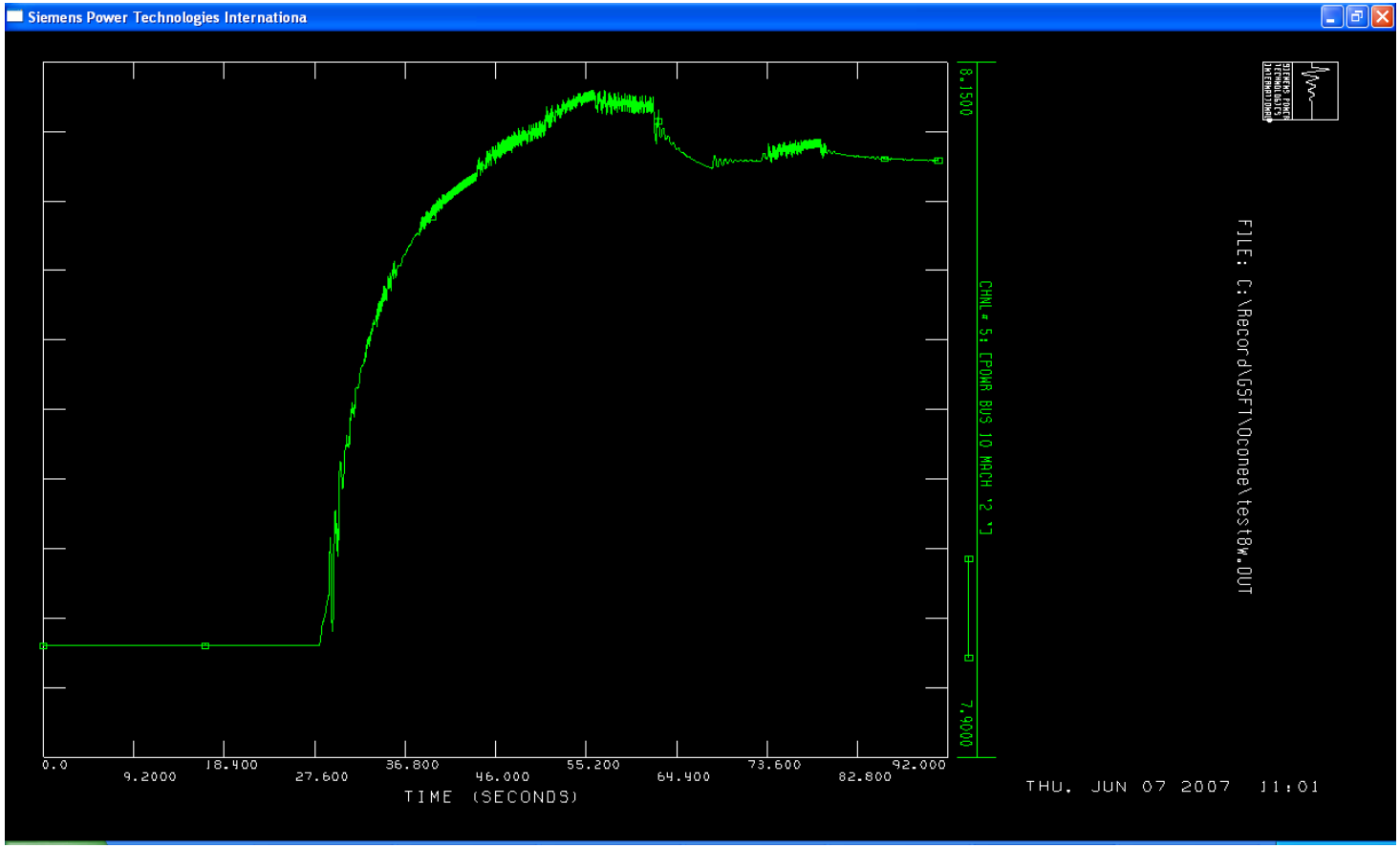
Check type of governor model submitted:

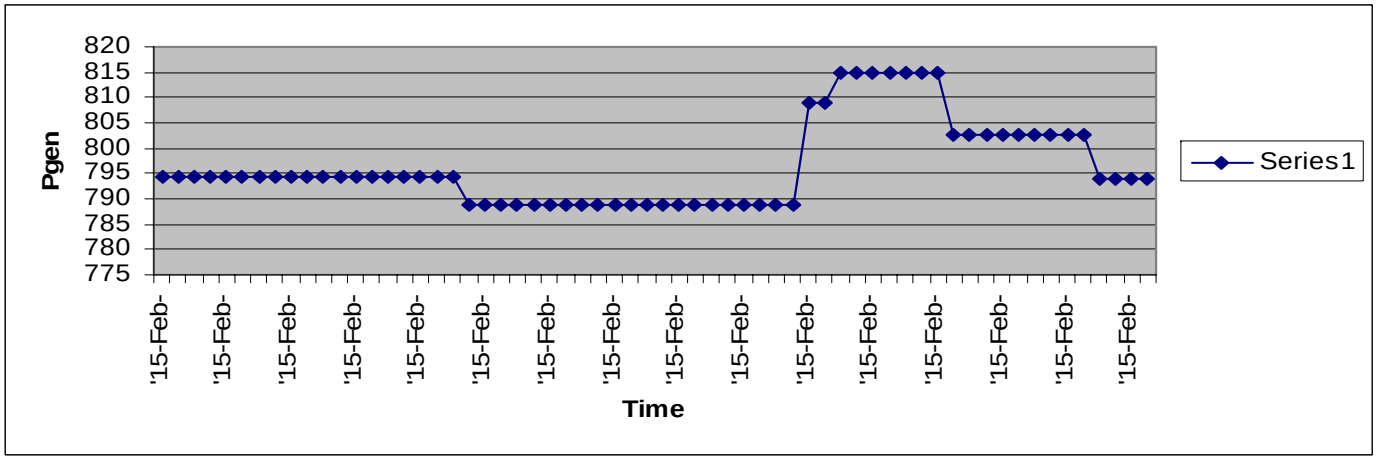
- [ ] PTI Standard Model with As built parameters
- [x] PTI Standard Model with Estimated Parameters
- [ ] PTI Standard Model with Parameters derived from event(s) based Validation(s)

Droop Setting (%): ___5_____

Oconee Event

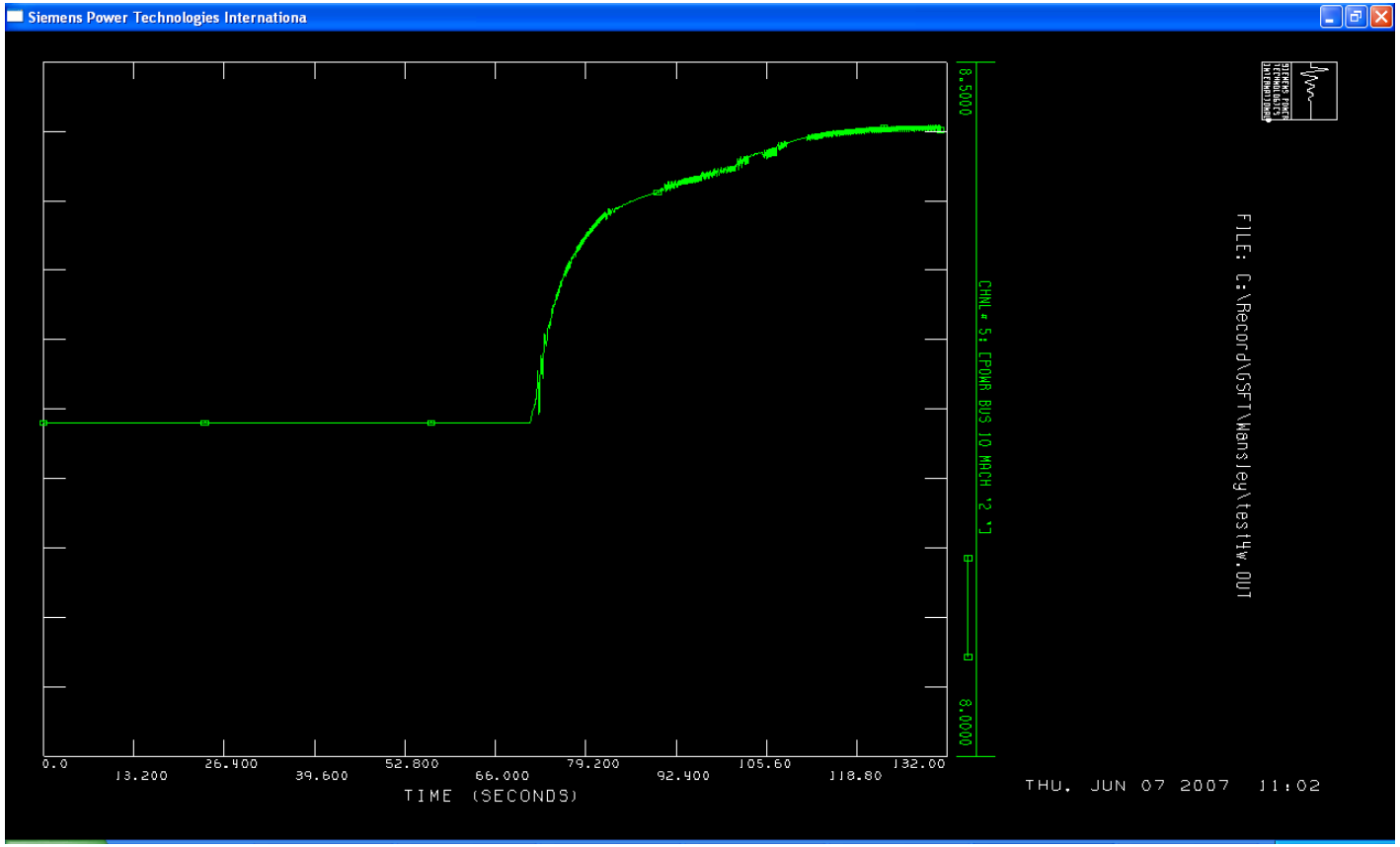
Simulation at White Bluff U1 (Coal fired)

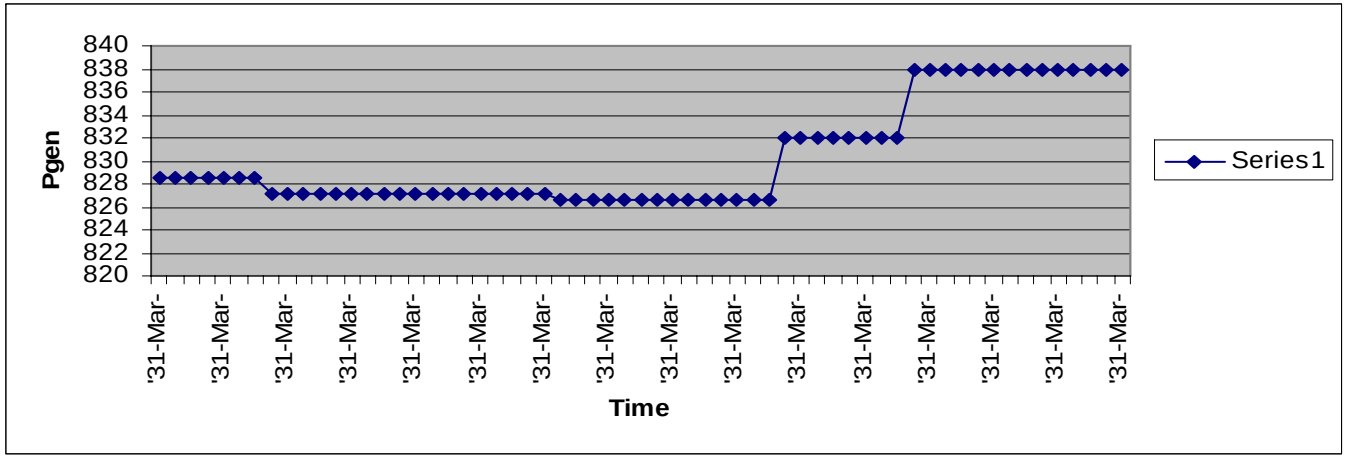

Siemens Power Technologies Internationa
8.1500
7.9000
CHNL # 5: [PONR BUS 10 MACH 2]
FILE: C:\Record\GSFT\Oconee\test8w.OUT
0.0
9.2000
18.400
27.600
36.800
46.000
55.200
64.400
73.600
82.800
92.000
TIME (SECONDS)
THU, JUN 07 2007 11:01


Pgen
820
815
810
805
800
795
790
785
780
775
'15-Feb-
Time
Series1

Wansley Event

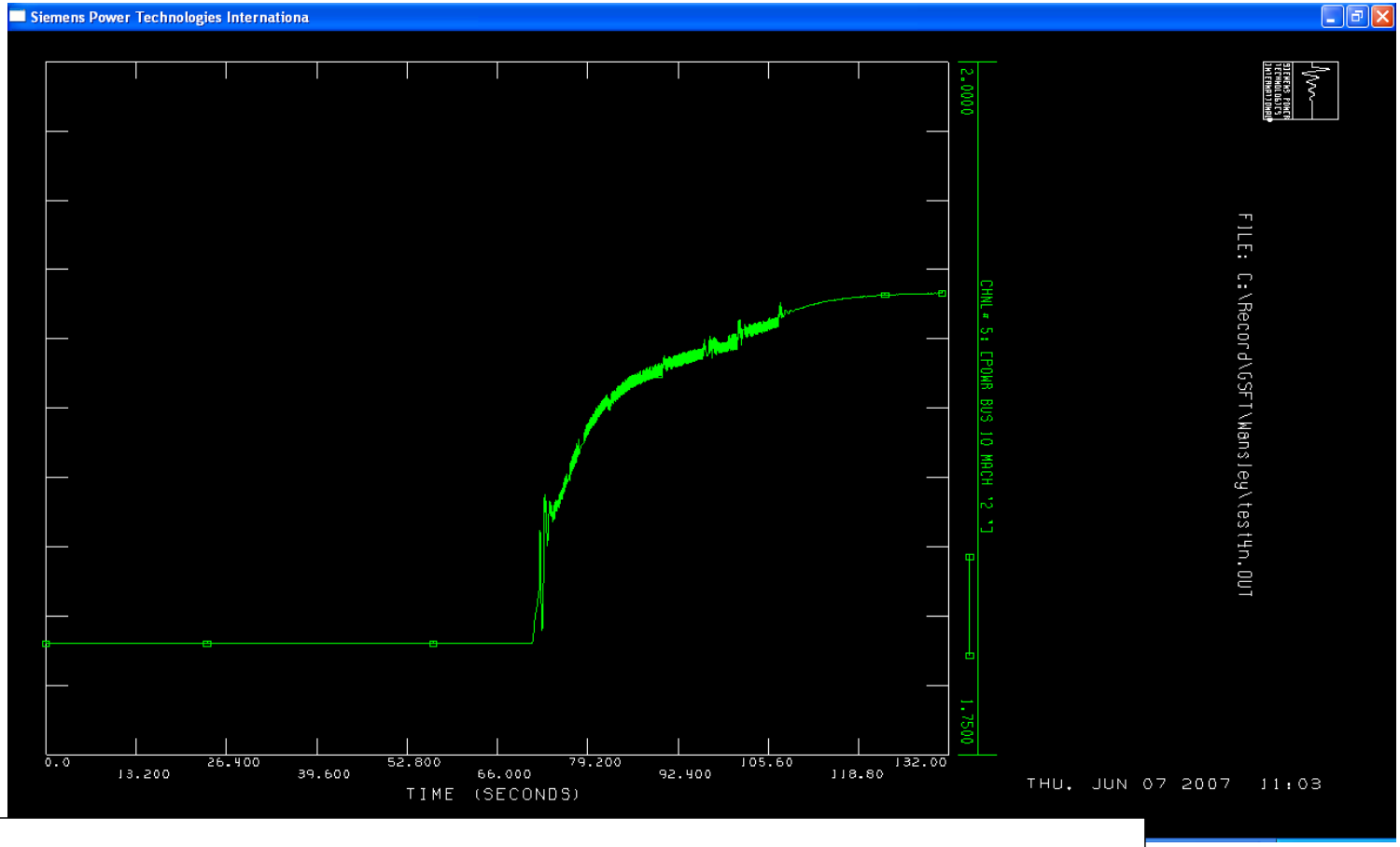
Simulation at White Bluff U2 (Coal fired)

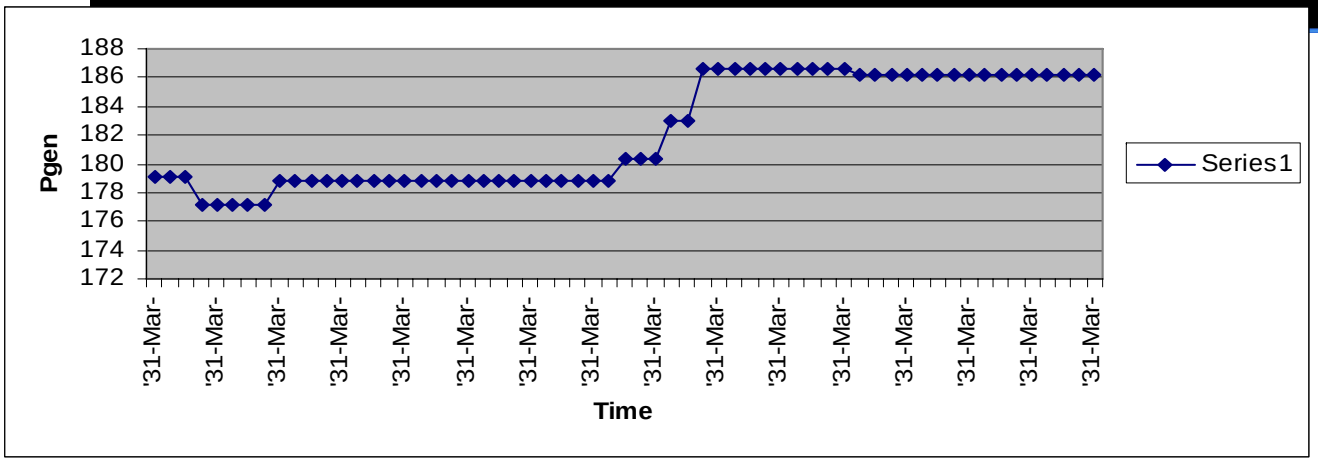

Siemens Power Technologies Internationa
8.5000
8.0000
CHNL # 5: [POWR BUS 10 MACH '2 ']
FILE: C:\Record\GSFT\Wansley\test4w.OUT
0.0
13.200
26.400
39.600
52.800
66.000
79.200
92.400
105.60
118.80
132.00
TIME (SECONDS)
THU. JUN 07 2007 11:02


Pgen
840
838
836
834
832
830
828
826
824
822
820
'31-Mar-
Time
Series1

Wansley Event

Simulation at Nelson U4 (Gas fired)


Siemens Power Technologies Internationa
2.0000
CHNL# 5: EPOWR BUS 10 MACH 12 ']
1.7500
0.0
13.200
26.400
39.600
52.800
66.000
79.200
92.400
105.60
118.80
132.00
TIME (SECONDS)
FILE: C:\Record\GSFT\Wansley\test4n.OUT
THU, JUN 07 2007 11:03


Pgen
188
186
184
182
180
178
176
174
172
'31-Mar-
Time
Series1

MOD-027 SERC Field Test Reporting Form

The purpose of this form is to provide a consistent report format for field testing results after using the SERC Field Test Guideline "Verification of Generator Unit Frequency Response". Documentation of the test results will provide feedback showing that the field test was successful and/or will help to enhance the test guideline.

Use the attached SERC Field Test Guideline "Verification of Generator Unit Frequency Response" to perform the test (engineering study). Complete one (1) report form for each unit tested.

Provide the following information:

1. Is there a maintenance management program in place for the turbine speed load governor control system (analog and/or digital based)? (Yes or No) NOT SURE
   - If yes, what is the maintenance interval? (months)
2. Is there a configuration management program in place for the turbine speed load governor control system (analog and/or digital based)? (Yes or No) NOT SURE
3. Was good correlation between the generator output (MW vs. time) and the model obtained? (Yes or No) We were not able to perform this test. Our EMS currently does not log individual Unit MWs at 6 seconds or less intervals. I was able to get MWs for some units from unit controllers, but unit control system clocks were not synchronized with the EMS clock. Our TO was also tied up gathering material for the NERC compliance filing.

   3. A. **If yes:** (Use additional pages if needed to explain.)
   - How long did it take to obtain the generator output data? (hours)
   - How long did it take to set up the model to simulate this event? (hours)
   - How long did it take to compare the generator output data to the model? (hours)
   - Did the model parameters or type need to be changed?

   3. B. **If No:**
   - Use additional pages to explain.
4. List any material costs associated with this study.
5. Please list any suggested changes to the guideline?
6. Provide a completed Attachment # 2 to the SERC Field Test Guidelines for Verification of Generator Unit Frequency Response (MOD-027).
7. Name of the person completing the form: Pat Longshore Phone Number: 803-217-7490 Company Name: SCE&G

Send the completed report form and supporting documentation electronically to: phuntley@serc1.org.

Attachment 2

Sample Reporting Form

Turbine and Governor (Speed/Load) Controls Questionnaire

1. Unit Name: GREENE COUNTY UNIT 1
2. Company: ALABAMA POWER COMPANY
3. Date: JUNE 5th, 2007
4. Submitter: ROSS CAMPBELL
5. Phone No. 205-992-7174 (8-992-7174)

Governor Information:

Identify general type of governor control:

Mechanical hydraulic (MHC)
Analog electro-hydraulic (EHC)
X Digital electro-hydraulic (DEH)
_____

Check type of governor model submitted:

X PTI Standard Model with As built parameters
PTI Standard Model with Estimated Parameters
PTI Standard Model with Parameters derived from event(s) based Validation(s)

Droop Setting (%): 5

MOD-027 SERC Field Test Reporting Form

The purpose of this form is to provide a consistent report format for field testing results after using the SERC Field Test Guideline "Verification of Generator Unit Frequency Response". Documentation of the test results will provide feedback showing that the field test was successful and/or will help to enhance the test guideline.

Use the attached SERC Field Test Guideline "Verification of Generator Unit Frequency Response" to perform the test (engineering study). Complete one (1) report form for each unit tested.

Provide the following information:

1. Is there a maintenance management program in place for the turbine speed load governor control system (analog and/or digital based)? (Yes or No) Under Development
   - If yes, what is the maintenance interval? 36-60 (months) (Depending on Unit Maintenance requirements)

2. Is there a configuration management program in place for the turbine speed load governor control system (analog and/or digital based)? (Yes or No) Yes

3. Was good correlation between the generator output (MW vs. time) and the model obtained? (Yes or No)

   3. A. **If yes:** (Use additional pages if needed to explain.)

   - How long did it take to obtain the generator output data? (hours)
   - How long did it take to set up the model to simulate this event? (hours)
   - How long did it take to compare the generator output data to the model? (hours)
   - Did the model parameters or type need to be changed?

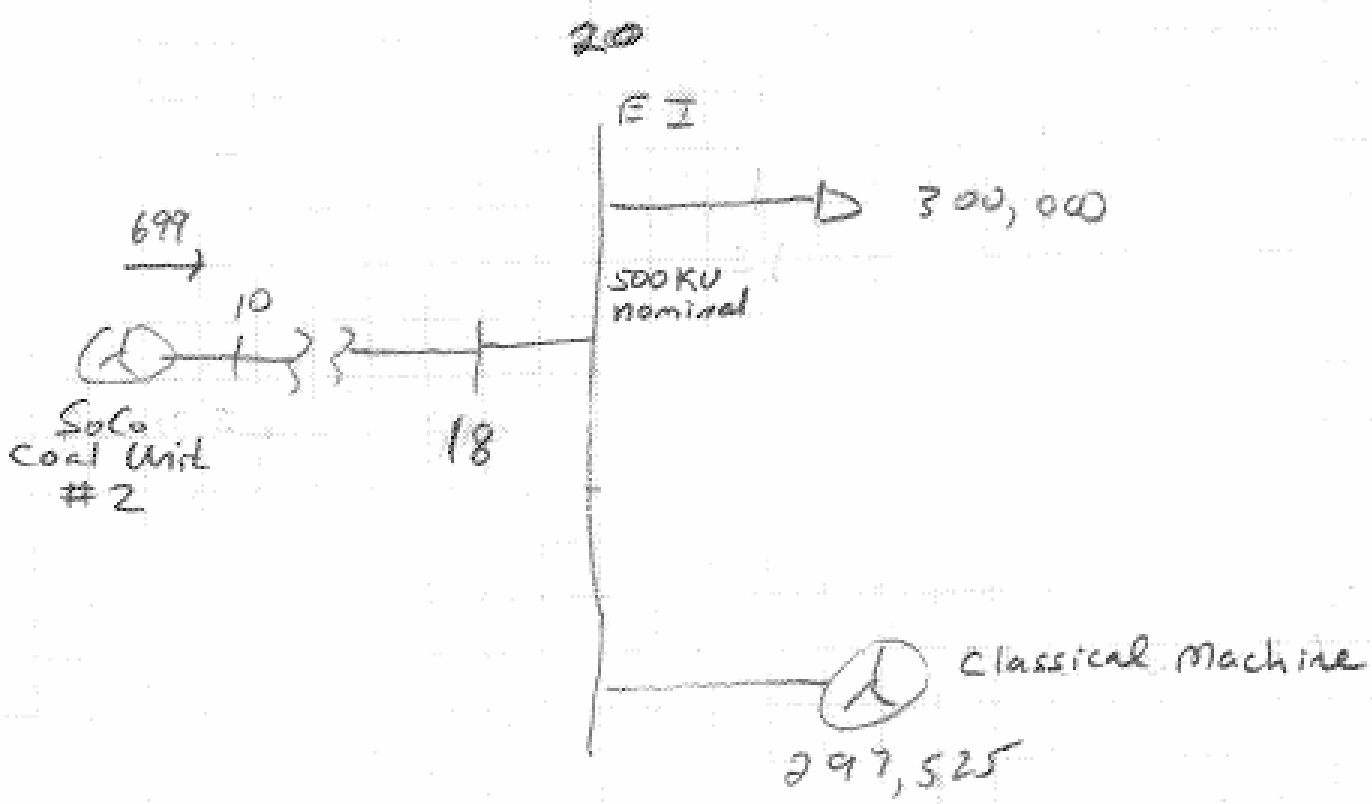
   3. B. **If No:**

   - Use additional pages to explain.

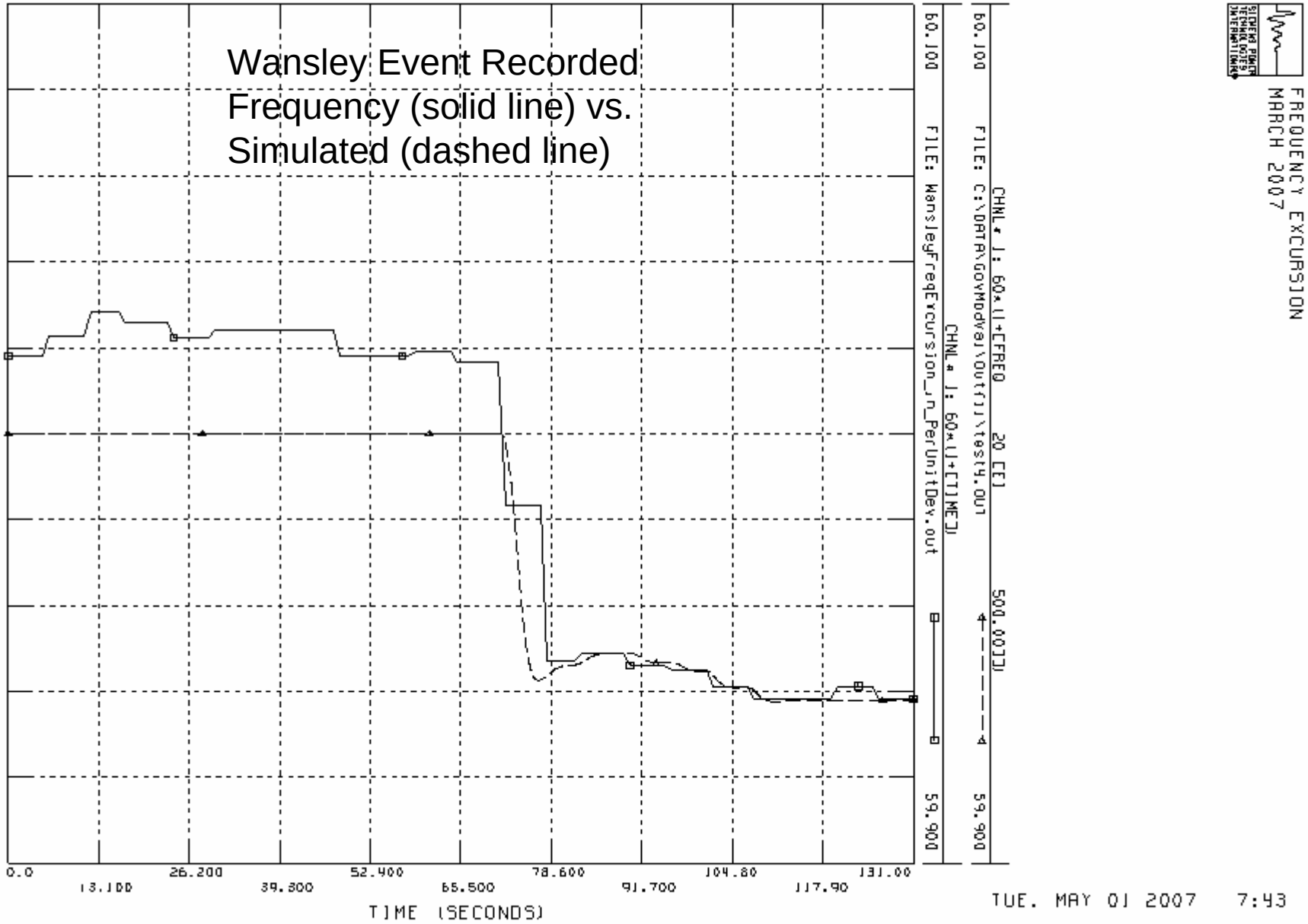
4. List any material costs associated with this study.
5. Please list any suggested changes to the guideline?
6. Provide a completed Attachment # 2 to the SERC Field Test Guidelines for Verification of Generator Unit Frequency Response (MOD-027).

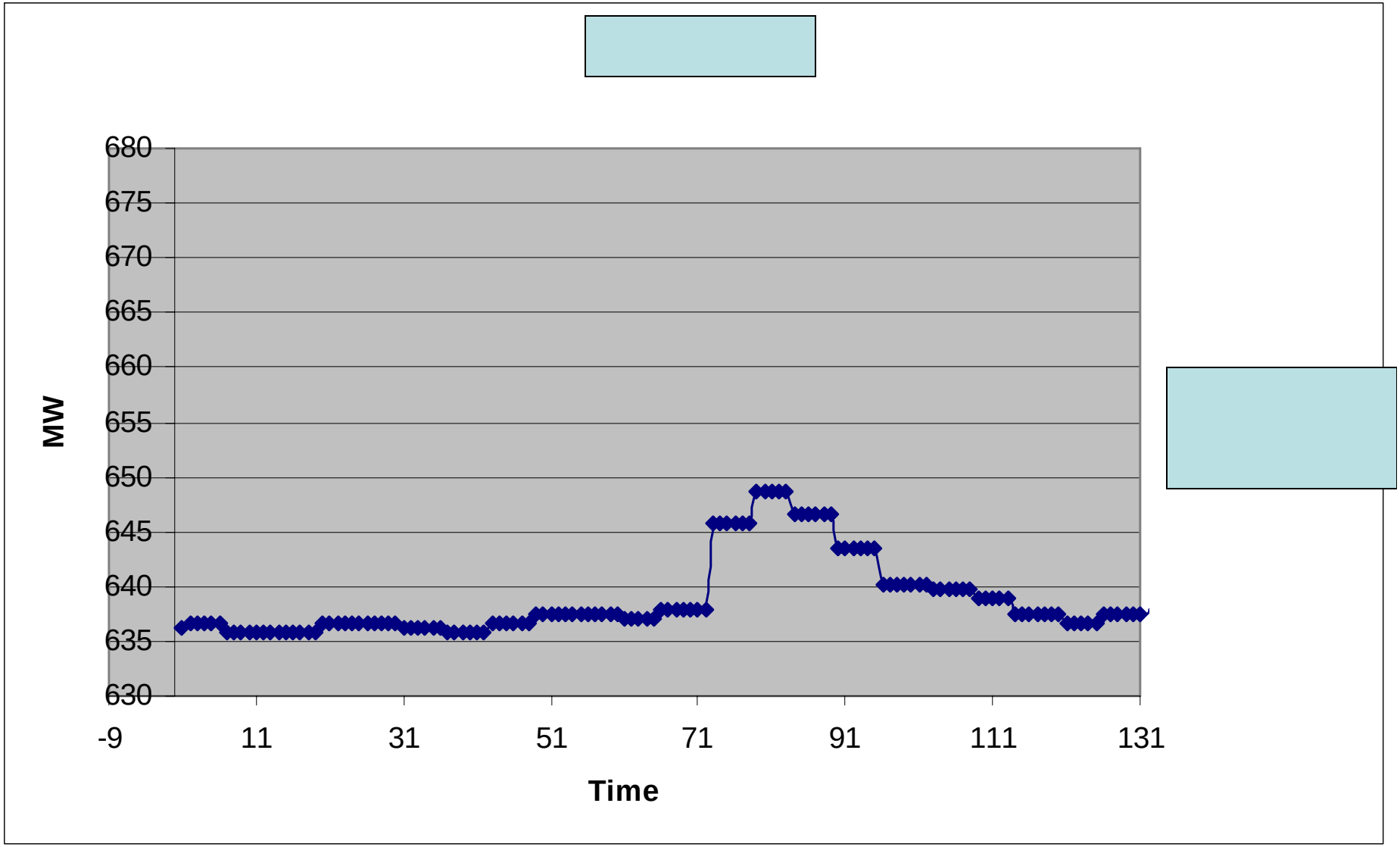
7. Name of the person completing the form: Ross Campbell Phone Number: 205-992-7174 Company Name: Southern Company Services

Send the completed report form and supporting documentation electronically to: phuntley@serc1.org.

