NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Guideline

Power Plant Model Verification and Testing for Synchronous Machines

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RELIABILITY | ACCOUNTABILITY

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

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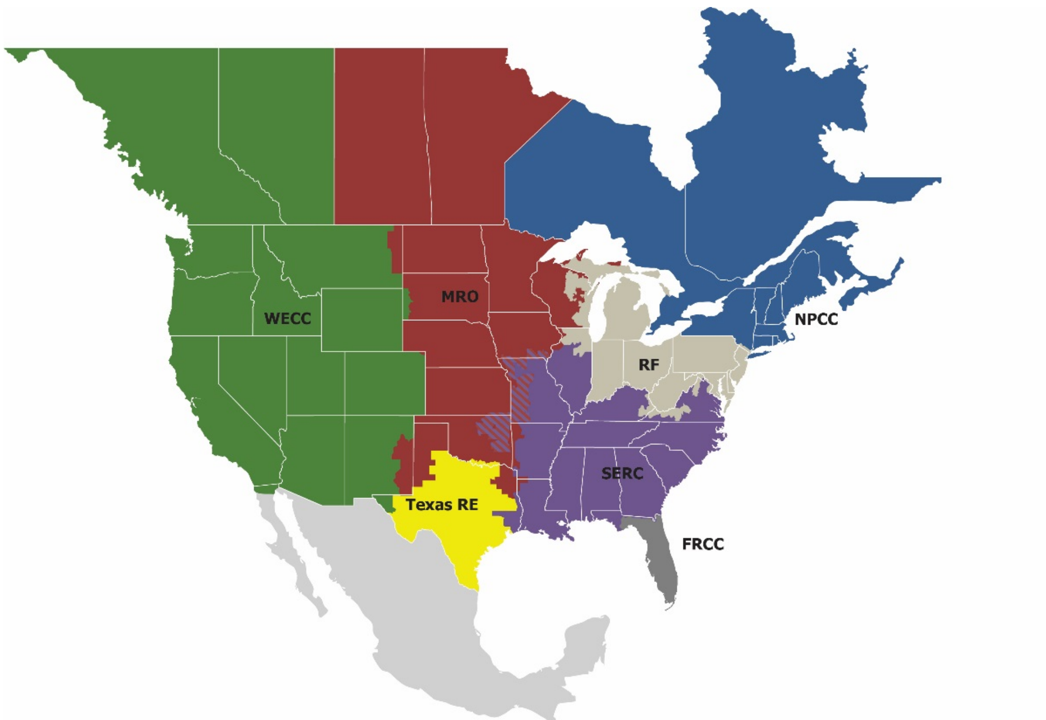
Preface

The vision for the Electric Reliability Organization (ERO) Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the seven Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

The North American BPS is divided into seven RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Region while associated Transmission Owners/Operators participate in another.



FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Preamble

It is in the public interest for NERC to develop guidelines that are useful for maintaining or enhancing the reliability of the Bulk Electric System (BES). The NERC technical committees (the Operating Committee (OC), the Planning Committee (PC), and the Critical Infrastructure Committee (CIPC)) are authorized by the NERC Board of Trustees (Board), per their charters,[1] to develop reliability (OC and PC) and security guidelines (CIPC). These guidelines establish a voluntary set of recommendations, considerations, and industry best practices on a particular topic for use by BES users, owners, and operators in assessing and ensuring BES reliability. These guidelines are coordinated by the technical committees and include the collective experience, expertise, and judgment of the industry.

The objective of this reliability guideline is to distribute key practices and information related to power plant modeling and verification that are critical to maintain the highest levels of BES reliability. Reliability guidelines are not to provide binding norms or create compliance type parameters similar to compliance standards that are monitored or enforced; guideline practices are strictly voluntary and are designed to assist in reviewing, revising, or developing individual entity practices to achieve the highest levels of reliability for the BES. Further, these guidelines are not intended to take precedence over regional procedures or requirements.

NERC, as the FERC-certified ERO,[2] is responsible for the reliability of the BES and has a suite of tools to accomplish this responsibility, including but not limited to: lessons learned, reliability and security guidelines, assessments and reports, the Event Analysis program, the Compliance Monitoring and Enforcement Program, and mandatory Reliability Standards. Each entity, as registered in the NERC compliance registry, is responsible and accountable for maintaining reliability and compliance with the mandatory standards to maintain the reliability of their portions of the BES. Entities should review this guideline in detail in conjunction with the periodic review of their internal processes and procedures and make any needed changes to their procedures based on their system design, configuration, and business practices.

[1] http://www.nerc.com/comm/OC/Related%20Files%20DL/OC%20Charter%2020131011%20(Clean).pdf
http://www.nerc.com/comm/CIPC/Related%20Files%20DL/CIPC%20Charter%20(2)%20with%20BOT%20approval%20footer.pdf
https://www.nerc.com/comm/PC/Related%20Files%202013/NERC_PC_Charter_2016_FINAL.pdf

[2] http://www.ferc.gov/whats-new/comm-meet/072006/E-5.pdf

Executive Summary

The August 1996 outage in the Western Interconnection highlighted the need for models and simulation results that accurately represent the actual behavior of the bulk power system (BPS).[3] These models are used in planning to identify and mitigate potential planning criteria violations, determine transfer capability, and develop transmission system reinforcement plans. They are also used in operations for outage coordination studies, establishment of system operating limits, and real-time assessment tools. Equipment owners (e.g., Generator Owners (GOs) and Transmission Owners (TOs)) of individual BPS elements provide steady-state and dynamic models that are compiled by the Transmission Planners (TPs) and Planning Coordinators (PCs) to form the steady-state powerflow and dynamics cases used for reliability studies. These interconnection-wide base cases, and the verification of models used in these cases and in local planning studies, are the primary focus of this guideline.

The NERC MOD Standards—namely MOD-025-2, MOD-026-1, and MOD-027-1—were developed to ensure that verification activities take place for the steady-state and dynamic models used to represent the actual behavior of installed BES generating resources. These Reliability Standards primarily apply to the equipment owners since it is their responsibility to prove that the modeled response reasonably represents reality when the equipment is in-service and operational. This often requires some form of testing (or possibly on-line disturbance-based verification) and other verification activities to demonstrate that the responses match. Many of the activities performed to meet the requirements of these Reliability Standards are described in this reliability guideline to provide technical reference material and guidance related to power plant testing, model verification, and modeling practices for synchronous generators.

The guideline covers many of the potential tests that may need to be performed to develop or ensure a verified model; however, not all of these tests are necessary under all verification scenarios. A well-developed baseline model created during commissioning may still be accurate many years later, and verification may be completed fairly easily with certain verification tests. On the other hand, when detailed equipment data is not available (e.g., older plants, multiple owners, undocumented equipment upgrades), more extensive testing may need to be performed to ensure a reasonable match. Most importantly, testing and verification should ensure the safety of plant personnel and protection of the equipment under test at all times. The intent of the guideline is to serve as a foundational repository of useful information related to testing; however, the expertise of plant personnel and the testing engineer should take precedence over any other guidance.

The guideline recommends close coordination between the equipment owner (e.g., GO), the testing engineer (if different than the GO), the TP and PC (the model user), and the equipment manufacturer (if necessary). In addition, other entities are often involved in the testing, development, or use of these models, including the Generator Operator (GOP), Transmission Operator (TOP), and Reliability Coordinator (RC). This guideline aligns with NERC's mission of improving reliability through sharing industry practices for planning and operating the BPS. It primarily applies to GOs, GOPs, PCs, TPs, TOPs, RCs, testing engineers, and other applicable subject matter experts related to NERC MOD standards pertaining to model verification and capability testing.

[3] D. N. Kosterev, C. W. Taylor and W. A. Mittelstadt, "Model validation for the August 10, 1996 WSCC system outage," in *IEEE Transactions on Power Systems*, vol. 14, no. 3, pp. 967-979, Aug. 1999.

Background

This guideline provides GOs, TOs, and TPs with technical reference material and guidance related to testing, model verification, and modeling practices for synchronous generating resources.[4] These activities center around the relevant NERC Reliability Standards (listed below) related to model development and verification for reliable planning and operation of the BPS.[5] The majority of the material in this guideline is dedicated to power plant testing and model verification, and the other relevant standards related to these activities are also covered in varying depths throughout the guideline.

The following are the relevant power plant testing and model verification standards:

- **MOD-025-2:** Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability
- **MOD-026-1:** Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Function
- **MOD-027-1:** Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

The following are the relevant power plant protection and limiter coordination standards:

- **PRC-019-2:** Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

The following are the relevant interconnection-wide model development and verification standards:

- **MOD-032-1:** Data for Power System Modeling and Analysis
- **MOD-033-1:** Steady-State and Dynamic System Model Validation

The development and verification of accurate steady-state and dynamic models of the power system (i.e., MOD-032-1 and MOD-033-1) is a complex yet crucial component of system studies performed to ensure reliable planning and operation of the BPS. While the component data is provided by the equipment owners, such as the GO (MOD-032-1 R2), the development and verification of the system models (MOD-032-1 and MOD-033-1) and system studies are often performed by the TPs, PCs, and RCs. Results from these system studies are fundamental in the assessment of BPS reliability and therefore are of direct concern for the GOs even though they are typically not involved with the development of system models or the execution of system studies. The quality of the results in these studies, as well as the confidence in the conclusions from such studies, is directly related to the quality of the information provided for the development of the steady-state and dynamic models used in these studies. One of the goals of this guideline is to help in the coordination and sharing of information between the transmission and generation entities, helping to bridge the gap between the data owners and the data users.

Several other NERC Reliability Standards (MOD-025-2, MOD-026-1, MOD-027-1, PRC-019-2, etc.) apply to the equipment owners, particularly GOs, and require testing and verification of models, and documentation and analysis of the coordination between protection, limiters, and capabilities. These standards provide critical information that form much of the data that is supplied by a GO in support of the case creation process, per MOD-032-1.

[4] Including synchronous generators, synchronous condensers, synchronous motors, and pumped storage.
[5] In general, the dynamic models described in this guideline are used to develop the interconnection-wide models used to plan and operate the BPS. The NERC List of Acceptable Models can be found HERE.

As such, this guideline covers an array of testing considerations, actual testing procedures, and how those tests help derive or verify model parameters as related to MOD-025-2, MOD-026-1, and MOD-027-1. This guideline serves as a compendium of potential tests that may or may not need to be performed, depending on specific designs, configurations, operating requirements and limitations, regulatory requirements, and other factors at a generating facility. In general, a broader set of tests may be performed during commissioning in the development of a baseline[6] model while a reduced set of tests may suffice for model reverification purposes.

In addition to the dynamic model verification processes, the inter-related aspects of generator protection coordination (PRC-019-2) and generator capability testing (MOD-025-2) are considered in the guideline to provide necessary guidance on these activities. The modeling and verification of equipment (plant) performance serve as the fundamental layer to provide the necessary information to create and verify the fidelity of the Interconnection-wide models namely associated with MOD-032-1 and MOD-033-1. As these standards come into effect, it is important that relevant registered entities have reference material and guidance to understand the vast topics covered in this guideline. This guideline also serves as a focal point to raise industry awareness, understanding, and expertise in the area of power plant model verification (PPMV) and testing (predominantly the responsibility of GOs) and how these efforts support the development of accurate and representative Interconnection-wide models (predominantly the responsibility of the TP, PC, and RC) used to plan and operate the BPS.

This guideline aligns with the NERC's mission of improved reliability through sharing industry practices for planning and operating the BPS. It primarily applies to GOs, GOPs, PCs, TPs, TOPs, and RCs. It also applies to generator testing engineers, software vendors, and other modeling experts.