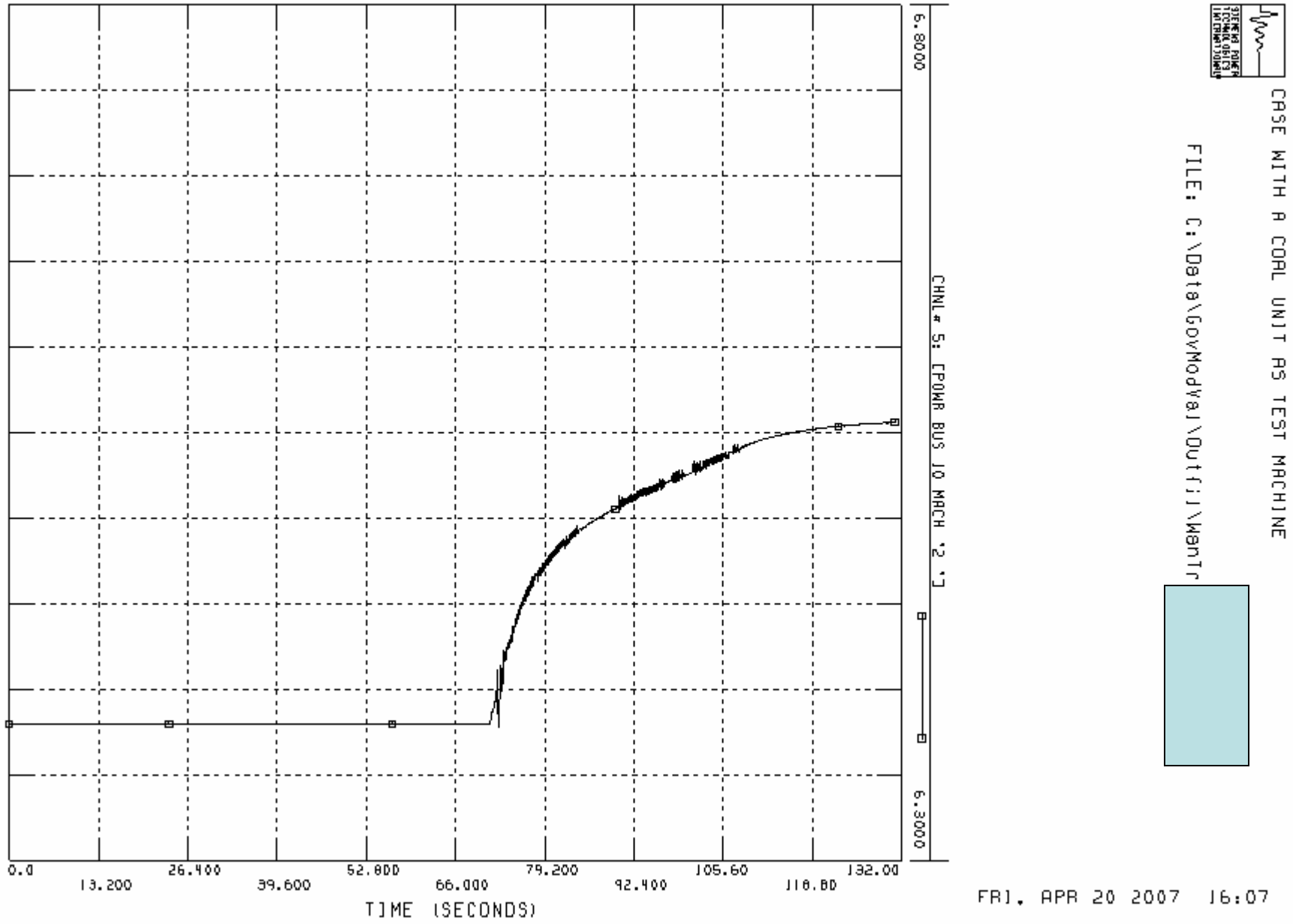

20
E I
300,000
699
10
500 KV
nominal
SoCo
Coal Unit
#2
18
Classical Machine
297,525

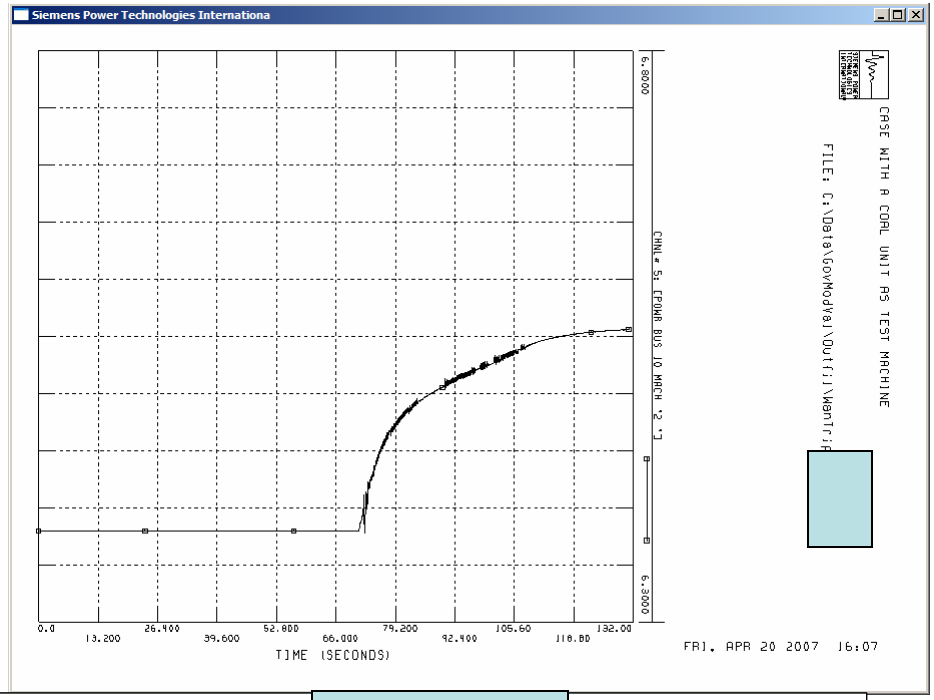
Siemens Power Technologies Internationa

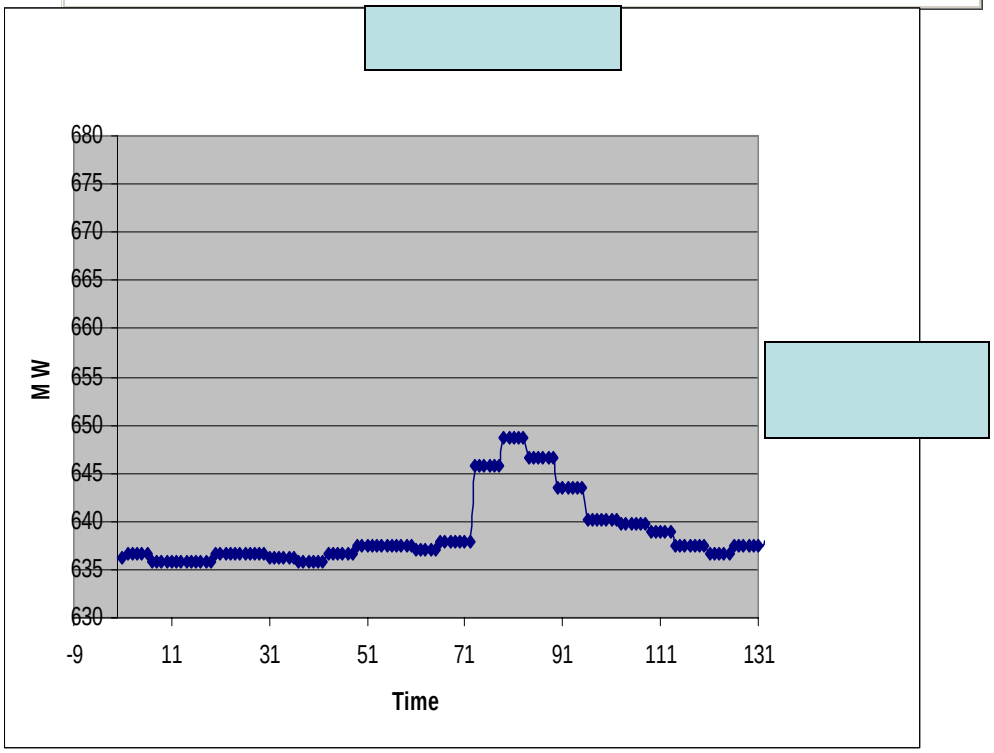


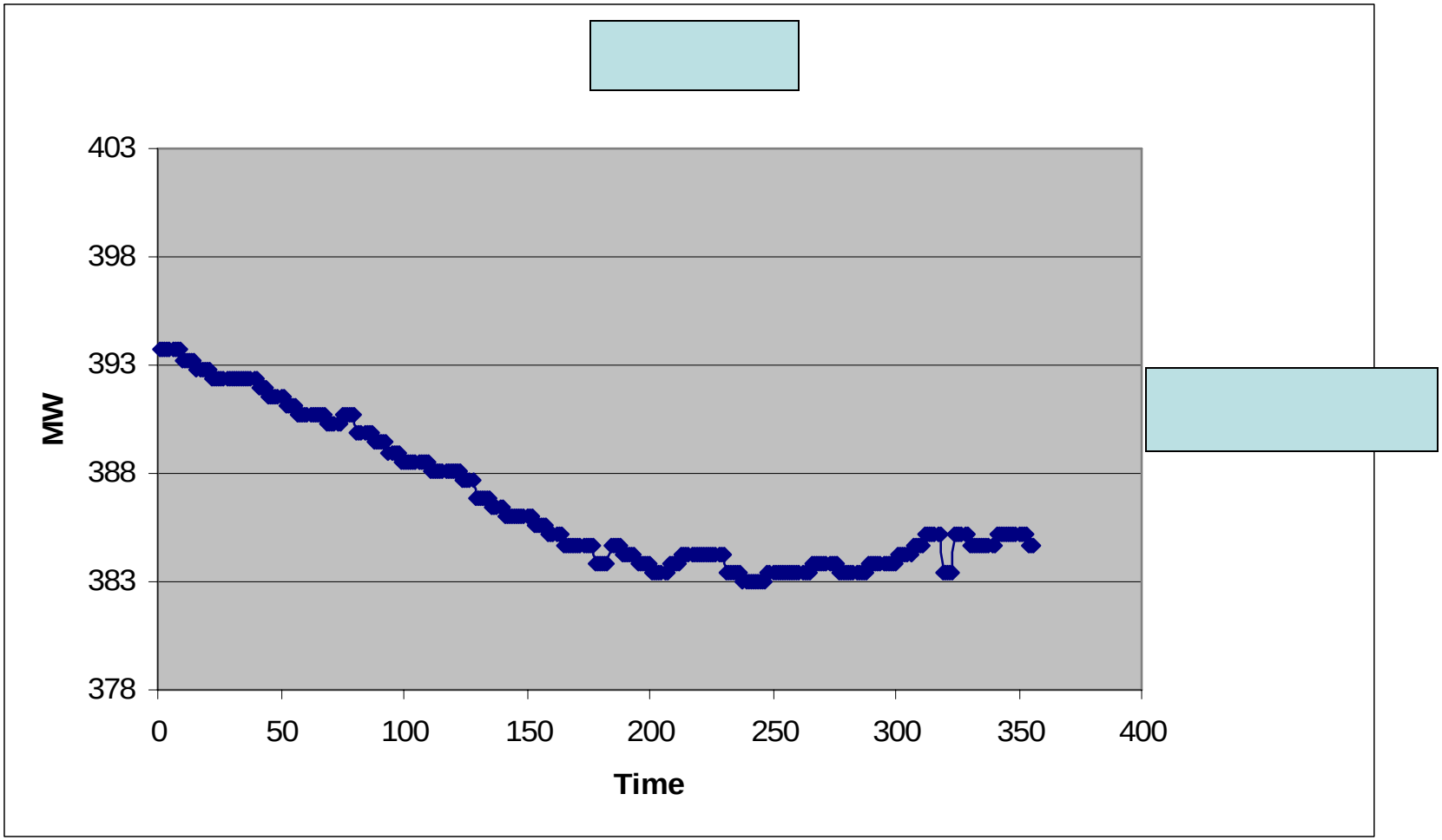

680
675
670
665
660
655
650
645
640
635
630
MW
-9
11
31
51
71
91
111
131
Time

Siemens Power Technologies Internationa

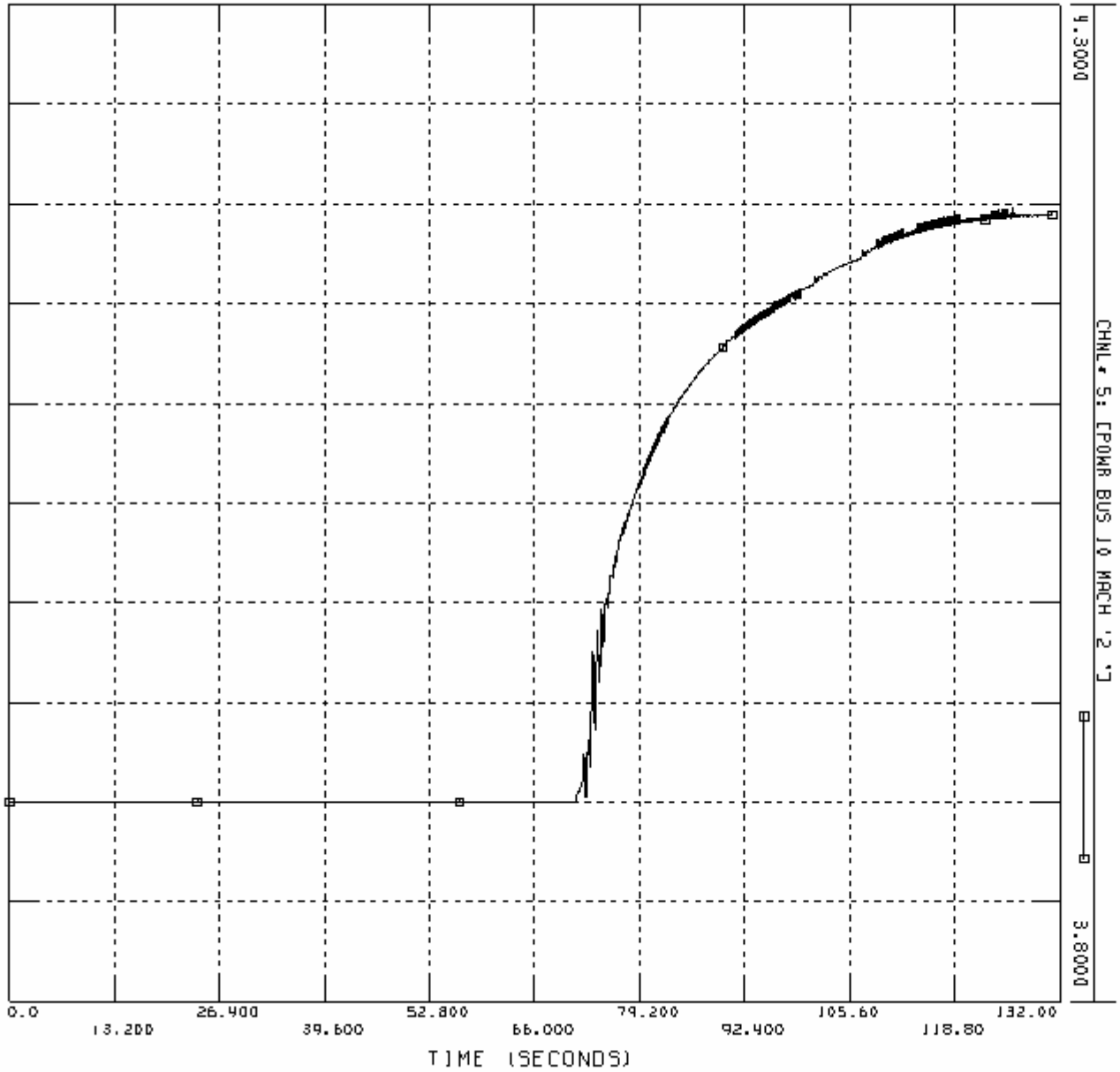


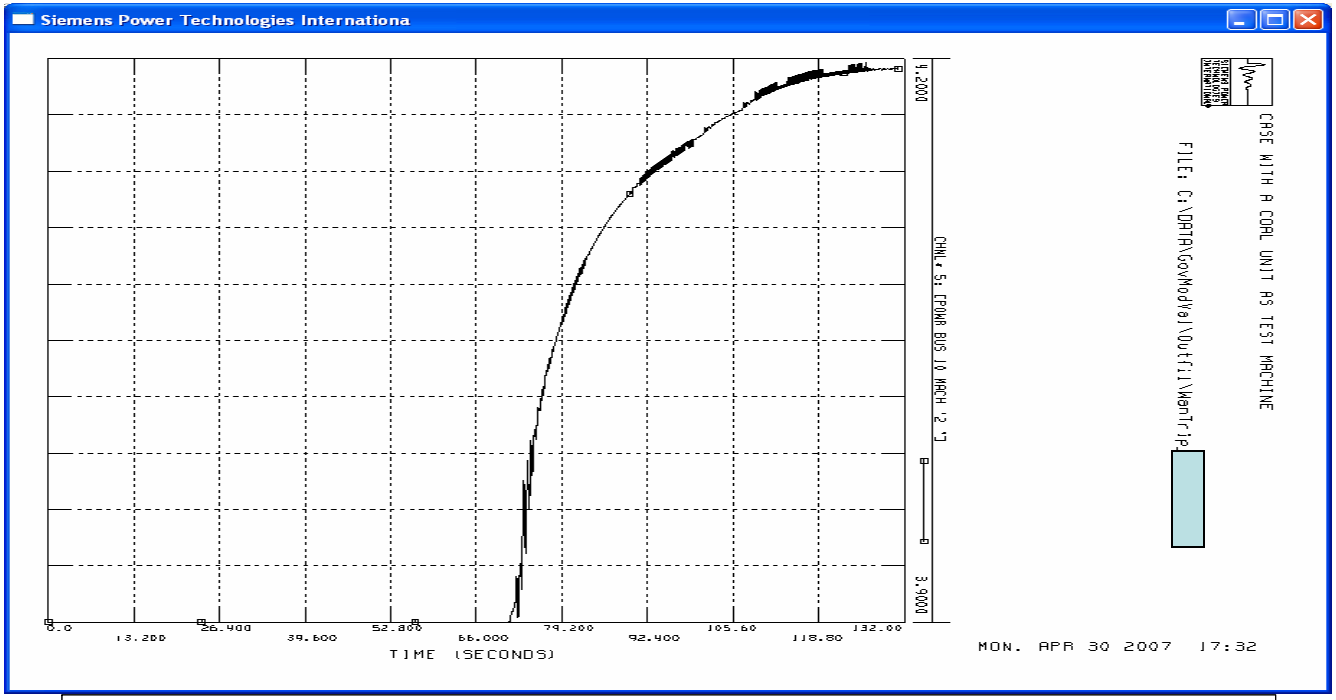

Siemens Power Technologies Internationa
CASE WITH A COAL UNIT AS TEST MACHINE
FILE: C:\Data\GovMod\ai\Outfi\Mantrip
CHNL# 5: [PGMR BUS 10 MACH 2.]
6.0000
-6.0000
0.0
13.200
26.400
39.600
52.800
66.000
79.200
92.400
105.60
118.80
132.00
TIME (SECONDS)
FRI, APR 20 2007 16:07

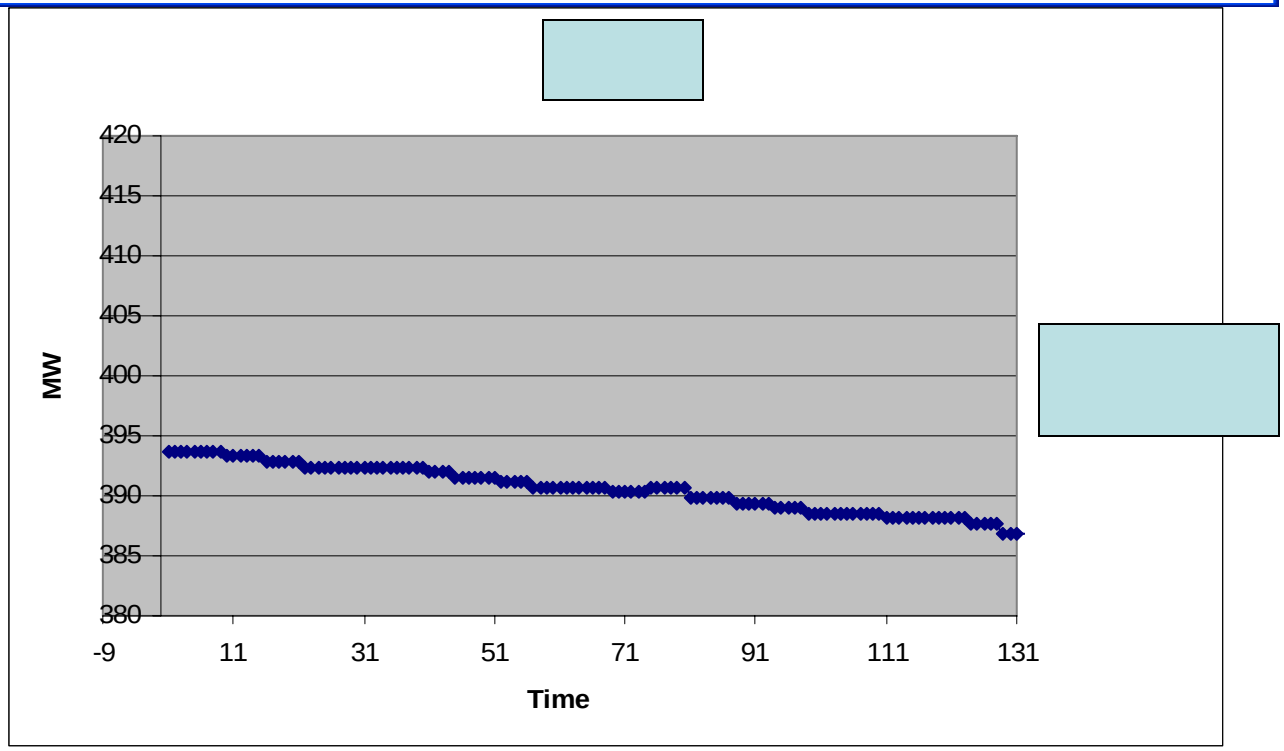

MW
680
675
670
665
660
655
650
645
640
635
630
-9
11
31
51
71
91
111
131
Time

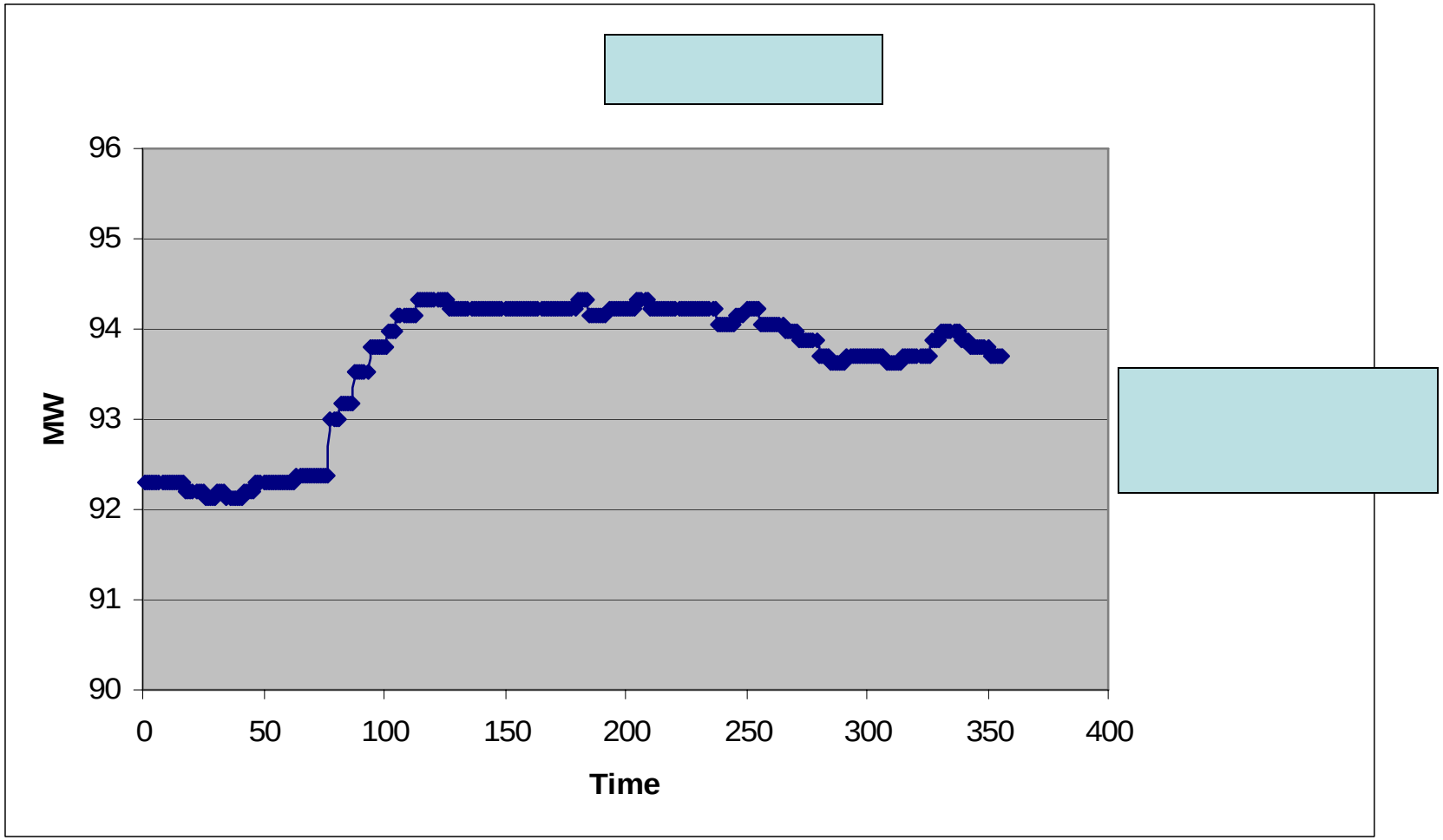

403
398
393
388
383
378
MW
0
50
100
150
200
250
300
350
400
Time

Siemens Power Technologies Internationa

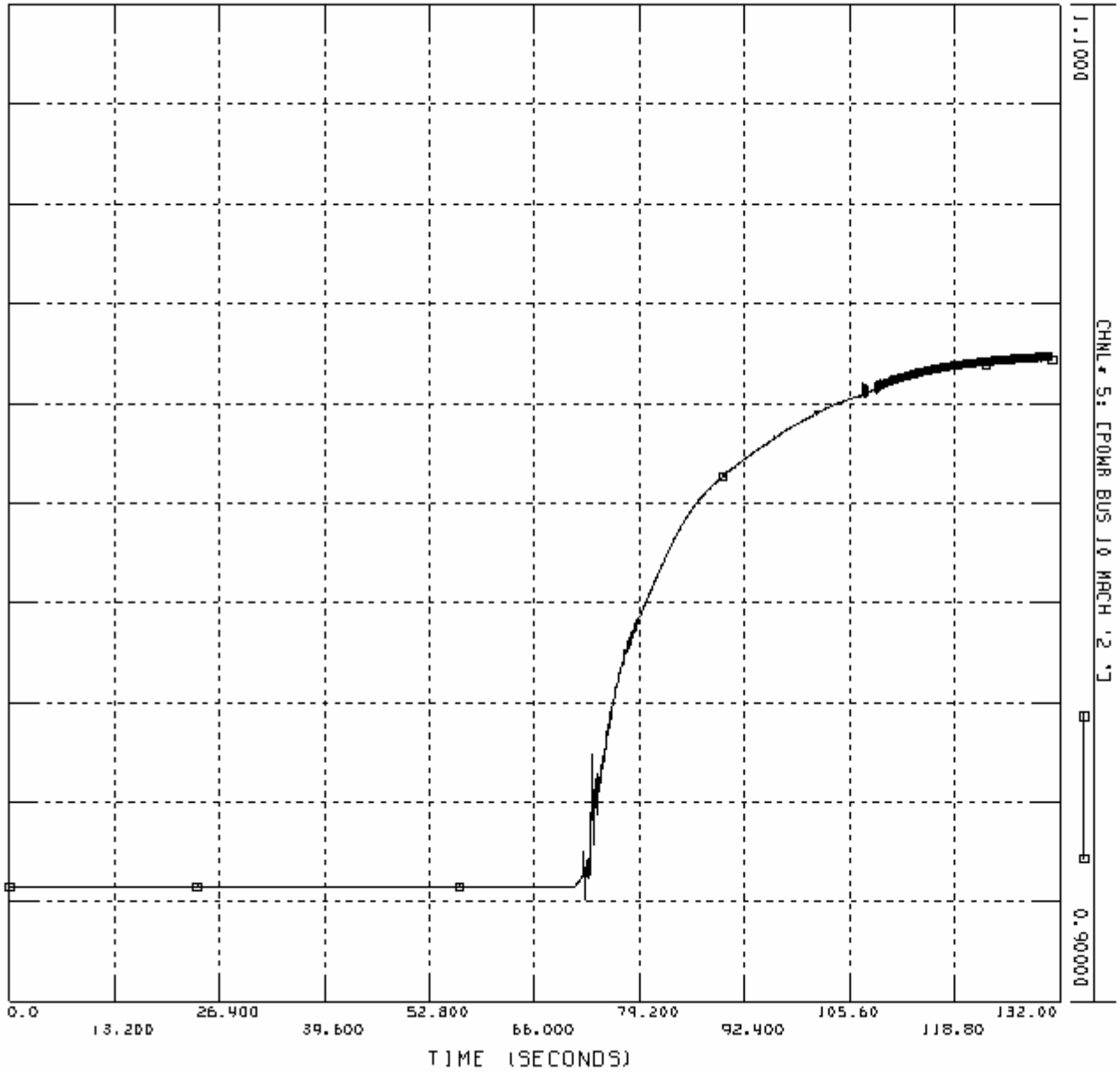


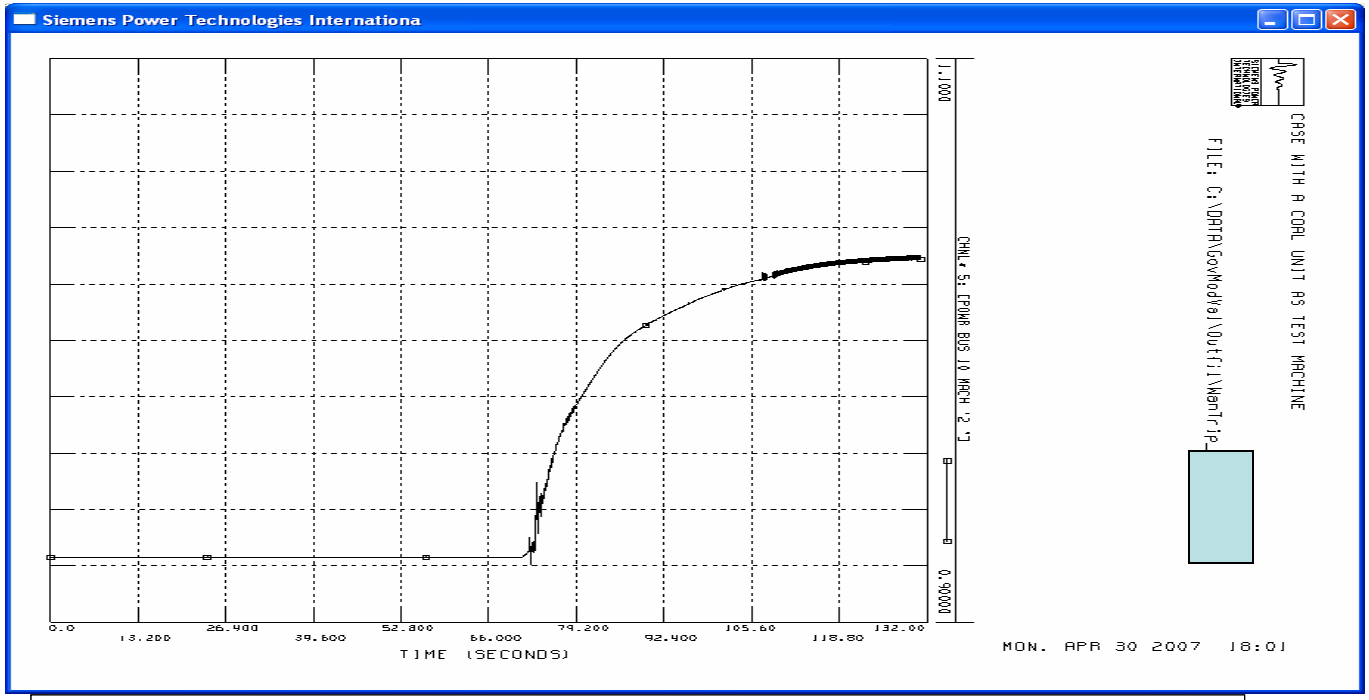

Siemens Power Technologies Internationa
CASE WITH A COAL UNIT AS TEST MACHINE
FILE: C:\DATA\GovModyl\Outfil\WanTrip
CHAN# 5: [PWR BUS 10 MACH 2.]
1.2000
3.9000
0.0
13.200
26.400
39.600
52.800
66.000
79.200
92.400
105.60
118.80
132.00
TIME (SECONDS)
MON. APR 30 2007 17:32

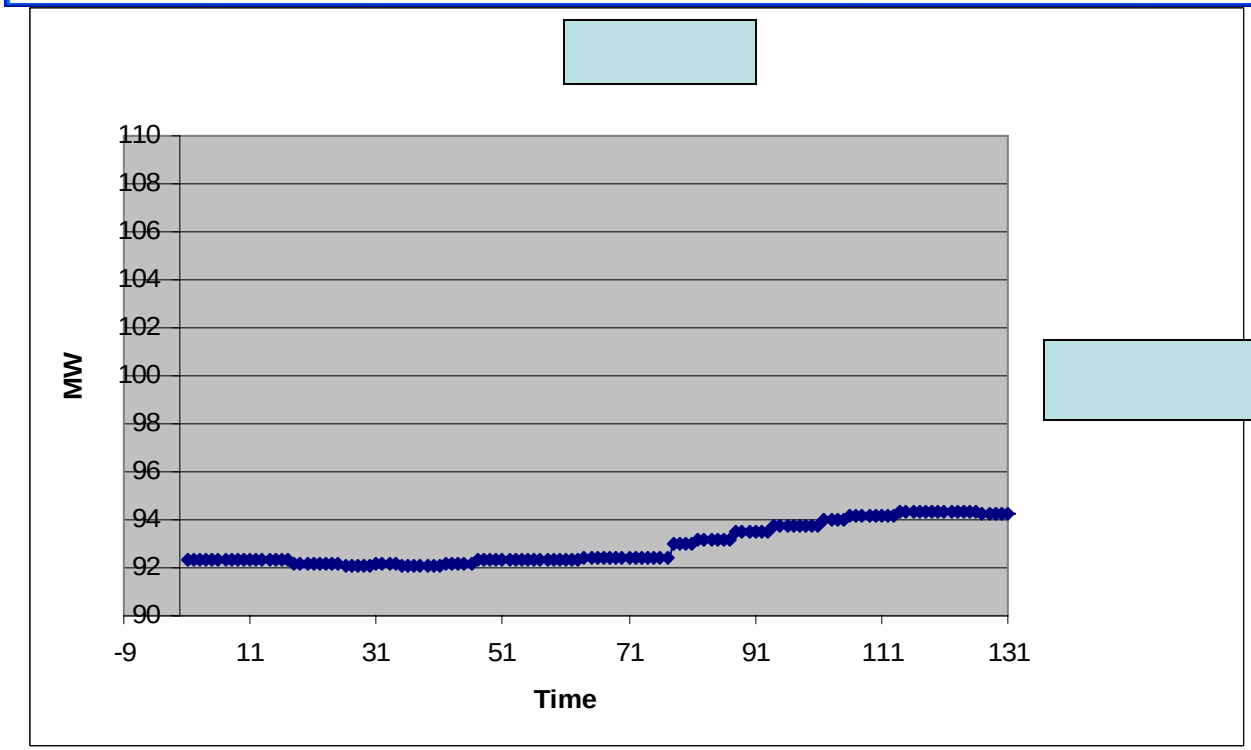

MW
420
415
410
405
400
395
390
385
380
-9
11
31
51
71
91
111
131
Time


96
95
94
93
92
91
90
MW
0
50
100
150
200
250
300
350
400
Time

Siemens Power Technologies Internationa

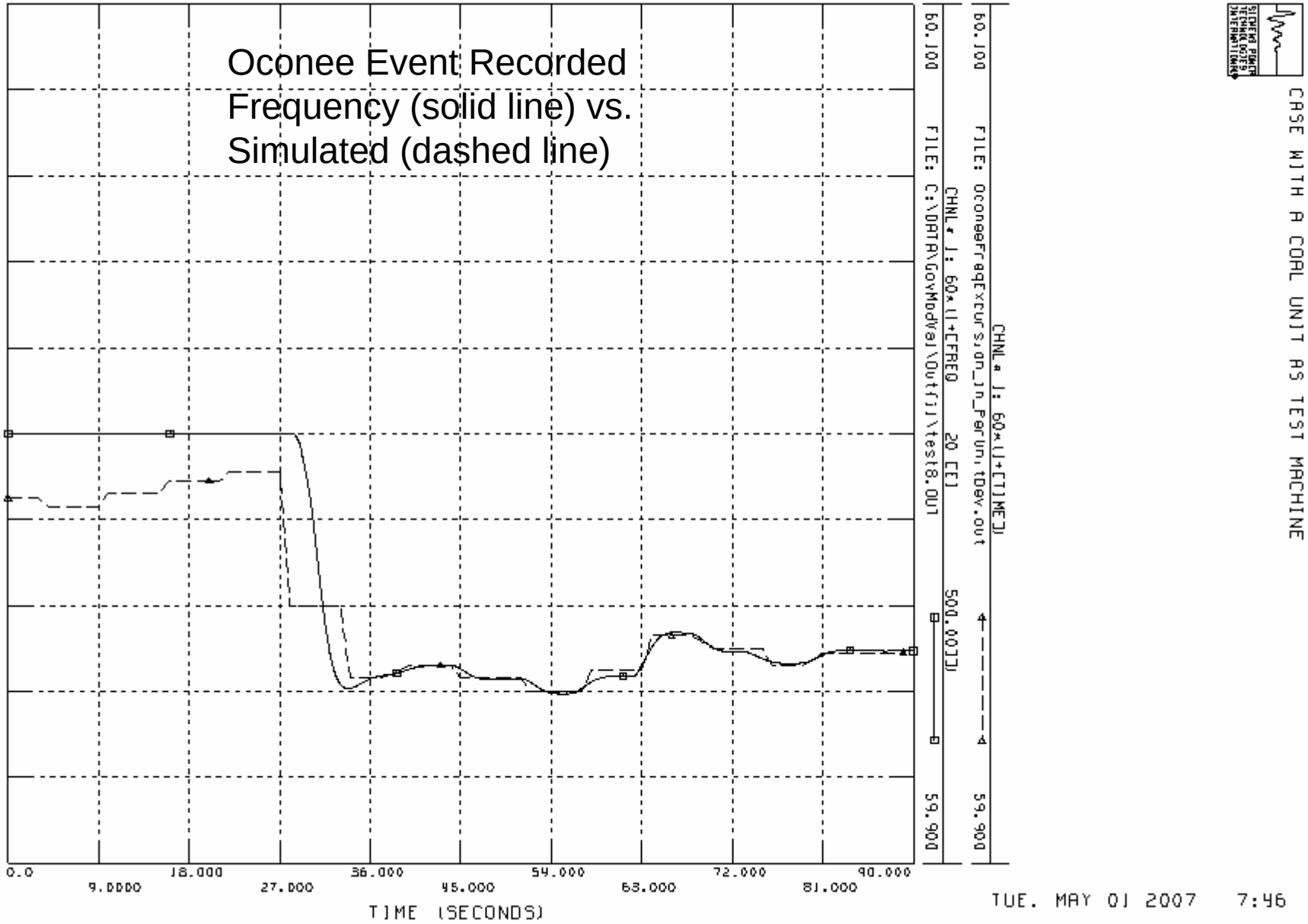



Siemens Power Technologies Internationa
CASE WITH A COAL UNIT AS TEST MACHINE
FILE: C:\DATA\GovMod9j\Outfi\NomTrip
CHNL: 5: EPOWR BUS 10 MACH 2 "J
1.1000
0.9000
0.0
13.200
26.400
39.600
52.800
66.000
79.200
92.400
105.60
118.80
132.00
TIME (SECONDS)
MON. APR 30 2007 18:01


MW
110
108
106
104
102
100
98
96
94
92
90
-9
11
31
51
71
91
111
131
Time

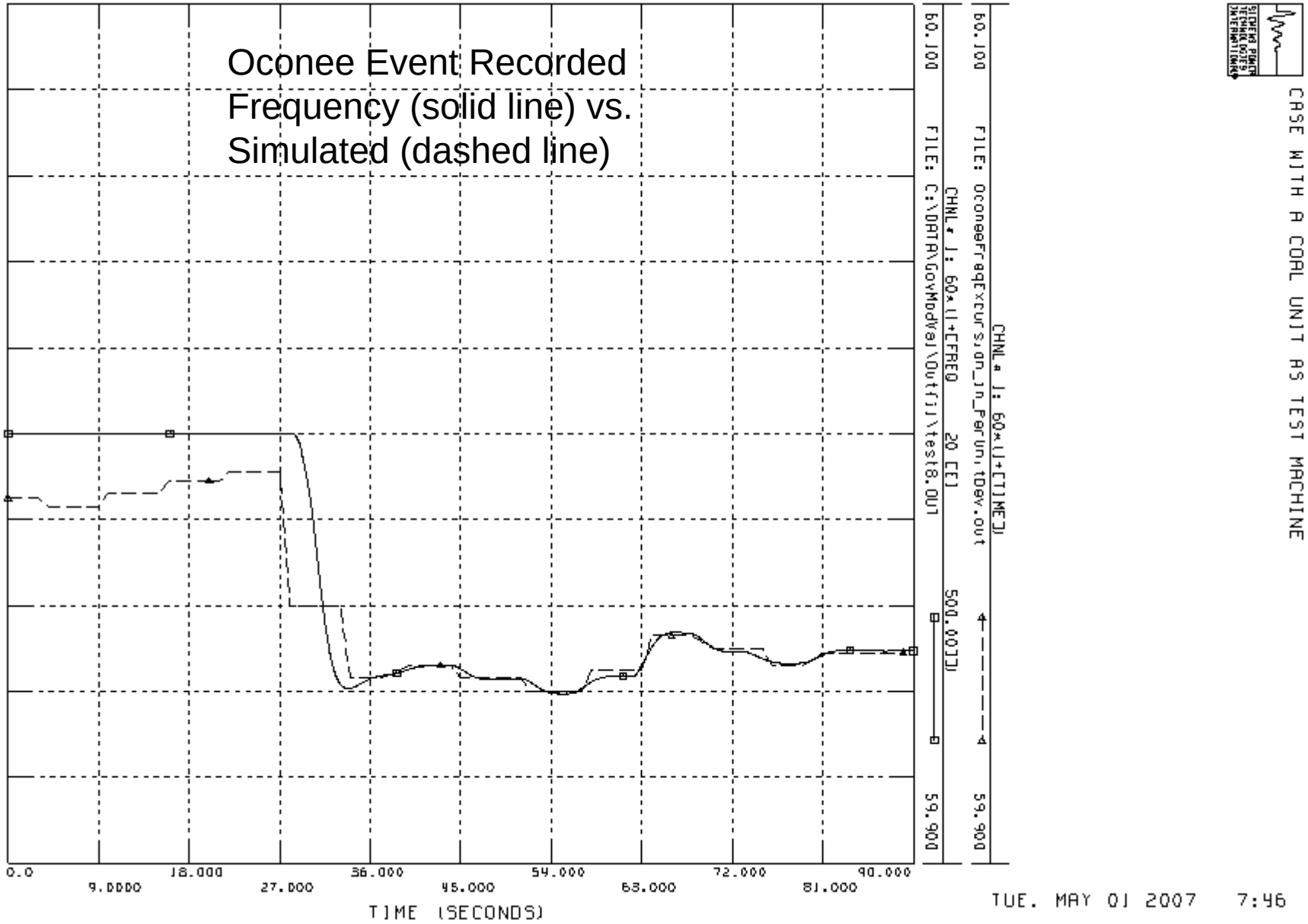
Oconee Trip Responses

Siemens Power Technologies Internationa



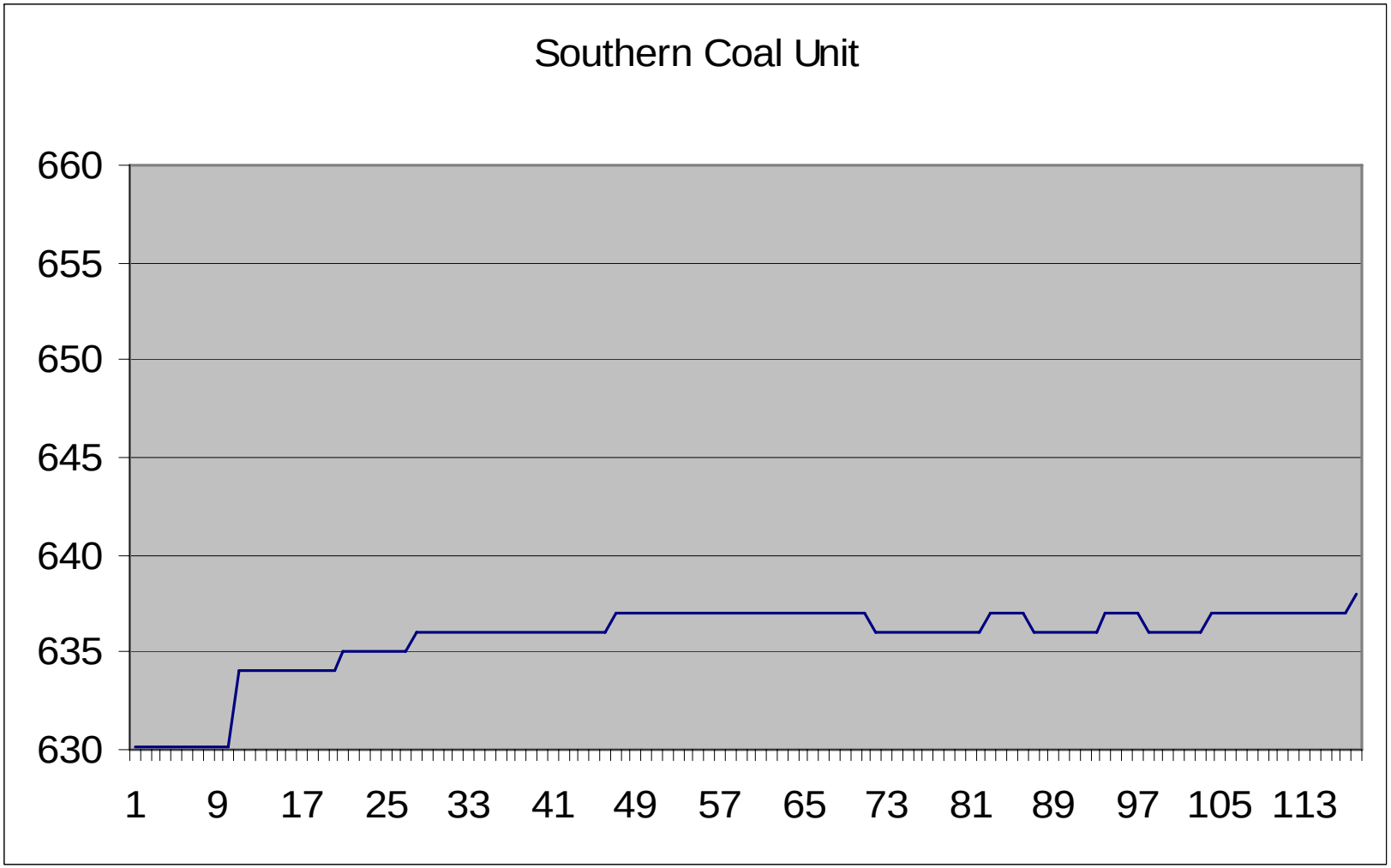
Oconee Event Recorded Frequency (solid line) vs. Simulated (dashed line)

Siemens Power Technologies Internationa

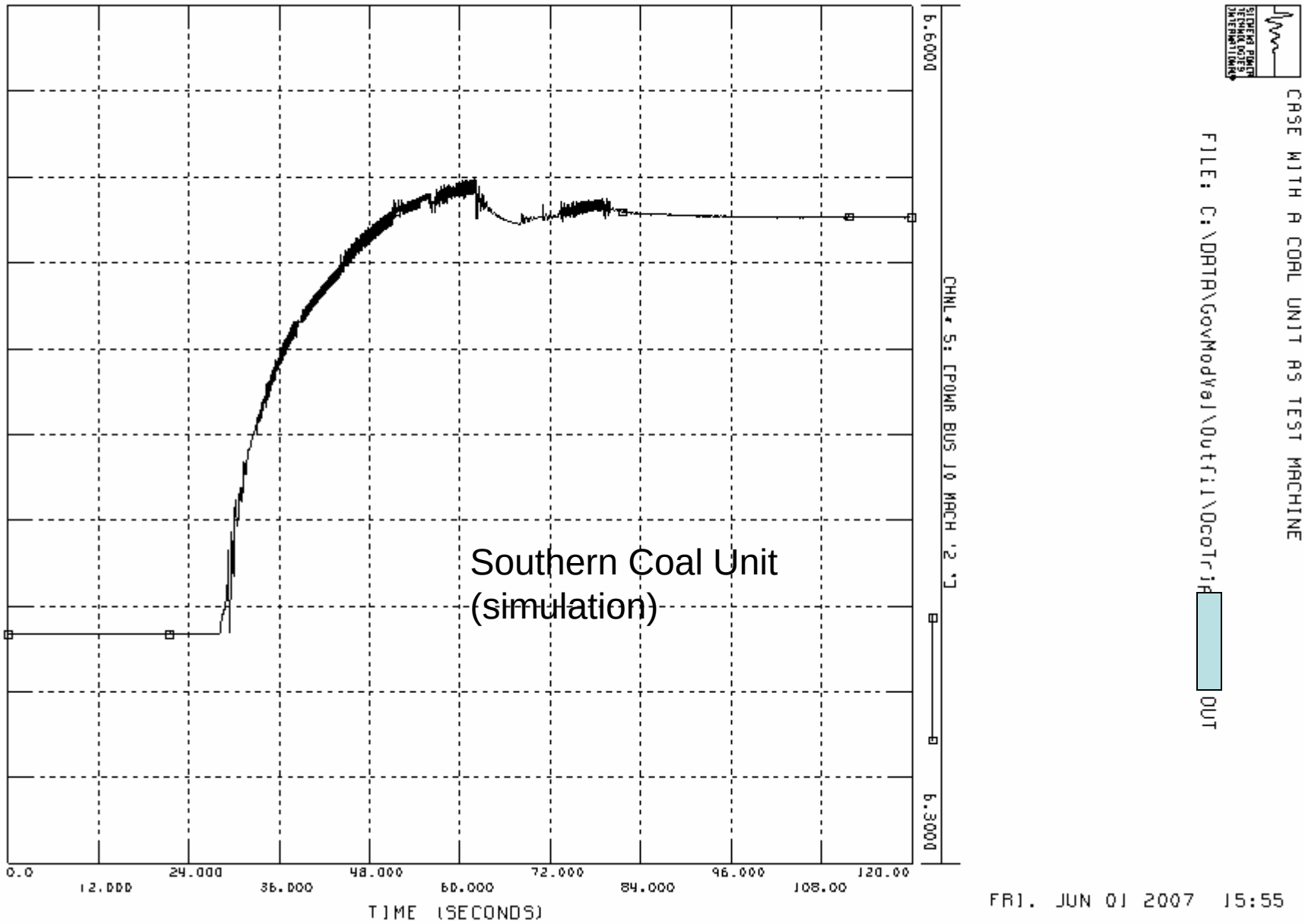


Oconee Event Recorded Frequency (solid line) vs. Simulated (dashed line)

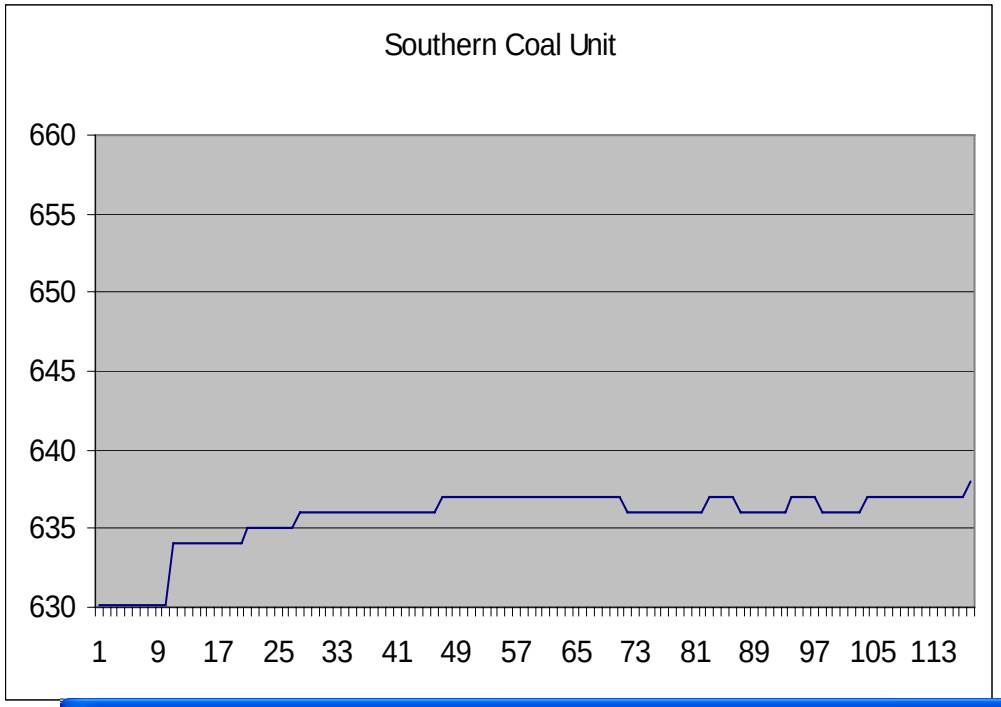
Southern Coal Unit (event data)



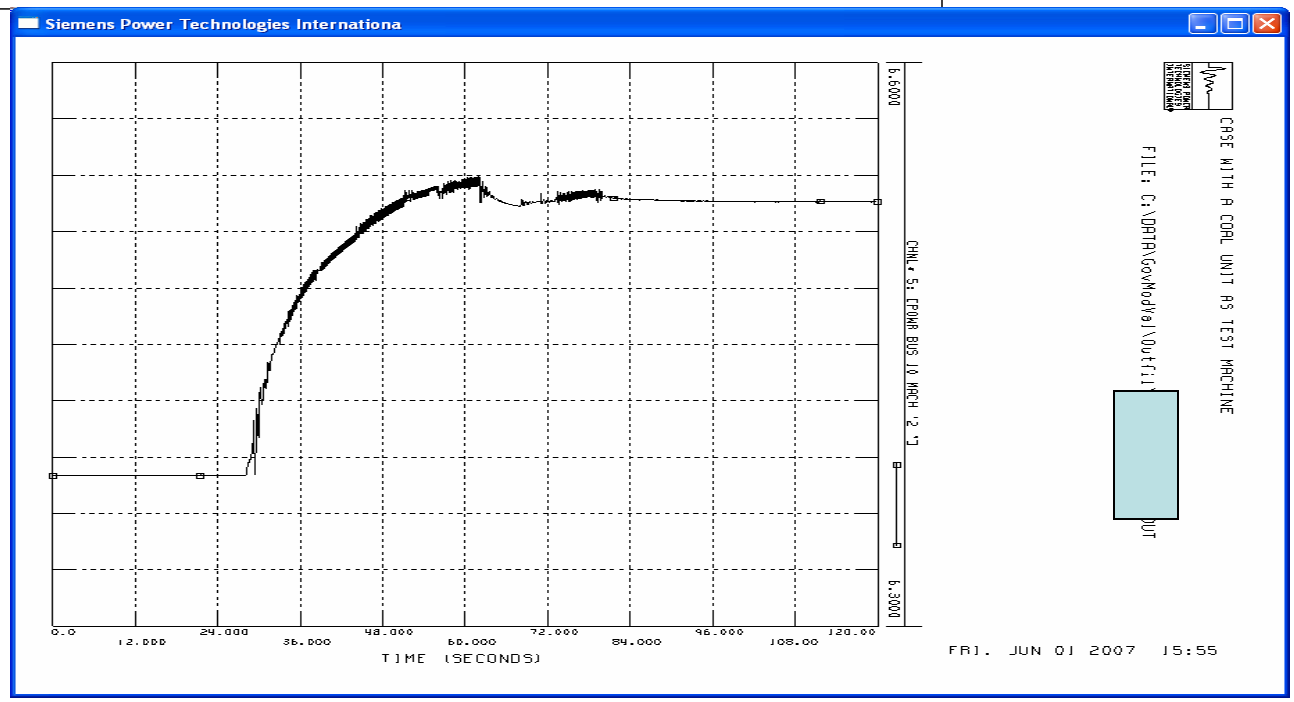
Siemens Power Technologies Internationa



Southern Coal Unit
(simulation)



Observations – unit had just ramped up about 5 MW before the event – after the event, it did not respond. Expected response for a 5% droop – approximately 14 MW



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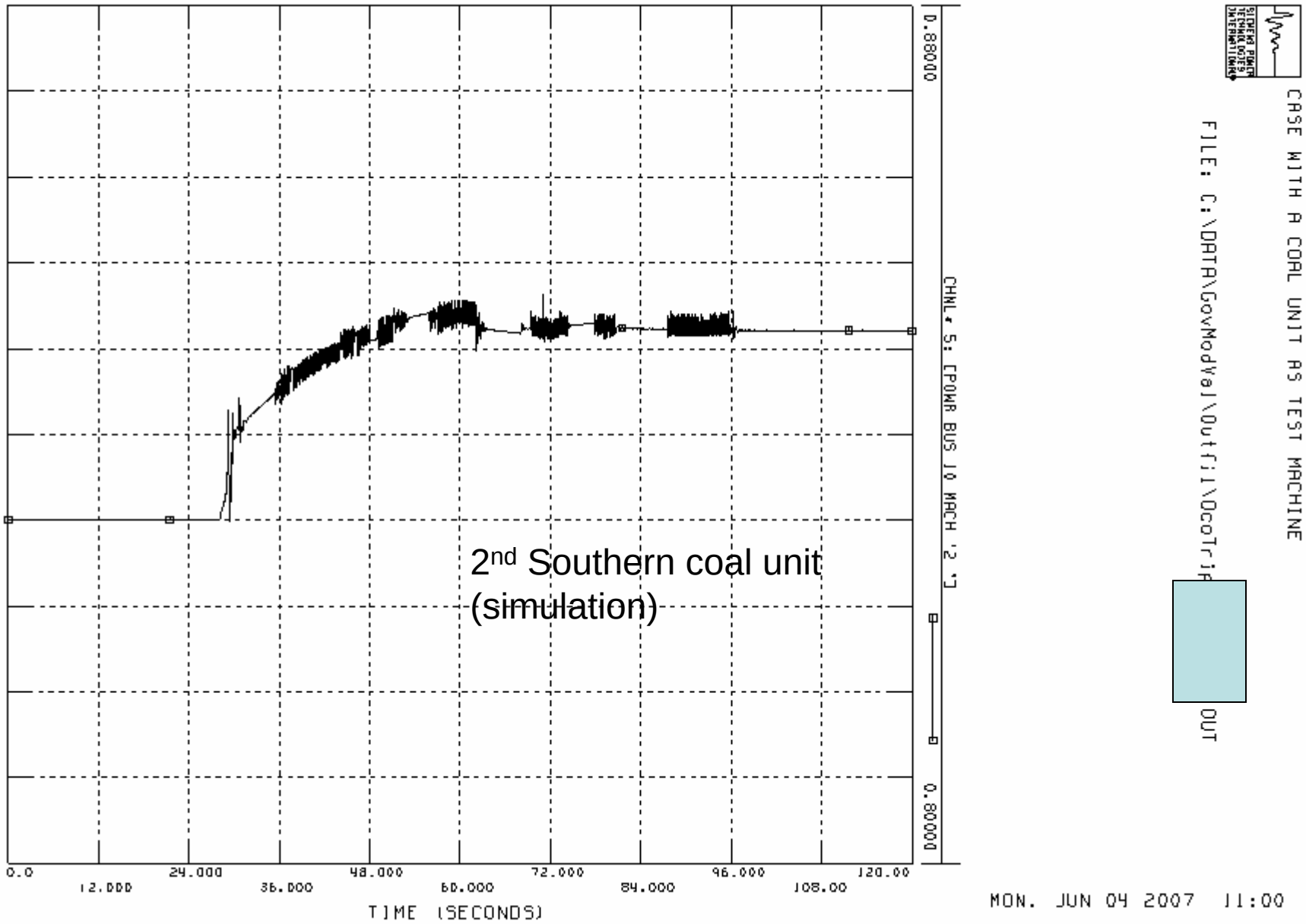
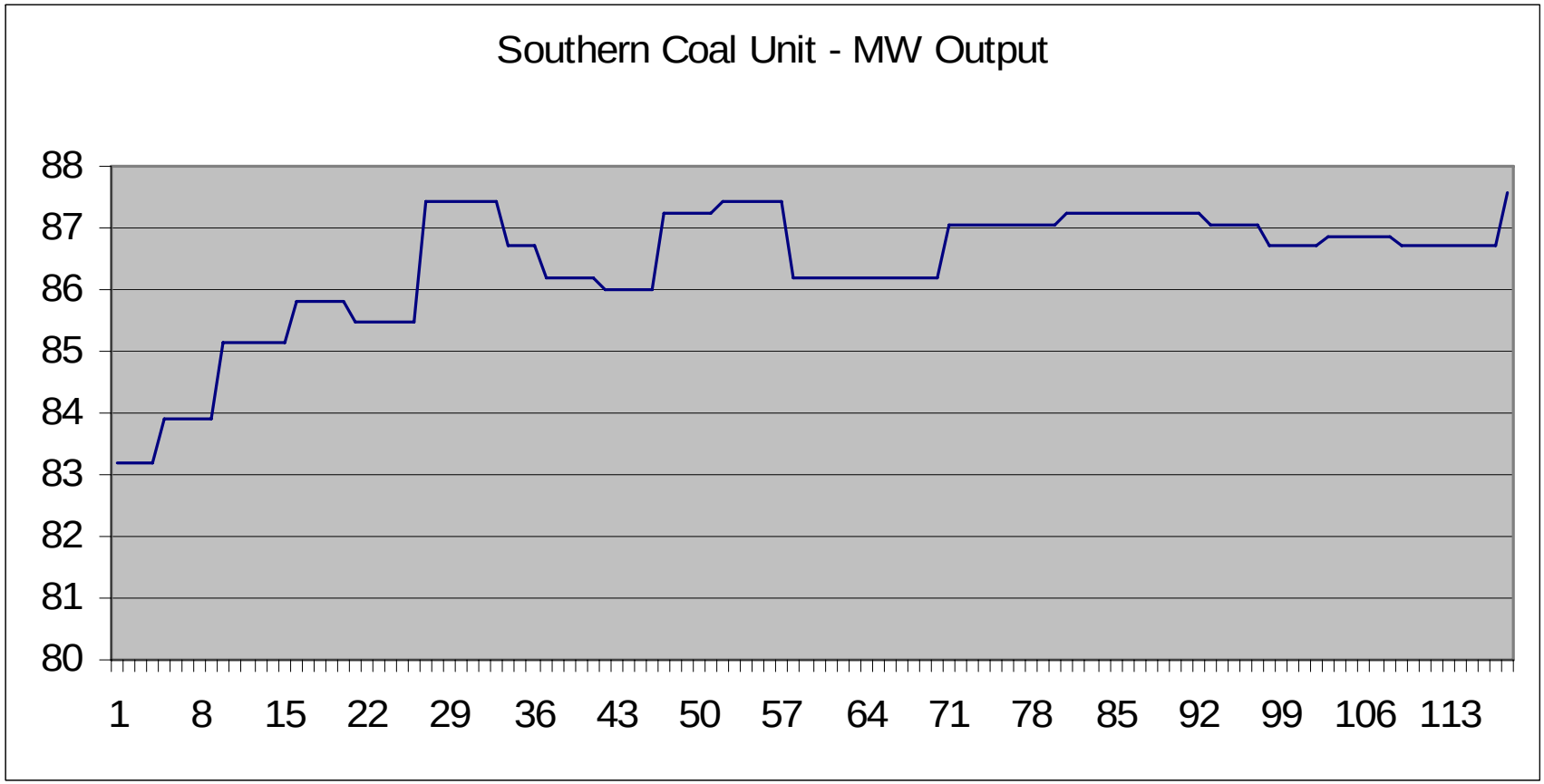
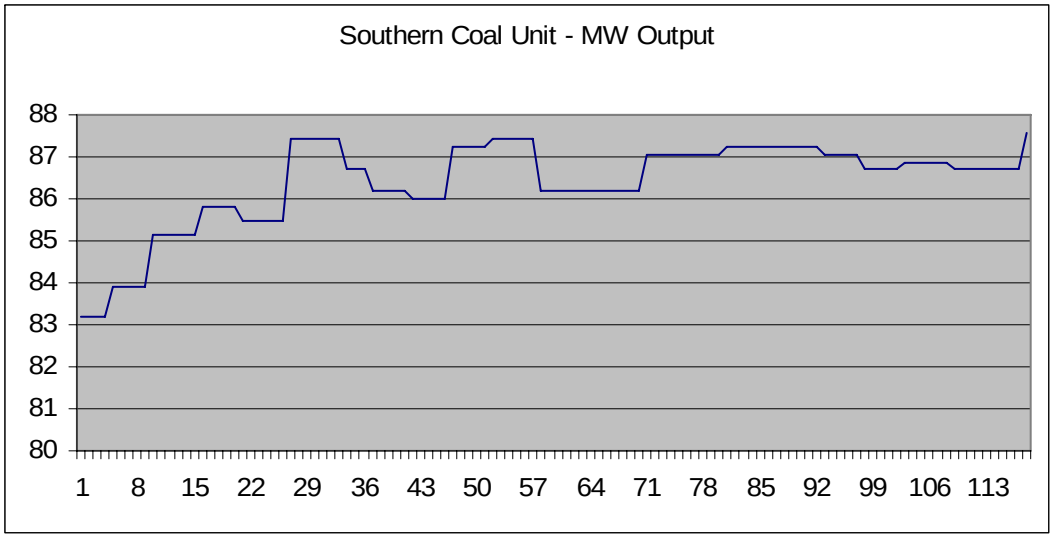


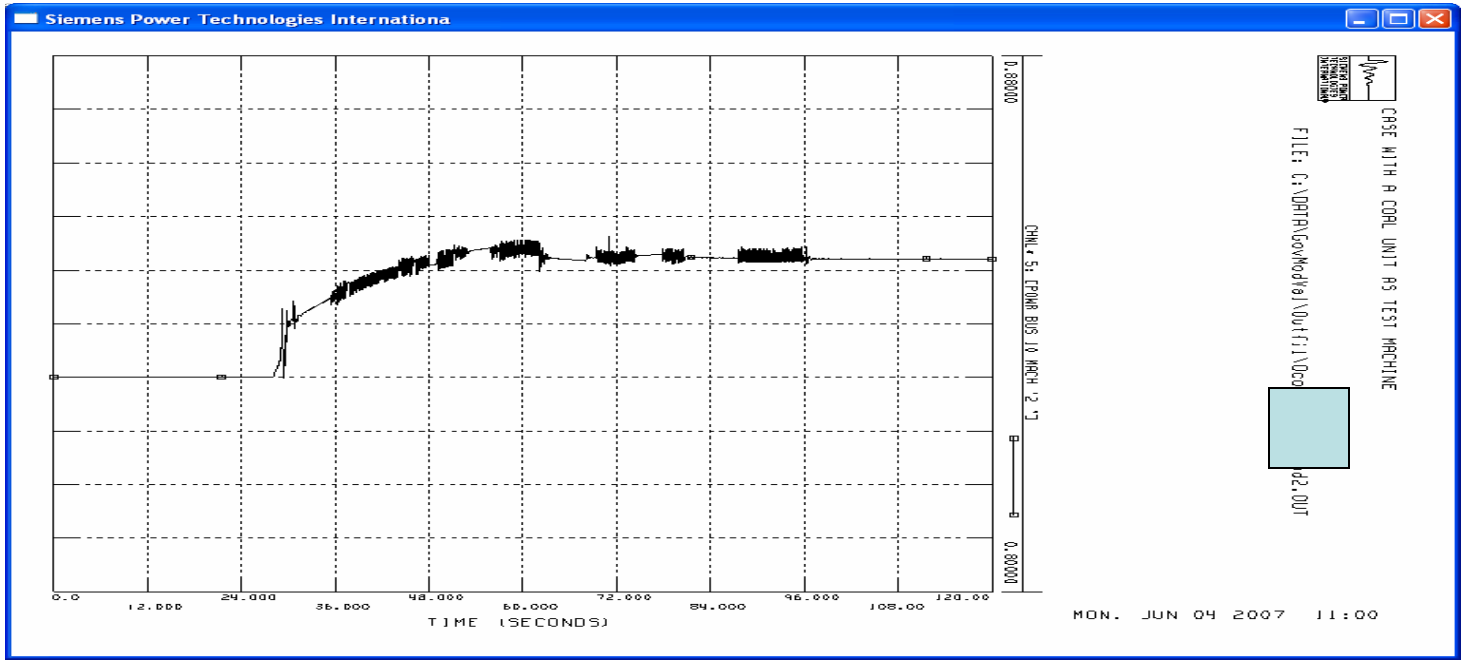
2nd Southern coal unit (simulation)

2nd Southern Coal Unit (event data)





Observations – event data shows that the unit increased approximately 3.5 MW – actually surpassing the approximate expected 2.5 MW increase for a 5% droop. Model predicted a 3 MW increase



Attachment 5
PRC-019 Test Results

- **SERC PRC-019 Field Test Reporting Form - COE 6-8-2007.pdf**
- **Generator Volts per Hertz.pdf**
- **09. PRC-019 Field Test Reporting Form Dominion.doc**
- **Generator Capability Curve.pdf**
- **Entergy SERC PRC-019 Field Test Reporting Form Rev 1 _11-2-06_.pdf**
- **Entergy PRC019 Field Test.pdf**
- **serc prc-019 field test reporting form rev 1 (11-2-06)(Completed).doc**
- **PRC-019 Curves.xls**
- **SCG PRC-019 Field Test Reporting Forms.pdf**
- **SCG PRC-019 Sample Generator Coordination Plots.pdf**

SERC PRC-019 Field Test Reporting Form

The purpose of this form is to provide a consistent report format for field testing results after using the SERC Field Test Guideline "Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection". Documentation of the test results (this field test may actually be considered an engineering study) will provide feedback showing that the field test was successful and/or will help to enhance the test guideline.

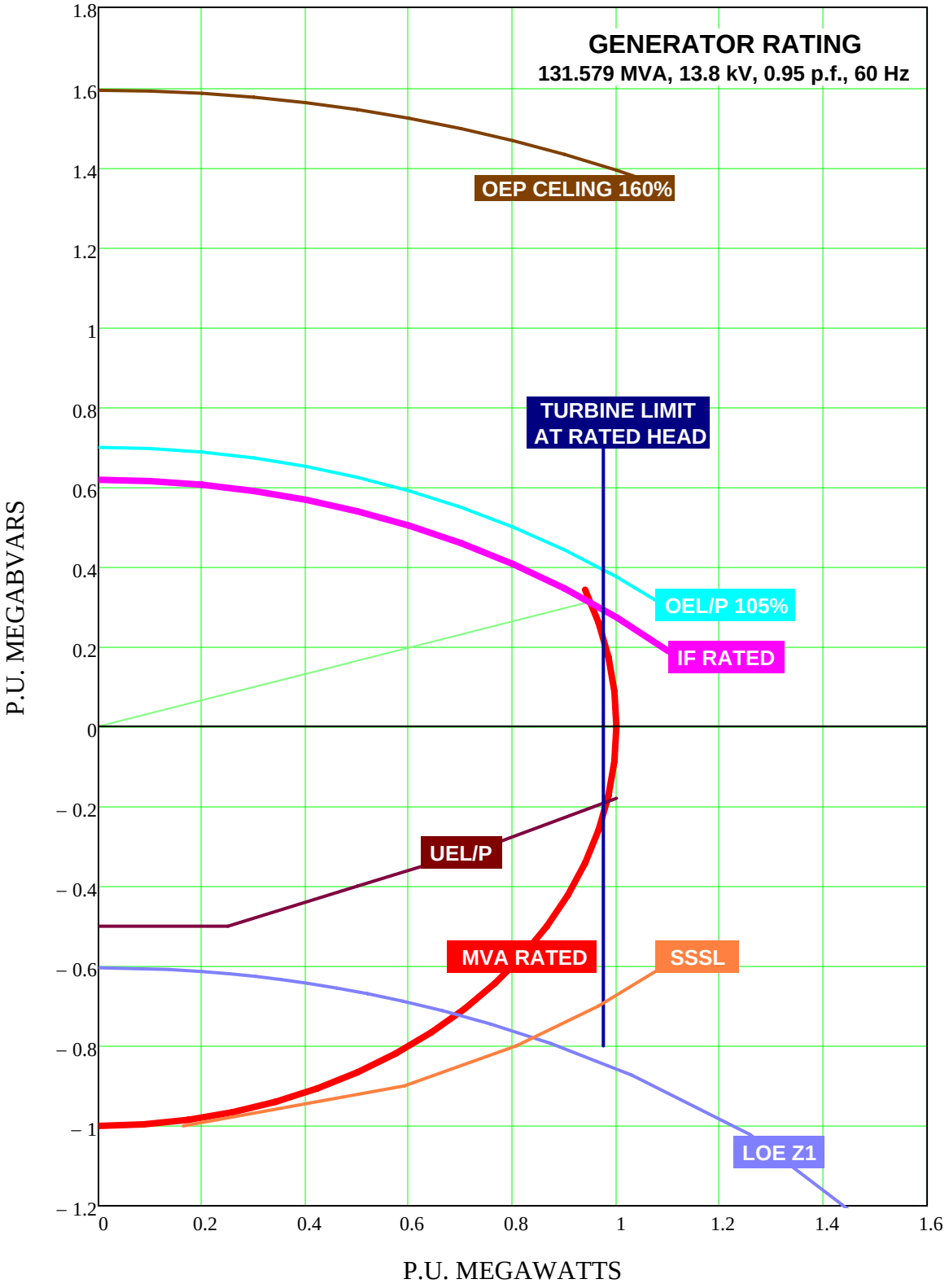
Use the SERC Field Test Guideline "Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection" to perform the test (engineering study). It is suggested that a newer, more modern generating unit be used for the test, to verify the coordination of more different types of protection relay systems (versus an older unit that may not have as many generator protection relays). Complete one (1) report form for each unit tested (studied).

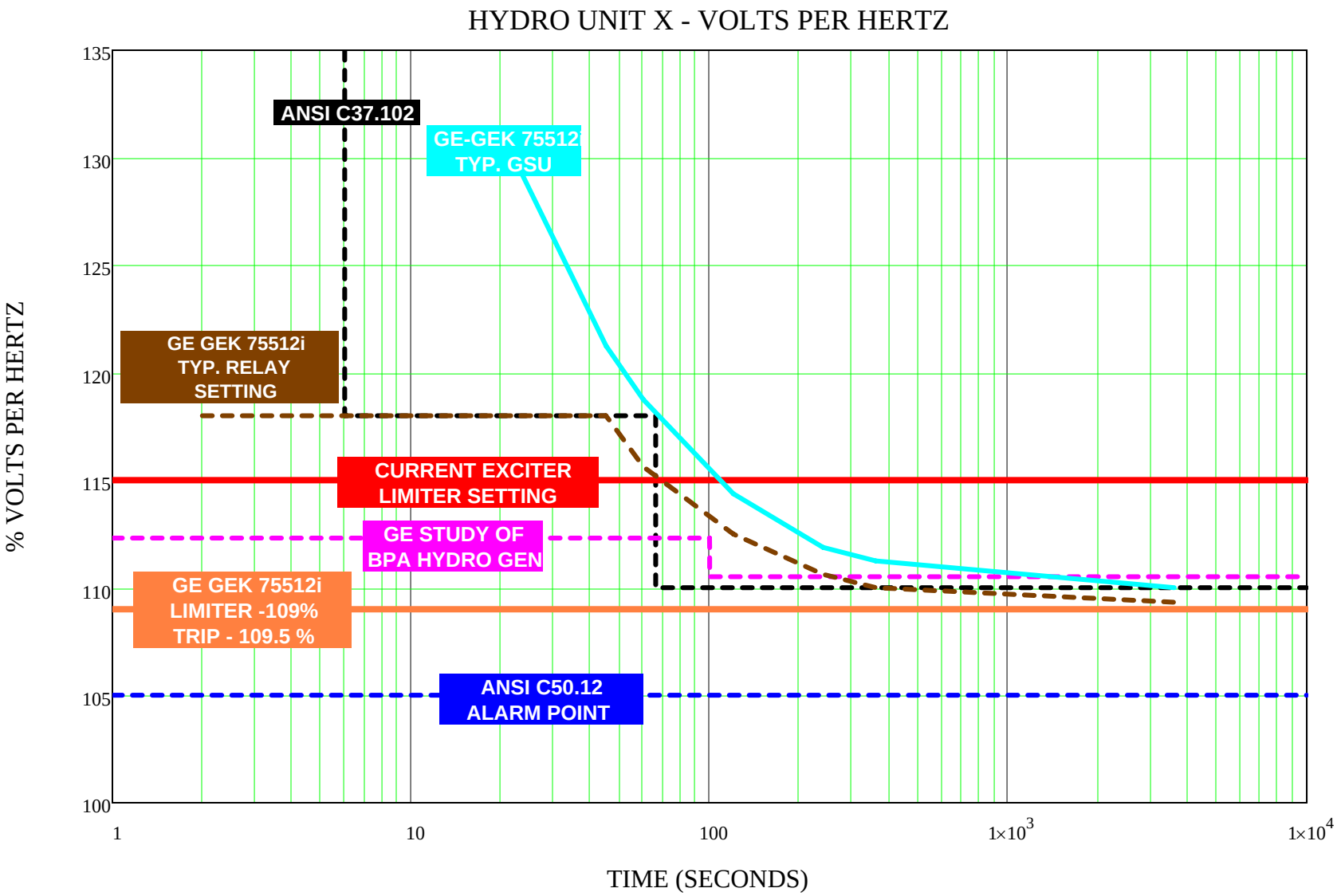
Provide the following information:

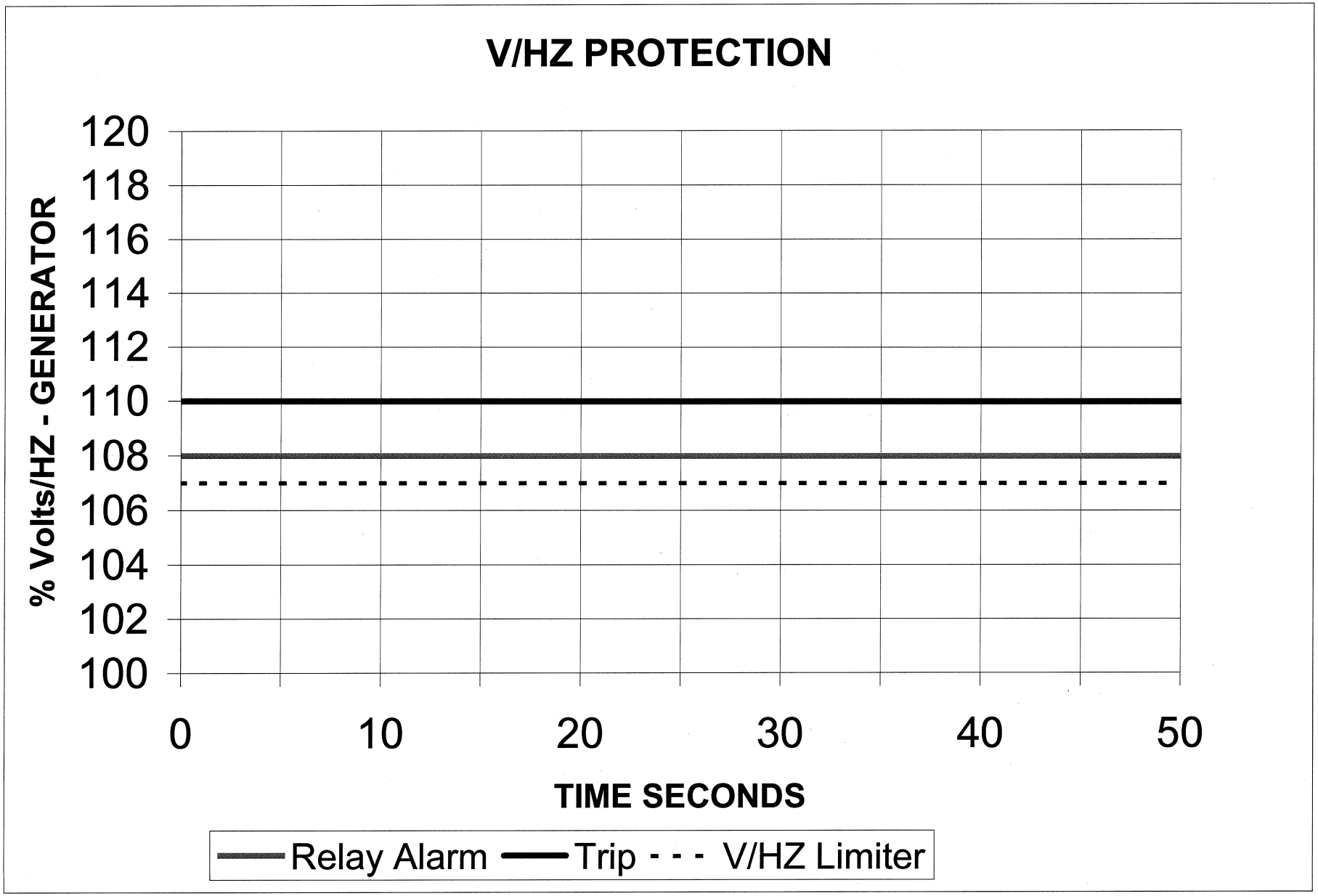
1. How long did it take to assemble (bring together) the technical data (generator capability curve(s), voltage regulator settings, protective relay settings, etc.) needed to perform the engineering study? ___40_____ Hours
2. What methodology / tools were used to perform the coordination studies?
   - ☐ Computerized coordination curves
   - ☐ Manual coordination curves
   - ☒ Combination (computerized / manual)
3. How many man-hours did it take to develop the methodology / tools? ___320_____
4. How long did it take to analyze the technical information and draw the curves (plots)? __40_____ Hours
5. List any material costs associated with this study. ____Curve plotting Software $1,810._____
   _____
6. Were the voltage regulator settings and the protective relay settings coordinated with the generator capability curve (as found)? __Yes_____ (Yes or No)
7. If not, list the devices that needed configuration changes: ___The settings were coordinated with the capability curve; however the Volts/Hz limit and trip were set to high.
   _____
8. Please list any suggested changes to the guideline or Draft NERC Reliability standard?
   _____
9. Provide the completed curves (plots). Remove all references that would identify the unit (company, station, and unit names, etc). Attached.
10. Name of person completing form: _David Williams__ Phone number _706.643.0313__Company name __Corps of Engineers – Mobile District _____

Send the completed report form and coordination curves electronically to: phuntley@serc1.org.