Key Testing Principles

The following principles form the basis for generator testing and model verification for reliable operation of the BPS:

- The first and foremost priority of testing is the safety of plant personnel and plant equipment. Testing should never call for increased risks to the safety of the personnel involved and should never result in damage or harm to the turbine-generator, its components, or other plant equipment. In many situations, this is the foremost consideration that will determine what is prudent to do in specific circumstances.
- Testing confirms the structure and performance of control systems and the correct operation and coordination of these controls relative to the protection systems and limiters. It also provides evidence that the controls have been reasonably tuned to provide acceptable response without oscillatory or undesired response that could have adverse impacts to the plant or BPS reliability.
- Testing develops or verifies the mathematical models used by TOPs, TPs, PCs, and RCs for system studies to represent the behavior of actual equipment installed in the field to the best extent possible.
- The verification of dynamic models and model parameters can be completed in a number of different ways. This guideline provides illustrative examples of tests and how those tests support the development and verification of models. However, there may be other means of verifying these models (e.g., other methodologies, future technologies).
- Staged testing and model verification is intended to develop a model that accurately, to the most possible extent, represents the performance of the unit when synchronized to the BPS. Simulations for the BPS in

[6] The development of a baseline model, particularly during commissioning, is critical in the overall model creation and verification process. The ability to perform a broader suite of tests and develop an accurate and representative model during this time period can often simplify the verification process in the future and minimize potential model discrepancies in the longer term. These initial tests are often termed "baseline testing" to develop a "baseline model."

planning studies typically use an integration time step on the order of 4 ms (quarter-cycle) for simulation lengths of up to 30–60 seconds. These models are not expected to emulate the equipment performance exactly, rather they are intended to match the general dynamic behavior of the machine within reason.[7] Differences between simulation and actual response during testing should be explained by the testing engineer. This is a good example of how engineering judgment should be applied to any type of testing and model verification activities, while being mindful of the needs and expectations of the various parties (GO, TP, RC, testing engineers, etc.).

These principles should be considered throughout the entirety of this guideline as well as in the field while performing actual testing and verification practices.

Modeling and Verification Perspectives

While accurate modeling and verification of these models, for the purposes of reliably operating and planning the BPS, is well understood by all involved parties, there are different perspectives between GOs, TPs, PCs, testing engineers, and original equipment manufacturers (OEMs) that should be considered. Table I.1 proves some of the perspectives from each entity and is intended to shine a light on the different functional aspects of the model the purpose of the model and the need for accurate and verified models.

Table I.1: Overview of Model Verification and Testing Standards

Entity	Perspectives
Transmission Planner/ Planning Coordinator	• Accurate steady-state, dynamic, and short circuit models are needed and used to reliably plan and operate the BPS. These models are used to develop powerflow, dynamics, and short circuit cases for reliability studies. • Model accuracy can impact the determination of system operating limits, Interconnection reliability operating limits, and large BPS investment decisions. • The dynamic models should be accurate out to at least 30 seconds and usually to 60 seconds. Any plant-level controls that interact within this time frame should be modeled. • Most reliability studies are performed using positive sequence powerflow and dynamic simulation tools; however, some special studies may require more detailed electromagnetic transient tools and associated models.[8] • Powerflow and dynamics data needs to be collected in a timely and efficient manner for the purposes of building Interconnection-wide cases as well as performing planning studies.

[7] The simulated and actual response is expected to match fairly closely. Use of numerical thresholds for sufficient match are not recommended. Rather, engineering judgment and expertise should be used to determine the sufficiency of a match. And technical justification should be provided for any discrepancies.

[8] Note that what is discussed in this document, and in the context of the NERC MOD Standards, are typically positive sequence models.

Table I.1: Overview of Model Verification and Testing Standards	
Entity	**Perspectives**
Generator Owner	• Safety of equipment and personnel within the plant is of utmost importance. • PPMV should be performed at a reasonable cost for the reliability benefit achieved. Any time the unit is off-line for the purposes of testing is lost revenue for the plant. • The GO may not be a model user and therefore may have limited understanding of how these models are developed and verified; this often requires consultation with other experts. • Compliance obligations should not create undue burden on the GO. • Plant operators have the ultimate judgment on what is reasonable and safe to perform in terms of testing when consulting with the testing engineer. • Guidance on the types of verification tests and sufficient model accuracy for the purposes of the NERC MOD Reliability Standards is useful. • Phasor measurement unit (PMU) data can be used to perform disturbance-based model verification to ensure that the model developed during testing matched actual performance.
Testing Engineer	• Review of testing procedures with plant personnel prior to testing ensures that testing risks are mitigated and testing can be carried out effectively. • Understanding the intended use of the models helps develop a test plan that meets the modeling needs at least cost. • Some tests should be performed at the operating point(s) closest to the normal operating range of the equipment.[9] Other tests may require operation at or near a specific machine loading. • Measurement error cannot be completely eliminated; however, reasonable effort should be taken to minimize these errors.[10] • It is desirable to have either manufacturer-provided data or previously validated data to start with model verification. Therefore, it is important to gather sufficient data from existing plant documentation. • Model parameters should fall into reasonable ranges before being submitted to the GO.

[9] For example, a baseload generator should have the governor step response test performed at about 80 percent to 90 percent of the machine baseload while making sure sufficient governor headroom is reserved. Similarly, verification of the voltage response with an on-line voltage reference step test, if possible, near baseload is likely more representative.

[10] Calibration of measurement devices, proper selection of device measurement range to ensure optimal measurement resolution, etc.

Table I.1: Overview of Model Verification and Testing Standards	
Entity	**Perspectives**
Original Equipment Manufacturer	• The model is a numerical representation of actual equipment and is not an exact match of all plant physics and controls. This is true of any model, even the most detailed EMT models. • Proprietary, vendor-specific, "black box" models will typically provide a more accurate representation of the dynamic response compared with publicly available generic models. • The sharing of proprietary models, or access to block diagrams, usually requires the execution of NDAs, which have proven challenging for collaboration between involved entities.[11] • While not perfect, generic models are generally sufficiently accurate for the purposes of powerflow and positive sequence dynamic simulations. • Understanding the intended use of the model will help ensure that models can be developed and delivered to the GO and TP/PC effectively and accurately. • Coordination with the GO during commissioning and operation and engaging with the TP/PC as necessary on any reliability issues is critical. • Understanding the metrics used for determining model accuracy between actual and simulated response aids in model development.

Commissioning, Baseline Model Development, and Reverification Tests

Power plant testing and model verification can take place at different times in a generating unit's life with different needs and goals. Baseline model development for new units occurs during initial commissioning and is necessary to develop a baseline understanding of the characteristics of the machine and to develop a representative model of the machine. Baseline models for existing units are being developed or refined through the application of MOD-026-1 and MOD-027-1 requirements mentioned in the Introduction. The development of baseline models often alleviates or minimizes the potential need for reverification testing in the future (i.e., disturbance-based verification or other options may be more suitable if an effective baseline model is established). Model reviews and verification will also need to occur when certain power plant components are replaced or refurbished (e.g., generator stator rewind or rotor field winding replacement that impacts generator model parameters, exciter or governor equipment replacement, turbine rotor replacements that impact machine inertia, etc.). Lastly, NERC Reliability Standards require a periodic reverification of the dynamic models used to represent the generator components to ensure that these models reflect a reasonable representation of the equipment in the field. Different methods or approaches can be used to reverify the power plants models, including the following:

- Staged testing
- Disturbance-based monitoring
- Operational data

While staged testing procedures and modeling methods are the primary focus of this guideline, this guideline also stresses the necessity of relying on manufacturer-supplied data as likely the most accurate data available to represent some aspects of the machine and its controls. Disturbance-based PPMV is also discussed in this

[11] For this reason, the interconnection-wide models do not allow proprietary models. See the NERC List of Acceptable Models. Available: https://www.nerc.com/comm/PC/System%20Analysis%20and%20Modeling%20Subcommittee%20SAMS%20201/Acceptable_Models_List_2017-08-19.xlsx

guideline, particularly in situations where baseline testing has developed an accurate and representative model in the past.

In all situations, a review of local, regional, contractual requirements, and engineering judgment should be used to determine which set of tests may be required for the specific task at hand. For example, local requirements may require a new unit to perform a more exhaustive set of tests to confirm parameters that are based on physical characteristics of the equipment. These tests are needed for baseline model performance testing (e.g., power vs. gate curve for a hydroelectric unit) and are not expected to differ materially over the life of the equipment. In this time frame, operational data will not exist and disturbance-based monitoring may not be appropriate (i.e., disturbance-based monitoring requires a baseline model). For the power vs. gate curve example, this specific test may not need to be performed upon reverification if a good baseline model already exists. Conversely, if a new turbine runner is installed, the power vs. gate curve will need to be remeasured.

Figure I.1 shows an illustrative diagram of the many tests discussed in this guideline and the general applicability of these tests for unit commissioning, initial verification, or reverification. The diagram does not stipulate that one must perform all the tests listed; rather, it illustrates that commissioning may require more testing to prove that the equipment will operate in a stable fashion, provide data for tuning the controls, and to develop a baseline model that can be used for reverification purposes. Verification activities may only need to draw on a select number of these tests depending on the quality of the baseline model and ability to match staged test results with simulation.

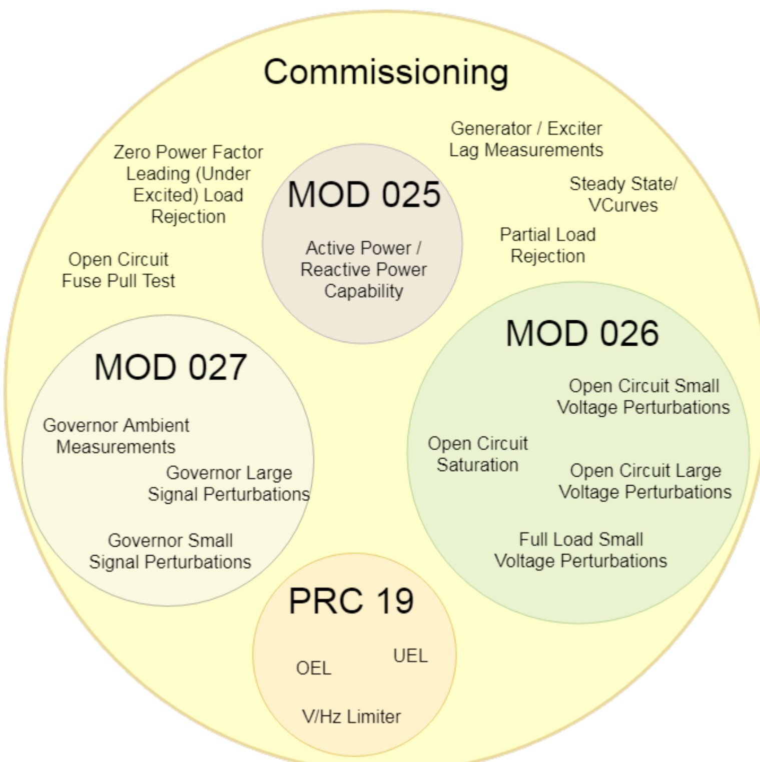


Figure I.1: Framework of Commissioning Tests [Source: IESO]

Disturbance-Based Power Plant Model Verification

Disturbance-based PPMV using dynamic disturbance recording data (e.g., synchrophasor data from PMUs), digital fault recorders (DFRs), or other high resolution disturbance monitoring data can serve as a recurring test to ensure that the modeled response to system events matches actual response of the power plant or generating unit. Thus, disturbance-based model verification is used as a binary check ("yes/no") that the model is performing as expected. On-line performance monitoring that uses disturbance-based PPMV provides a cost effective and efficient means of ensuring that the model is accurate. From the TP's perspective, this approach provides expeditious verification that modeled performance is a reasonable representation of the behavior of actual unit operation.[12] Any significant differences can be used to instigate a model check by the GO and can also be used to guide the GO towards potential corrections to the model. From the GO's perspective, on-line verification that uses high resolution measurement data can provide evidence of compliance by demonstrating the validity of the model by on-line measurement. Therefore, the GO may not have to take the unit off-line for testing of model parameters. Taking the unit off-line and bringing in an outside contractor to perform model verifications can be costly for the GO. In addition, disturbance-based verification enables more frequent verification than the 10-year period required by MOD-026-1 and MOD-027-1 and enables detection of anomalous plant behavior or model changes on a more frequent basis.

Figure I.2 shows a high-level illustration of a PMU[13] that is monitoring phasor quantities of voltage and current signals from the power plant. The response of the unit(s) is measured by the dynamic disturbance recording and playback capability available in most commercially available transient stability simulation software programs used to recreate the event in simulation. The simulated and actual response of the unit are compared. **Figure I.3** shows an example comparison for a large nuclear power plant steam turbine generator. The figures show real and reactive power response as the measures of success of how well the model matches reality. In this case, the simulated response matches the modeled response quite well. In situations where the model does not match the simulated response, disturbance-based PPMV can identify the discrepancy, but additional analysis, testing, or calibration[14] would need to be performed to determine the source of the differences.

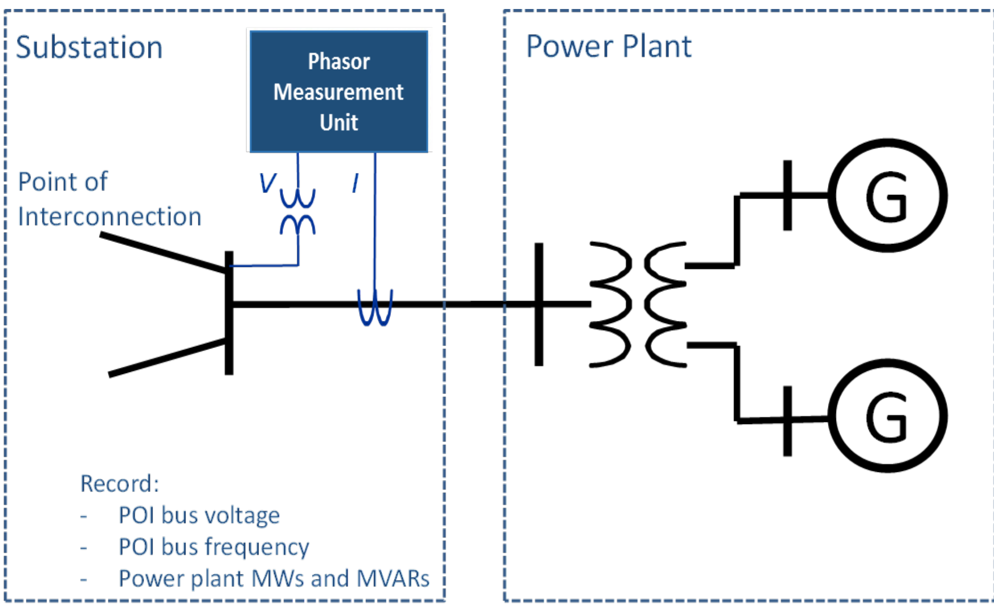


Figure I.2: On-line Disturbance Monitoring (Source: BPA)

[12] Les Pereira, John Undrill, Dmitry Kosterev, Donald, Davies and Shawn Patterson, "A New Thermal Governor Modeling in WECC," IEEE Transactions on Power Systems, vol.18, no.2, pp.819-829, May 2003.

[13] Other types of DDR (e.g., digital relay or DFR can also be configured for disturbance-based PPMV as well.

[14] Model calibration from disturbance-based PPMV requires extensive knowledge of the unit and dynamic parameters being studied, and also requires a high level of engineering judgment to be applied throughout. Using numerical curve fitting calibration techniques to optimize/fit parameters to a model without using engineering judgment is not recommended.

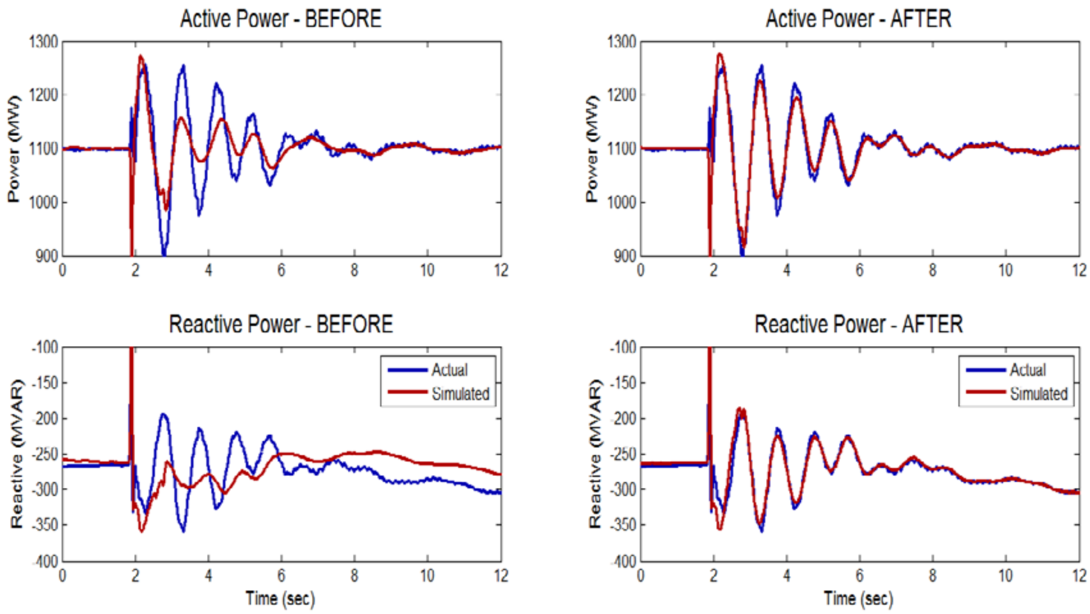


Figure I.3: Nuclear Plant Calibration Example—Before (Left) and After (Right) Calibration [Source: Bonneville Power Administration]

The recommended approach[15] is for the model user (the TP and PC) and the model owner (the GO) to work together to perform the disturbance-based verification. The TP and PC have the software tools, including the playback capability, and the GO may have the necessary data to play back and compare the simulated response. GOs should identify potential sources of high speed data recording capability to enable disturbance-based PPMV. Many options for acquiring the data (e.g., digital relays, DFRs, and PMUs) are available today. In some cases, the TO may have a PMU monitoring the unit(s) and can provide that data to the GO if requested for the purposes of model verification. To capture the dynamic response of the unit, higher resolution data is recommended (i.e., typically 60 samples per second). Lower resolution data may not fully capture the necessary dynamics for play-in and comparison of the actual and modeled response.

It is generally more practical for a GO to collect disturbance data at the low-side of the generator step-up (GSU) using either a DFR, digital relay, or standalone PMU. Also recording field voltage and current of the generator (or exciter in the case of a brushless unit) may enable some model tuning in addition to the verification. Recordings at the generator terminals can be an effective tool for troubleshooting issues within the power plant.

The NERC Synchronized Measurement Subcommittee developed a guideline[16] on the topic of disturbance-based PPMV and the steps to performing the verification.

[15] While this is the recommended approach, the GO is responsible for verifying the dynamic models of its resources, per MOD-026-1 and MOD-027-1.
[16] http://www.nerc.com/pa/RAPA/rg/ReliabilityGuidelines/Reliability%20Guideline%20-%20Power%20Plant%20Model%20Verification%20using%20PMUs%20-%20Resp.pdf

Chapter 1: Relevant NERC Reliability Standards

Several NERC Reliability Standards are interrelated and significant in obtaining accurate and representative Interconnection-wide models used for planning and operating the BPS. These standards work in tandem and aim to ensure the development and verification of models as well as the sharing of these models between applicable entities. Each standard has a specific applicability and set of requirements and should be read in its entirety to understand how to meet it. This section will provide a high-level overview of the relevant standards as well as some recommendations and key takeaways to consider with respect to each standard.

Development and verification of Interconnection-wide steady-state and dynamic simulation models is mostly the responsibility of the TPs and PCs (MOD-032-1, MOD-033-1). These standards set the data and reporting requirements for the equipment owners of the elements on the BPS (e.g., TOs, GOs). Therefore, the equipment owners have the responsibility of developing accurate and representative models for their equipment, providing those models to the TP and PC for development of Interconnection-wide models, and verifying the accuracy of these models over time (i.e., the intent of MOD-026-1 and MOD-027-1).

Several NERC Reliability Standards deal with the accuracy and verification of the information and models, particularly from generating resources. In this regard, it is important to distinguish between standards that require actual testing at a generator facility (e.g., MOD-025-2, MOD-026-1, and MOD-027-1) and standards that may not directly require an actual test (e.g., PRC-019-2, PRC-024-2, and PRC-025-1). Regardless, these standards require documentation and analysis of power plant protection, limiters, and capabilities and are important steps in the planning and preparation for power plant tests.

The standards are described below in three categories to aid in the understanding and discussion of each standard and its goal:

- Power plant testing and model verification standards
- Power plant protection and limiter coordination standards
- Interconnection-wide model development and verification

This guideline primarily addresses power plant testing and model verification activities related to MOD-026-1 and MOD-027-1. However, the other related standards are described to help contextualize how these standards all work together to ensure accurate and verified models are developed and provided for power system operations and planning studies.

Power Plant Capability Testing and Model Verification Standards

The power plant testing and model verification standards include MOD-025-2, MOD-026-1, and MOD-027-1. **Table 1.1** provides a high-level overview of these standards. It includes information related to the applicability of the standard, which facilities are included, the types of tests that are performed, periodicity of the testing requirements, the focus of the standard, data recording speed requirements, and whether it is recommended that the GOP coordinate with transmission entities. The testing and verification practices that are used for these standards are discussed in this guideline. Refer to the standards for specific details on requirements.

Table 1.1: Overview of Model Verification and Testing Standards

Topic	MOD-025-2	MOD-026-1	MOD-027-1
Effective Date	July 1, 2016	July 1, 2016	July 1, 2016
Applicability	• GO • TO[17]	• GO • TP	• GO • TP
Facilities[+]	• Individual unit > 20 MVA • Synchronous condenser > 20 MVA • Plant/Facility > 75 MVA	Eastern or Quebec Interconnections: • Individual unit > 100 MVA • Plant* consisting of multiple units > 100 MVA Western Interconnection: • Individual generating unit > 75 MVA • Plant consisting of multiple units > 75 MVA ERCOT Interconnection:[18] • Individual generating unit > 50 MVA • Plant consisting of multiple units > 75 MVA All Interconnections (MOD-026-1)[19]	
Types of Tests	Steady-State	Steady-State Dynamic	Steady-State Dynamic
Periodicity	5 years	10 years	10 years
Primary Focus	Real and Reactive Generator Capability	Dynamic model verification for synchronous generator, exciter, voltage regulator, impedance compensation, and power system stabilizer (PSS) (if applicable)	Dynamic model verification for turbine-governor and load control or active power-frequency control
Data Recording Requirements	Slow Recording (Steady-State)	Slow and Fast Recording (Steady-State and High Resolution)	Slow and Fast Recording (Steady-State and High Resolution)
Coordination between GOP, TOP, and TP/PC	Recommended	Recommended	Recommended

* Directly connected at a common BES bus with total generation
[+] Gross nameplate rating for individual units or gross aggregate nameplate rating for multiple units

[17] That owns synchronous condenser(s)
[18] ERCOT Nodal Operating Guides require new generating Facilities over 20 MVA aggregated at a single site placed into service after January 2, 2017, to include PMUs for purposes of model validation.
[19] In MOD-026-1, Facilities for all Interconnections include "Technically justified unit that meets NERC registry criteria but is not otherwise included in the above Applicability sections 4.2.1, 4.2.2, or 4.2.3 and is requested by the Transmission Planner." Technical justification is achieved by the TP demonstrating that the simulated unit or plant response does not match the measured unit or plant response.