HYDRO UNIT X


GENERATOR RATING
131.579 MVA, 13.8 kV, 0.95 p.f., 60 Hz
OEP CELING 160%
TURBINE LIMIT
AT RATED HEAD
OEL/P 105%
IF RATED
UEL/P
MVA RATED
SSSL
LOE Z1
P.U. MEGABVARS
P.U. MEGAWATTS
1.8
1.6
1.4
1.2
1
0.8
0.6
0.4
0.2
0
– 0.2
– 0.4
– 0.6
– 0.8
– 1
– 1.2
0
0.2
0.4
0.6
0.8
1
1.2
1.4
1.6


HYDRO UNIT X - VOLTS PER HERTZ
% VOLTS PER HERTZ
TIME (SECONDS)
135
130
125
120
115
110
105
100
1
10
100
1×10^3
1×10^4
ANSI C37.102
GE-GEK 75512i
TYP. GSU
GE GEK 75512i
TYP. RELAY
SETTING
CURRENT EXCITER
LIMITER SETTING
GE STUDY OF
BPA HYDRO GEN
GE GEK 75512i
LIMITER -109%
TRIP - 109.5 %
ANSI C50.12
ALARM POINT


V/HZ PROTECTION
% Volts/HZ - GENERATOR
120
118
116
114
112
110
108
106
104
102
100
0
10
20
30
40
50
TIME SECONDS
Relay Alarm
Trip
V/HZ Limiter

SERC PRC-019 Field Test Reporting Form

The purpose of this form is to provide a consistent report format for field testing results after using the SERC Field Test Guideline "Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection". Documentation of the test results (this field test may actually be considered an engineering study) will provide feedback showing that the field test was successful and/or will help to enhance the test guideline.

Use the SERC Field Test Guideline "Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection" to perform the test (engineering study). It is suggested that a newer, more modern generating unit be used for the test, to verify the coordination of more different types of protection relay systems (versus an older unit that may not have as many generator protection relays). Complete one (1) report form for each unit tested (studied).

Provide the following information:

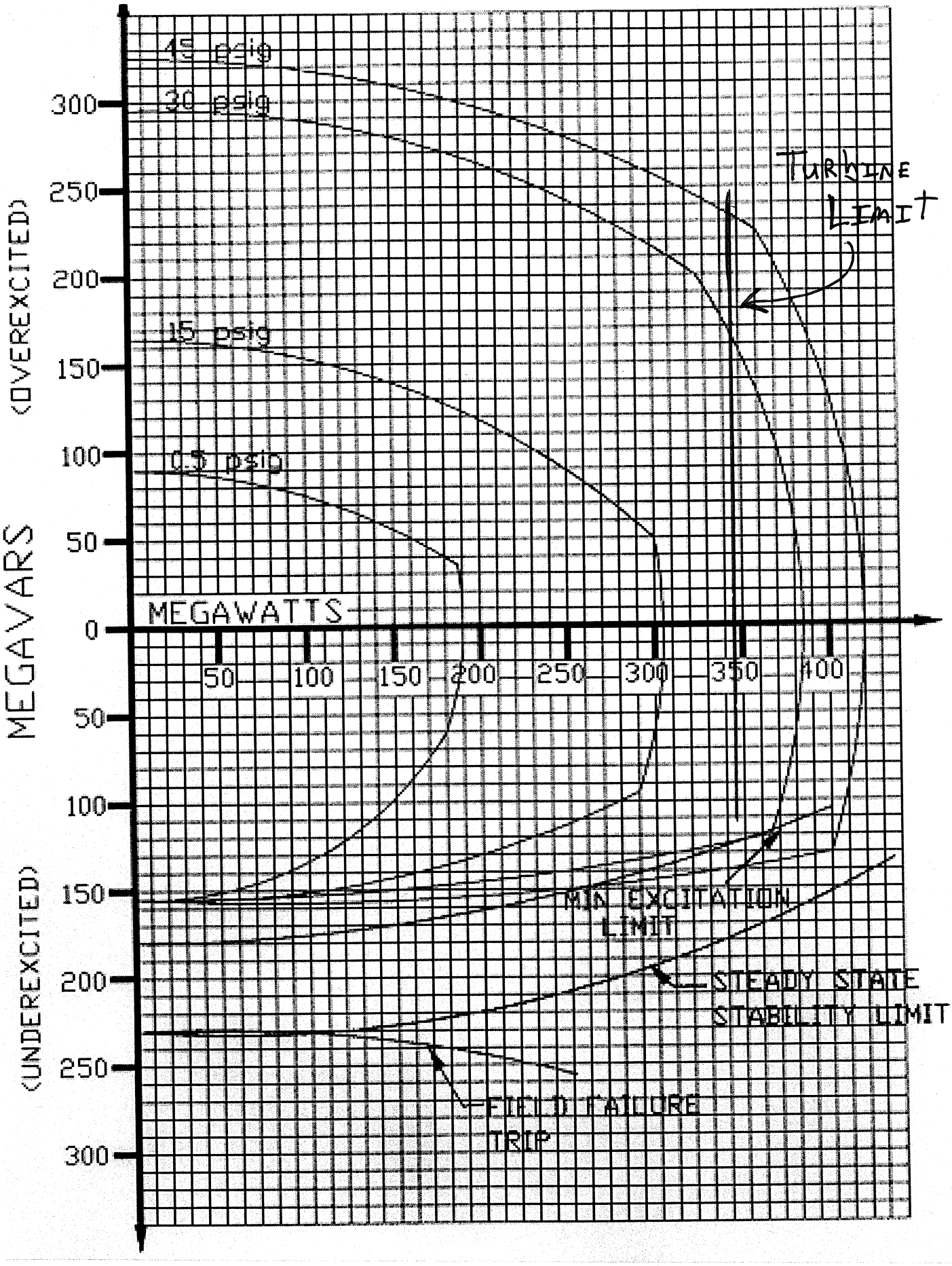
1. How long did it take to assemble (bring together) the technical data (generator capability curve(s), voltage regulator settings, protective relay settings, etc.) needed to perform the engineering study? __20__ Hours
2. What methodology / tools were used to perform the coordination studies?

   ☐ Computerized coordination curves

   ☒ Manual coordination curves

   ☐ Combination (computerized / manual)
3. How many man-hours did it take to develop the methodology / tools? ____10____
4. How long did it take to analyze the technical information and draw the curves (plots)? __20____ Hours
5. List any material costs associated with this study.
   _____None_____
   _____
6. Were the voltage regulator settings and the protective relay settings coordinated with the generator capability curve (as found)? _Yes____ (Yes or No)
7. If not, list the devices that needed configuration changes:
   _____
   _____
   _____
8. Please list any suggested changes to the guideline or Draft NERC Reliability standard?
   _____None_____
   _____
   _____
9. Provide the completed curves (plots). Remove all references that would identify the unit (company, station, and unit names, etc)

Send the completed report form and coordination curves electronically to: phuntley@serc1.org.


45 psig
30 psig
15 psig
0.5 psig
TURBINE LIMIT
MEGAVARS
(OVEREXCITED)
(UNDEREXCITED)
300
250
200
150
100
50
0
50
100
150
200
250
300
MEGAWATTS
50
100
150
200
250
300
350
400
MIN EXCITATION LIMIT
STEADY STATE STABILITY LIMIT
FIELD FAILURE TRIP

SERC PRC-019 Field Test Reporting Form

The purpose of this form is to provide a consistent report format for field testing results after using the SERC Field Test Guideline "Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection". Documentation of the test results (this field test may actually be considered an engineering study) will provide feedback showing that the field test was successful and/or will help to enhance the test guideline.

Use the SERC Field Test Guideline "Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection" to perform the test (engineering study). It is suggested that a newer, more modern generating unit be used for the test, to verify the coordination of more different types of protection relay systems (versus an older unit that may not have as many generator protection relays). Complete one (1) report form for each unit tested (studied).

Provide the following information:

1. How long did it take to assemble (bring together) the technical data (generator capability curve(s), voltage regulator settings, protective relay settings, etc.) needed to perform the engineering study? ___80_____ Hours
2. What methodology / tools were used to perform the coordination studies?

   ☐ Computerized coordination curves

   ☐ Manual coordination curves

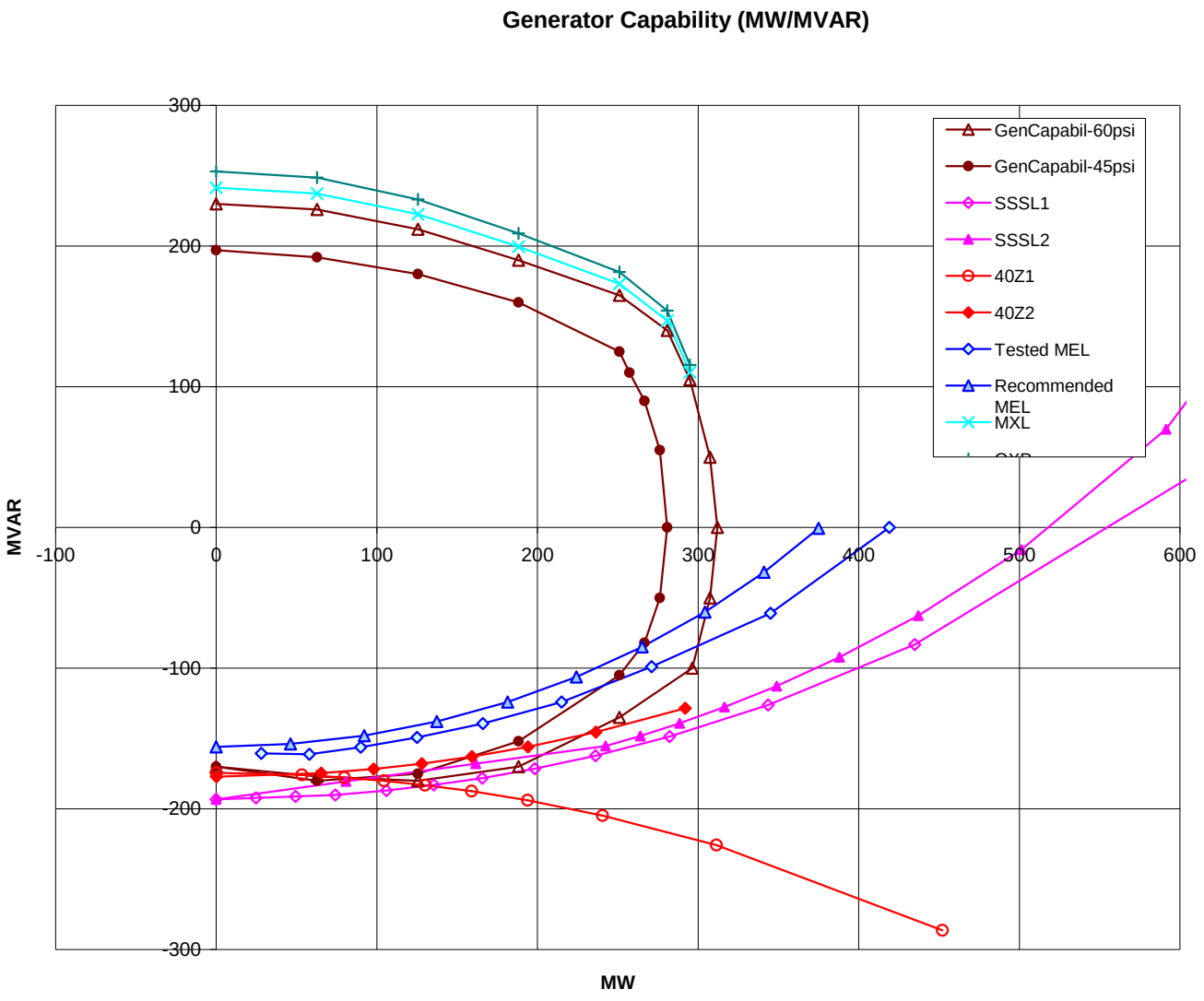
   ☒ Combination (computerized / manual)
3. How many man-hours did it take to develop the methodology / tools? ____200_____
4. How long did it take to analyze the technical information and draw the curves (plots)? ___30_____ Hours
5. List any material costs associated with this study. __$35k contractor costs ____Regulator calibration and coordination study. _____
6. Were the voltage regulator settings and the protective relay settings coordinated with the generator capability curve (as found)? ___Yes_____ (Yes or No)
7. If not, list the devices that needed configuration changes: _____MEL and V/HZ adjusted_____
8. Please list any suggested changes to the guideline or Draft NERC Reliability standard?

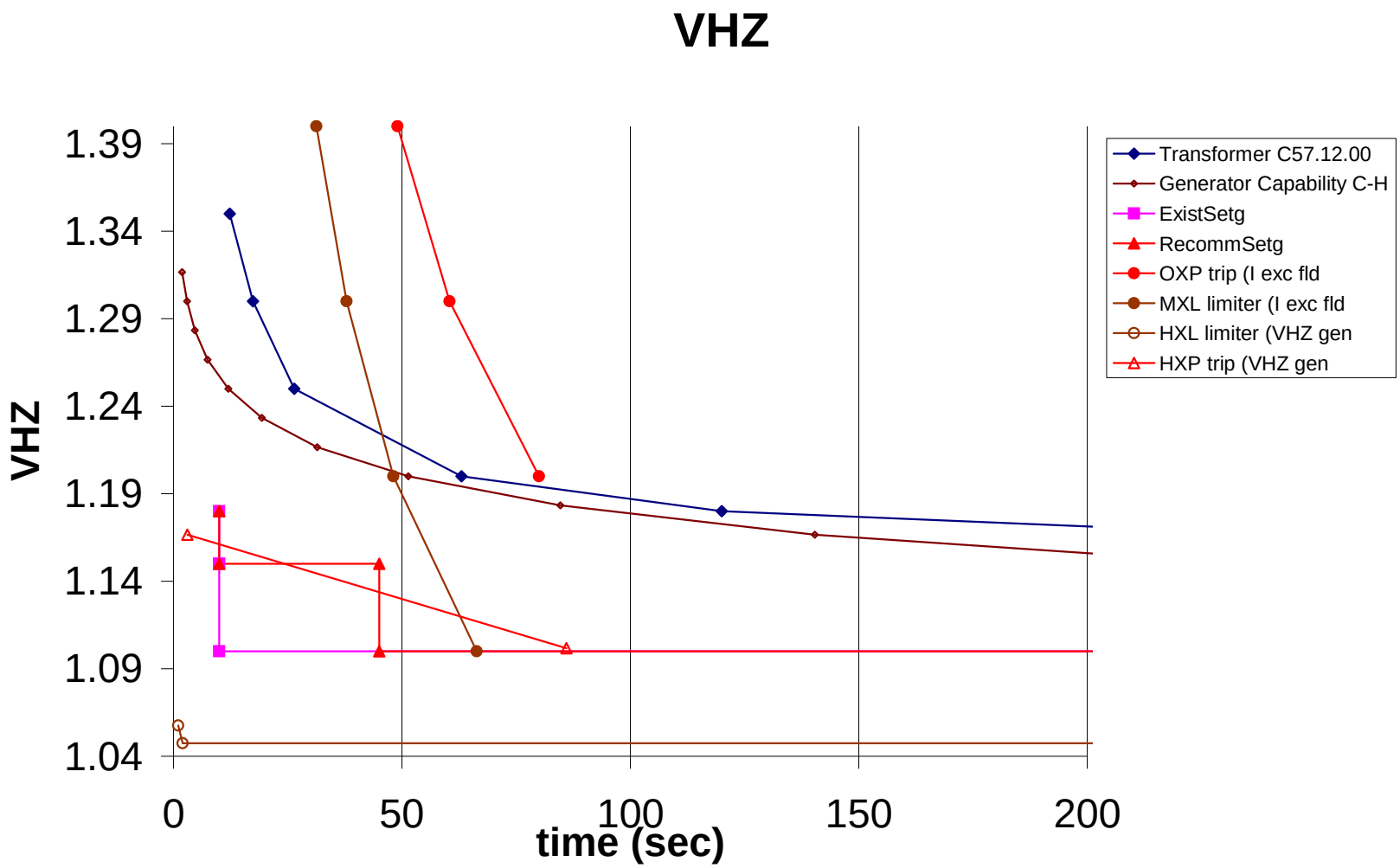
   _____

   _____
9. Provide the completed curves (plots). Remove all references that would identify the unit (company, station, and unit names, etc)
10. Name of person completing form: _Art Howell Phone number:281-297-3470

    Company name: Entergy

Send the completed report form and coordination curves electronically to: phuntley@serc1.org.


Generator Capability (MW/MVAR)
MVAR
MW
300
200
100
0
-100
-200
-300
-100
0
100
200
300
400
500
600
GenCapabil-60psi
GenCapabil-45psi
SSSL1
SSSL2
40Z1
40Z2
Tested MEL
Recommended MEL
MXL


VHZ
1.39
1.34
1.29
1.24
1.19
1.14
1.09
1.04
VHZ
0
50
100
150
200
time (sec)
Transformer C57.12.00
Generator Capability C-H
ExistSetg
RecommSetg
OXP trip (I exc fld
MXL limiter (I exc fld
HXL limiter (VHZ gen
HXP trip (VHZ gen

SERC PRC-019 Field Test Reporting Form

The purpose of this form is to provide a consistent report format for field testing results after using the SERC Field Test Guideline "Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection". Documentation of the test results (this field test may actually be considered an engineering study) will provide feedback showing that the field test was successful and/or will help to enhance the test guideline.

Use the SERC Field Test Guideline "Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection" to perform the test (engineering study). It is suggested that a newer, more modern generating unit be used for the test, to verify the coordination of more different types of protection relay systems (versus an older unit that may not have as many generator protection relays). Complete one (1) report form for each unit tested (studied).

Provide the following information:

1. How long did it take to assemble (bring together) the technical data (generator capability curve(s), voltage regulator settings, protective relay settings, etc.) needed to perform the engineering study? ____20____ Hours
2. What methodology / tools were used to perform the coordination studies?

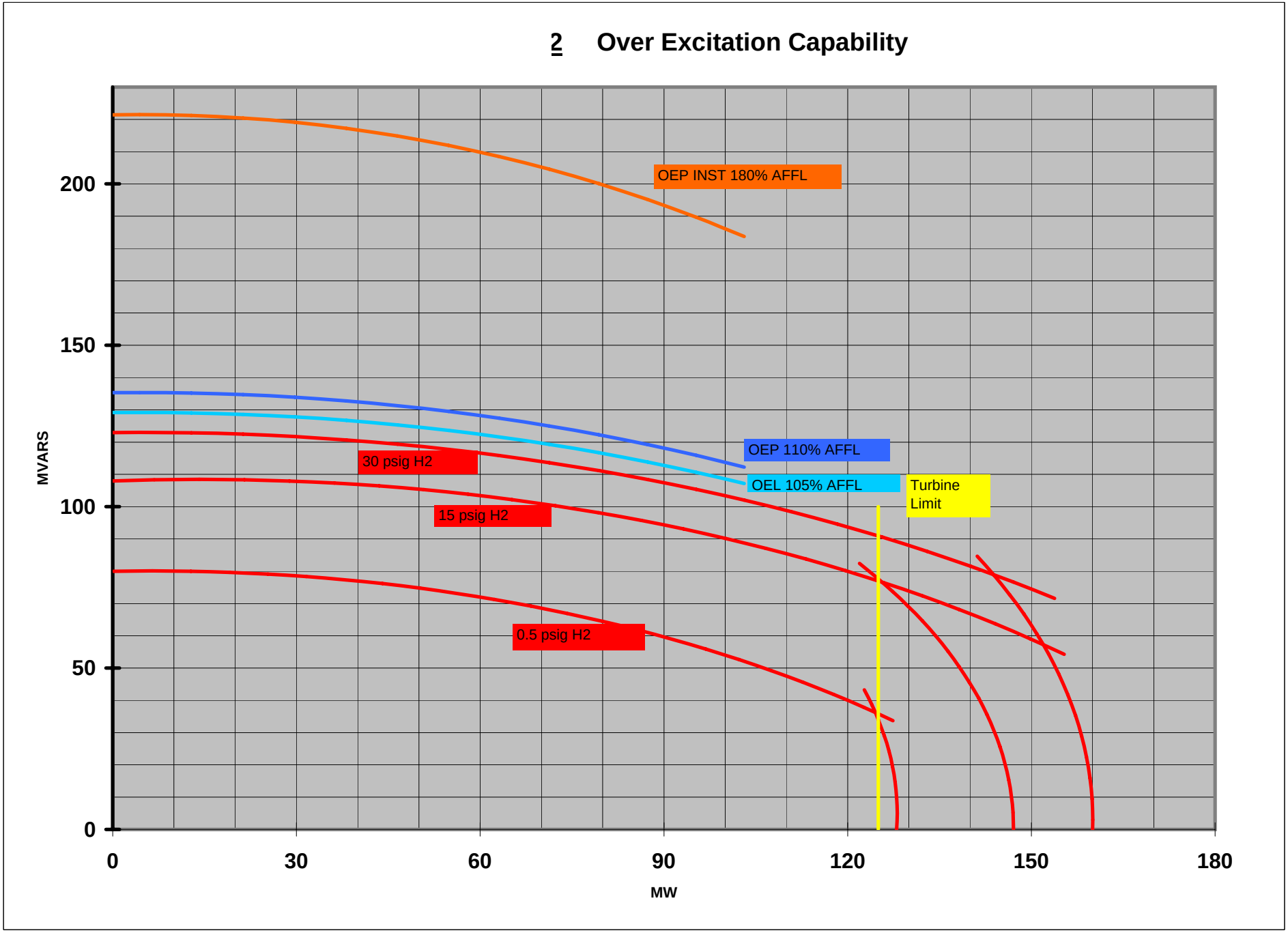
   ☐ Computerized coordination curves

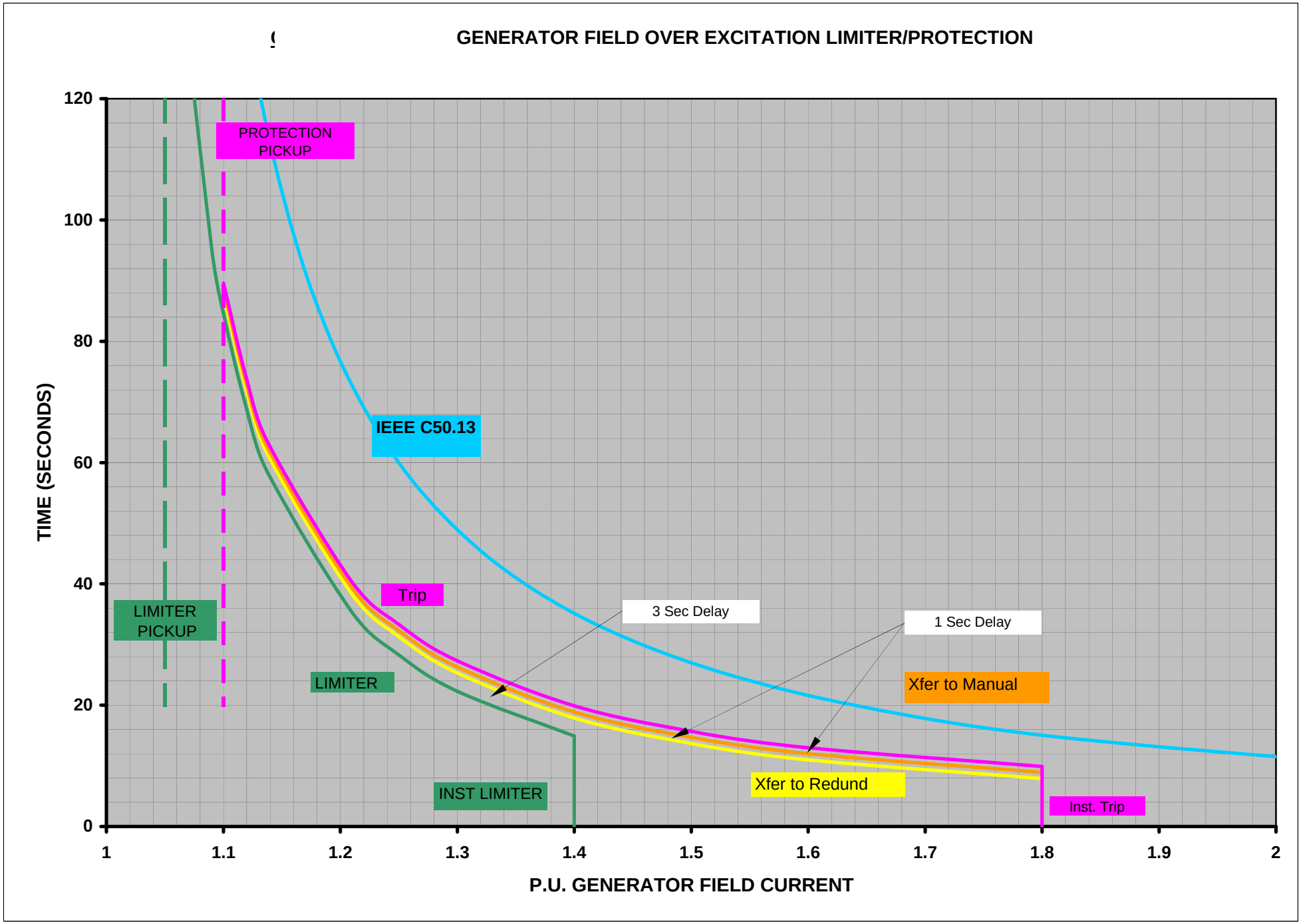
   ☐ Manual coordination curves

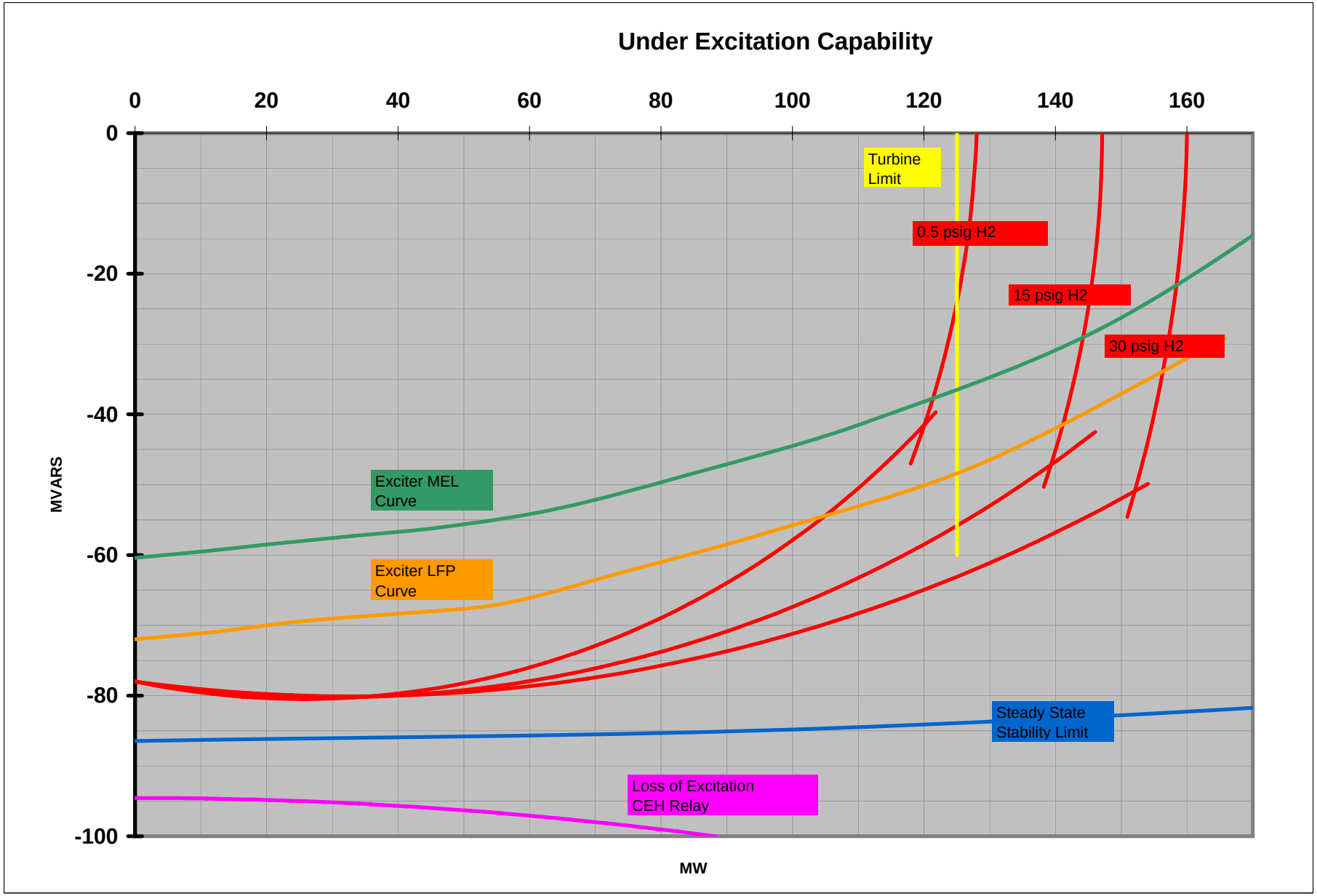
   ☒ Combination (computerized / manual)
3. How many man-hours did it take to develop the methodology / tools? ___80_____
4. How long did it take to analyze the technical information and draw the curves (plots)? ____80____ Hours
5. List any material costs associated with this study.
   _____minimal_____
   _____
6. Were the voltage regulator settings and the protective relay settings coordinated with the generator capability curve (as found)? ___Yes_____ (Yes or No)
7. If not, list the devices that needed configuration changes: _____ Need to look more closely at volts/hertz_____
8. Please list any suggested changes to the guideline or Draft NERC Reliability standard?
   _____
   _____
9. Provide the completed curves (plots). Remove all references that would identify the unit (company, station, and unit names, etc)
10. Name of person completing form: _Pat Longhsore_ Phone number _803-217-7490__

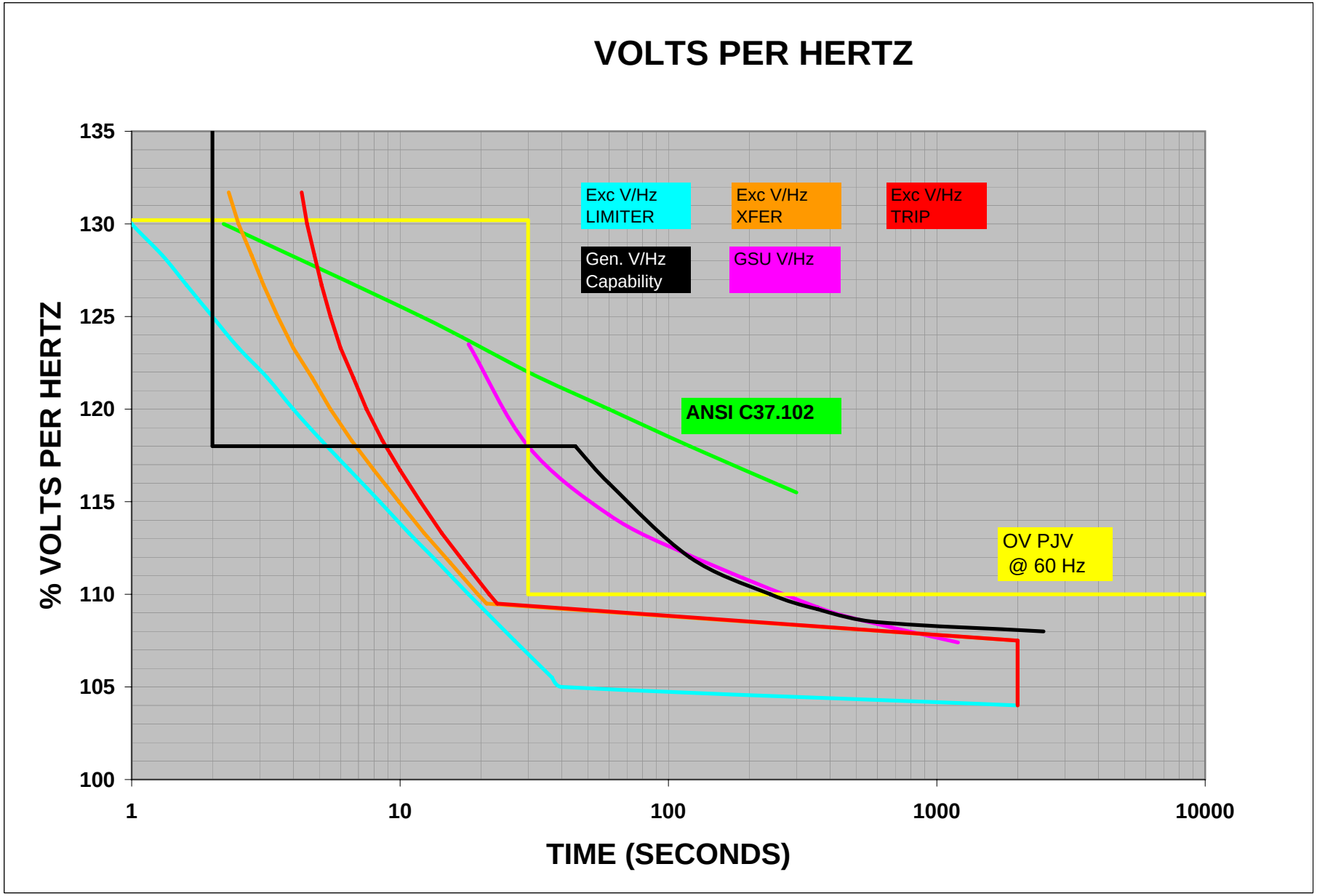
    Company name _S. C. Electric & Gas Co._____

Send the completed report form and coordination curves electronically to: phuntley@serc1.org.


2 Over Excitation Capability
OEP INST 180% AFFL
OEP 110% AFFL
OEL 105% AFFL
Turbine Limit
30 psig H2
15 psig H2
0.5 psig H2
MVARS
MW
0
50
100
150
200
0
30
60
90
120
150
180


GENERATOR FIELD OVER EXCITATION LIMITER/PROTECTION
TIME (SECONDS)
P.U. GENERATOR FIELD CURRENT
120
100
80
60
40
20
0
1
1.1
1.2
1.3
1.4
1.5
1.6
1.7
1.8
1.9
2
PROTECTION PICKUP
IEEE C50.13
Trip
LIMITER PICKUP
LIMITER
INST LIMITER
3 Sec Delay
1 Sec Delay
Xfer to Manual
Xfer to Redund
Inst. Trip


Under Excitation Capability
0
20
40
60
80
100
120
140
160
0
-20
-40
-60
-80
-100
MVARS
MW
Turbine Limit
0.5 psig H2
15 psig H2
30 psig H2
Exciter MEL Curve
Exciter LFP Curve
Steady State Stability Limit
Loss of Excitation CEH Relay


VOLTS PER HERTZ
% VOLTS PER HERTZ
135
130
125
120
115
110
105
100
1
10
100
1000
10000
TIME (SECONDS)
Exc V/Hz LIMITER
Exc V/Hz XFER
Exc V/Hz TRIP
Gen. V/Hz Capability
GSU V/Hz
ANSI C37.102
OV PJV @ 60 Hz

SERC PRC-019 Field Test Reporting Form

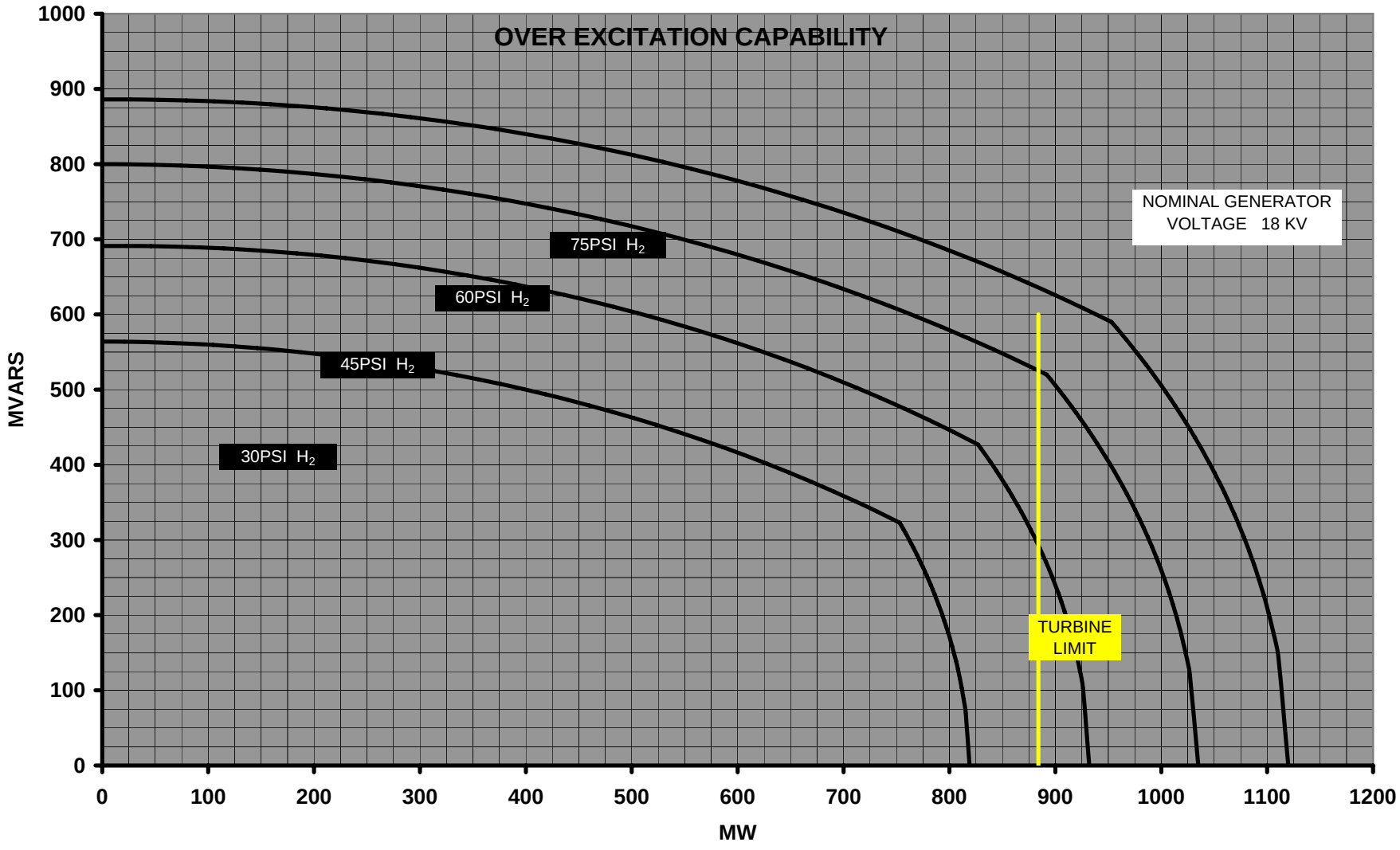
The purpose of this form is to provide a consistent report format for field testing results after using the SERC Field Test Guideline "Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection". Documentation of the test results (this field test may actually be considered an engineering study) will provide feedback showing that the field test was successful and/or will help to enhance the test guideline.

Use the SERC Field Test Guideline "Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection" to perform the test (engineering study). It is suggested that a newer, more modern generating unit be used for the test, to verify the coordination of more different types of protection relay systems (versus an older unit that may not have as many generator protection relays). Complete one (1) report form for each unit tested (studied).