Each of the modeling and verification standards (namely MOD-025-2, MOD-026-1, and MOD-027-1) has a key purpose and primary objectives, including the following:

- **MOD-025-2:** Physical testing confirms by observation from measurement that the generator can continuously operate within the specified capability curve without tripping or being unexpectedly limited. Supplementary information that builds on measurements (e.g., power vs. ambient temp curves) can and should be used if actual capability cannot be reached due to limitations in the plant or in the grid, and this allows one to extrapolate up to the expected capability. Identification of any coordination issues (tripping, limiters, etc.) can start a process to further analyze and correct these issues. This can lead to confirmation of accurate P_{min}, P_{max}, Q_{min}, Q_{max}, and transformer tap values used in the powerflow cases (assuming capability is reached or calculated as intended by the standard). The test can also confirm accuracy of telemetry, operation in automatic voltage control, and other items that may be required for other local criteria as applicable.
- **MOD-026-1/MOD-027-1:** Dynamic model verification confirms that the dynamic performance of the excitation system (generator, excitation system, PSS, and voltage compensator) and turbine-governor models provided to the TP/PC accurately reflect actual response of the equipment installed in the facility. This ensures that the studies performed to plan and operate the BPS as accurate as possible.

Interconnection-Wide Model Development and Verification Standards

Once the individual component models have been developed and verified, MOD-032-1 and MOD-033-1 establish requirements for the PCs to develop Interconnection-wide models and test the overall performance of these models (see Table 1.2 for an overview). The system-wide validation of these models creates a feedback loop that can and may instigate further model verification or model review.

Table 1.2: Overview of Interconnection-Wide Model Standards

Topic	MOD-032-1	MOD-033-1
Effective Date	R1: July 1, 2015 R2, R3, R4: July 1, 2016	July 1, 2017
Applicability	• BA • RP • TP • GO • TO • TSP • PC	• PC • RC • TOP
Periodicity	Continuous / data submittal at least once every 13 months	24 months
Primary Focus	Establish consistent modeling data requirements and reporting procedures for development of steady-state, dynamics, and short circuit planning cases	Establish consistent validation requirements to facilitate collection of data and building of planning models
Data Recording Requirements	N/A	Sufficient data to perform steady-state and dynamic verification for PC portion of system

Chapter 2: General Testing Considerations

If disturbance-based PPMV is not an option, testing is necessary to perform the model verification for MOD-026-1 and MOD-027-1. This chapter, and the forthcoming chapters, provide useful considerations during testing.

Pretesting Considerations

The following topics should be considered leading up to and during testing:

- **Calibrated Measurement Equipment:** Ensure that the measurement equipment used to record the response of the generating unit to various tests is properly calibrated.
- **Minimize Setup Time:** To the extent possible, prior to testing, some planning should be done to identify the measurement points and needed preparation for testing in order to minimize set up time at the plant. Nevertheless, flexibility by the testing staff is still necessary since power plant safety of the personnel and equipment always comes first. Thus, last-minute alterations and changes may be required in test procedures and plans.
- **Signal Check Procedure:** All connection points and signals being measured should first be checked to ensure proper and safe connections have been made and the expected quantities are being measured before any testing commences.
- **Noise Mitigation:** Power plants are electrically noisy environments, and precautions should be taken to reduce noise level in the signals being measured. For example, use shielded, twisted pairs to reduce electromagnetic interference, keep unshielded leads short and twisted, and use balanced differential signals. In the end, some signals (e.g., field voltage and current) will naturally contain significant amounts of noise/ripple (e.g., ripple in rectified field voltage); these will require some form of hardware or software filtering.
- **Expertise and Experience:** The end goal of model verification is to perform the minimum number of tests in order to collect the necessary data, together with baseline data, to derive and validate the computer simulation models for a power plant. This process (as with any other engineering task) is a combination of technical details, sound engineering judgment, and experience. There is no absolute right or wrong way of addressing this issue, and each facility/plant will require certain site-specific augmentations and flexibility in the process used due to limitations that could be encountered on-site. Thus, every effort must be made to ensure the safety of personnel and equipment while performing the necessary test and collecting the intended data for the purpose of model verification. Expertise and judgment must be exercised to avoid inadvertent mistakes.
- **Controller Settings, Data Sheets, and Calculations:** Ensure that all controller settings (e.g., PSS settings, automatic voltage regulator (AVR) settings, operating modes, over-/under-excitation limiters (UELs)) are well understood and documented to the best extent possible.

Expected Testing Schedule

It is important to lay out a testing schedule so the GO, GOP, and testing personnel clearly understand the expectations and constraints for testing. This also helps ensure data collection prior to testing, procurement of any necessary fuel, coordination with the TOP, and clearing for outages properly performed. **Figure 2.1** shows an example of a typical testing schedule from the testing engineer's perspective. An experienced testing engineer can typically test a unit in about half a day to a full day depending on the circumstances. Any potential constraints that may arise during testing may extend the testing schedule or hinder completion of testing within this time frame. Once testing is concluded and all necessary data is collected, significant work goes into developing and verifying the models and model parameters. This may require further coordination with the GO.

Each of the steps of this example testing schedule are described in detail throughout this guideline.

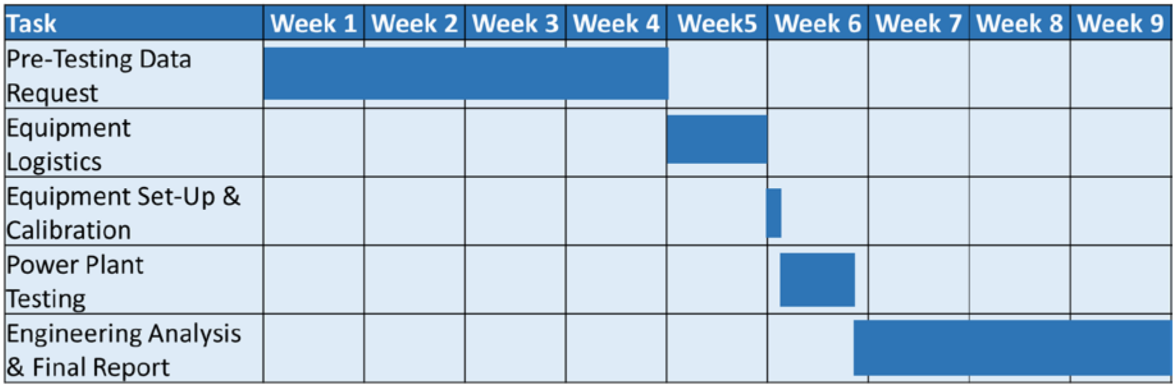


Figure 2.1: Example of Testing Schedule [Sources: GE, Kestrel]

Pretest Data Request

Prior to testing, the GO should gather all relevant data related to plant, generator, controls, and protection systems. The individual performing testing will need much of this documentation to understand the type of systems being tested and to develop the documentation and simulation results. These results should demonstrate verification of the modeled performance with actual testing. This data request will often happen about a month or more prior to actual testing. If the data is not provided in a timely manner, the testing schedule may have to be extended since the testing entity may not have sufficient information to prepare for the day of testing.

Table 2.1 provides examples of types of information the GO should gather that may be requested prior to testing. This information can be in the form of tables, models, block diagrams, electrical diagrams, plant schematics, past testing reports, etc.

Table 2.1: Possible Requested Plant Information

Category	Relevant Data
General	Station information, plant supervisor and operator contact information, overall plant one-line diagrams, auxiliary equipment operating limits, plant/unit voltage schedule
Transformer Data	MVA base and rating, turns ratio, configuration, tap settings, impedances, powerflow model, diagrams
Generator Data	Individual generator IDs, capability curve diagram, machine ratings (MVA, speed, voltage, field quantities, etc.) open circuit saturation curve, manufacturer data sheet (unsaturated reactances), dynamic model
Excitation System Data	Exciter and AVR type, manufacturer information (name, model, model number), block diagrams and manufacturer-specified parameters, dynamic model, schematics, connection diagrams, saturation curve, commissioning report, digital settings, most recent calibration report

Table 2.1: Possible Requested Plant Information	
Category	**Relevant Data**
Power System Stabilizer Data	PSS type, manufacturer information (name, model, model number), block diagrams and manufacturer-specified parameters, dynamic model, schematics, connection diagrams, latest PSS tuning study[20]
Turbine-Governor Data	Governor type, manufacturer information (name, model, model number), block diagrams and manufacturer-specified parameters, dynamic model, schematics, connection diagrams, turbine rating and rated speed, control mode used for normal operation conditions
Protection System Data	Types of active protection (e.g., V/Hz, loss of field, over-/under-voltage, out-of-step, etc.), protective relay specification sheets, protection schematics and settings sheets, relay PT and CT ratios, PRC-019-2 reports
Plant-Level Controls Data	Plant volt/var or power/frequency controls, connection and controls diagrams, data logs, historical plant data

Each entity performing the testing or model verification may require or specify data in different formats or depth.[21] To the most possible extent, this information should be provided in its entirety to aid in the successful development and verification of a model as well as to ensure an effective and efficient testing process. It should also be understood that, in some cases and particularly for older equipment, some of the above data (e.g., machine parameters, exciter saturation curves) may not be available despite the best efforts by the GO to gather them. In these cases, a combination of engineering judgment and testing will need to be used to derive the most feasible estimate of the missing parameters. When using tests to derive parameter values, some level of error is expected since no test or measurement process is free of error, but it will be the only plausible course of action.

Data Acquisition, Signals, and Measurement Locations

Model verification requires comparison of actual test results against simulated or modeled values. This requires measurement of electrical quantities during the test conditions. These quantities are either directly measured or extracted from modern digital control systems, and measurement equipment should record electrical quantities at a high resolution. Typically, these recordings are in the range of 10–25 kHz[22] with at least six to eight recording channels for external devices. Many digital systems may have recording capability integrated into the existing platform. Table 2.2 shows the signals, the secondary measured range, and the location of measurement usually necessary for power plant testing, depending on the specific tests being performed. Instrumentation and wiring will need to be configured to gather these signals as necessary, and wiring should be done carefully so as not to cause any safety or reliability issues.

[20] Without the latest tuning report, testing the PSS may require starting from scratch and retuning the PSS (or some other way to verify the existing tuning). It is important to retain the PSS tuning reports.
[21] As an example, see "Generator Controls Testing Data Collection" form. Available: http://kestrelpower.com/Articles.php.
[22] Some quantities may not need to be captured at high resolution (i.e., those collected during steady-state tests).

Table 2.2: Measured Signals		
Signal	**Range[23]**	**Location**
Input	Varies	Varies – test signal that is inducing a response in the unit (used for comparison of response)
Controller Output Signal	4–20 mA or 0–10 V_{DC} or digital output	From DA transducer, electrical output, or PLC digital output signal
Stator Voltage	0–120 V_{AC}	From stator PT secondary in protection/metering panels or exciter cabinets
Stator Current	0–5 A_{AC}	Using clamp-on transducer or CT secondary in protection/metering panels or exciter cabinets
Field Voltage	0–1000 V_{DC}	From exciter field voltmeter or directly across dc bus
Field Current	0–300 mV	From field current shunt in exciter cabinet
Frequency or Speed	N/A	Deriving or calculating frequency (speed) is likely more reliable than direct frequency measurement
Valve Position	4–20 mA or 0–10 V_{DC}	From output of LVDT[24] or potentiometer (if available)
Fuel Flow	Typically in percentage	Digital output from turbine controls on digital control systems
Gate Position (Hydro)	4–20 mA or 0–10 V_{DC}	From output of LVDT or output from governor on digital control systems
Blade Position (Hydro)	4–20 mA or 0–10 V_{DC}	From output of LVDT or output from governor on digital control systems
Jet Deflector Position (Hydro)	4–20 mA or 0–10 V_{DC}	From output of LVDT or potentiometer (if available)

Note 1: In the case of brushless excitation systems, the field voltage and field current of the exciter is measured. The field voltage of the exciter can be much lower in magnitude (e.g., as low as 0–50 V_{DC}) and the field current of the exciter may be measured using clamp-on CTs.
Note 2: In some older control systems, it may not be feasible to accurately measure valve position, fuel flow, etc. These quantifies are generally useful to have but not essential.
Note 3: In the case of a steam turbine, there is no single valve position. Thus, if plausible and necessary, the main steam throttle valve control command might be measured. Again, this a useful quantity to have for verification purposes but not essential.
Note 4: Stator voltage and current, and field voltage and current need to be measured at high resolution. The other signals may or may not need to be sampled at higher resolution based on the resource type.