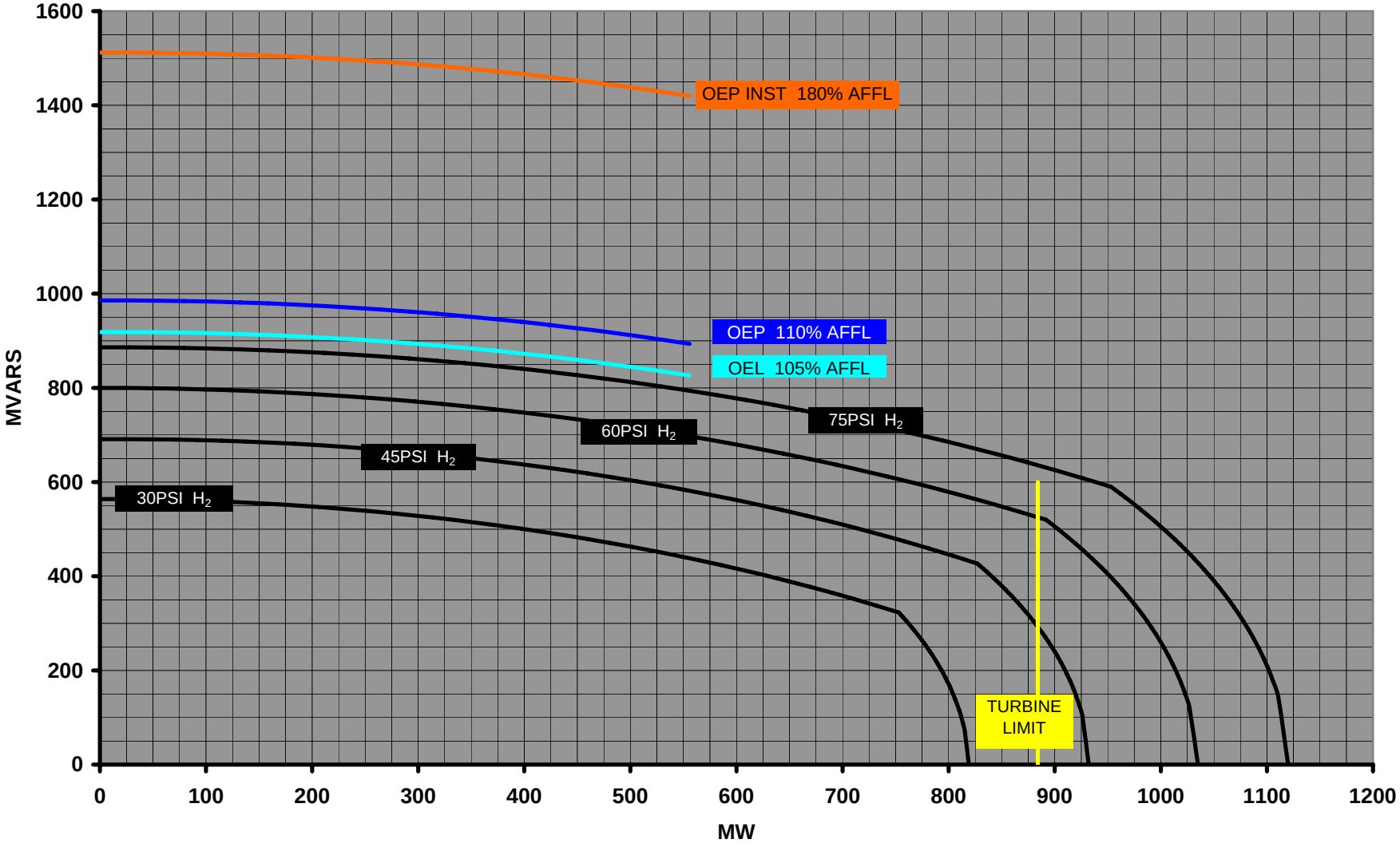
Provide the following information:

1. How long did it take to assemble (bring together) the technical data (generator capability curve(s), voltage regulator settings, protective relay settings, etc.) needed to perform the engineering study? 16 Hours
2. What methodology / tools were used to perform the coordination studies?
   - ☐ Computerized coordination curves
   - ☐ Manual coordination curves
   - ■ Combination (computerized / manual)
3. How many man-hours did it take to develop the methodology / tools? 1000
4. How long did it take to analyze the technical information and draw the curves (plots)? 40 Hours
5. List any material costs associated with this study.
6. Were the voltage regulator settings and the protective relay settings coordinated with the generator capability curve (as found)? YES (Yes or No)
7. If not, list the devices that needed configuration changes:
   SOME MEL SETTING CHANGES
8. Please list any suggested changes to the guideline or Draft NERC Reliability standard?
9. Provide the completed curves (plots). Remove all references that would identify the unit (company, station, and unit names, etc)

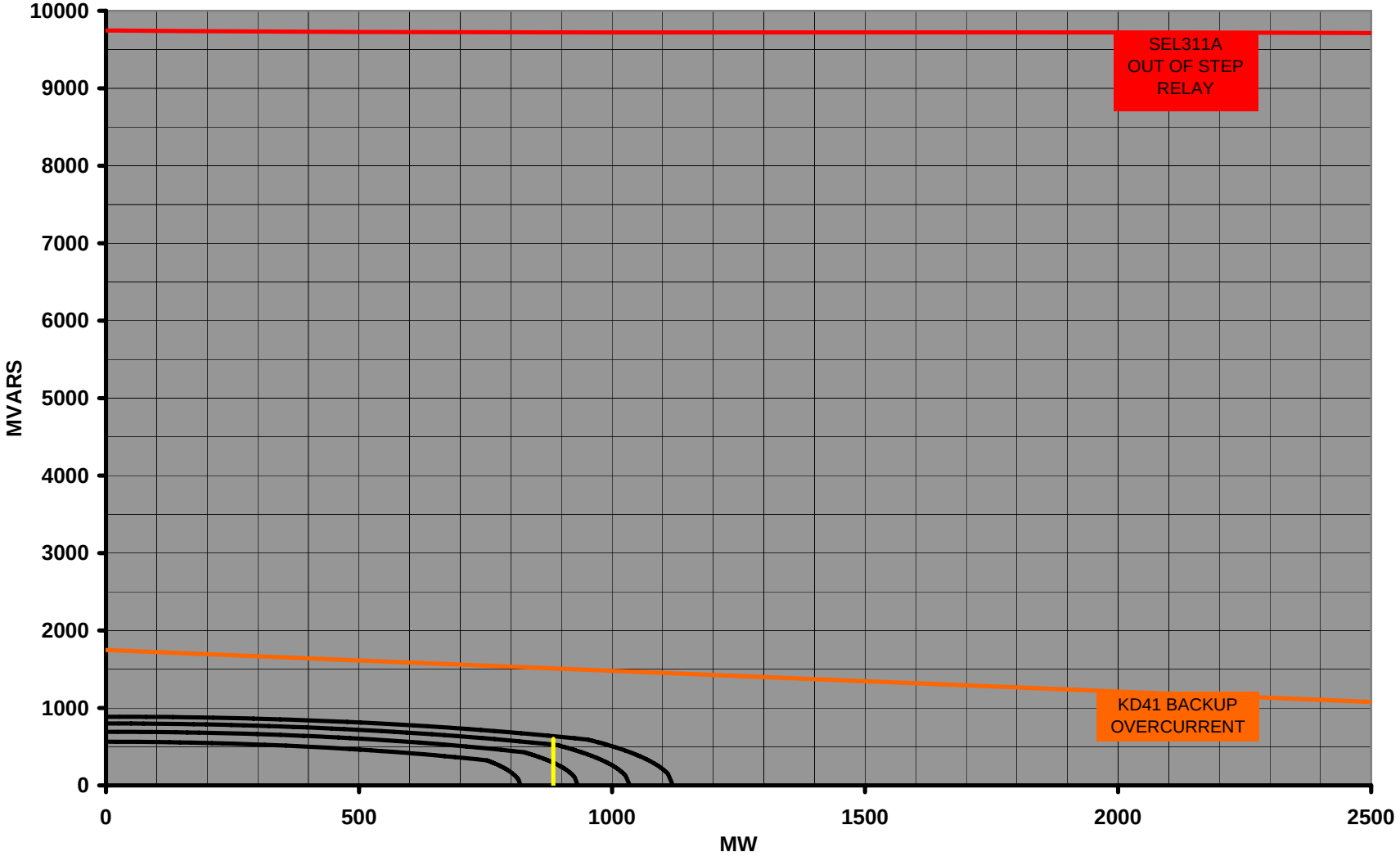
Send the completed report form and coordination curves electronically to: phuntley@serc1.org.

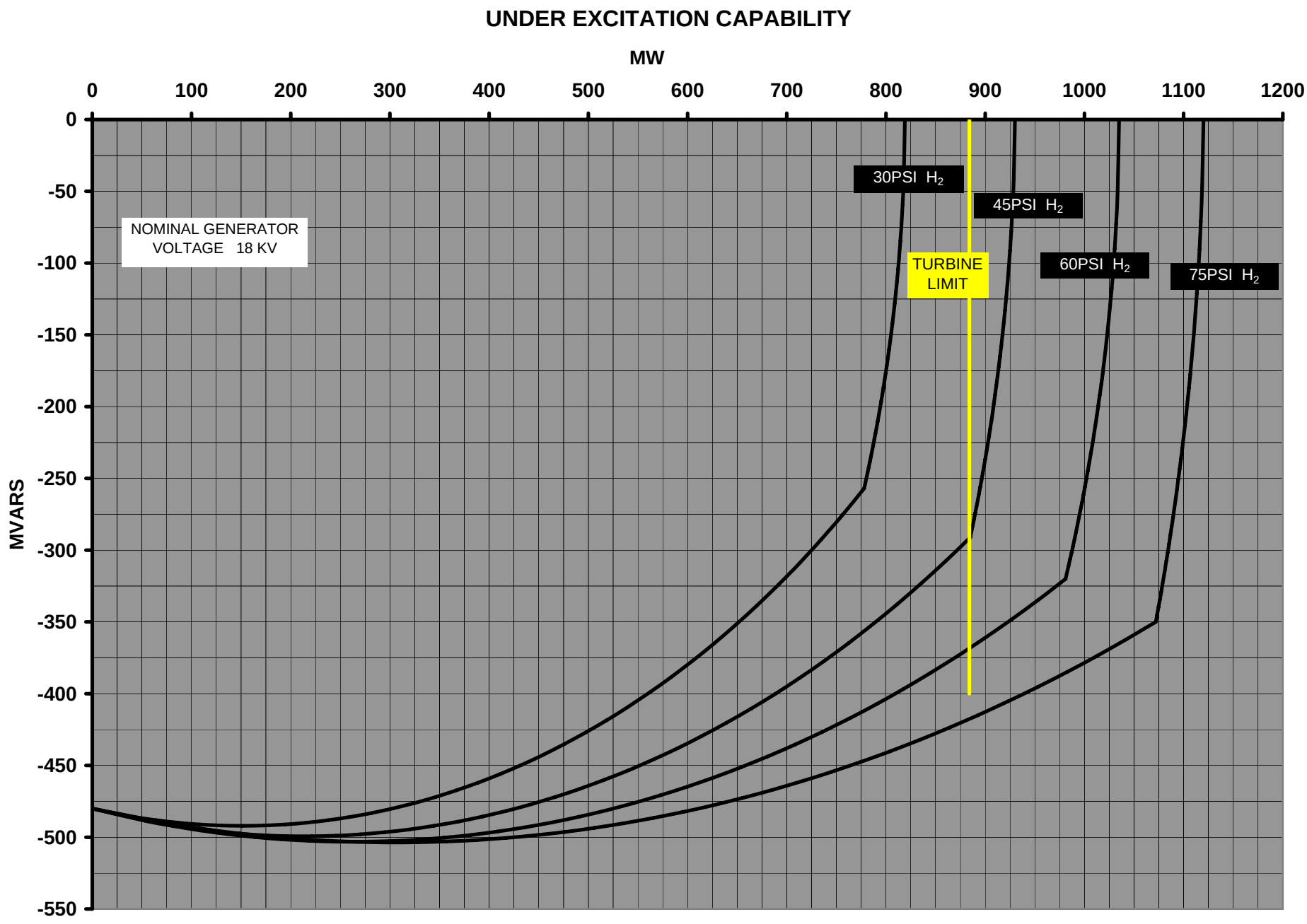

OVER EXCITATION CAPABILITY
NOMINAL GENERATOR VOLTAGE 18 KV
75PSI H_2
60PSI H_2
45PSI H_2
30PSI H_2
TURBINE LIMIT
MVARS
MW
0
100
200
300
400
500
600
700
800
900
1000
1100
1200

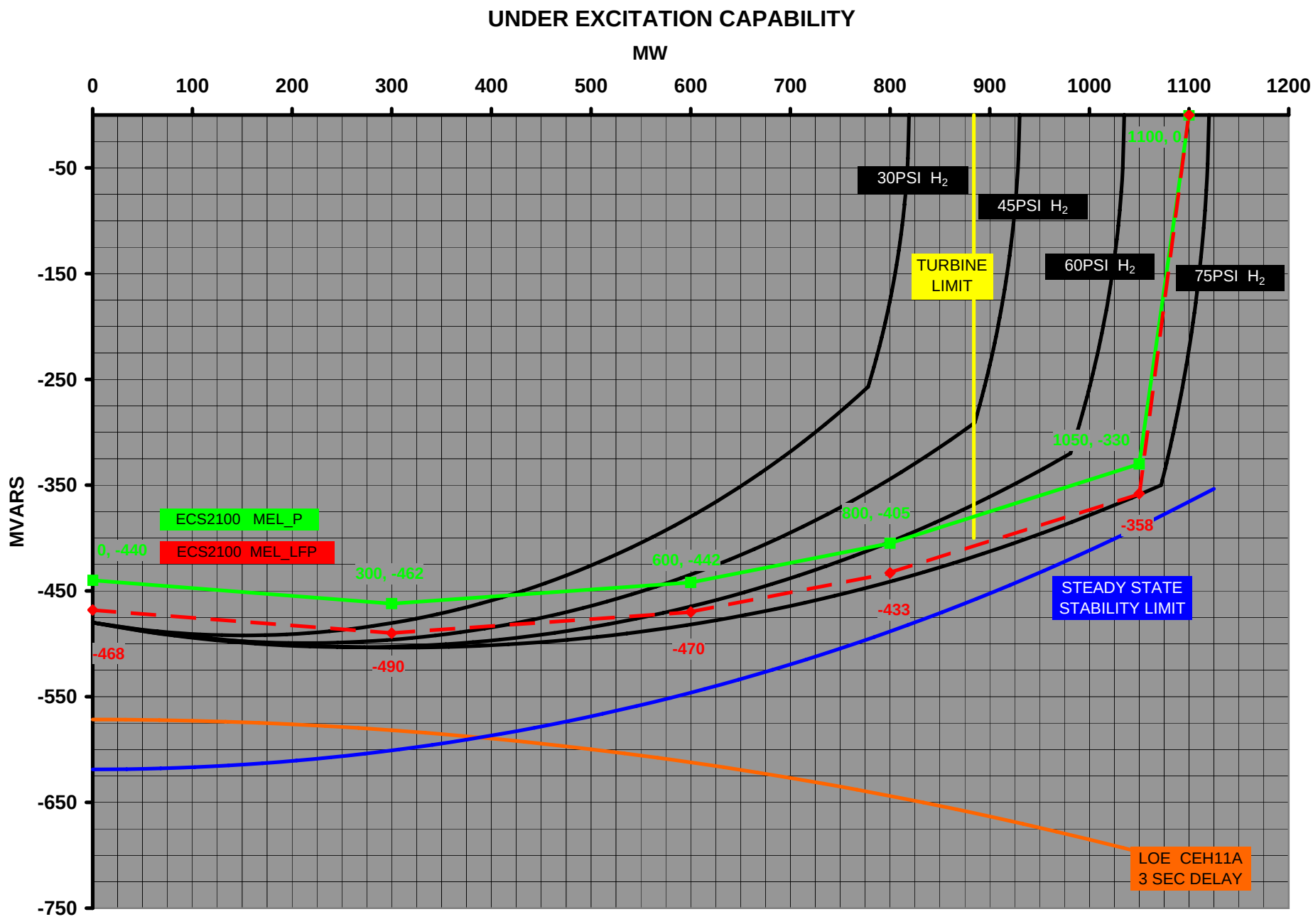
OVER EXCITATION CAPABILITY

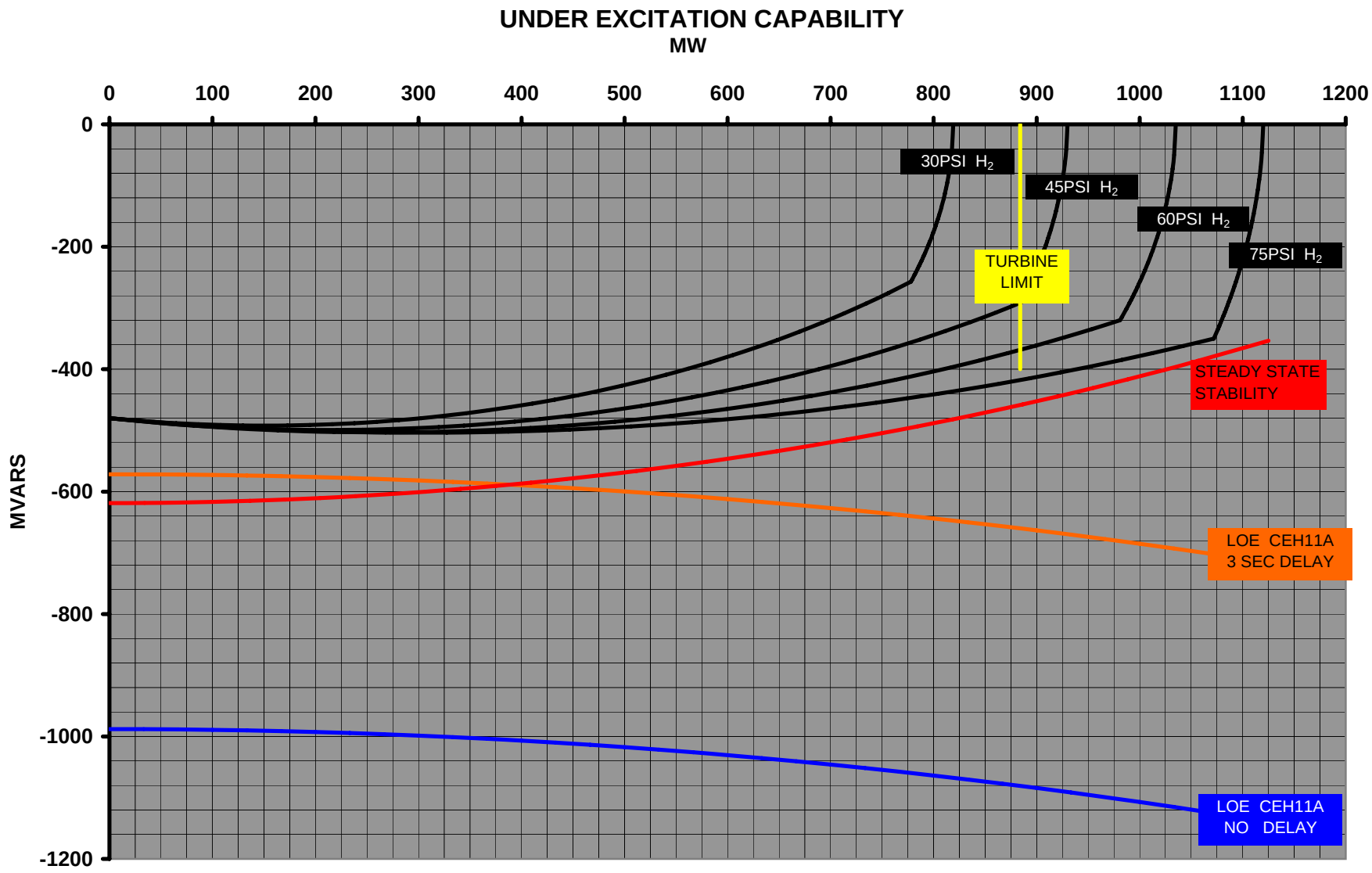


OVER EXCITATION CAPABILITY

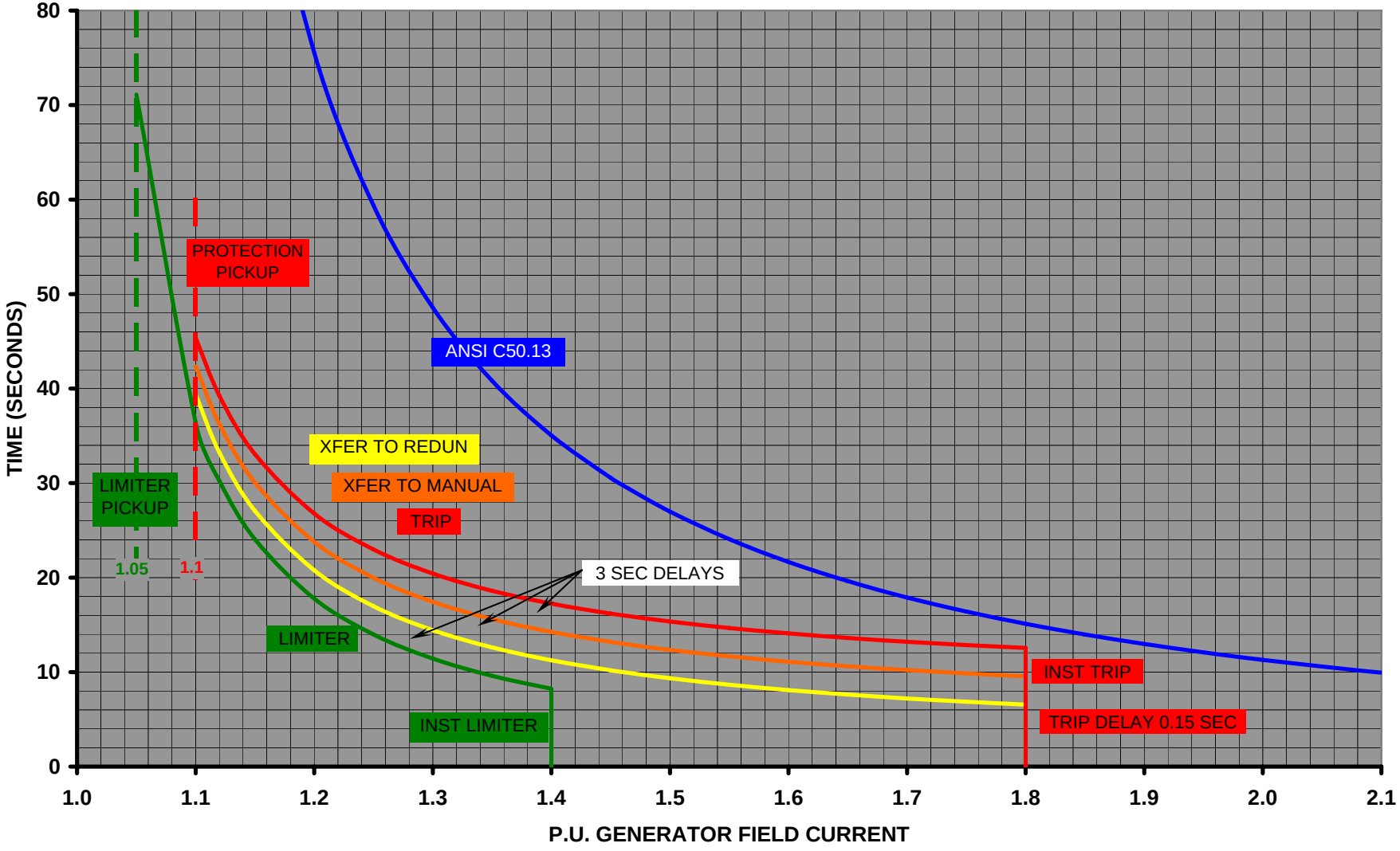



UNDER EXCITATION CAPABILITY
MW
0
100
200
300
400
500
600
700
800
900
1000
1100
1200
MVARS
0
-50
-100
-150
-200
-250
-300
-350
-400
-450
-500
-550
NOMINAL GENERATOR
VOLTAGE 18 KV
30PSI H_2
45PSI H_2
60PSI H_2
75PSI H_2
TURBINE
LIMIT

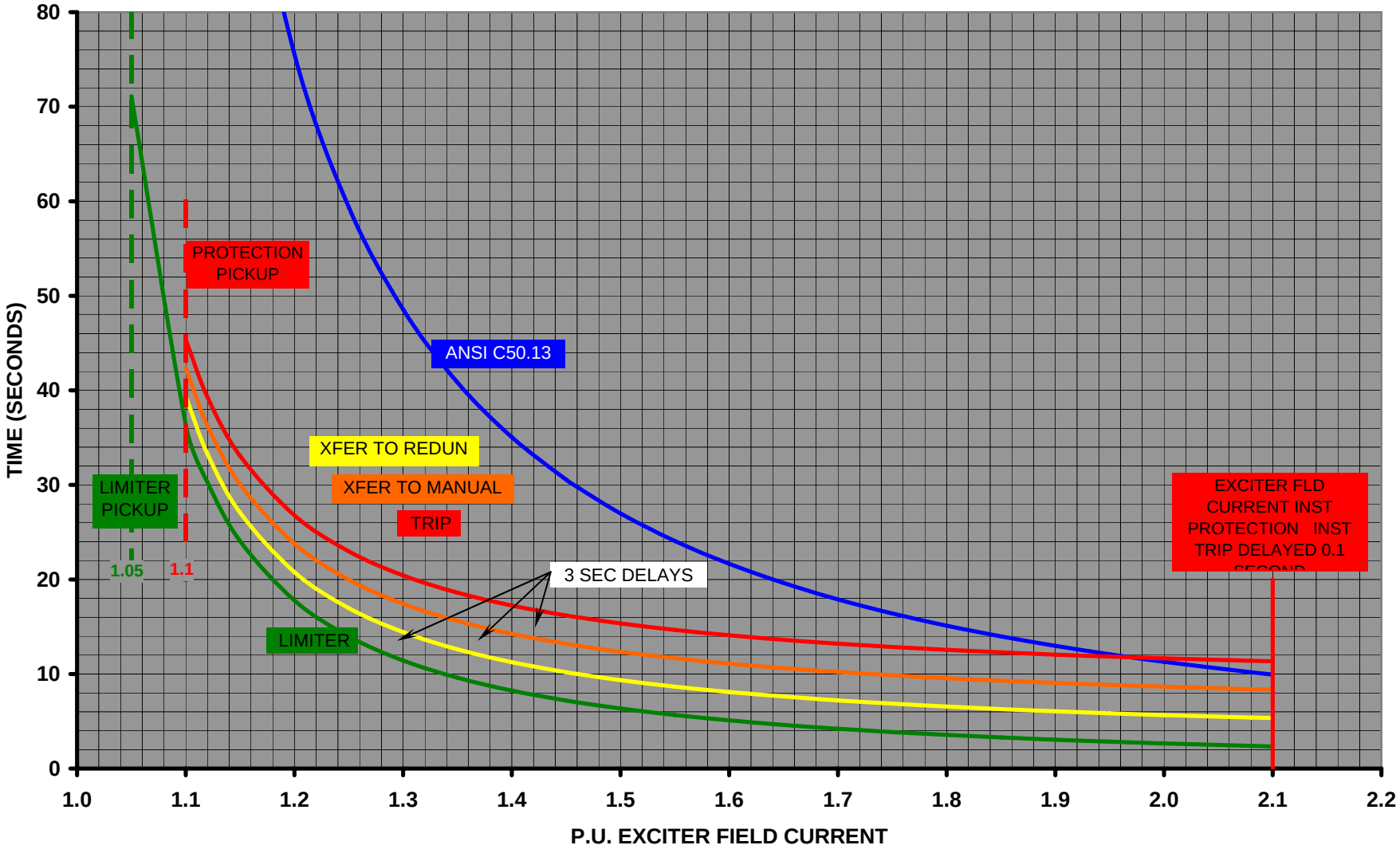

UNDER EXCITATION CAPABILITY
MW
0
100
200
300
400
500
600
700
800
900
1000
1100
1200
MVARS
-50
-150
-250
-350
-450
-550
-650
-750
30PSI H2
45PSI H2
60PSI H2
75PSI H2
TURBINE LIMIT
1100, 0
1050, -330
800, -405
600, -442
300, -462
0, -440
ECS2100 MEL_P
ECS2100 MEL_LFP
-358
-433
-470
-490
-468
STEADY STATE STABILITY LIMIT
LOE CEH11A 3 SEC DELAY

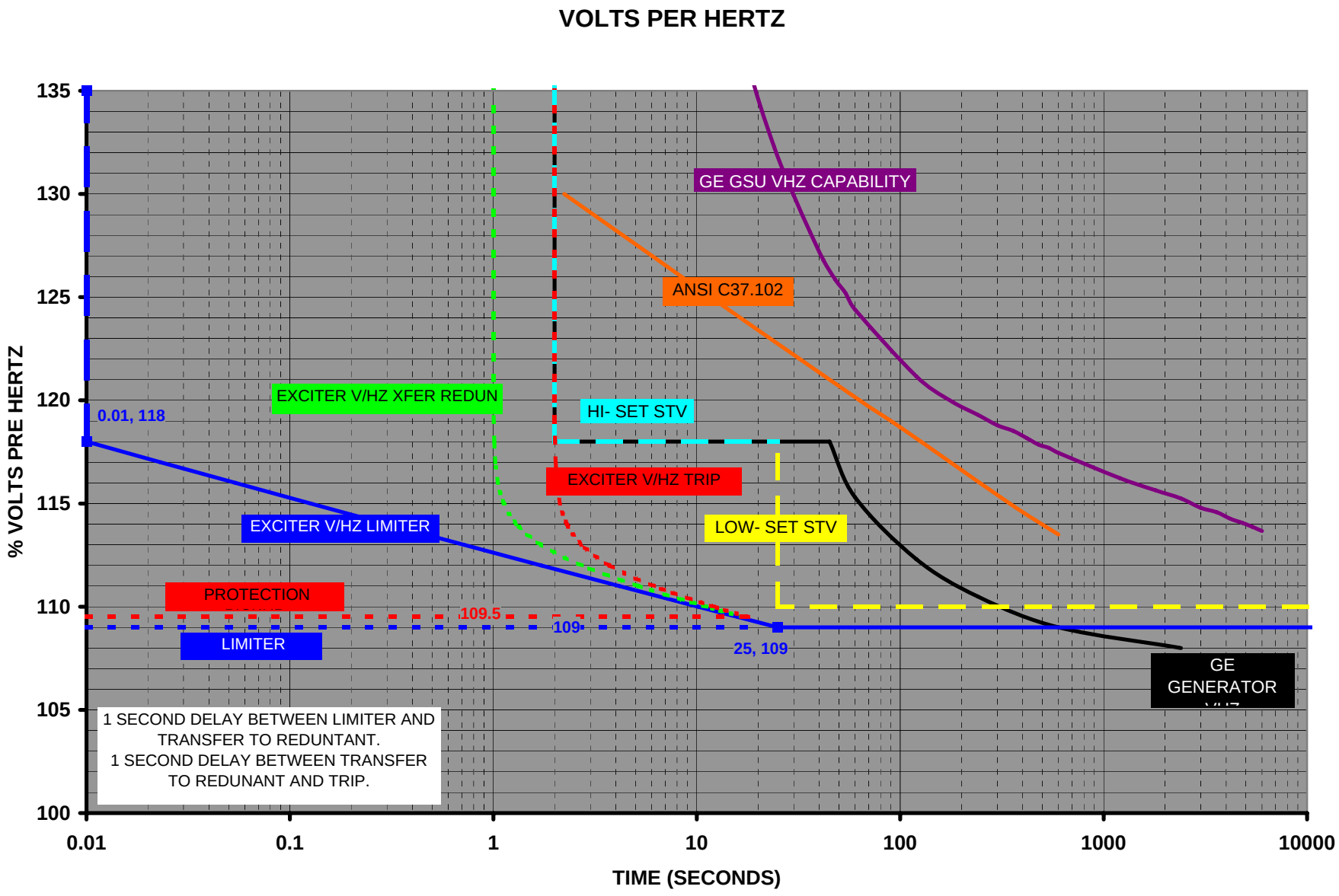

UNDER EXCITATION CAPABILITY
MW
0
100
200
300
400
500
600
700
800
900
1000
1100
1200
MVARS
0
-200
-400
-600
-800
-1000
-1200
30PSI H_2
45PSI H_2
60PSI H_2
75PSI H_2
TURBINE LIMIT
STEADY STATE STABILITY
LOE CEH11A 3 SEC DELAY
LOE CEH11A NO DELAY

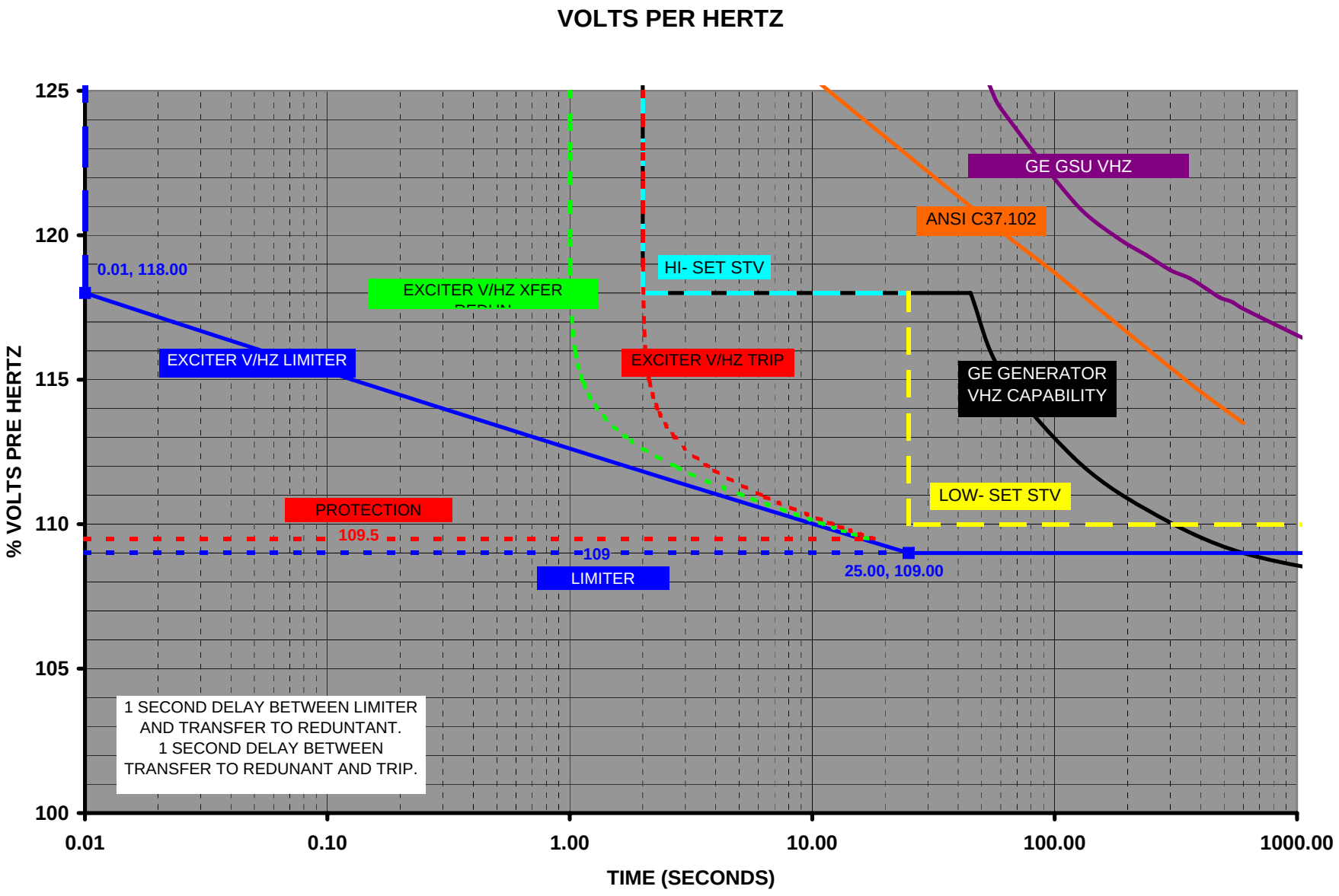
GENERATOR FIELD OVER CURRENT LIMITER/PROTECTION



EXCITER FIELD OVER CURRENT LIMITER/PROTECTION




VOLTS PER HERTZ
% VOLTS PRE HERTZ
TIME (SECONDS)
135
130
125
120
115
110
105
100
0.01
0.1
1
10
100
1000
10000
GE GSU VHZ CAPABILITY
ANSI C37.102
EXCITER V/HZ XFER REDUN
HI- SET STV
EXCITER V/HZ TRIP
LOW- SET STV
EXCITER V/HZ LIMITER
PROTECTION
LIMITER
0.01, 118
109.5
109
25, 109
GE GENERATOR
1 SECOND DELAY BETWEEN LIMITER AND TRANSFER TO REDUNTANT.
1 SECOND DELAY BETWEEN TRANSFER TO REDUNANT AND TRIP.


VOLTS PER HERTZ
% VOLTS PRE HERTZ
TIME (SECONDS)
125
120
115
110
105
100
0.01
0.10
1.00
10.00
100.00
1000.00
0.01, 118.00
EXCITER V/HZ LIMITER
EXCITER V/HZ XFER
HI- SET STV
EXCITER V/HZ TRIP
GE GSU VHZ
ANSI C37.102
GE GENERATOR
VHZ CAPABILITY
LOW- SET STV
PROTECTION
109.5
109
LIMITER
25.00, 109.00
1 SECOND DELAY BETWEEN LIMITER
AND TRANSFER TO REDUNTANT.
1 SECOND DELAY BETWEEN
TRANSFER TO REDUNANT AND TRIP.

Attachment 6
PRC-024 Test Results

- **SERC PRC-024 GO Field Test Reporting Form - COE 6-8-2007.pdf**
- **SERC PRC-024 Field Test Reporting Form Dominion June 7 2007.doc**
- **Dominion Voltage Excursion Example.pdf**
- **SERC PRC-024 GO Field Test Reporting Form (SCG 6-8-07 Rev 0).doc**
- **PRC-024_SS (SCG 6-8-07).pdf**
- **PRC-024_Dynamics (SCG 6-8-07).pdf**
- **Additional Comments PRC-024 June 11,2007.doc**
- **SERC Voltage Ride thru Attachment A.doc**
- **SERC Voltage Ride thru Attachment B.doc**

Generator Owner PRC-024 SERC Field Test Reporting Form

The purpose of this form is to provide a consistent report format for field testing results after using the SERC Field Test Guideline "Generator Performance During Frequency and Voltage Excursions". Documentation of the test results will provide feedback showing that the field test was successful and/or will help to enhance the test guideline.

Use the attached SERC Field Test Guideline "Generator Performance During Frequency and Voltage Excursions" to perform the applicable engineering studies. Complete one (1) report form for each unit tested.

Provide the following information:

1. How long did it take to assemble (bring together) the technical data needed to plot the expected unit frequency withstand capability? 8 Hours
2. If frequency excursion plots were created, what methodology / tools were used to construct the frequency excursion coordination plots?

   ☐ Computerized coordination curves

   ☐ Manual coordination curves

   ☒ Combination (computerized / manual)
3. If frequency excursion plots were not created, please explain the methodology used to demonstrate coordination with the draft SERC frequency excursion characteristic.
4. How many man-hours did it take to develop the methodology / tools? 4
5. Did the results indicate that the generator would be expected to remain on line for the draft SERC frequency Characteristic? ☒Yes ☐ No

   If no please attach additional information as appropriate.
6. How long did it take to analyze the technical information and draw the frequency curves (plots)? 2Hours
7. List any material costs associated with the generator frequency withstand capability portion of this field test. Curve ploting software $1,810.
8. How long did it take to assemble (bring together) the technical data needed to plot the expected Low Voltage Ride Through (LVRT) capability? Hours
9. If LVRT plots were created, what methodology / tools were used to construct the frequency excursion coordination plots?

   ☐ Computerized coordination curves

   ☐ Manual coordination curves

   ☒ Combination (computerized / manual)
10. If LVRT plots were not created, please explain the methodology used to demonstrate coordination with the draft SERC LVRT characteristic.
11. How many man-hours did it take to develop the methodology / tools? 16

Generator Owner PRC-024 SERC Field Test Reporting Form

12. Did the results indicate that the generator would be expected to remain on line for the draft LVRT characteristic? ☒Yes ☐ No Note: The current Unit and Bus under voltage relay settings will ride through the draft LVRT curve. Presently our organization does not have sufficient data to determine if the current excitation and AVR settings will ride through the draft LVRT curve.

    If no please attach additional information as appropriate.