[23] These are typical ranges. There may be some variations to each of these and are provided here as reference only.
[24] Linear Variable Differential (Displacement) Transformer

While **Table 2.2** lists the signals to ideally be measured, the absolute minimum required set of measurements are the three stator voltages, stator currents, field voltage, and field current. These measured quantities are then used, through signals processing and conditioning, to calculate the actual quantities needed for model verification, including the following:

- 3-phase active power (MW)
- 3-phase reactive power (MVAR)
- Positive sequence stator voltage (V_t)
- Field voltage (E_{fd})
- Field current (I_{fd})
- Speed/frequency at the generator terminals (Hz)

Where possible, signals for valve position and fuel flow may also be useful. Gate/blade position is also important for hydro units. With that said, there are exceptions in the field and nonideal conditions that may lead to the necessity of making appropriate compromises. For example, modern digital controls from certain vendors do not have a field shunt; rather, field current is a digitally calculated value in the controls. In these cases, there is no useful measurement of field current that can be made for comparison between measured and simulated transient events (e.g., voltage reference step test).

Good Vendor Data

In the case of power plants built after around the 1980's, reliable data from the OEM should be available and accurate. This includes data sheets for the generator, excitation system, turbine-governor, and other relevant generator components. **Figure 2.2** show examples of parts of a data sheet for a Brush machine.

In the case of some older units (i.e., before the 1970s to 1980s), this type of detailed data sheet may or may not exist for all components (i.e., generator electrical parameters, open-circuit saturation curve, and generator capability curve):

- If it exists, is traceable directly to the specific unit (by serial numbers), and no material changes to the unit have been made (or new data sheets issued for rotor/stator rewinds), then experience has shown that this data is "good" (reliable) and that field testing would not yield parameters for the electrical generator (i.e., Xd, X'd, X''d) that are more accurate than those provided by the OEM data sheets.[25] This type of "good" (reliable) OEM data should be the starting point of any model verification process, and parameters should not be changed unless there is justifiable evidence to do so after careful consultation with the OEM and other parties involved.

Key Takeaway:
If reliable OEM data exists, it is likely the most accurate data source for many of the generator model parameters. Datasheets should be updated with the actual gains/tuning set upon commissioning and any modification to these parameters. Likewise, the model parameters should be updated to reflect any changes to actual installed equipment and communicated to the TP and PC for inclusion in their system studies.

[25] Some parameters do change in the field and dramatically from the OEM-supplied data due to the physics of the machine. For example, the generator field time constant will change with unit loading because as the unit is loaded the rotor temperature will rise. This increases the rotor circuit resistance and decreases the field time constant. This is a reality of the physical world that cannot be captured by the constant-parameter type models used in large-scale power system simulations.

- If it does not exist and cannot be collected by the GO (e.g., for older units), it may be necessary to consult with the OEM or perform additional tests (described in some of the following chapters) to make a reasonable estimate of the model parameters.

However, it is quite common to find through testing and model verification that the gains and tunable time constants on control systems differ from those in the OEM-supplied datasheets. This is typically because standard datasheets provide gains and tuning that are default values and may often not be updated after the equipment is commissioned and tuned in the field for the specific conditions of the local interconnection to the BPS. If baseline model development through testing and verification has been performed at plant commissioning, then more than likely the models provided upon commissioning will form a reliable baseline model for all equipment. In any case, datasheets should be updated with the actual gains/tuning set upon commissioning and any modification to these parameters. Likewise, the model parameters should be updated to reflect any changes to actual installed equipment and then communicated to the TP and PC for inclusion in their system studies.

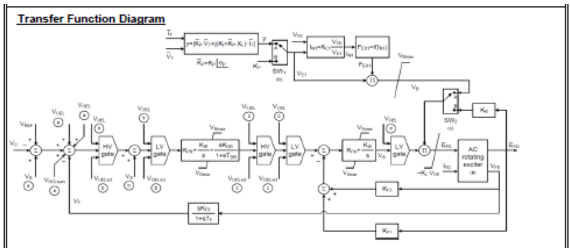
"Good" vendor data is not only reliable and available but also comprehensive enough to deduce information about the machine and to develop model parameters. This often includes block diagrams with respective parameter values, base values, saturated and unsaturated parameters (as applicable), ratings under specified conditions, sensitivity curves, etc.

ELECTRICAL DATA SHEET - CONTINUATION

BDAX 7-290ER, 64.900 MW, 0.850 pf, 13.800 kV, 60.0 Hz

3.	NEGATIVE SEQUENCE CAPABILITY		
	3.1	Max short time negative sequence I_2^2t	30
	3.2	Max continuous I_2 unbalance	15
4.		REACTANCE AND SEQUENCE RESISTANCES	
A)	Direct Axis Reactances:		
	4.1	Saturated synchronous reactance, $X_{d(v)}$	227%
	4.2	Unsaturated synchronous reactance, $X_{d(i)}$	252%
	4.3	Saturated transient reactance, $X'_{d(v)}$	21.3 %
	4.4	Unsaturated transient reactance, $X'_{d(i)}$	26.2 %
	4.5	Saturated subtransient reactance, $X''_{d(v)}$	15.4 %
	4.6	Unsaturated subtransient reactance, $X''_{d(i)}$	19.4 %
	4.7	Saturated negative sequence reactance, $X_{2(v)}$	15.1 %
	4.8	Unsaturated negative sequence reactance, $X_{2(i)}$	18.9 %
	4.9	Zero sequence reactance, X_0	10.2 %
	4.10	Potier reactance, X_P	22.2 %
	4.11	Saturated stator leakage, $X_{sl(v)}$	8.8 %
	4.12	Unsaturated stator leakage, $X_{sl(i)}$	13.9 %
	4.13	Short circuit ratio	0.44
B)	Quadrature Axis Reactances:		
	4.14	Saturated synchronous reactance, $X_{q(v)}$	181 %
	4.15	Unsaturated synchronous reactance, $X_{q(i)}$	231 %

Transfer Function Diagram



Generator / Exciter Parameters at 100°C

	V_R	1 per unit exciter field voltage on air gap line (hot)	4.1	volts
	R_F	Exciter field resistance (hot)	7.1	ohms
	V_{PMG}	AVR input voltage	270	volts
	E_{FD}	1 p.u. Exciter output voltage	53.8	Volts
J+20	T_E	Exciter field time constant	1.2	sec
J+19	K_E	Exciter constant	1.0	
J+24	$S_E[E_{E1}]$	Exciter saturation function at 100% ceiling exciter output voltage	1.72	
J+23	E_1	100% ceiling exciter output voltage	8.9	p.u.
J+26	$S_E[E_{E2}]$	Exciter saturation function at 75% ceiling exciter output voltage	0.17	
J+25	E_2	75% ceiling exciter output voltage	6.7	p.u.
J+18	K_D	Demagnetising factor (function of exciter reactance)	2.00	
J+17	K_C	Rectifier loading factor	0.67	
J+21	V_{FEMAX}	Maximum exciter field current	24.3	p.u.
J+22	V_{EMIN}	Minimum exciter current	0	p.u.

Automatic Voltage Regulator Parameters

	R_C	Resistive component of load compensation	0	p.u.
	X_C	Reactance component of load compensation	0	p.u.
J	T_R	Regulator input filter time constant	0	s
J+1	K_{PR}	Voltage regulator proportional gain	40	
J+2	K_{IR}	Voltage regulator integral gain	5.6	
J+3	K_{DR}	Voltage regulator derivative gain	0	
J+4	T_{DR}	lag time constant for derivative channel of PID controller	0.005	sec*
J+5	V_{Rmax}	Maximum regulator output	3.2	p.u.
J+6	V_{Rmin}	Minimum regulator output	-3.2	p.u.
J+7	K_{PA}	Field current regulator proportional gain	34.7	p.u.*

Figure 2.2: Generator Electric Data Sheet Examples [Source: Brush]

Representation of Typical Operating Mode(s)

One of the main purposes of model verification and testing is to ensure that the behavior of the resource can be accurately predicted via a set of steady-state and dynamic models. These models are expected to represent the expected operation under normal operating conditions. While power plants may have multiple modes of operation, these modes of operation should be well understood by the GO and should be communicated to the TP and PC who are performing the system studies using these models. It is not realistic to develop models for all potential operating conditions; however, a model that represents the "normal operating condition" should be provided.

In situations where there are multiple "typical" operating modes (and subsequent variances in modeling parameters), the GO should coordinate with their BA and TP to understand the implications of these operating modes. The BA and TP will likely expect the plant to be operating in one mode based on the model provided and may also be able to provide guidance on the operating mode that will best support BPS reliability. For example, governor response from generating resources can be categorized into the following:

- **Frequency Responsive:** The generating unit is responsive to changes in grid frequency and the turbine-governor controls generator output based on deviations in frequency.
- **Load Control/Outer-Loop MW Control (Frequency Response Withdrawal):** The generating unit is controlled to a load set point. It may respond to changes in grid frequency but will return to a load set point relatively quickly (typically the initial 30–60 seconds following the disturbance). Governor load control or outer loop controls will interact[26] or override the described response of the turbine-governor.
- **Nonresponsive:** The generating unit will not respond to changes in grid frequency due to blocked controls or operating modes that do not respond to changes in grid conditions. Temperature control and sliding pressure are considered nonresponsive. Use of frequency (or speed/error) deadband does not justify the unit as nonresponsive.

Setting changes and dynamic model changes that occur due to status changes (e.g., dual setting AVRs based on status of the PSS) and when these situations may arise during normal plant operation should be reported to the TP and PC. Plant controllers and their interaction with the dynamic response of the unit should also be taken into consideration when determining the modes of operation and an appropriate dynamic model. The dynamic models are generally used for transient simulations typically studying conditions up to 60 seconds.[27]

TPs and PCs should ensure they understand the mode(s) of operation of the generating fleet in their footprint and apply engineering judgment in the use of the models supplied for system studies. Any potential variances in operating conditions should be studied by the TP/PC to identify any potential reliability issues. In situations where there is evidence of alternate operating modes or uncertainty in the expected operating condition, the most conservative representation of machine response should be considered (e.g., nonresponsive). Model verification and testing should help clarify these issues.

[26] It is important to accurately model both the turbine-governor as well as the outer loop/load controls that overlay this response.

[27] Most transient stability simulations are often performed for at least 10–15 seconds and commonly up to 30 seconds. Specialized studies or studies of poorly damped oscillations may be run up to 60 seconds. Units that take longer to react (e.g., STGs of combined cycle plants) are considered to be non-responsive during this time frame.

Chapter 3: MOD-025-2 Testing Procedures

The purpose of MOD-025-2 is to ensure that accurate information on generator gross and net real and reactive power capability and synchronous condenser reactive power capability is available for the planning models used to assess BES reliability. The standard applies to GOs and TOs that own synchronous condensers. The requirements outline a process for the applicable entities to provide their TP with documentation of the verification of the active and reactive power capability of each applicable unit, following the specifications outlined in Attachment 1 by using Attachment 2 (or a form similar to Attachment 2).[28] **Figure 3.1** provides an overview of the specifications in Attachment 1 and how those specifications relate to specific tests for different types of generation[29] units. The flow of information is unidirectional as the GOs and applicable TOs provide verification reports to the TP for review. While TPs are not an applicable entity in MOD-025-2, the TP and GO (or applicable TO) should coordinate to ensure the capability testing and verification is completed successfully (described in detail in Appendix D).