13. How long did it take to analyze the technical information and draw the LVRT curves (plots)? Hours

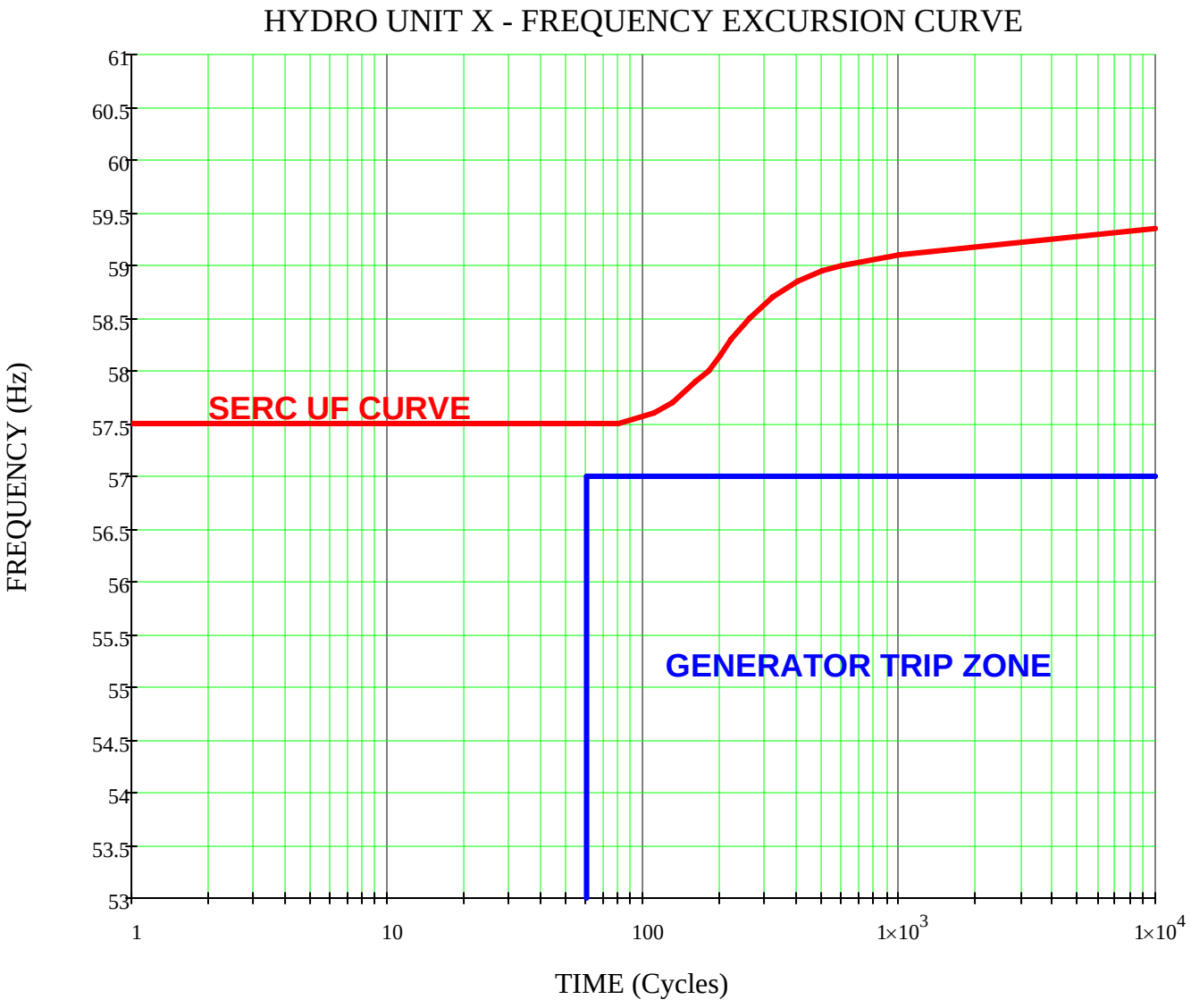
14. List any material costs associated with the generator LVRT capability portion of this field test. Curve ploting software $1,810.

15. Please list any suggested changes to the guideline or the draft NERC Reliability Standard.

16. Provide the completed curves (plots) and other applicable documentation. Remove all references that would identify the unit (company, station, and unit names, etc). See attached.

17. Name of the person completing the form: David Williams Phone Number 706.643.0313 Company Name Corps of Engineers - Mobile District

Send the completed report form, plots, models and documentation to **phuntley@serc1.org**


HYDRO UNIT X - FREQUENCY EXCURSION CURVE
FREQUENCY (Hz)
61
60.5
60
59.5
59
58.5
58
57.5
57
56.5
56
55.5
55
54.5
54
53.5
53
SERC UF CURVE
GENERATOR TRIP ZONE
1
10
100
1×10^3
1×10^4
TIME (Cycles)

HYDRO UNIT X - VOLTAGE EXCURSION CURVE
SERC UV CURVE
BUS AND UNIT
UNDER VOLTAGE
TRIP ZONE
VOLTAGE (P.U.)
TIME (SECONDS)
1
0.95
0.9
0.85
0.8
0.75
0.7
0.65
0.6
0.55
0.5
0.45
0.4
0.35
0.3
0.25
0.2
0.15
0.1
0.05
0
− 1
− 0.5
0
0.5
1
1.5
2
2.5
3
3.5
4
4.5
5
5.5
6

Generator Owner PRC-024 SERC Field Test Reporting Form

The purpose of this form is to provide a consistent report format for field testing results after using the SERC Field Test Guideline "Generator Performance During Frequency and Voltage Excursions". Documentation of the test results will provide feedback showing that the field test was successful and/or will help to enhance the test guideline.

Use the attached SERC Field Test Guideline "Generator Performance During Frequency and Voltage Excursions" to perform the applicable engineering studies. Complete one (1) report form for each unit tested.

Provide the following information:

1. How long did it take to assemble (bring together) the technical data needed to plot the expected unit frequency withstand capability? **2 Hours**
2. If frequency excursion plots were created, what methodology / tools were used to construct the frequency excursion coordination plots?

   ☐ Computerized coordination curves

   ☐ Manual coordination curves

   ☐ Combination (computerized / manual)
3. If frequency excursion plots were not created, please explain the methodology used to demonstrate coordination with the draft SERC frequency excursion characteristic. **Most of our generating units would be tripped manually during frequency excursions. Each control room has three Annunciator alarms for frequency changes; 59.8 Hz, 58.1 Hz, and 57.6 Hz. The 59.8 Hz alarm alerts the control room operator (CRO) that there is an issue with the frequency. The CRO will manually trip the unit if the frequency is at 58.1 Hz for 30 seconds or at 57.6 Hz for 1 second.**
4. How many man-hours did it take to develop the methodology / tools?
5. Did the results indicate that the generator would be expected to remain on line for the draft SERC frequency Characteristic? ☐Yes ☒ No

   If no please attach additional information as appropriate. **See number 15**.
6. How long did it take to analyze the technical information and draw the frequency curves (plots)? **0 Hours**
7. List any material costs associated with the generator frequency withstand capability portion of this field test. **$0**
8. How long did it take to assemble (bring together) the technical data needed to plot the expected Low Voltage Ride Through (LVRT) capability? Hours
9. If LVRT plots were created, what methodology / tools were used to construct the frequency excursion coordination plots?

   ☐ Computerized coordination curves

   ☐ Manual coordination curves

   ☐ Combination (computerized / manual)

Generator Owner PRC-024 SERC Field Test Reporting Form

10. If LVRT plots were not created, please explain the methodology used to demonstrate coordination with the draft SERC LVRT characteristic. **One of our relay engineers evaluated the characteristics of the back-up impedance relay. Determined that the generating unit would not stay on line for a voltage profile shown on the "Proposed SERC Generator Voltage Excursion Curve". Also, see the attached example showing that other types of generating unit equipment can force a unit off line during voltage excursions.**

11. How many man-hours did it take to develop the methodology / tools? **1 hour**.

12. Did the results indicate that the generator would be expected to remain on line for the draft LVRT characteristic? ☐Yes ☒ No

    If no please attach additional information as appropriate. **See number 15.**

13. How long did it take to analyze the technical information and draw the LVRT curves (plots)? **2 Hours**.

14. List any material costs associated with the generator LVRT capability portion of this field test. **$0**

15. Please list any suggested changes to the guideline or the draft NERC Reliability Standard.

Proposed UF Excursion Curve:

After a review by our turbine engineers and equipment vendors, the operating limits for frequency excursions could possible be adjusted to comply with the proposed curve.

Proposed UV Excursion Curve:

I suggest that the implementation of this standard be delayed until:

A. Industry specialists analyze, develop, and provide a method(s) for reviewing generating equipment and protective relay characteristics to guide generator operators on how to comply with the proposed standard.

B. A cost benefit analysis should be performed to determine the most economical and logical way to achieve the desired end result; should generator owners perform engineering studies and equipment/protective relay changes or should transmission owners/planners/operators change the system models and/or install new transmission equipment/relays or both?

16. Provide the completed curves (plots) and other applicable documentation. Remove all references that would identify the unit (company, station, and unit names, etc)

17. Name of the person completing the form: **Larry Whanger** Phone Number **804.273.3576** Company Name **Dominion.**

Send the completed report form, plots, models and documentation to **phuntley@serc1.org**

Generator Owner PRC-024 SERC Field Test Reporting Form

Note: See the attached example of what actually happened during a voltage excursion at one of our power stations.

Fossil & Hydro Technical Services

TECHNICAL REPORT

[redacted]

Loss of Generation

Due to

Transmission Fault Event

Technical Report
Loss of Generation Due to Transmission Fault

1. EXECUTIVE SUMMARY

This report is prepared due to an event that occurred on January 31,2006 that caused three of four generating units at the [redacted] to trip. The event that took place involved a rare type of fault combined with a rare equipment failure. The fault that occurred suppressed the voltage at the station and the circuit breaker failure prolonged the duration of the event to the extent that station equipment malfunctioned and could not be overcome before most of the generating units were lost.

This Technical Report provides data calculated by the Transmission Department reflecting a fault study and the associated Voltages that can be expected to occur at the [redacted] Switchyard for various fault scenarios. Using this data, and reliability data published in the IEEE Std 493 (Recommended Practice for the Design of Reliable Industrial and Commercial Power Systems) for similar equipment and faults, the probabilities associated with different events are calculated. Each such event, will cause varying degrees of Voltage Sags and impacts to the Station Auxiliaries Electrical System and operating Units.

The impacts from various fault conditions for each transmission line are projected in a somewhat subjective manner based on the prior impact and expected operating conditions that will occur and the lack of a uniform standard for equipment tolerance to Voltage Sag events for which to base a solid predictive model. These impacts are based on traditional design philosophies of power stations in general, and a full detailed assessment and testing program are required to improve the confidence factor of these assessments.

The costs of Generation losses resulting from an event on the Transmission system are calculated by using replacement power costs for the year 2006, averaged across all four units with each unit at maximum capacity, multiplied by the various probabilities and the expected impact that each event occurrence should produce. The expected annual costs for this type of event is [redacted].

Based on the Reliability Data published, and the characteristics of the transmission lines connected, the transmission lines connected to [redacted] should expect 4.06 outages (momentary or sustained) per year.
The cost of replacement power for all units is based on a six-hour loss for each for a combined total of 3750 MWH at [redacted].

Recognizing that the most economical alternatives for corrective action should be focused at specific equipment, recommendations are offered for the known equipment and suggestions regarding testing techniques are provided for the unknown equipment. Future critical equipment upgrades should include voltage tolerance requirements as part of the equipment specification and as conditions warrant.

Other factors for future consideration that are beyond the scope of this report, include Voltage Profile Studies of the Station Auxiliary Electrical System to determine that all transformers are being operated at their optimum taps, and Switchyard upgrades that may improve specific risks, but at increased costs.

2. INTRODUCTION

On January 31, 2006, the [redacted] sustained a voltage sag of approximately 45% for 26 cycles as indicated in the attached exhibits. The voltage sag resulted from a double line to ground fault caused by a lightning strike approximately 6.9 miles from the station on Line 164. The terminal Breaker at Reeves Ave substation failed to trip and initiated the Breaker Failure Scheme. As a direct result, the power station lost three of four generating units that were operating at the time.

2.1. Purpose

One objective for this document is to provide some insight and understanding regarding the previous event, and understand the consequences/probabilities of future events.

Another objective is to determine the risk of exposure to a similar event that will happen in the future, identify weaknesses in the existing protection against these events. Recommend measures that may be appropriate to mitigate these risks and to quantify these measures by providing an economic evaluation based on the likelihood of experiencing a future event.

2.2. References

The following publications have been used to derive data and information

ANSI/IEEE Std 493-1997 493 Recommended Practice for the Design of Reliable Industrial and Commercial Power Systems
ANSI C84.1-1982 American National Standard for Electric Power Systems and Equipment (60 Hz)– Voltage Ratings
ANSI/IEEE Std 666-1991 Design Guide for Electric Power Service Systems for Generating Stations
ANSI/IEEE Std 1159-1995 IEEE Recommended Practice for Monitoring Electric Power Quality

3. [redacted] UNIT TRIPS

The following information is based on a report issued by the station concerning the events that occurred January 31, 2006

[redacted] summary of events observed/recorded for each unit, 01/31/06

At approximately 06:21:15 a line fault occurs in the system (at Reeves Ave). 115KV voltage at [redacted] substation drops to about ½ (~65KV) for 4 cycles and does not fully recover for at least 26 cycles; total time about ½ of a second. See Exhibit 1.

The affect on each of the generating unit is reproduced from a station report repeated here.

3.1. Unit 1

06:21:15 (PI) All 3 coal feeder motors in service stopped running (480V feed to Merrick controls). No alarms are received in the control room. Running status was not removed in logic. Approximately 1.5 minutes after motors stop the unit trips on loss of flame scanners, black furnace.

3.2. Unit 2

06:21:15 (PI) All 3 coal feeder motors in service stopped running (480V feed to Merrick controls). No alarms are received in the control room. Running status was not removed in logic. Approximately 1.5 minutes after motors stop the unit trips on loss of flame scanners, black furnace.

Note: The coal feeder running status issue was verified on restart of unit 2 A mill feeder. The feeder motor stopped but no notification to the control room operator occurred. The feeder running status was still 'proven' but the motor was not on. If the feeder status worked correctly the units' would have tripped on 'loss of fuel' and not 'black furnace'. Removal of all fuel sources to the boiler is an MFT condition.

3.3. Unit 3

06:21:15 (SOE) 'C' coal feeder motor stopped (480V supply). Coal feeder stopped is recorded on the sequence of events recorder (SOE). The unit goes into runback mode after approximately 2 minutes due to loss of fuel from 'C' mill. The Control Room operator who was consumed with unit 4's related issues determines that unit 4 is not recoverable and switches attention to unit 3 and recovers the unit.

The unit 3 turbine board recorder reboots due to the electrical fault as indicated by loss of turbine data in PI.

3.4. Unit 4

3.4.1. 06:21:15 (SOE) 'C' coal feeder not running (480V supply to speed controller)

3.4.2. 06:21:15 (PI) BFPT main LO pump stopped (480V motor)

3.4.3. 06:21:15 (PI) 'A' dil. air fan on the SCR stopped (480V motor)

3.4.4. 06:21:16 (SOE) 'C' coal feeder running. It appears that the fault knocked 'C' feeder motor out but it came back due to a maintaining contact to run from Modicon.

3.4.5. The feeder speed in PI drops in half and then recovers.

3.4.6. 06:21:16 (SOE) BFPT tripped. The BFPT tripped after the BFPT main LO pump motor stopped. The Aux LO pump and DC back up pump started within two seconds of the main pump stopped. The Aux pump did not catch the autostop oil pressure from dropping below 60 psi. At 60 psi the low autostop oil pressure switches tripped the BFPT.

3.4.7. 06:22:29 (SOE) Low Drum Level Trip

3.4.8. 06:24:18 (SOE) Unit is taken off line by the CRO (opened breakers). The turbine solenoid trip was at 06:22:29, throttle valves recorded closed at 06:22:30.

3.5. Root Cause of Motors Stopping

The probable cause of the various motors stopped was the large drop in system voltage which also dropped the units' 480V buses to either drop out motor starter contactors or fault motors due to a voltage drop below minimum required running voltage.

5. STATION EQUIPMENT

5.1. Industry Standards

IEEE Standard C84.1 establishes Nominal voltages for Power System Equipment and also defines recommended ranges for equipment to operate. Voltage tolerance limits are based on the ANSI/NEMA MG-1, which established the criteria for standard induction motors at +/- 10% of nameplate ratings 230V, 460V, etc. Since motors represent a large component of utilization equipment, they were given primary consideration in establishing the standard. However, there is no national standard that requires particular immunity for voltage sags that may occur on the system. Some specialized interests such as the semi-conductor industry have established specification criteria for tolerance against Voltage Sags for equipment manufactured for their plants (See Exhibit 11).

It should be noted that Generating Stations are not typical in regard to the Voltage Sags that equipment should be expected to operate satisfactorily. Generating station Voltage Limits have always required tolerance against the starting duty of very large motors connected to the system, and consequently, design criteria is to allow starting of this large equipment without dropping out relays and contactors for lower voltage motors and equipment. It is also acceptable to have lower voltages because of the high degree of instrumentation used to monitor process conditions. Most station equipment originally installed with the unit should continue to operate with Voltage sags to 75 – 80% of nominal voltage.

5.2. Equipment Vulnerable to Voltage Disturbances

Equipment that is most vulnerable to voltage disturbances include solid state equipment including Control equipment specifically DCS and PLCs, Soft Start Motor Controllers, and Adjustable Speed Drives. To a lesser degree, electromechanical components such as relays, solenoids and contactors, since these all react slightly slower due to the inherent energy storage characteristics.

The ability of an individual piece of equipment varies from manufacturer to manufacturer. The Voltage Ride-through times must be evaluated for eash specific equipment suspected of being sensitive to the voltage variation.

Some examples of typical equipment –

- Solenoids 10% overvoltage and 15% undervoltage.
- Control Relays and Motor contactors are required by standrds to operate at + 10% and –15% voltage, however most will hold in down to 65% and some event to 50%.

5.3. Techniques for Improving Tolerances to Disturbances

Three-phase equipment is less susceptible to transmission events than single-phase equipment and while most power station equipment is supplied from three-phase sources, there are some equipment supplied from single-phase systems including panels feeding instruments and controls.

Control Transformers used for motor control, if oversized, provide better ride-through capability for the motor contactor. Control Transformers located in the same MCC

should be connected to alternating primary phases, A-B, B-C, C-A, to reduce the chances of losing all of the equipment as opposed to just a third of the equipment.

Constant Voltage Transformers (CVT) also known as ferroresonant transformers can provide an economical solution for small loads which are fairly constant.

All solid state controls and instrumentation equipment such as embedded controllers within a equipment package should be fed from the UPS if the equipment is critical to production.

5.4. Specific Recommendations for Limited Station Equipment

Test and verify alarms from Coal system weigh feeders
This testing should incorporate the validity of an alarm, for example, a Weigh Feeder flow alarm should incorporate or prove both, conveyor movement and load. Models that have a paddle switch activation only, may not provide an alarm if the belt just stops with coal on it.

If the Weigh Feeder Controller is not fed from UPS, a Vital Bus Circuit should be supplied to it.

Consider changing out the existing DC adjustable speed drive with 1980 vintage rectification equipment, with an AC Variable Frequency Drive with much better ride-through capability.

Survey equipment and bus operating voltages at various station and system loading conditions in order to determine that transformers so equipped, are set at taps conducive to providing better voltage during Voltage Sags.

Consider implementing a testing program that incorporates the use of a Voltage Sag Generator to identify equipment that may be susceptible to Voltage Sags.

5.5. Future Considerations

The most economical solutions are almost always associated with the individual components that make up a system. System alternatives provide less economical solutions.

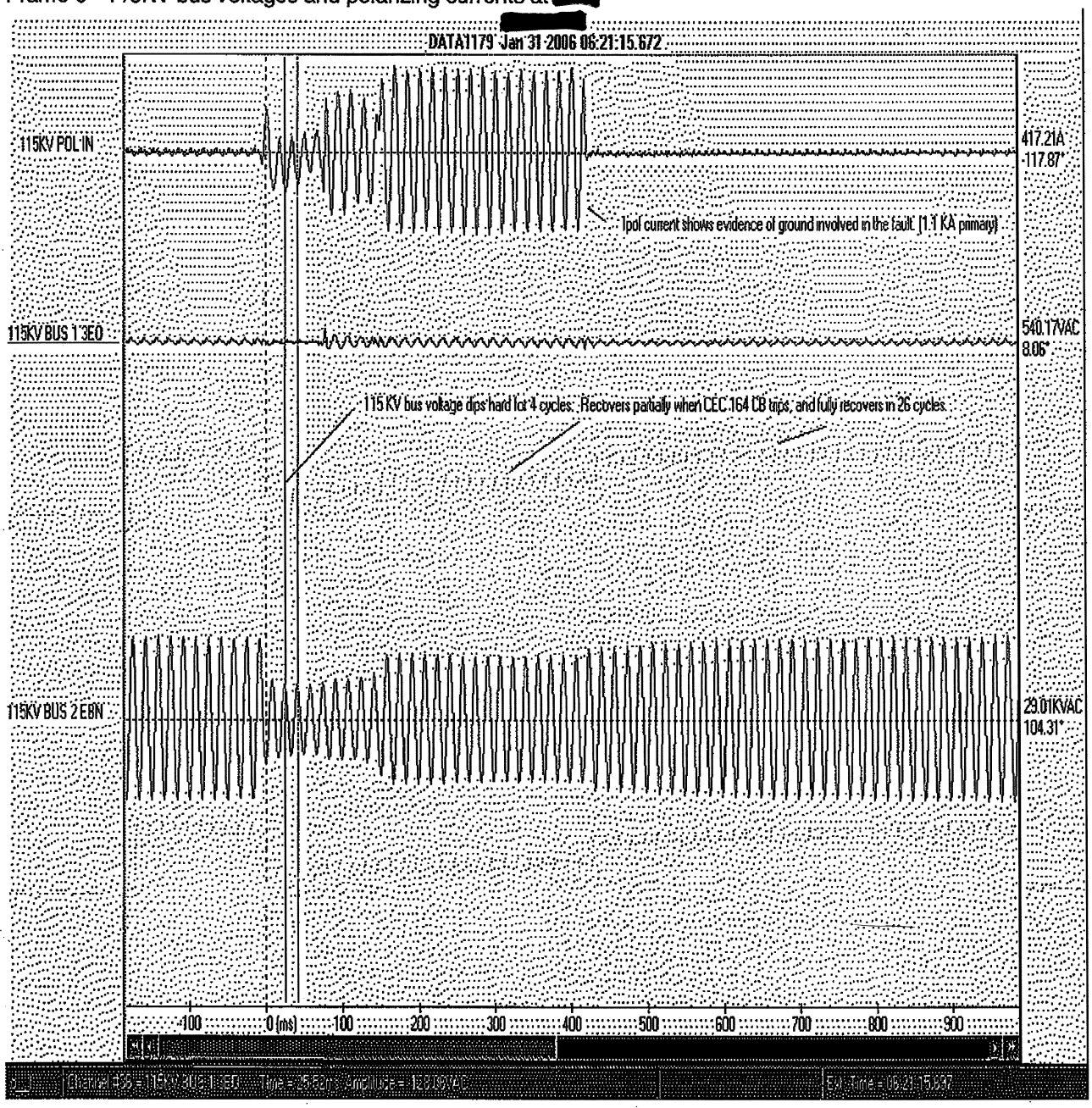
Identifying the weakest link in various critical systems will provide the most economical results.

System studies for obtaining the most beneficial Voltage profiles for the operating systems should be considered, and may not be cost prohibitive after the current efforts to construct accurate models of all of the stations is complete.

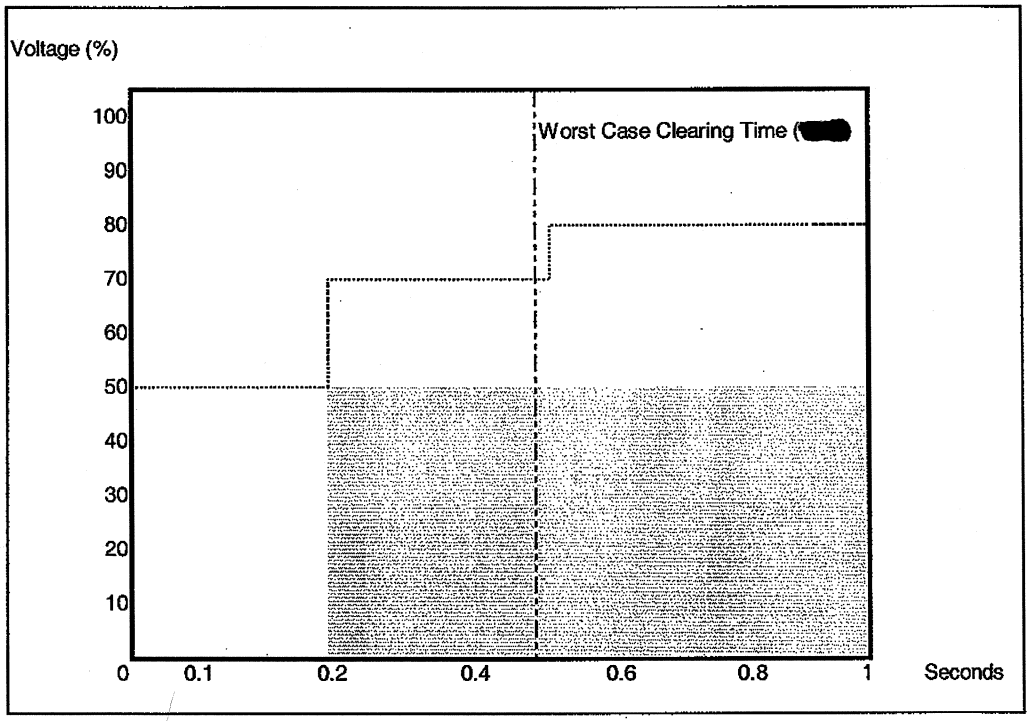
Future transmission considerations should include replacing old equipment if the age is associated with failures, particularly at the [redacted] Switchyard. These replacements could provide opportunities to further sectionalize the bus to provide better reliability if economically justifiable.

6. EXHIBIT 1 - FAULT RECORDER DATA FROM JANUARY 2006

Frame 9 - 115KV bus voltages and polarizing currents at [redacted]



11. EXHIBIT 6 – VOLTAGE SAG TOLERANCE CURVE FOR SEMICONDUCTOR INDUSTRY


Voltage (%)
100
90
80
70
60
50
40
30
20
10
0
0.1
0.2
0.4
0.6
0.8
1
Seconds
Worst Case Clearing Time ([redacted]

Generator Owner PRC-024 SERC Field Test Reporting Form

SC Generation and Transmission Submittal Date: 6-07-2007

The purpose of this form is to provide a consistent report format for field testing results after using the SERC Field Test Guideline "Generator Performance During Frequency and Voltage Excursions". Documentation of the test results will provide feedback showing that the field test was successful and/or will help to enhance the test guideline.

Use the attached SERC Field Test Guideline "Generator Performance During Frequency and Voltage Excursions" to perform the applicable engineering studies. Complete one (1) report form for each unit tested.

Provide the following information:

1. How long did it take to assemble (bring together) the technical data needed to plot the expected unit frequency withstand capability? **2 Hours**
2. If frequency excursion plots were created, what methodology / tools were used to construct the frequency excursion coordination plots?

   ☐ Computerized coordination curves

   ☒ Manual coordination curves

   ☐ Combination (computerized / manual)
3. If frequency excursion plots were not created, please explain the methodology used to demonstrate coordination with the draft SERC frequency excursion characteristic. **See Curve #2 of the first attachment.**
4. How many man-hours did it take to develop the methodology / tools? **2 Hours**
5. Did the results indicate that the generator would be expected to remain on line for the draft SERC frequency Characteristic? **X** Yes No

   If no please attach additional information as appropriate.
6. How long did it take to analyze the technical information and draw the frequency curves (plots)? **2 Hours**
7. List any material costs associated with the generator frequency withstand capability portion of this field test. **Minimal**
8. How long did it take to assemble (bring together) the technical data needed to plot the expected Low Voltage Ride Through (LVRT) capability? **2 Hours**
9. If LVRT plots were created, what methodology / tools were used to construct the frequency excursion coordination plots?

   Computerized coordination curves

   ☐ Manual coordination curves

   ☒ Combination (computerized / manual)
10. If LVRT plots were not created, please explain the methodology used to demonstrate coordination with the draft SERC LVRT characteristic. **For the first attempt, calculated the high side voltage required for the unit to absorb**

DRAFT

enough Mvars to operate the Back-up Over Current Relay (BUOC) via steady state evaluation with steady state Mvar limits relaxed. A small bus loadflow was created for dynamic simulations – with the test machine and a large dominant "Eastern Interconnection" machine with high inertia and constant excitation. Fault impedances were varied to approximate the LVRT characteristic in the Field Test guidelines at the highside of the GSU for the test machine. MVA was plotted from the test machine to see if the BUOC relay, set at 1.3 times unit MVA with a 70 cycle time delay, would pick up and time out. Other less severe faults within the LVRT characteristic were also assessed to ensure exciter dynamics, when presented with higher voltages at the exciter PPTs, would not result in operation of the aforementioned BUOC relay.

11. How many man-hours did it take to develop the methodology / tools? **N/A**
12. Did the results indicate that the generator would be expected to remain on line for the draft LVRT characteristic? ☐Yes ☒ No **(No, per steady state simulations)**

    ☒ Yes No **(Yes, per dynamic simulations- see second attachment)**

    If no please attach additional information as appropriate. **See Curve #1 of first attachment.**
13. How long did it take to analyze the technical information and draw the LVRT curves (plots)? **4.5 Hours (steady state) + 8.0 Hours (dynamics)**
14. List any material costs associated with the generator LVRT capability portion of this field test. **Minimal**
15. Please list any suggested changes to the guideline or the draft NERC Reliability Standard. **Back-up Over Current setting can not be relaxed without compromising the generator protection. If units are identified where the BUOC is limiting, application of a very inverse time over-current relay and an impedance relay could <u>possibly</u> be set to provide adequate generation protection.**
16. Provide the completed curves (plots) and other applicable documentation. Remove all references that would identify the unit (company, station, and unit names, etc)

    See attached Curve #1 (Voltage) and Curve #2 (Frequency) of first attachment.
17. Name of the person completing the form:

    R.T. Wingard and Lee Taylor

    Phone Number **205-992-7167 and 205-257-7467**

    Company Name **Southern Company Services**

Send the completed report form, plots, models and documentation to **phuntley@serc1.org**

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Generator Owner PRC-024 SERC Field Test Reporting Form

Scan001.PDF

Steady State Voltage and Frequency Coordination Curves- **first attachment.**

SouthernCoalUnit5_LVRT.pdf

Dynamic Simulation Plots- **second attachment.**

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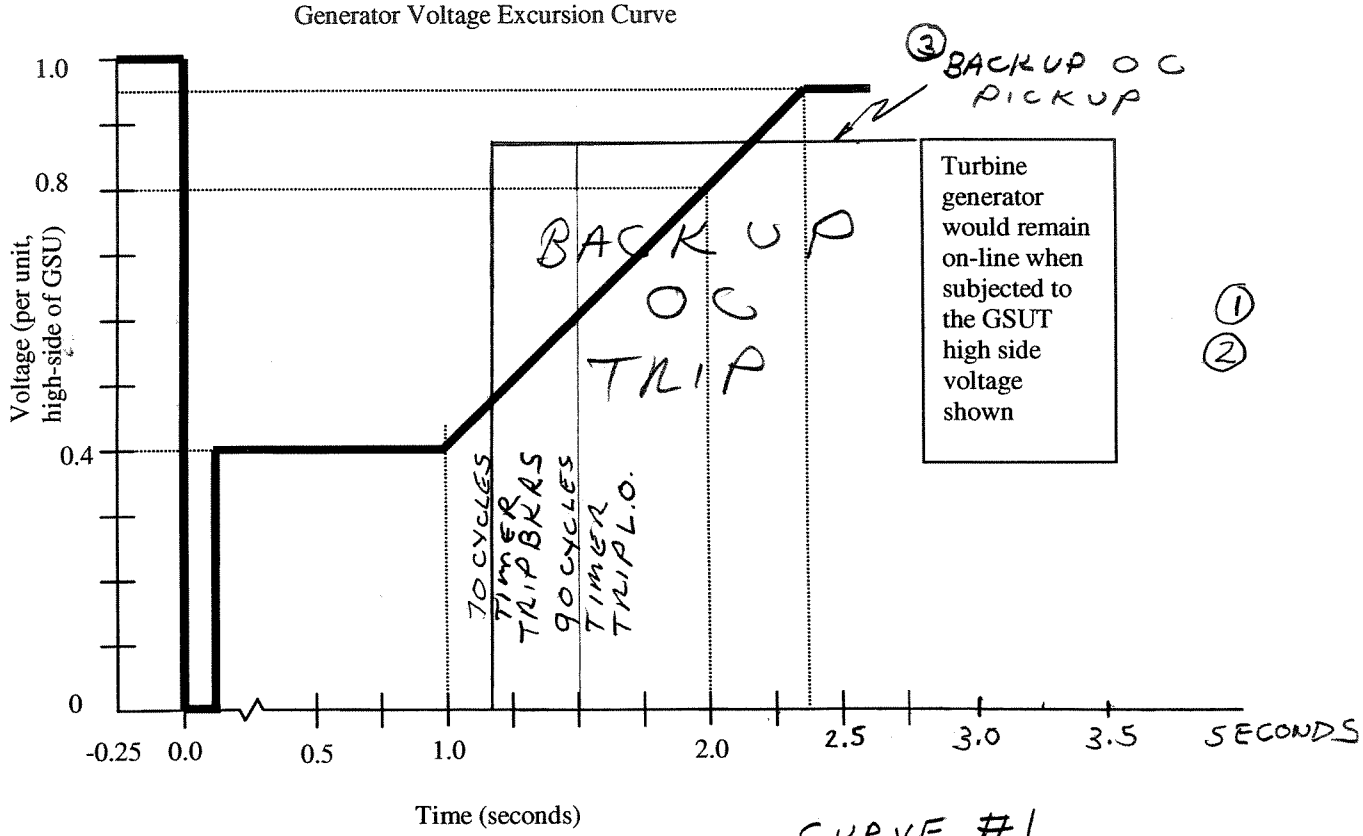
Proposed SERC
Generator Voltage Excursion Curve



CURVE #1

Figure 4

① BUS UV RELAYS ARE SET FROM 45 TO 60% WITH TIME DELAYS OVER 9 SECONDS.

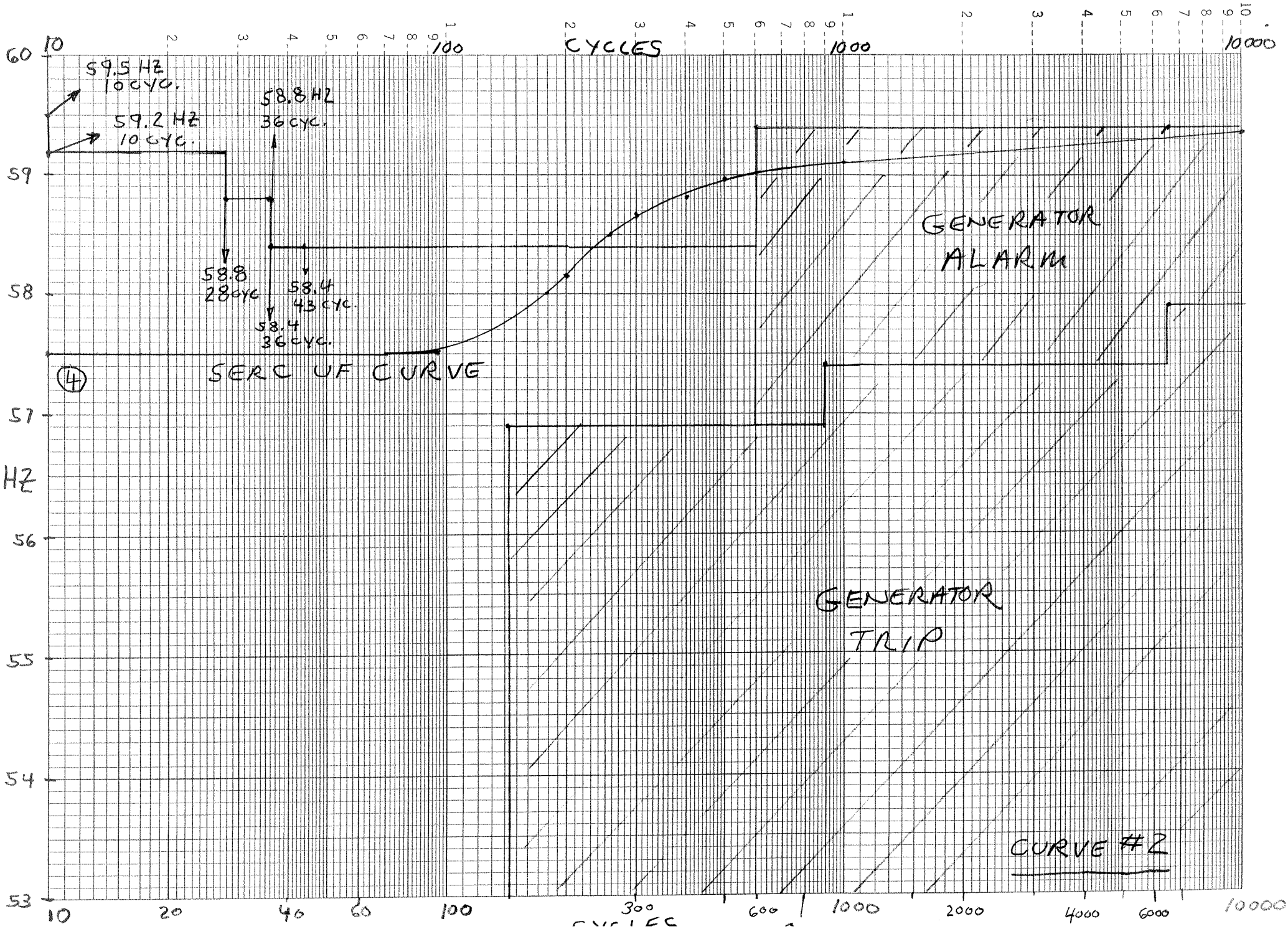
② LOSS OF EXCITATION RELAY WILL NOT OPERATE FOR MVARS OUT WHICH IS WHAT WOULD OCCUR WITH A LOW 230KV BUS VOLTAGE.

③ BACKUP O.C. WILL TRIP FOR THIS U.V. CURVE.

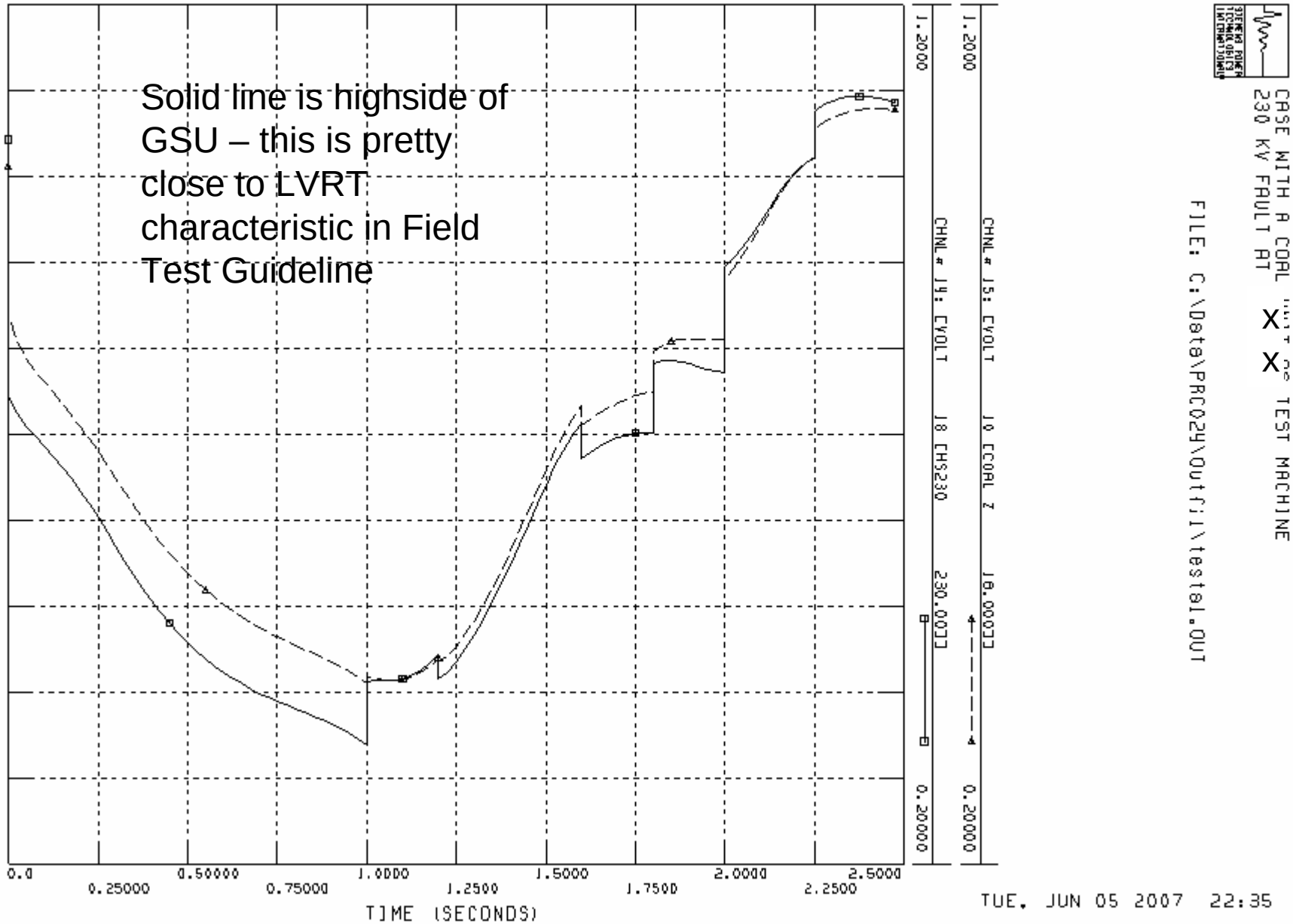
④ GENERATOR UF RELAYS COORDINATE WITH CURVE.

K+E SEMI-LOGARITHMIC • 3 CYCLES X 70 DIVISIONS
KEUFFEL & ESSER CO. MADE IN U.S.A.

46 5490

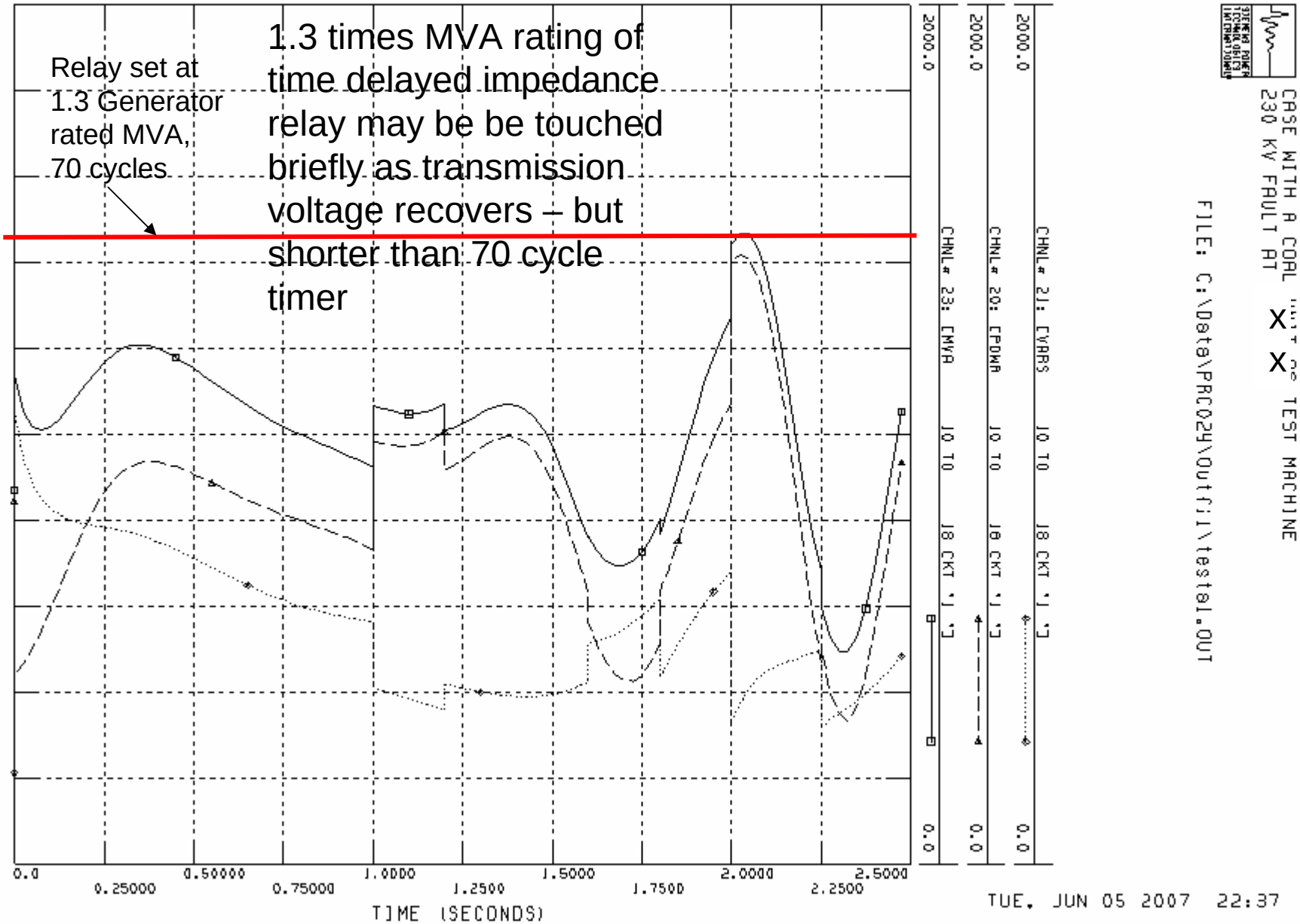


Siemens Power Technologies Internationa



Solid line is highside of GSU – this is pretty close to LVRT characteristic in Field Test Guideline

Siemens Power Technologies Internationa

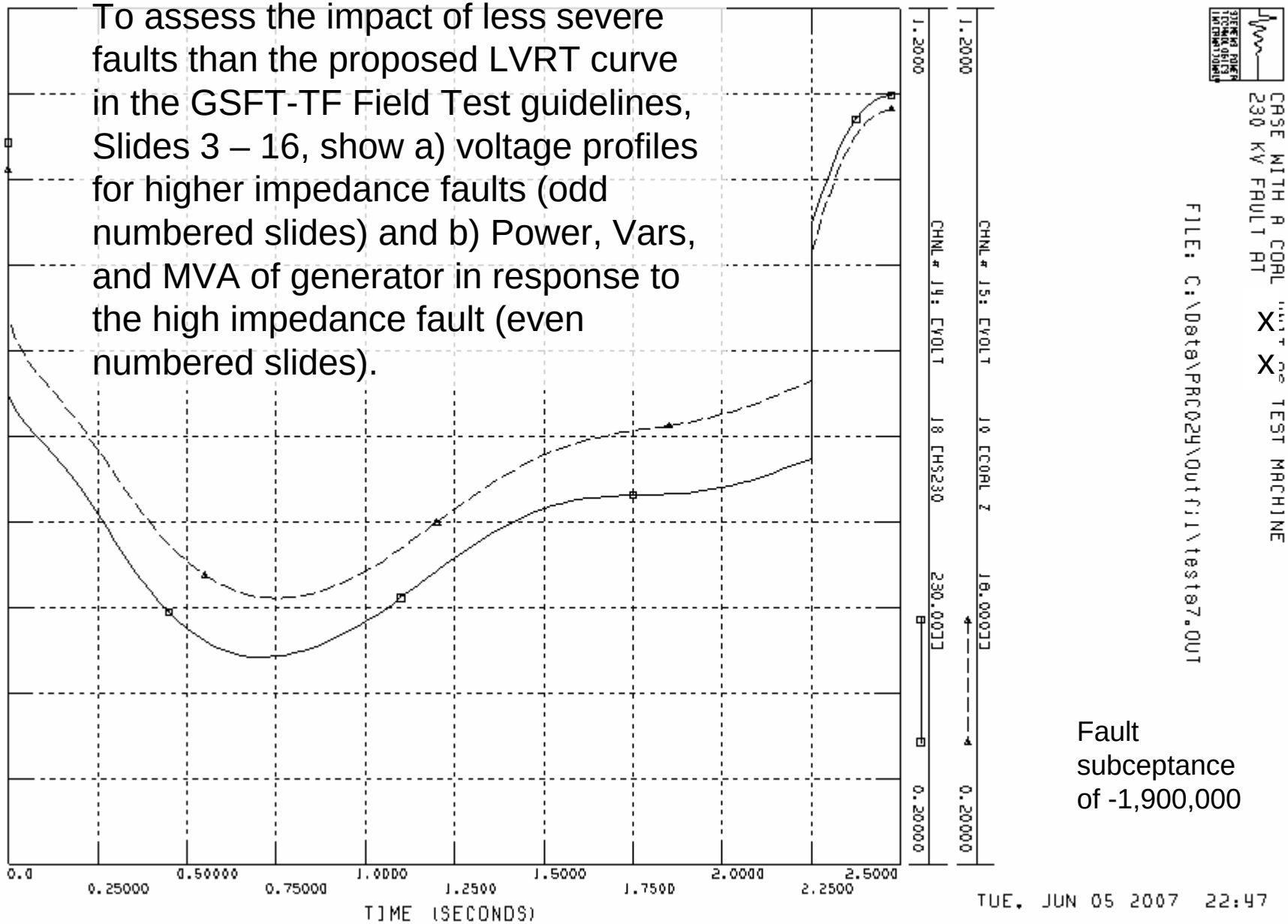


Relay set at 1.3 Generator rated MVA, 70 cycles

1.3 times MVA rating of time delayed impedance relay may be be touched briefly as transmission voltage recovers – but shorter than 70 cycle timer

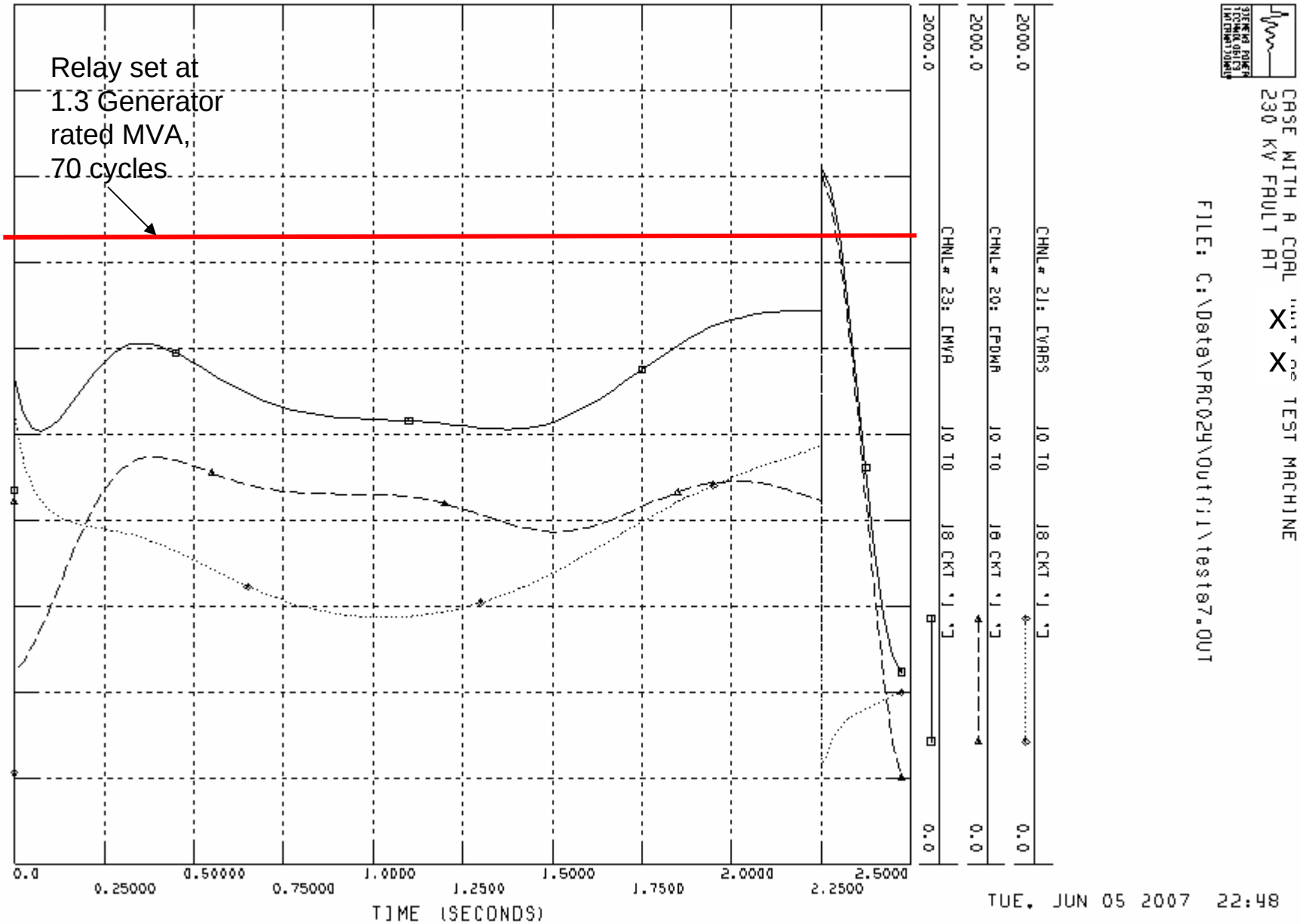
Siemens Power Technologies Internationa

To assess the impact of less severe faults than the proposed LVRT curve in the GSFT-TF Field Test guidelines, Slides 3 – 16, show a) voltage profiles for higher impedance faults (odd numbered slides) and b) Power, Vars, and MVA of generator in response to the high impedance fault (even numbered slides).



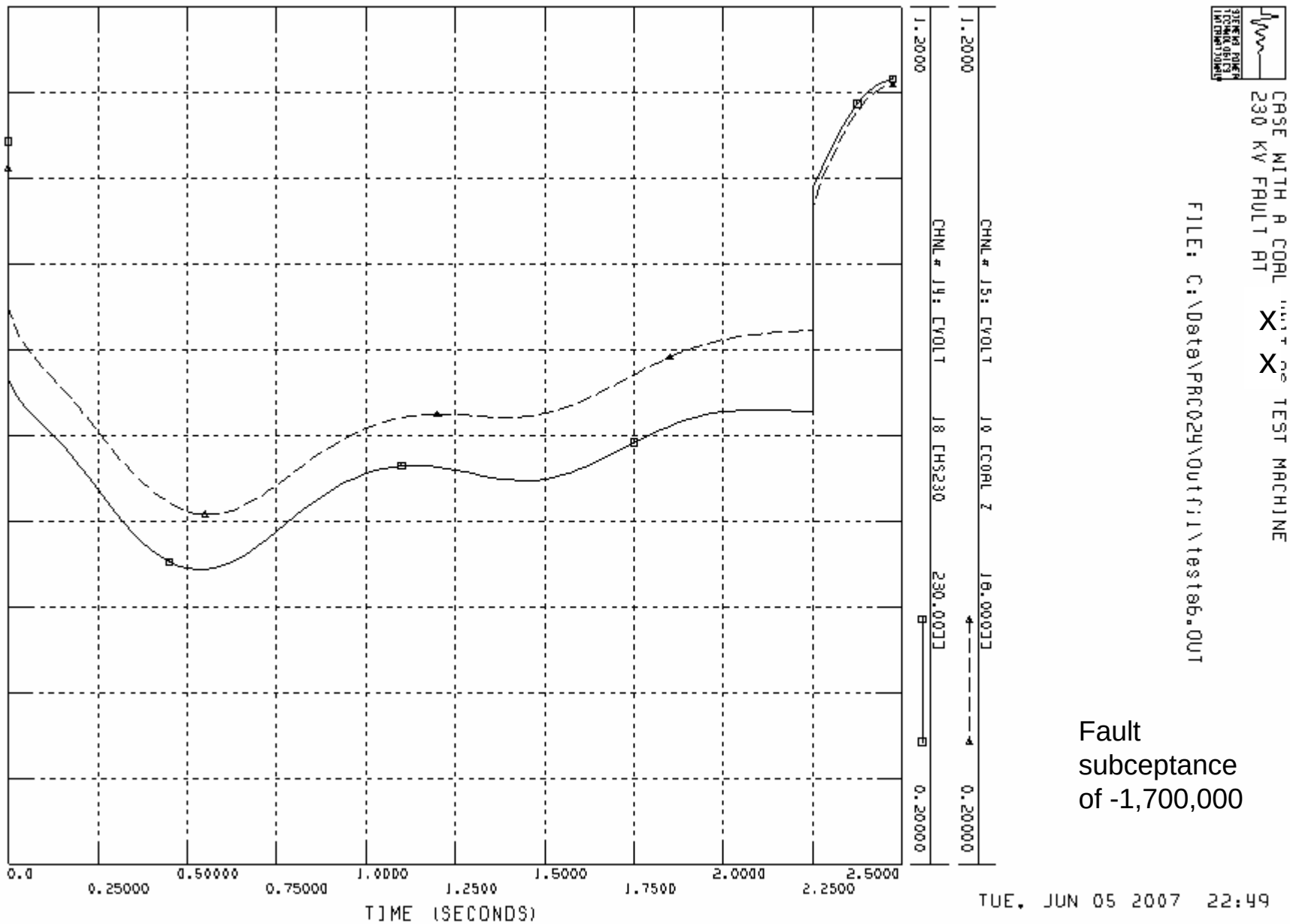
Fault subceptance of -1,900,000

Siemens Power Technologies Internationa



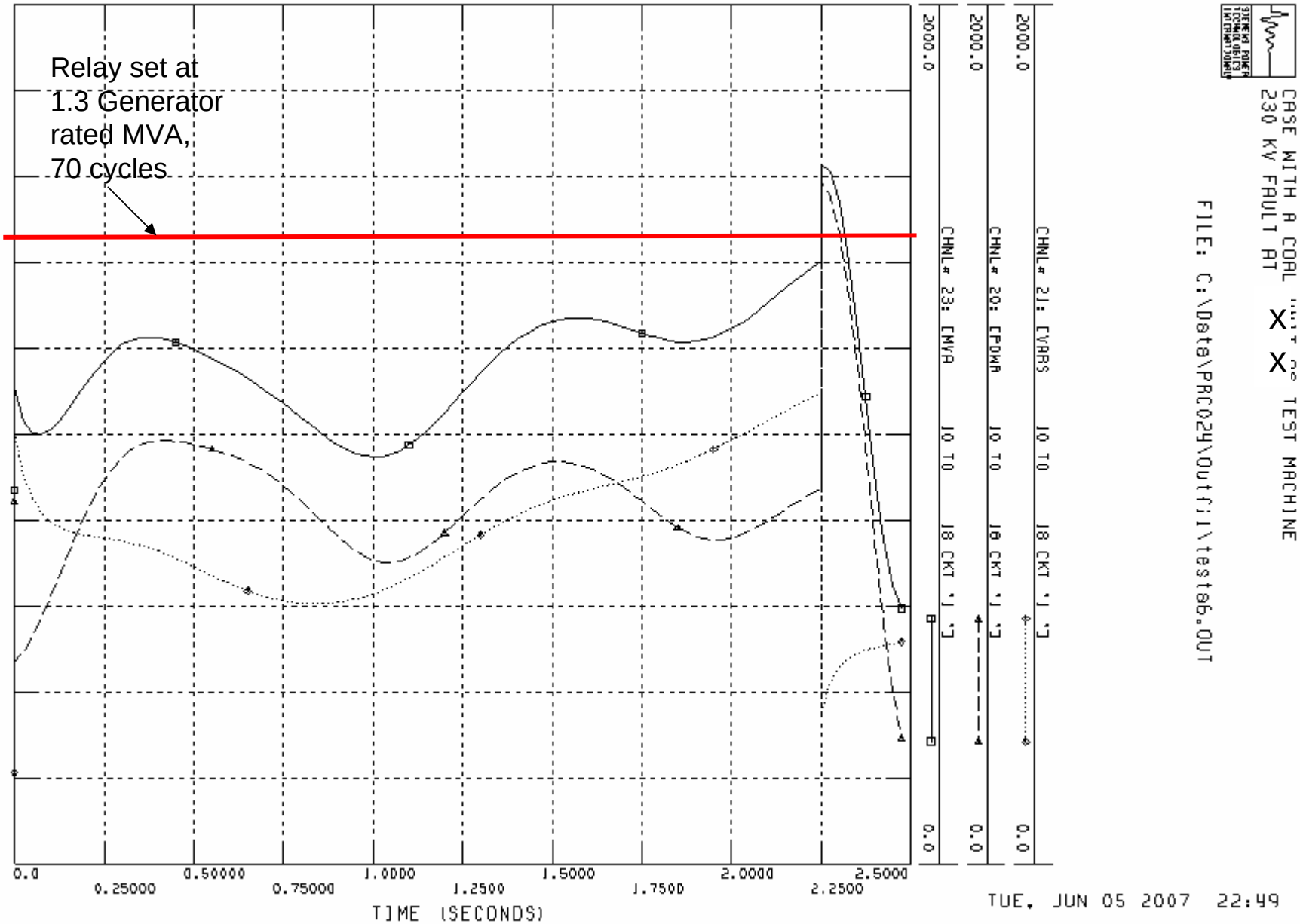
Relay set at
1.3 Generator
rated MVA,
70 cycles

Siemens Power Technologies Internationa



Fault subceptance of -1,700,000

Siemens Power Technologies Internationa



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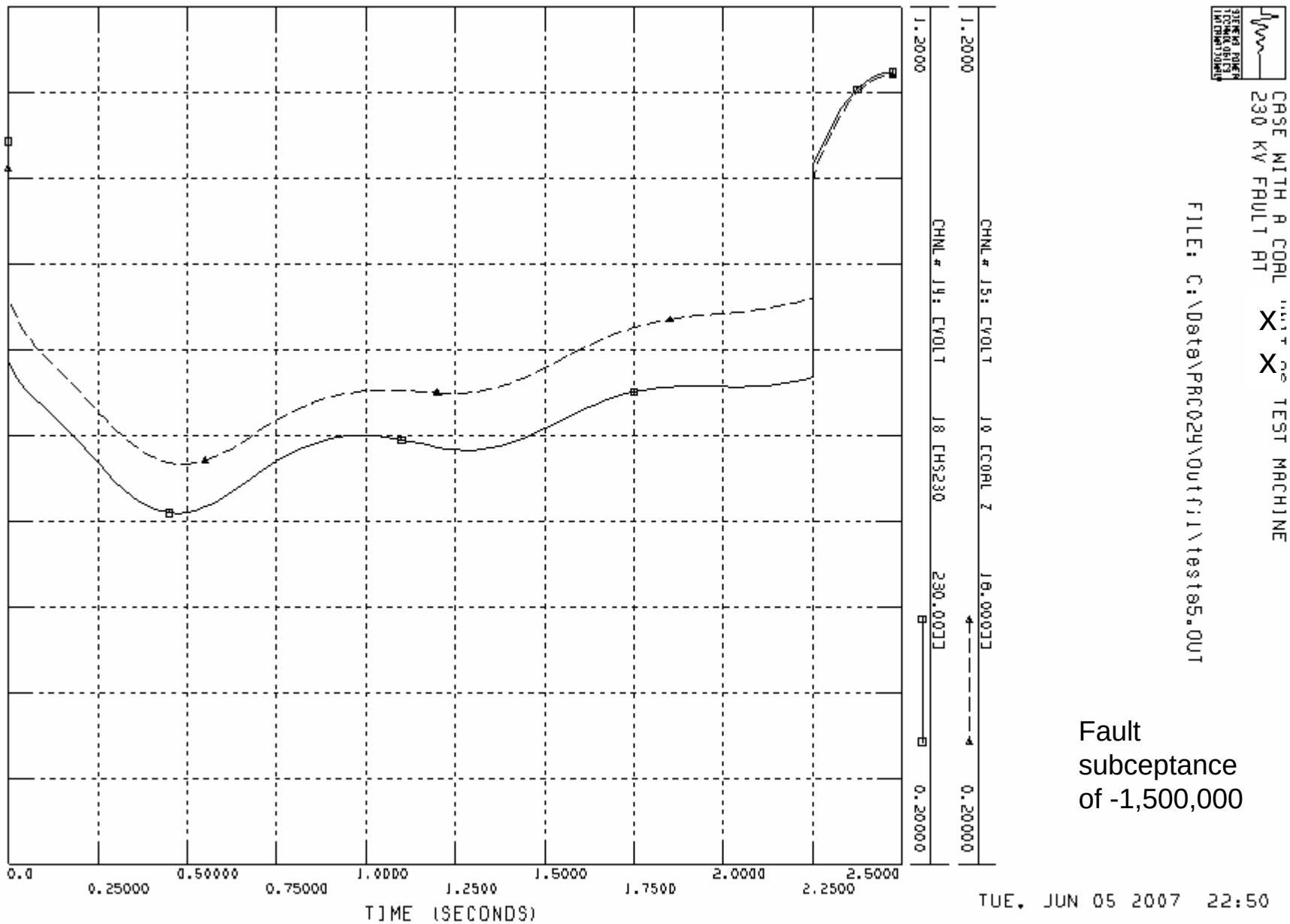
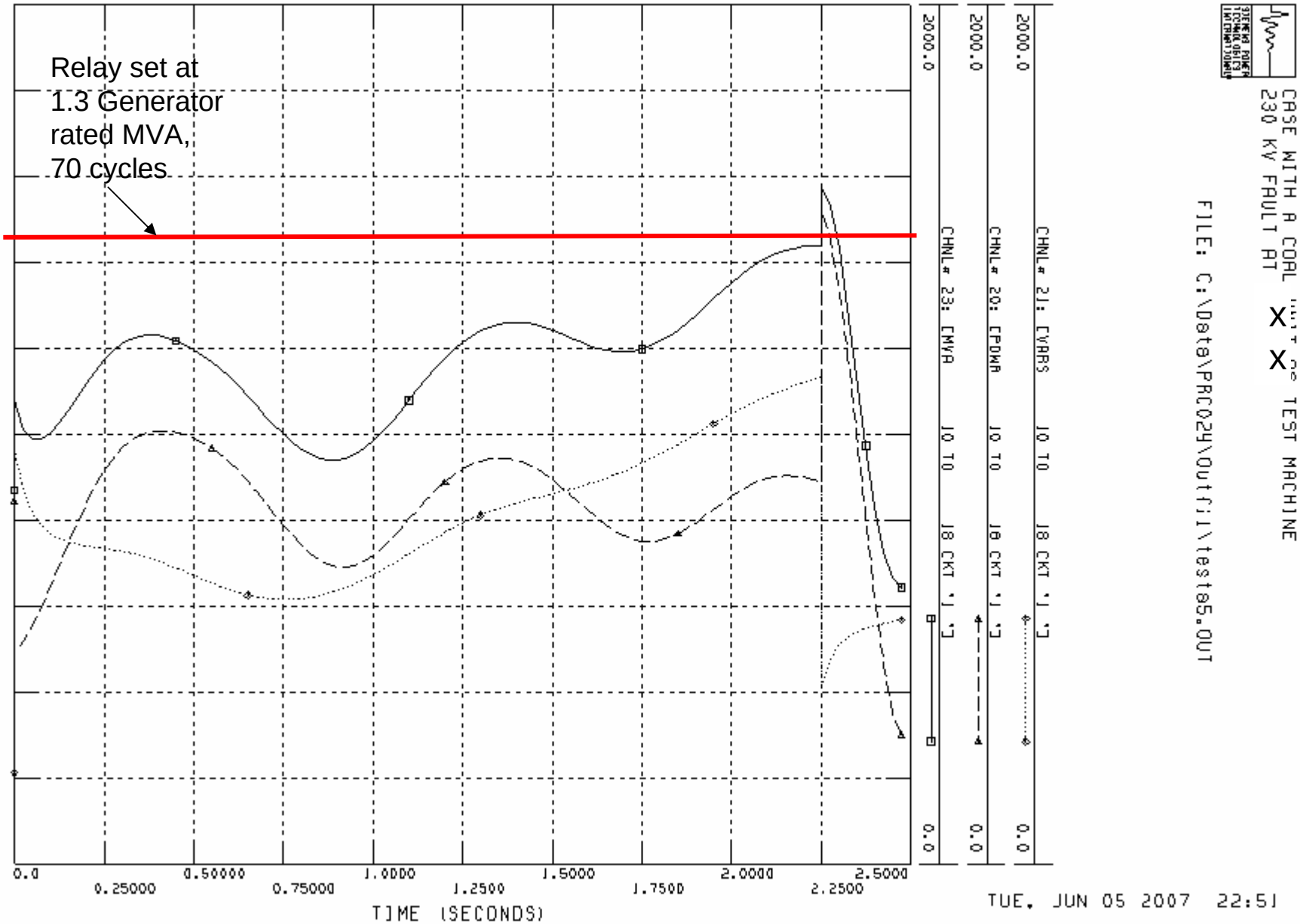


Fault subceptance of -1,500,000

Siemens Power Technologies Internationa



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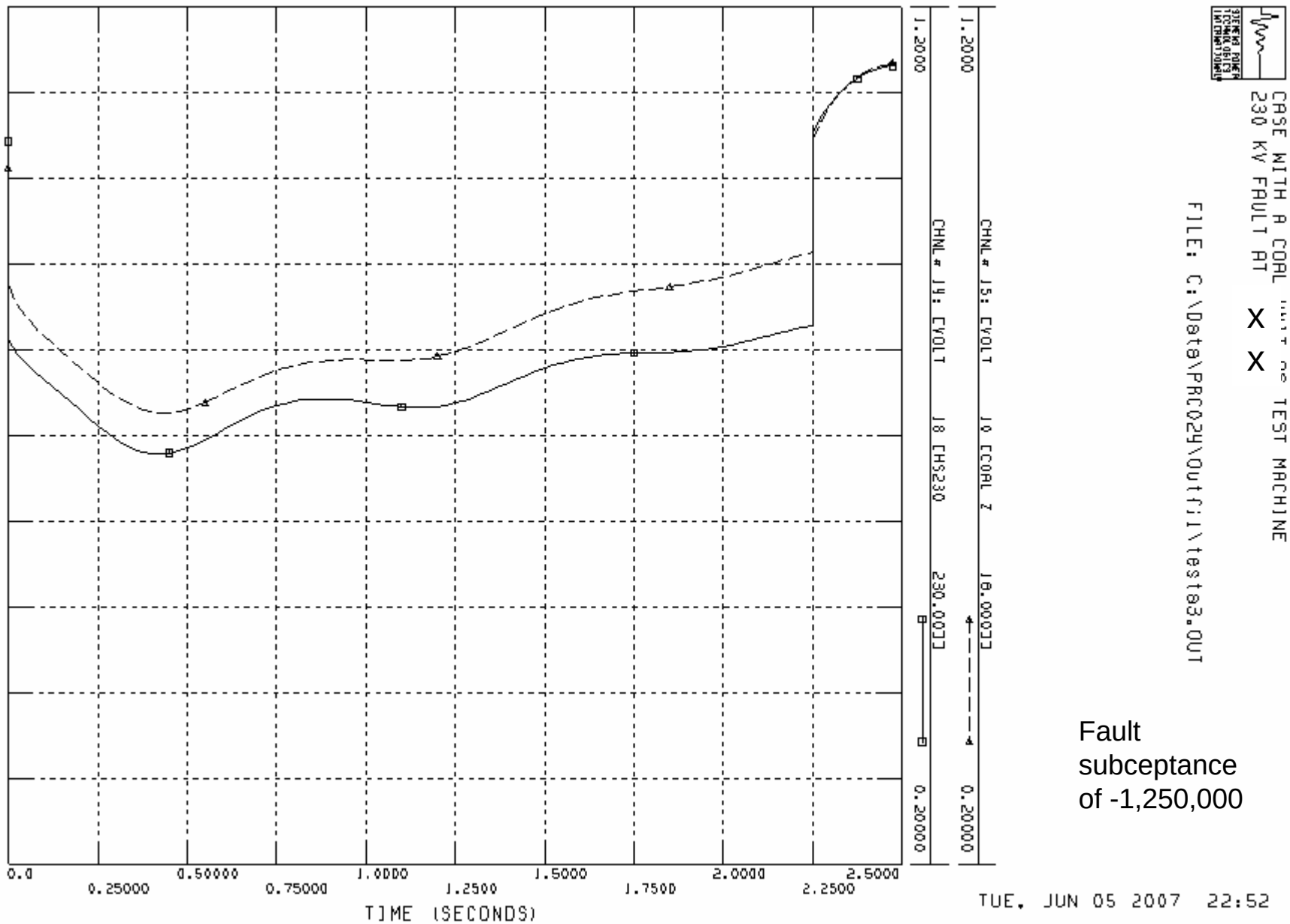
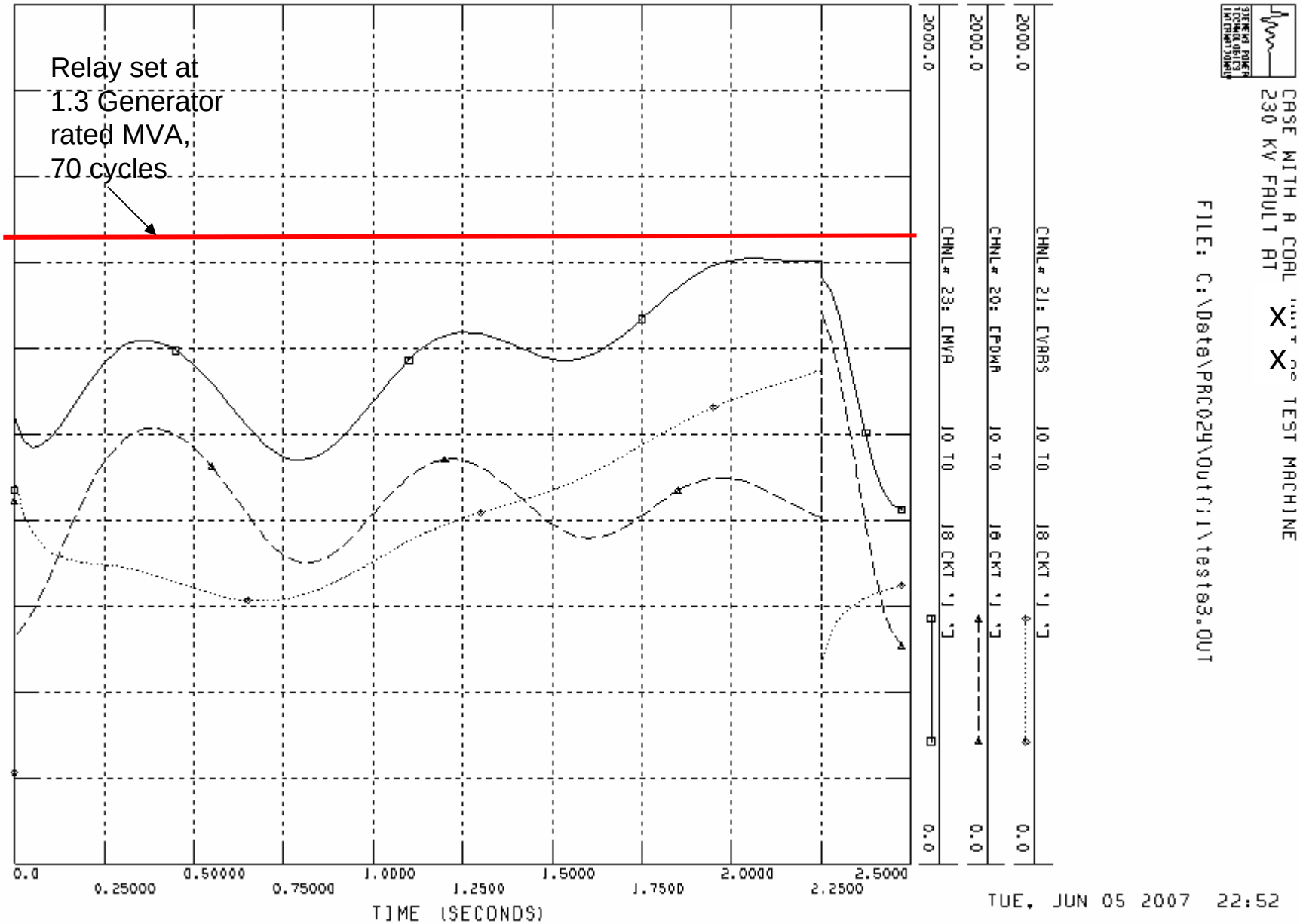