It is important to note that the tests associated with MOD-025-2 are quite similar to tests that may be required for Interconnection agreements or local criteria,[30] particularly regarding reactive capability. However, some differences may exist, and care must be taken to ensure all required data is collected and reported in accordance with MOD-025-2 requirements and all applicable agreements and rules. Given the similarities, the techniques and approaches for the testing of generating units to fulfill MOD-025-2 requirements are likely applicable to meeting[31] other requirements. GOs (or TOs) planning to perform MOD-025-2 testing should consult with their transmission service provider and independent system operator (ISO), if applicable, to determine if additional requirements apply and to streamline the execution of similar activities. Furthermore, some regional requirements[32] may include provisions for coordination with the system operator. Capability testing requirements may be challenging to meet without support from the system operator, and such coordination should occur prior to scheduling testing. While coordination with TOP is not a requirement in MOD-025-2, it is recommended.

The following sections describe technical aspects of MOD-025-2 testing and verification and how these tests relate to the data submitted for Interconnection-wide modeling pursuant to the requirements of MOD-032-1. Appendix D provides numerical examples that demonstrate various aspects of MOD-025-2 testing.

[28] NERC Reliability Standard MOD-025-2, "Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability," March 2014. [Online]. Available: HERE.

[29] Note that synchronous condensers are not covered in this flowchart, for simplicity. In addition, some variations apply to variable energy resources. For example, there is no way to hold maximum active power constant for one hour during testing since power fluctuates within a couple minutes or even seconds.

[30] For example, IESO Market Rules: Market Rules Chapter 4 Grid Connection Requirements

[31] Specific interconnection agreements, market rules, or other interconnection requirements should be addressed in their entirety along with the NERC MOD-025-2 standard. The material provided here should support all these efforts from an engineering perspective.

[32] ERCOT Nodal Operating Guide, Section 3.3.2.2 Reactive Testing Requirements. Available: http://www.ercot.com/mktrules/guides/noperating

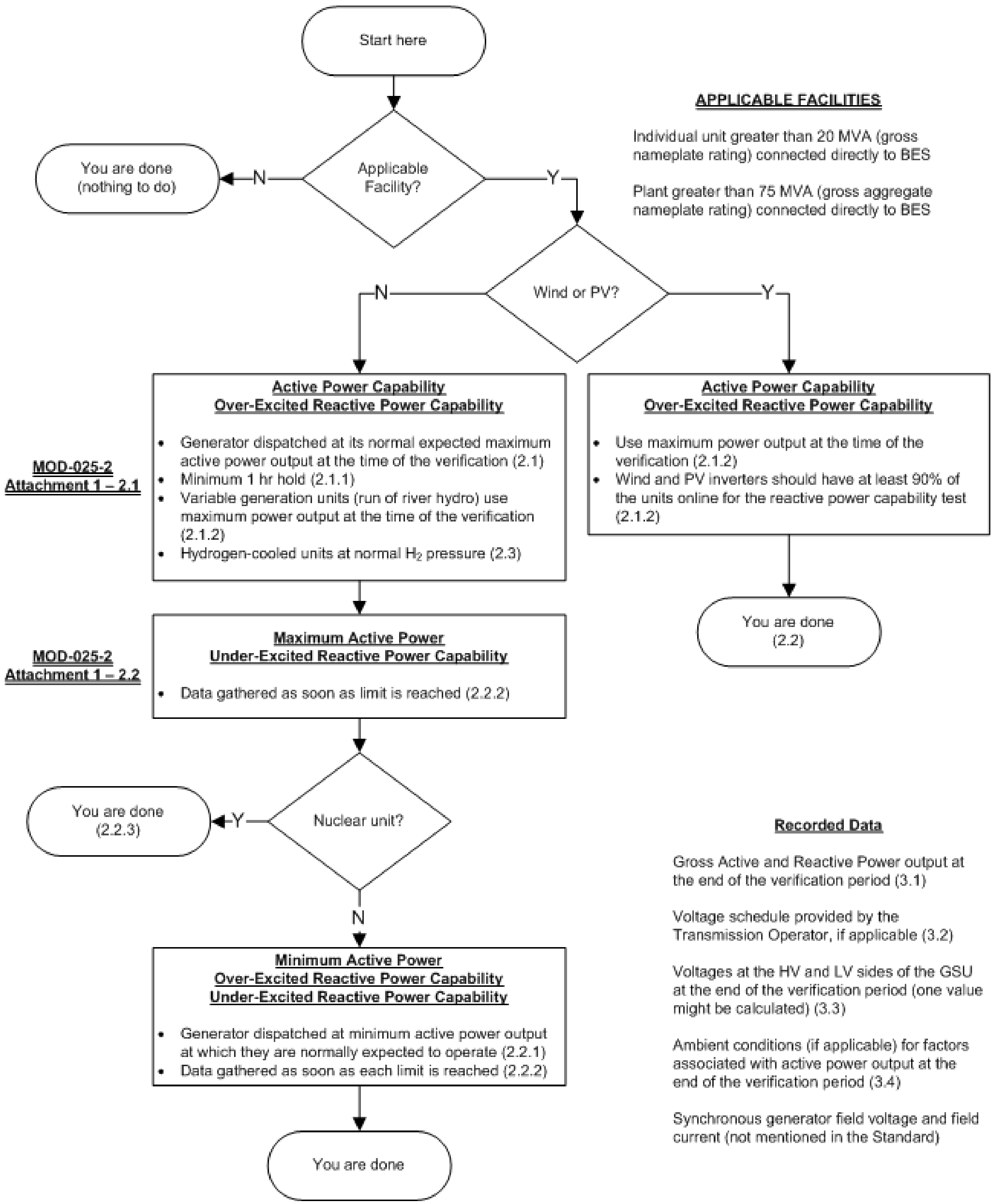


Figure 3.1: Flowchart of MOD-025-2 Attachment 1 Testing Requirements

PRC-019-2 Protection Coordination

Prior to performing NERC MOD-025-2 testing, it is highly recommended that the PRC-019-2 requirements be fulfilled. PRC-019-2 requires an engineering evaluation be performed to coordinate the voltage regulation controls, limiting functions, equipment capabilities, and protection settings of the unit/plant (see **Figure 3.2**). These analyses help prepare the way for successful MOD-025-2 testing by identifying desired MOD-025-2 test stopping points, the locations of the over-excitation limiter (OEL) and UEL, and by ensuring that running to these limits will not cause inadvertent tripping of the unit. If a unit does not have an OEL or UEL, then the MOD-025-2 test must be planned to avoid thermal damage to the generator and maintain safe margins to tripping functions.

In addition to the PRC-019-2 findings, operational limits for the plant equipment should be determined and adhered to. These limits may include the acceptable operating ranges for generator terminal voltage, stator current, auxiliary voltages, transmission level voltages, generator stator temperatures, and GSU transformer cooling temperatures. Operation outside these limits could often lead to equipment damage or operator alarms that would typically stop an operator from moving the operating point beyond that range. Manufacturers' ratings and curves typically reflect rated conditions; however, operating conditions during testing can vary significantly and operators should closely monitor equipment parameters especially when approaching equipment limits.

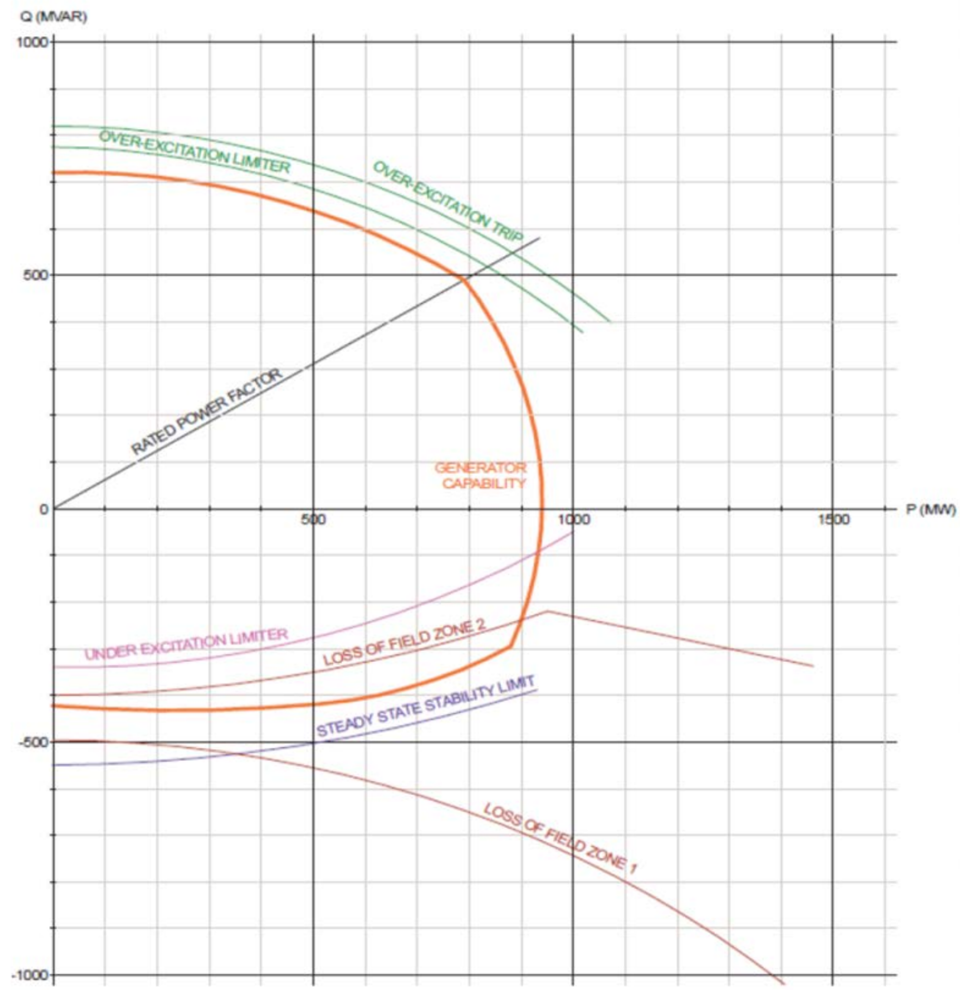


Figure 3.2: Generator Capability Curve

Fundamentals of Generator Ratings and Manufacturers Curves

The capability of a synchronous generator is defined in IEEE C50.13-2014. The rating of a generator is the MVA (apparent power) available continuously at the terminals at rated frequency, voltage, power factor, and primary coolant temperature. The standard specifies that, at rated frequency, generators shall be thermally capable of continuous operation within the confines of their reactive capability curves over the range of ± five percent in voltage. To define the reactive capability, generator manufacturers supply generator capability curves similar to the ones shown in **Figure 3.3**. Note that the capability curve on the left uses a different sign convention for leading (consuming) and lagging (producing) conditions. Also note that this curve is only for the generator itself and not the "composite capability curve" (see **Figure 3.2**) that also includes the protection and limiter curves.