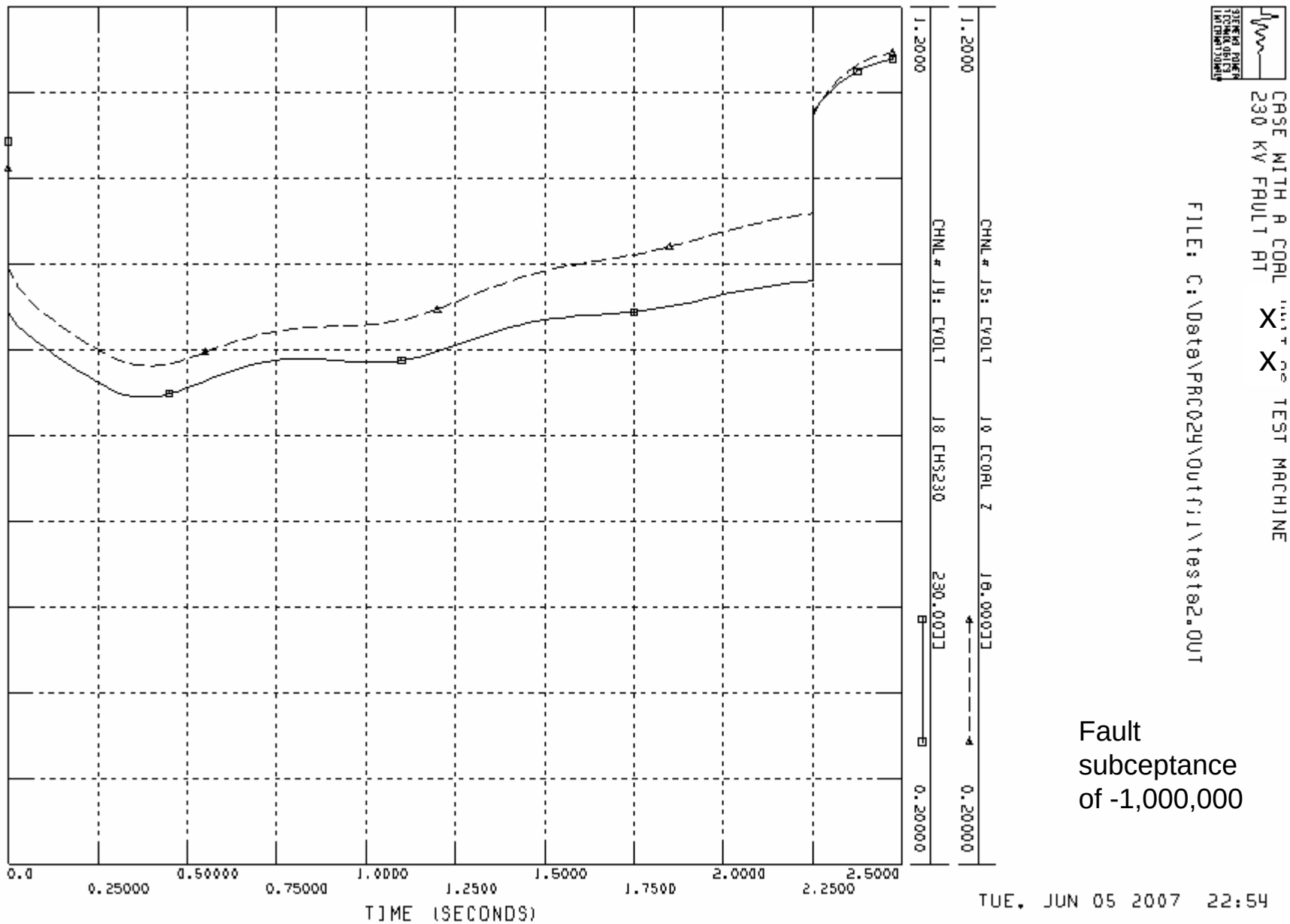
Fault subceptance of -1,250,000

Siemens Power Technologies Internationa



Relay set at
1.3 Generator
rated MVA,
70 cycles

Siemens Power Technologies Internationa



Fault subceptance of -1,000,000

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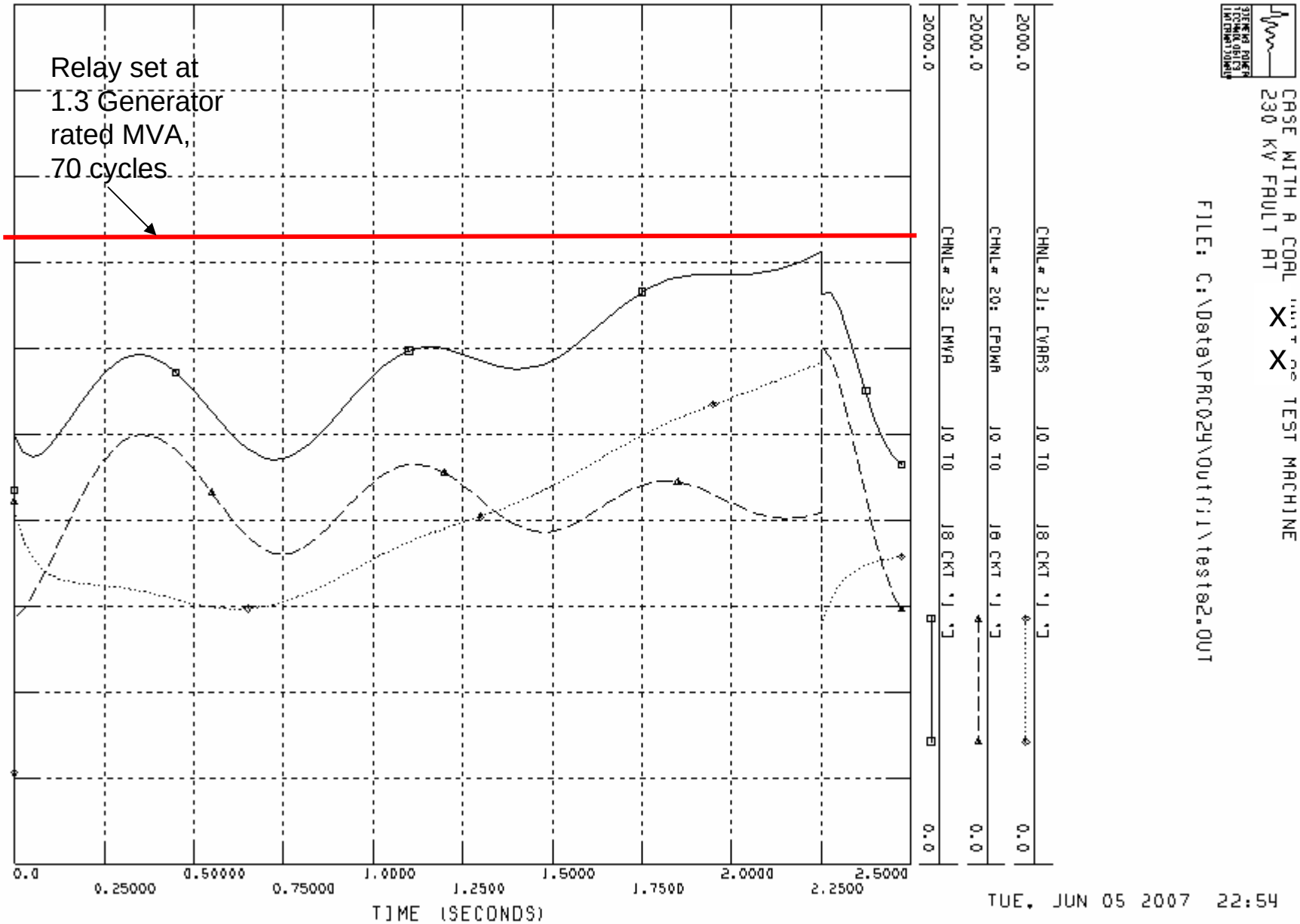

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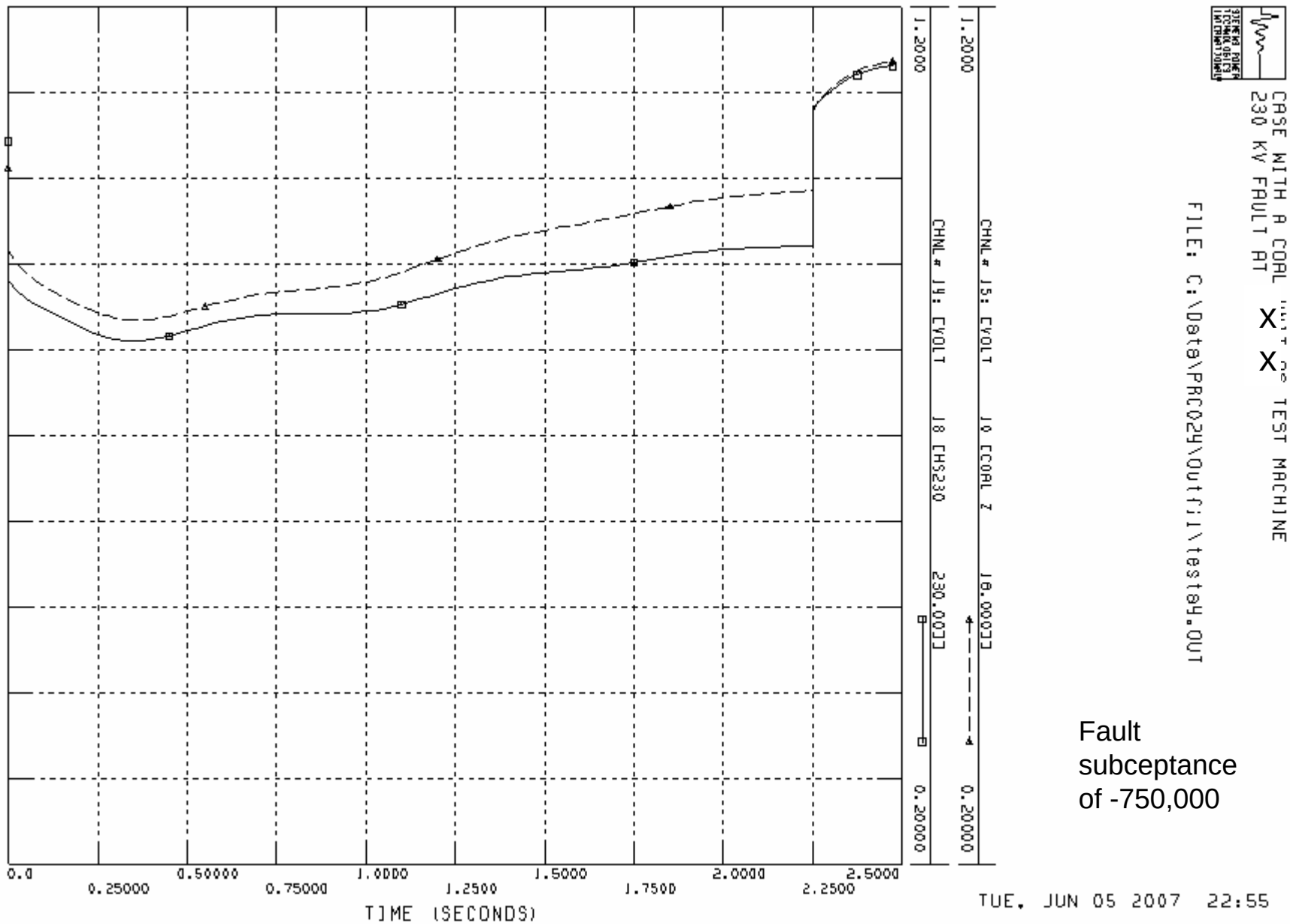
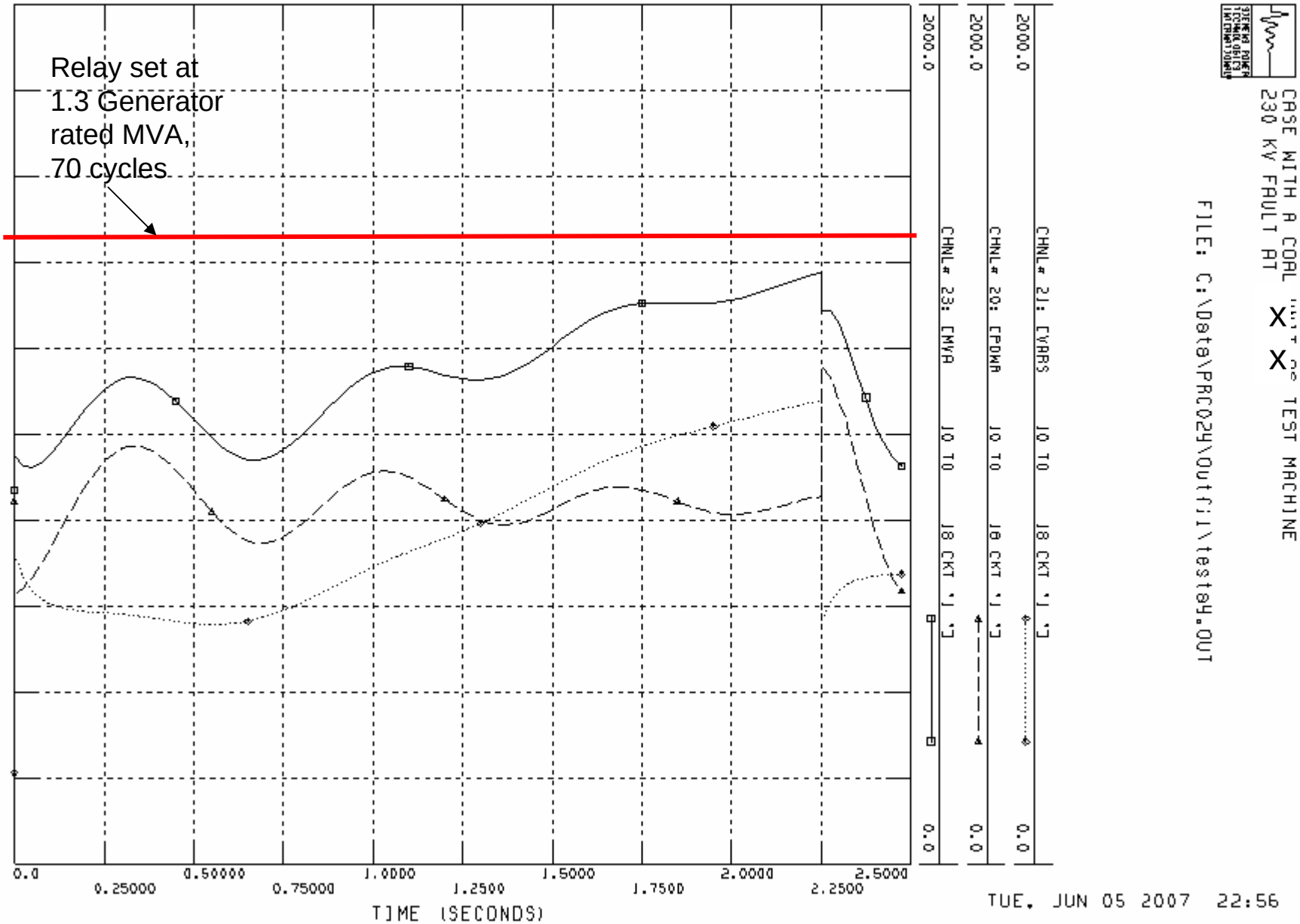


Fault subceptance of -750,000

Siemens Power Technologies Internationa



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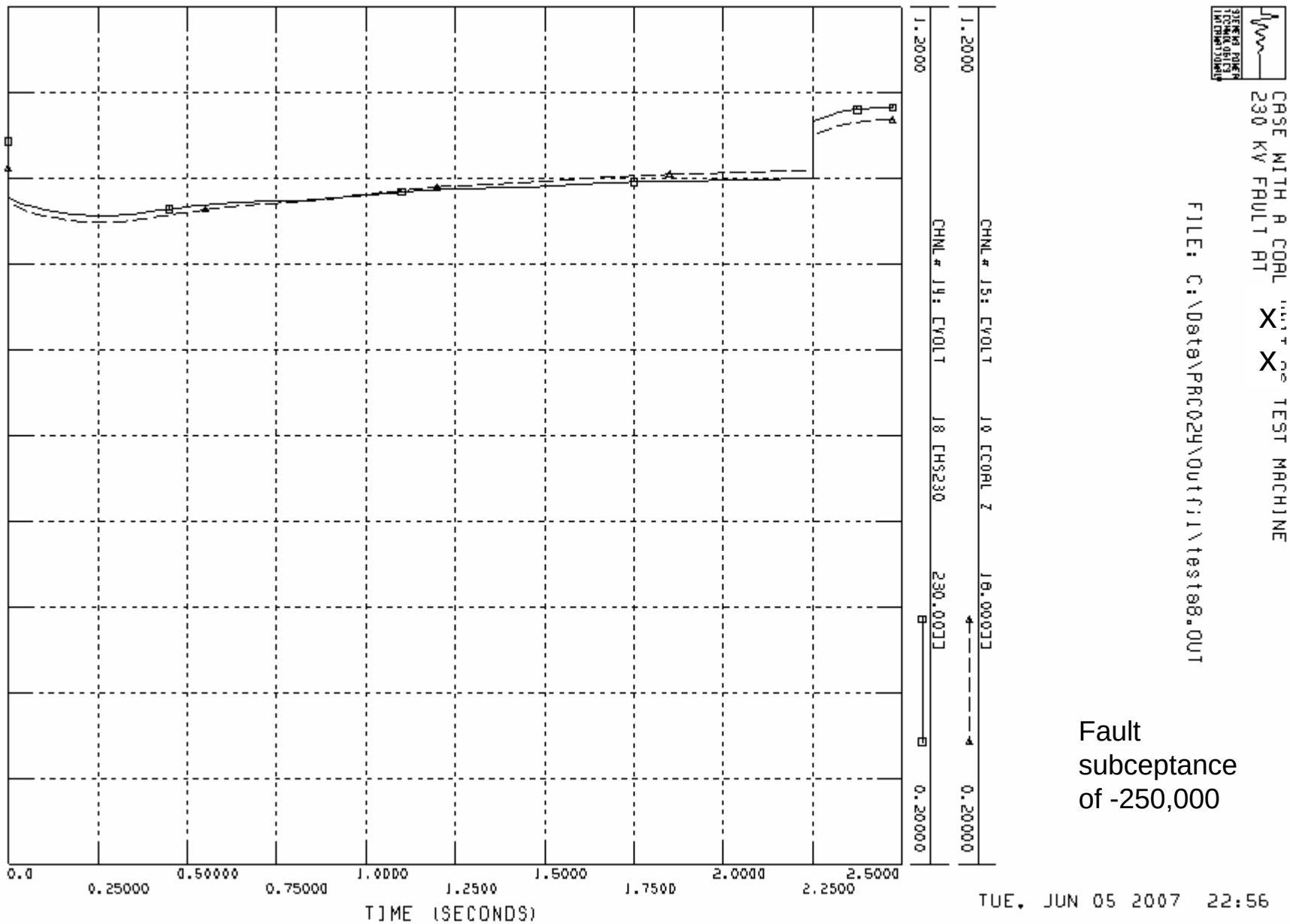

Fault subceptance of -250,000

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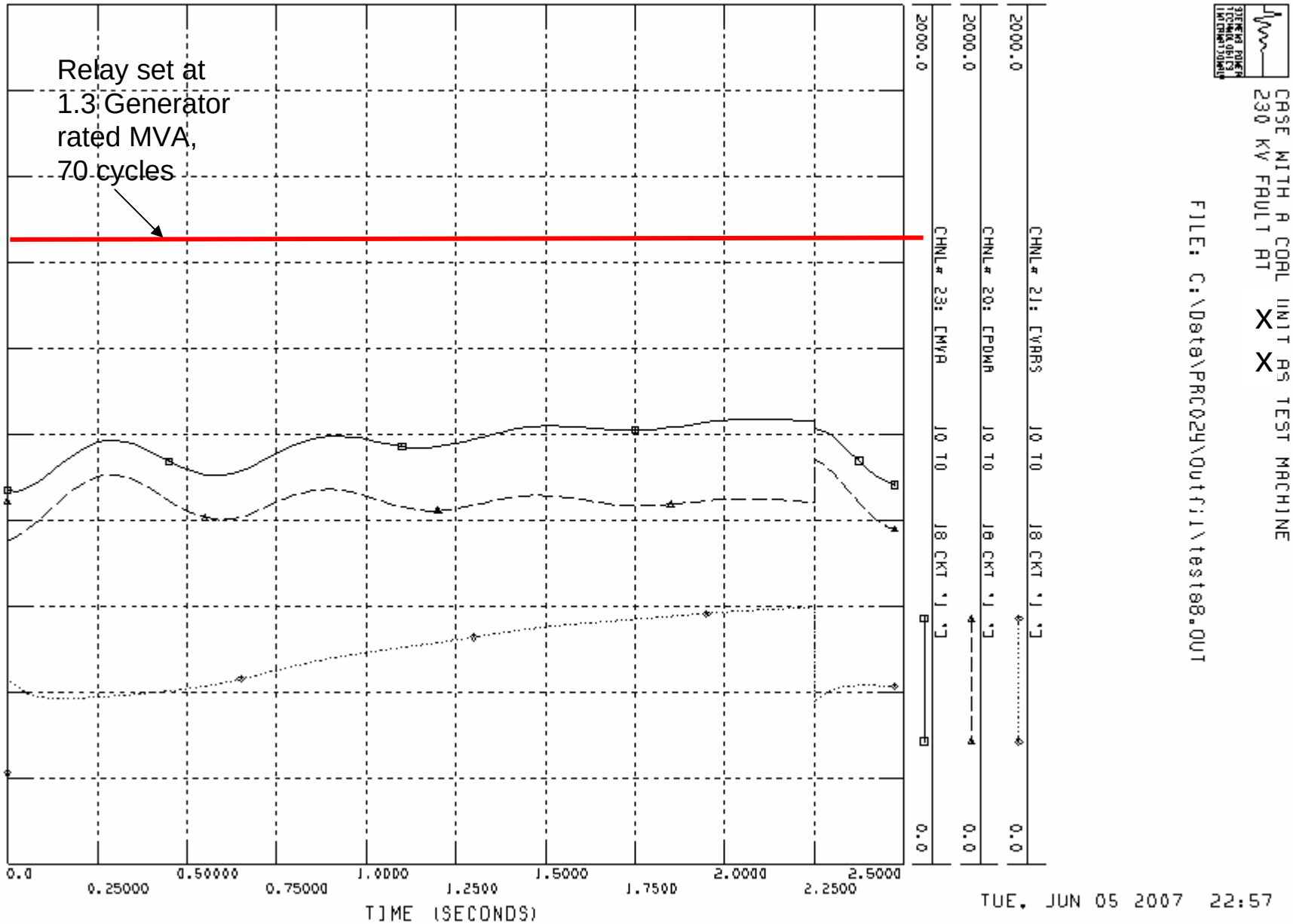


Comments Related to Balance of Plant Performance for SERC Proposed Frequency and Voltage Ride thru Curves
Rev. 0
Date: 6/11/2007

The proposed Under Frequency (UF) and Under Voltage (UV) requirements in "SERC Field Test Guidelines- Generator Performance during Frequency and Voltage Excursions" developed from the draft version of NERC Standard PRC-024 have been under review by power plant design engineers to access the impact on plant continuous performance. Due to the complexity of todays power generating stations this review is incomplete. However, the following does address a significant portion of the components and systems that can be impacted by the proposed UF and UV ride thru curves contained in the SERC document.

A. Under Frequency Ride Through Curves (Figure 1 of SERC Field Test Guidelines):

The ability of a unit/plant to ride through the proposed Under Frequency requirements depends on the under frequency response characteristics of the following equipment, systems and protective devices.

Note, in evaluating the effects of UF we assumed that in general the voltage also decreases in a similar manner as the frequency and thus the V/Hz does not increase significantly.

1. Turbine Generators: The primary units of concern are the turbo-generators and Combustion Turbines (CTs). Turbo-generators have under frequency limits established by the manufacturers due to turbine blade vibration (resonance) limitations. For most turbo-generating units, the subject limits are fairly well defined and typically are used to establish turbine under frequency protective and Under Frequency Load Shedding (UFLS) relay set-points. Based on the technical reviews to date, turbo-generator under frequency limitations are not expected to be a problem with the proposed curve and should coordinate.

Similar data on CTs needs to be developed but no published under frequency limits have been found. Finally, conventional hydro turbine-generators don't have under frequency limitations.

2. Boiler Control Systems: The comments on Boiler Control Systems (BCS) are primarily relating to the under voltage effects, however the issues are related. Most of the newer BCS's utilize UPS's which should minimize concerns with UF events. However, without reviewing the complete system, it cannot be confirmed that the BCS remote devices (instrument sending units and actuators) are

powered from dc or UPS supplies. On older plant designs, the BCS is typically fed from redundant ac sources (non UPS). Since both sources will see the same level of UF, one cannot generalize its performance during the UF event. Thus, this will require further study.

3. Nuclear Power Plants: The following relates to Pressurized Water Reactor (PWR) designs that utilize Reactor Coolant Pumps (RCPs). A critical part of the reactor protection system is to maintain flow through the reactor and the steam generators. This is accomplished with the RCPs. This is so critical that the subject pumps are equipped with flywheels to insure they will continue to turn for a specific period of time without ac power to the motors. The subject motors have under-frequency protection that will trip the ac supply breakers to the motors if the frequency drops (low frequency results in a slow down of the motor and thus the pump) below a specified set-point. A review of at least two PWR plants shows the proposed UF limit curve coordinates with the UF ride-thru curve. It is recommended that other PWR owner/operators review these set points to insure proper coordination.

Please note that Boiling Water Reactor (BWR) plants and systems were not reviewed and it is recommended that a detailed review be performed.

Another unique sub-system employed in Nuclear Power Plants that should be reviewed is the Emergency Diesel Generator (EDG). Each EDG typically has under frequency relays that protect it if a severe UF event occurs while the EDG is paralleled with the system for testing. A review of one plant showed the EDG UF relays to be set to trip in 20 cycles at 59.5 Hz. Thus, the EDG would likely trip for a severe UF event. However, this should not cause a unit trip or have any other adverse impact to the plant and, therefore, does not represent a coordination issue with the proposed UF requirements. Other Nuclear Plant owners/operators should review the EDG systems and the associated UF set points to ensure no adverse impacts are discovered.

Finally, it is recommended that the Reactor Trip System M-G Sets for a PWR nuclear unit be evaluated to determine if they could ride through the proposed under frequency excursion curve and maintain adequate power to the nuclear reactor rod controls. Time did not permit this review to be complete but if they are unable to ride thru, a reactor trip and, hence, unit trip will occur.

4. Generating Plant Protection Systems: A review of the protective relaying schemes applied at several generating stations was performed for the proposed UF curve. Of the units reviewed only one UF protection coordination problem was discovered. The subject coordination problem could be corrected to resolve the mis-coordination. Thus, the initial assessment is that the proposed UF requirements can be coordinated with plant protection.

Note: The above assumes the plant/system voltage will also decrease in a similar manner to the frequency. Otherwise, Volts per Hertz protection will need to be considered.

5. Station Service Loads: For station service loads, only induction motors and Adjustable Speed Drives (ASDs) were considered. In the case of an induction motor, the industry standards permit deviations of +/- 5% frequency deviation provided the voltage remains at rated. This operating limit is generally a continuous capability and would not apply for the short time period under consideration. If the frequency drops, the motor speed would be expected to drop in proportion to the frequency drop. Since the frequency drop is less than 5% motor loads are not expected to exhibit any significant short time performance problems.

For ASDs, more research is needed but, it is believed that they are also required to meet the +/- 5% deviation in rated frequency.

B. Under Voltage Ride Through (Figure 4 of SERC Field Test Guidelines):

1. Turbine-Generators: No specific short-time under voltage limits have been identified for turbine generators. On newer units or retrofit application that utilized static excitation systems powered from the generator or plant bus voltage, the proposed voltage transient would result in a reduction in excitation during the fault and voltage recovery period. Typically static systems are purchased with a minimum of 1.5 per unit ceiling voltage which means these systems would provide full excitation for generator bus voltages down to 75 % of rated. At voltages below this level, the excitation voltage would decrease during the fault profile given in the supplement. Calculations have been performed of expected generator and station service bus voltage for a sample plant which shows the generator bus voltage drops to approximately 30% for the switchyard fault (see Attachment A.) This would result in a maximum excitation voltage of 45% during the initial fault. Please note, even though the field voltage decreases almost instantaneously, the field current {terminal voltage producer} will take longer to decay from pre-fault levels.

Assessing the overall impact of the voltage profile further, would require dynamic studies of the unit/plant for the proposed transmission voltage profile.

2. Boiler Control Systems: The severity of the voltage transient and the resulting plant ac distribution system voltages would significantly impact the BCS even if it is powered from a UPS. The assessment to date indicates that some BCSs might require configuration changes and/or power supply changes to improve the possibility of survival of the subject event. As discussed above for UF events, each owner would need to evaluate the survivability of the BCS, actuators, transmitters, etc. for the stated voltage profile.

3. Station Service Loads: In general the station service loads are either unit connected (fed from transformers connected to the generator terminals) or fed from transformers supplied by the plant switchyard. Some plants designs have loads served from both sources (generator and switchyard) during normal operation. Examples of plants with some or all of station service loads normally supplied from the switchyard are nuclear power plants, many Combined Cycle plants, and plants with new scrubber loads.

To judge the overall impact of the proposed voltage ride through curve, two different plant distribution systems were modeled. A unit where all of the station service load is directly served from the generator was modeled first. The attachment titled "Typical Fossil Unit" (Attachment A) shows the generator bus voltage drops to approximately 30% for a high side fault. The corresponding station service bus voltages are also in the 30% range. It is judged that most of the station service load should ride thru the initial fault event of 15 cycles, but the performance and ride thru capability for the recovery phase of the proposed voltage profile curve cannot be predicted. A dynamic simulation would be required to determine if the station service loads would fully recover. This phase of the analysis was not completed.

Another issue identified for PWR Nuclear power units is the RCP under voltage protection. These under voltage relays are designed to trip the unit by tripping the rod control system in the event of a loss of voltage to the RCPs. A typical trip setting for these relays is less than 67% of the rated bus voltage (4160V) for 0.5 seconds. These relays would likely trip for the proposed voltage excursion curve, thus tripping these unit(s).

The second distribution system modeled is for a typical CC plant where all or a portion of the station service load is supplied from the switchyard. This arrangement also applies to the emergency buses for most Nuclear Power Plants. The results of this analysis are provided in Attachment B. For a high side fault the station service bus voltage drops to zero as one would expect. Again, it is expected that most of the loads would remain connected to the supply buses during the initial fault (approximately 15 cycles), but the long term response which would occur during the voltage recovery phase can not be assessed without dynamically modeling the system.

A special case for this configuration is the emergency buses for Nuclear Power Plants. For these buses, special protective relaying schemes are employed to detect loss of off-site voltage. If these relays operate, the buses are isolated from the transmission system, the EDGs will start and safety related loads are sequenced onto the isolated sources. This action is highly undesirable but within the design basis of the plant. If this event occurred it would be very unlikely that either type of unit (Nuclear or CC unit) would remain connected to the grid. In fact, for the two nuclear plants reviewed, it was determined that the proposed voltage excursion curve would cause the loss-of-offsite-power (LOSP/LOOP)

relays to actuate and trip the unit. Due to the very short time delays employed for nuclear plant LOSP/LOOP protection, it is believe that these relays would operate for most Nuclear units for the proposed curve. However, it is recommended that each nuclear unit be evaluated to determine if the proposed voltage ride thru would actuate the LOSP/LOOP relays and automatically trip the unit.

The final configuration to consider is where new scrubber systems are being installed and the station service load for the scrubber is fed from the switchyard. This configuration is also representative of the system shown in Attachment B. The consequence of momentary loss of supply voltage and slow voltage recovery time has not been fully evaluated. However, on some designs, initial reviews indicates that these units may survive the proposed voltage transient (lose the scrubber but not the unit.)

4. Generating Plant Protection Systems: Relay engineers have done a review of typical protection schemes utilized on most generating units in regard to protection responses to the voltage profile. The following addresses typical generator and station service protection. Special protective schemes for nuclear power stations (degraded grid, LOSP, Reactor Protection Systems) are not included except as noted above. The following relays are highlighted:

a. Generator Under voltage Relays: There are some units equipped with relays which trip for under voltage on the generator bus. Assuming the generator bus voltage follows the high-side transmission voltage exactly, there are a couple of these relays that were found to be marginal. However, since the generator voltage does not drop to zero for a transmission high side fault and the regulator will be attempting to boost the generator voltage back normal, the voltage seen by the relays should be less severe than a total loss of voltage the relays probably will not operate. A detailed model of the generator and exciter/voltage regulator would be required to determine the exact response of the relays to give a more definitive answer.

b. Power Potential Source Exciter PPT Secondary Relaying: Several units reviewed have under voltage relays connected on the low side of the exciter Power Potential Transformer (PPT) secondary which are intended to operate for close in faults if the excitation should collapse. The intended setting for these relays is 2 seconds at zero volts. Dynamic simulations show that the exciter would be expected to sustain itself for a fault on the transmission system since its voltage will not drop to zero.

c. Station Service Bus Under Voltage Relays: Some units have bus under voltage relays that trip motor loads for cases of extended under voltage. For the cases reviewed the time delay was found to be much longer than the UV excursion lasted.

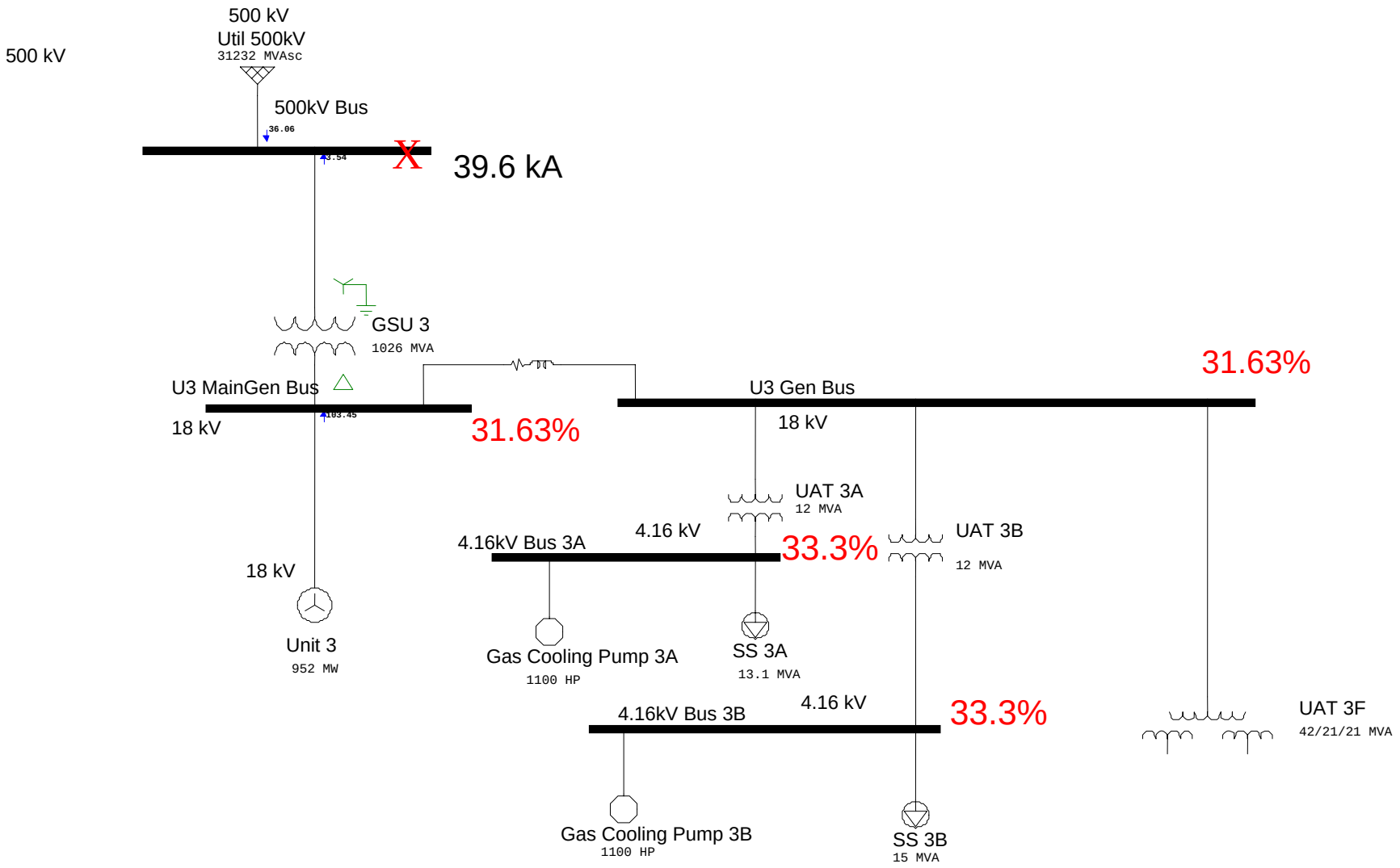
d. Backup Overcurrent Relays: Initially it was thought that these relays pose a potential problem. For the distance relay types, the trip setting is typically 75-120 cycles. Utilizing steady state solution techniques and the transmission voltages as shown on the LVRT curve, the generators would be supplying significant reactive current into the system for at least 90 cycles, which would cause the distance relays to trip. However, dynamic analysis has shown that the expected excitation system dynamics results in an expectation that these relays would not trip for the voltage excursion. The response of the voltage-restrained overcurrent type applied to some units would be even more difficult to obtain but could also be an issue.

C. Conclusion:

Overall, our review indicates more significant concerns with a unit/plant being able to remain on line during the UV event than the UF event. The overall opinion is for the proposed voltage profile that many generating units may potentially trip. However, a unit by unit study would be required to evaluate the probability.

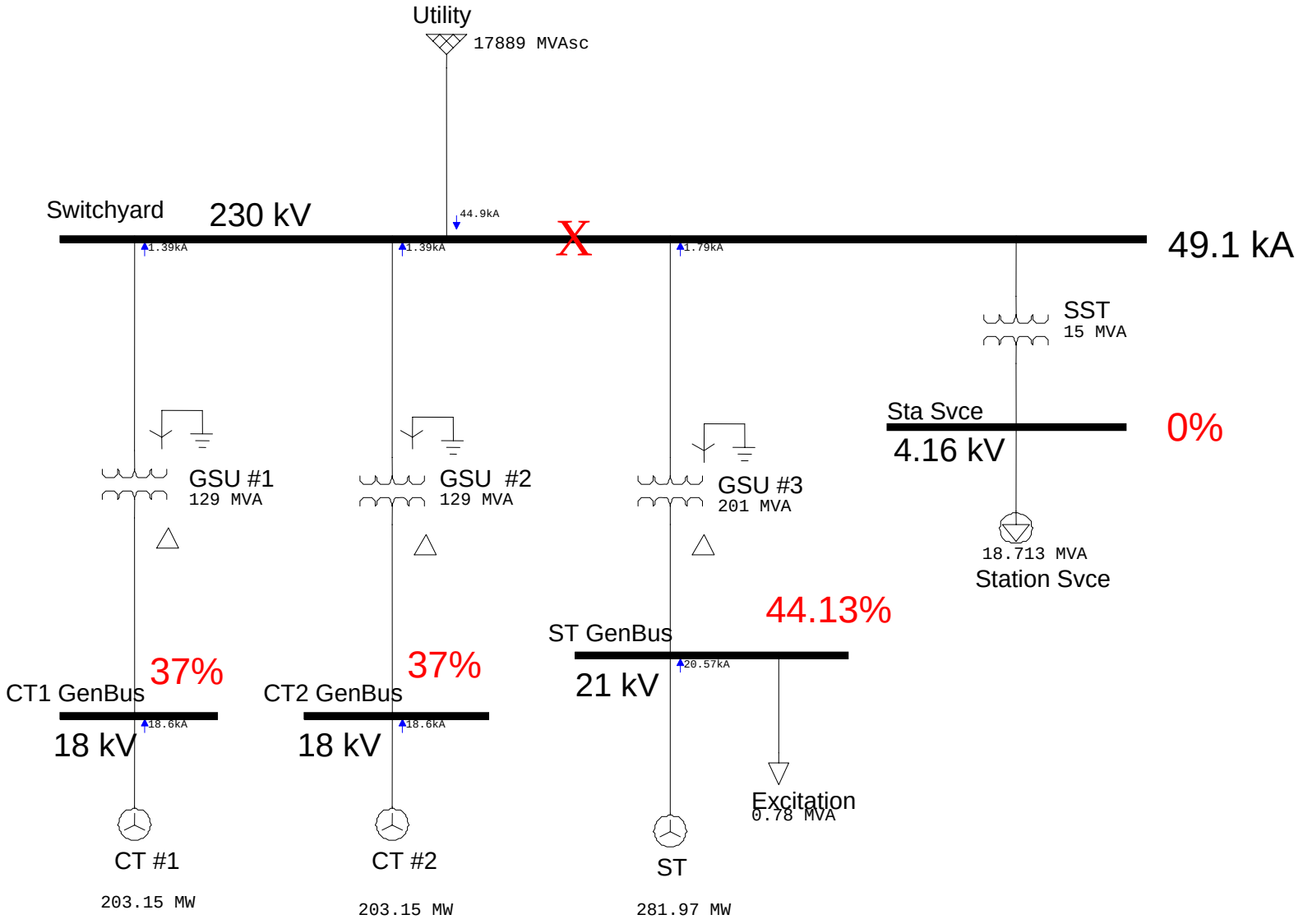
Typical Plant and Normal Station Service

Generator and 4160V (Unit Fed) Bus Voltages for Switchyard 3ϕ Bus Fault



Notes:

1) Values computed using ETAP 30 cycle fault analysis function.
2) All bus voltages in % of rated bus voltage.

Typical Combined Cycle Unit

Generator and 4160V (Unit Fed) Bus Voltages for Switchyard 3ϕ Bus Fault