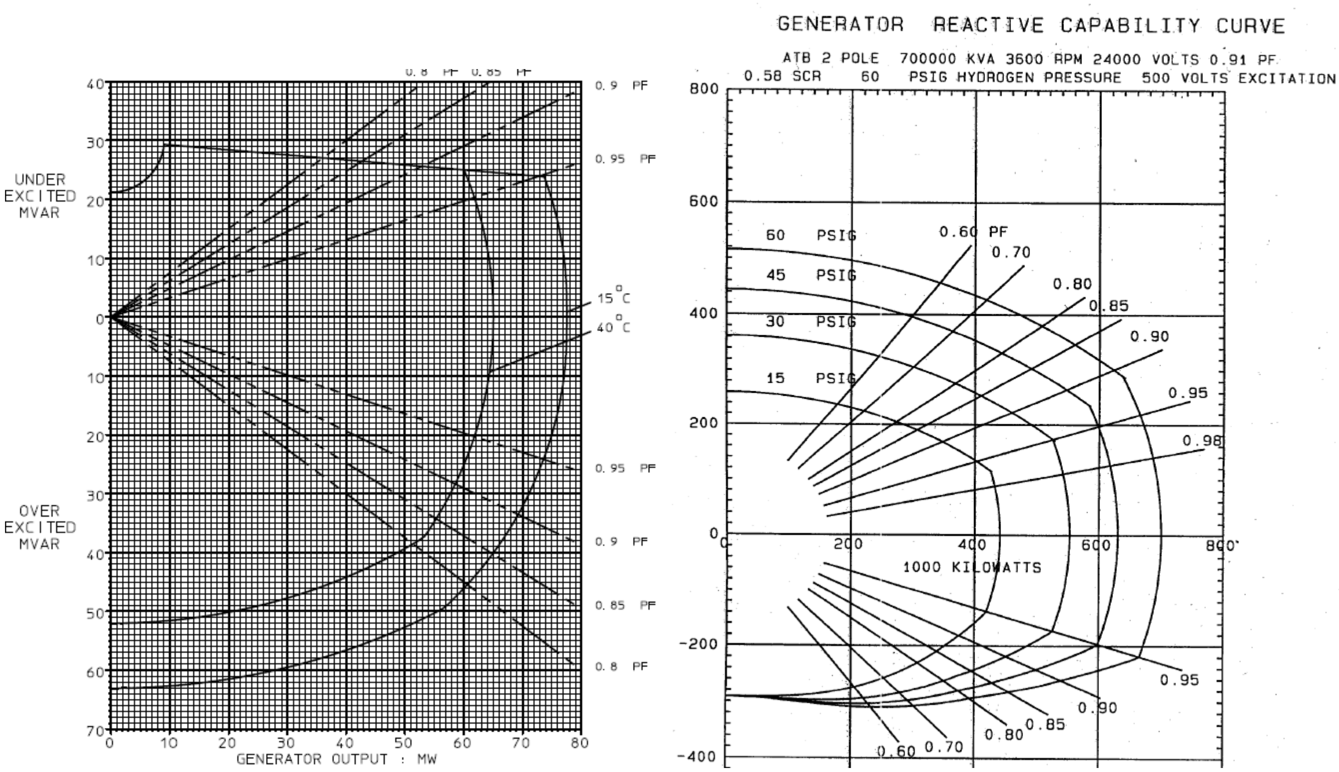


Figure 3.3: Reactive Capability Curve Examples [Sources: Brush, NRG Energy]

The generator capability curve consists of separate intersecting curves that may include the following:

- **Rotor Current Heating:** over-excited (lagging) reactive capability of the generator, established by the rated field current limit heating
- **Stator Current Heating:** operating limits at rated stator current and the highest output power at unity power factor
- **Stator End Iron Heating**: based on geometry of the conductors at the end turns, limit of operation in the under-excited (leading) region

Generator manufacturers also supply generator V Curves, which are graphical representations of the generator stator current vs. excitation field current for various loading combinations of power and power factor.

Note that the generator capability curve provided by the manufacturer only identifies permissible operation of the generator, independent of other factors. When a generator is connected to the BPS, the manufacturer's capability curve does not necessarily represent the achievable operating limits of the generating unit due to multiple factors including excitation limiters, GSU impedance, and turn ratio, the POI scheduled voltage, and auxiliary system voltage limits.[33] It is generally unlikely that a generating unit will operate to the manufacturer's capability curve limits in both the over-excited and under-excited regions.

Fundamentals of Maximum Reactive Capability and Field Current

The typical representation of a synchronous generator in steady state (power flow) calculations is shown in **Figure 3.4.** The generator bus is represented as a PV bus, describing the two primary operating variables within the control of the GOP—active power (P) and terminal voltage (V). P_{gen} is the active power generation and $|E_T|$ is the magnitude of bus voltage. From those quantities, the power flow solution calculates the bus voltage angle, θ, and the reactive power output of the generator, Q_{GEN}.

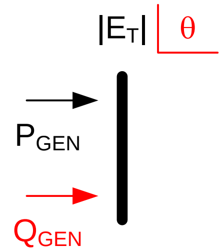


Figure 3.4: Power Flow Representation of a Synchronous Generator

In the simplest implementation of power flow software, the synchronous generator is modeled as a power source with defined active and reactive power limits, as shown in **Figure 3.5** with a rectangular capability defined by a minimum and maximum active power output for the generator (P_{min} and P_{max}) and a minimum and maximum reactive power output of the generator (Q_{min} and Q_{max}). The rectangular capability uses the reactive limits (Q_{max}/Q_{min}) at the maximum power output (P_{max}) as a conservative assumption since the reactive capability of the machine is greater at lower active power output levels. More detailed representations of generator reactive capability (e.g., piece-wise linear points defining Q_{max}/Q_{min} as a function of active power output) are available in various commercial software tools, but these do not represent the variation in reactive limits as a function of the terminal voltage magnitude.

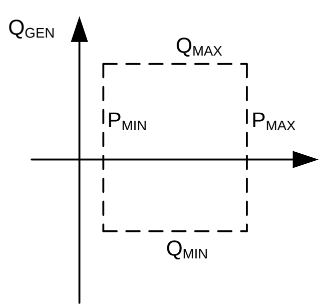


Figure 3.5: Simplified Representation of Synchronous Generator Capability in Powerflow

The power flow solution and with the dynamic model parameters are used to calculate the initial conditions of the dynamic simulation models as represented in **Figure 3.6**. Values from the power flow solution for the synchronous machine terminal conditions (bus voltage magnitude $|E_T|$, bus voltage angle θ, active power output P_{GEN}, and reactive power output Q_{GEN}) are used to determine the generator field current I_{FG} and field voltage E_{FG}

[33] MOD-025-2 Attachment 1, Note 1 indicates that "Under some transmission system conditions, the data points obtained by the reactive verification will not duplicate the manufacturer supplied thermal capability curve (D-curve)."

(shown in **Figure 3.6**) as well as turbine mechanical power P_{MECH} (not shown in **Figure 3.6**). These are the initial conditions of the excitation system model and turbine-governor model.

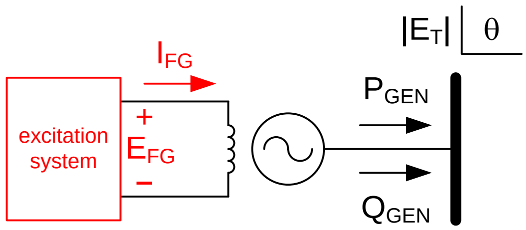


Figure 3.6: Representation Calculation of Initial Conditions for Excitation System Model

In the initialization of a dynamic simulation, the initial (steady-state) value for generator field current I_{FG} can be expressed as the function below. The diagram may give the wrong impression that the generator field current is a derived quantity from the selected terminal conditions of voltage active power and reactive power as expressed below.

$$I_{FG} = f(|E_T|, P_{GEN}, Q_{GEN})$$

In reality, the generator operating terminal voltage $|E_T|$ is controlled primarily by the function of field current I_{FG}. To a lesser extent, the magnitude to E_T is affected by variations of P_{GEN} and Q_{GEN} output.

$$|E_T| = f(I_{FG}, P_{GEN}, Q_{GEN})$$

I_{FG} is adjusted to control E_T. Consequently, adjusting E_T affects the output of Q_{GEN} based on interaction of the generator and the BPS as a new steady state is established. The magnitude of Q_{GEN} affects E_T and field current I_{FG} is adjusted as needed to support and maintain E_T at its set point. Normally, it is unacceptable to use Q_{GEN} as an established set point and drive I_{FG} and E_T as needed (per VAR-002-4.1 R1). Q_{GEN} is an interactive exchange of power between the machine and the system without a net transfer of energy (i.e., reactive power). The magnitude of reactive power is dependent on the magnitudes of E_T and the relative voltage of the system. Due to this interaction, the maximum reactive capability of a generating unit cannot be injected at will into the BPS. Rather, it is a product of relative voltage magnitude, excitation, and voltage set point.

Figure 3.7 shows simplified circuit diagrams and the relation of voltages and reactive power transfer between the generator and system. As E_T is raised higher than the system voltage E_{system}, the generating unit will export reactive power. Similarly, as E_T is lower than system voltage, the unit will import reactive power.

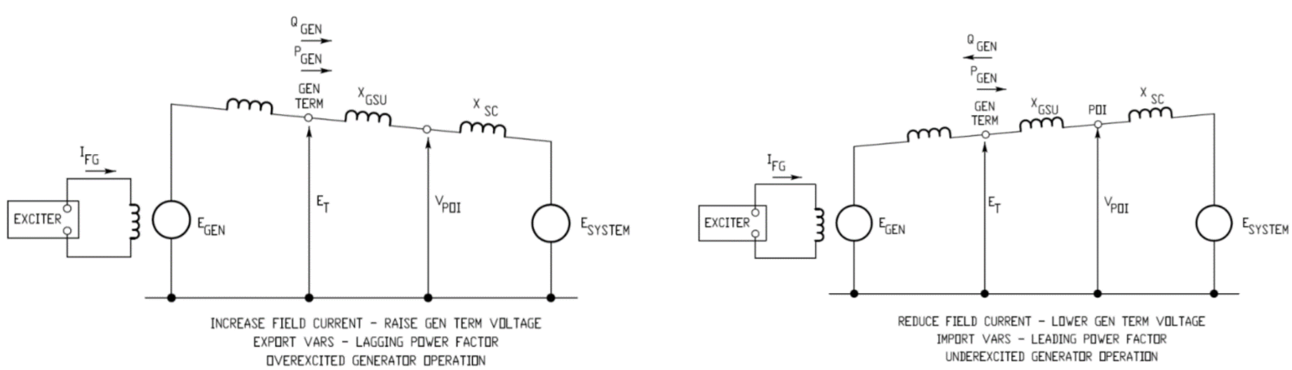


Figure 3.7: Circuit Diagram of Reactive Transfer [Source: NRG Energy]

The generator AVR controls terminal voltage to an established set point $|E_T|$ by adjusting I_{FG}. In the process, steady state values of P_{GEN}, and Q_{GEN} are achieved if not limited by other constraints. P_{GEN} is determined by the mechanical input power to the machine, which is the primary variable to determine angular separation of voltages and is approximated by (quantities in per unit):

$$P_{GEN} = \frac{|V_{POI}| \times |E_T|}{|X_{GSU}|} \sin(\theta)$$

where

V_{POI} = Point of interconnection (POI) voltage, assumed as the high-side of the GSU
X_{GSU} = Impedance of the GSU (neglecting resistance and due to high X/R ratio, i.e. |X| = |Z|)
θ = Angular separation between E_T and V_{POI}

Under steady-state operating conditions, the primary controllable variable in this equation is θ, based on the amount of mechanical input power applied to the turbine (i.e., the ability to control mechanical input power drives the ability to control electrical output power). On the contrary, the generator controls E_T (within the limits of the excitation system and transformer taps) but does not control the V_{POI}. Therefore, there is no equivalent mechanism for direct control over Q_{GEN} by the GOP. This is demonstrated by the approximated equation of Q_{GEN}, expressed as (in per unit):

$$Q_{GEN} = \frac{|E_T|^2}{|X_{GSU}|} - \frac{|E_T| \times |V_{POI}| \times \cos(\delta)}{|X_{GSU}|}$$

Active power output (and excitation) will determine θ, and the difference of voltage magnitudes between E_T and V_{POI} ($|E_T|$ - $|V_{POI}|$) is the primary variable to determine the generator reactive power output. As E_T is adjusted, the impact on V_{POI} will simultaneously affect the reactive output of the generator.

System operating conditions can affect the POI voltage, regardless of generator operating point, which impacts the reactive power output of the generating unit. Figure 3.8 illustrates this effect. The x-axis shows the representative measure of impedance (in pu) from the generator terminals to the Thevenin equivalent voltage of the BPS. The figures shows examples of different operating conditions during the time of testing and how that impacts MOD-025-2 testing.

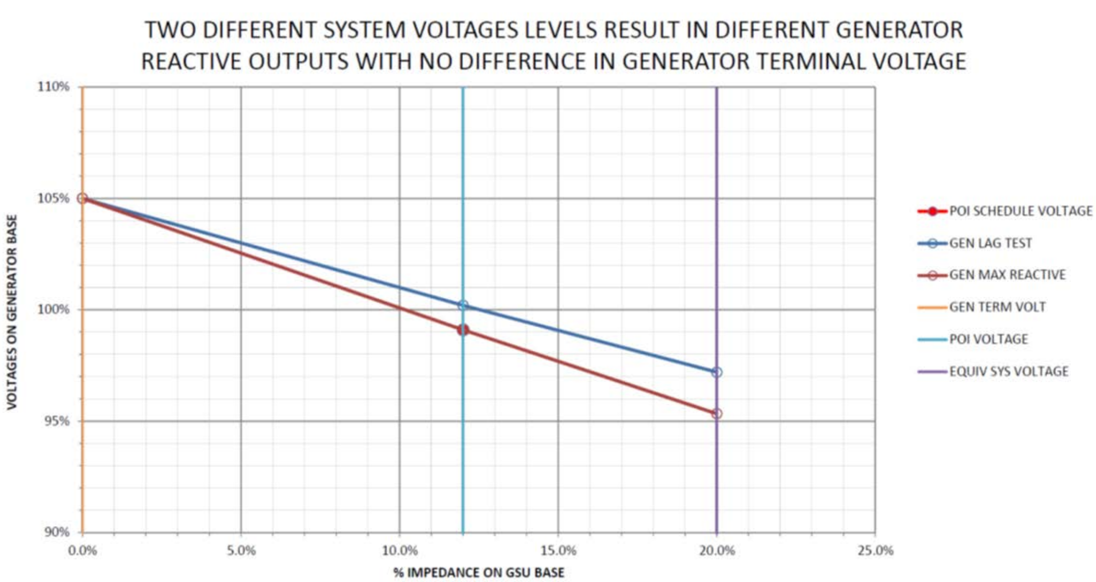


Figure 3.8: Impact of System Voltage on Test Results [Source: NRG Energy]

The generator maintains V_{POI} to the scheduled value by delivering the necessary reactive power; this is achieved by raising or lowering E_T by adjusting I_{FG} within operating ranges of power output. The purpose of MOD-025-2 is to confirm and provide a level of confidence for the operating limits of E_T and I_{FG} over the operating range of P_{GEN}. The reactive capability of the synchronous generator (in its over-excited condition) is dependent on the maximum limit on the generator field current $I_{FGlimit}$. Regardless, there is a defined limit on the maximum generator field current (which restricts maximum reactive power output Q_{max}) due to the thermal limit of the rotor winding. The OEL commonly limits I_{FG} and acts to keep the field current within the desired operating constraints. Most typically, the OEL limit has either a definite-time limit of field current or an inverse-time characteristic based on the pickup level of field current. Understanding that reactive power output of a synchronous generator is dependent on voltage magnitude $|E_T|$, active power output P_{GEN}, and field current I_{FG} is critical to the interpretation of the results of any reactive capability test, particularly those necessary to comply with MOD-025-2.

Before conducting generator reactive power capability verification tests, the current GSU tap setting, expected generator terminal voltages, and station service bus voltages should be reviewed since these will affect testing constraints. It is crucial to have a proper GSU tap setting for optimizing the utilization of the desired range of generator reactive capability.[34] Due to the fact that a GSU consumes reactive power, it is typically desirable to have a sufficient amount of the gross reactive production capability available to the transmission system. The voltage range (V_{max} and V_{min}) at the generator terminals is the typical limitation for utilizing the full range of the generator reactive capability. Figure 3.9 shows the expected operating points with various GSU tap settings at the same transmission bus voltage. With a lower tap setting (e.g., a=0.95 or 95 percent), the generator terminal voltage would likely be running high, and, consequently, reaching the high voltage limit at the generator bus or the other lower voltage buses. Therefore, only a small portion of the reactive power capability can be utilized. On the other hand with a higher tap setting (e.g., a = 1.05 or 105 percent), the full reactive production capability can most likely be utilized. Although the reactive absorption capability may be restricted with a higher tap setting due to the reactive power losses on the GSU, the generating facility should be able to effectively absorb a sufficient amount of reactive power from the transmission system when needed. The GO should coordinate with the TP and TOP (usually at commissioning) to set the tap according to expected operation to minimize the potential of limiting reactive power due to voltage constraints. The reactive capability testing is then performed under the expected or typical tap setting used during normal operation.

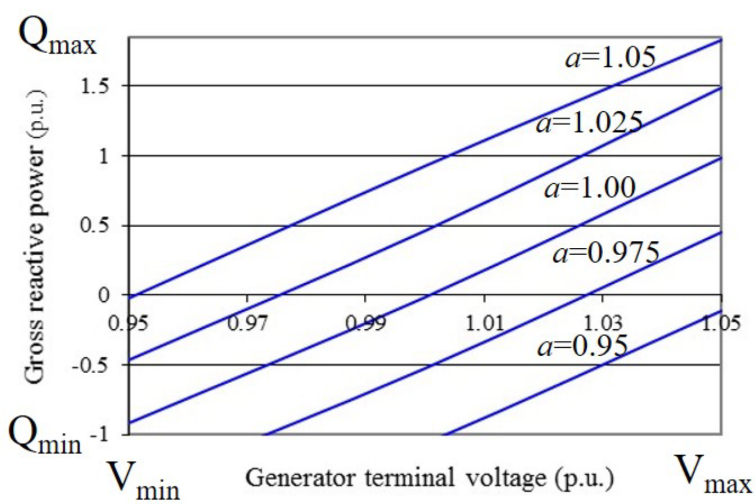


Figure 3.9: Generator Terminal Voltage vs. Gross Reactive Power [Source: Southern Company]

[34] S-M Hsu and H. J. Holley, "Utilization of Generator Reactive Capability: A Transmission Viewpoint," IEEE Power Engineering Review, June 2002, pp. 42-44.

MOD-025-2 Testing and Calculations Example

The capability curve of a synchronous machine consists of a number of different components, which may include the generator capability curve, overexcitation limiter curve, underexcitation limiter curve, loss of field protection curve, and steady-state stability limit curve. The "composite" capability curve is what is tested during MOD-025-2 testing and is the focus of data supplied for machine capability as part of MOD-032-1 (discussed in a following section). It is common to express machine capability in terms of a static capability curve, such as that drawn in Figure 3.2. However, a capability curve and the limiters associated with the capability are functions of voltage (see Figure 3.10) even though a machine capability curve is typically drawn at 1.0 pu voltage; this often causes confusion since the capability testing results obtained will likely differ from the OEM-supplied capability curve at 1.0 pu voltage.

To explain how generator capability testing is performed and illustrate some of the challenges associated with reactive capability testing, a set of example testing conditions and calculations are provided in Appendix D. The examples are based on an actual in-service generator, but the plant configuration and its connection to the grid is simplified and represented by a GSU transformer and a transfer impedance that connects the high voltage (HV) bus (plant POI) to an infinite bus representing the BPS.

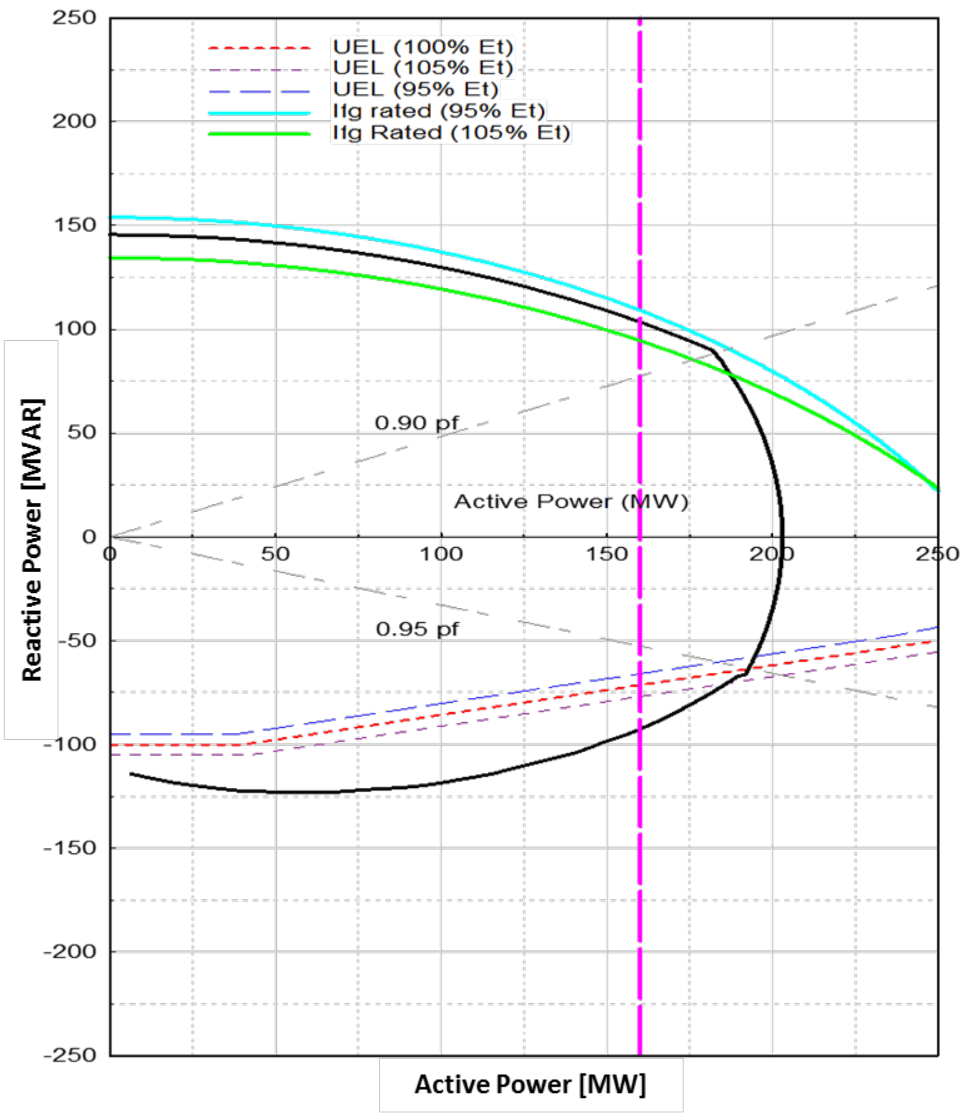


Figure 3.10: Impacts of Voltage on Capability Curve [Source: Kestrel]

Coordination with the Transmission Operator

Although the TOP is not listed in the Applicability section of MOD-025-2, the TOP plays a key role in generator capability testing; attachment 1 describes:

> "If the Reactive Power capability is verified through test, it is to be scheduled at a time advantageous for the unit being verified to demonstrate its Reactive Power capabilities while the Transmission Operator takes measures to maintain the plant's system bus voltage at the scheduled value or within acceptable tolerance of the scheduled value."

The GOP, TOP, and RC should coordinate with each other to ensure system bus voltages are within tolerance of the scheduled value. The coordination should include a clear understanding of the extent to which the system bus voltage can be varied during testing within reliability limits to provide the widest range of voltages such that generator capability can be tested to its fullest extent. The size of the generator relative to the strength of the system in which it is connected (e.g., short circuit ratio) impacts how much that generating unit can influence system voltage. Large generators, or generators connected to an area of the grid with relatively low short circuit ratio, may influence system voltage more. Hence, system voltage limits may be reached sooner and testing limited due to this constraint. If the TOP has sufficient time to study the potential to adjust system voltage levels (e.g., switching shunt capacitors or reactors, adjusting SVC or STATCOM voltage set points, adjusting nearby generator schedules), these options may be explored at the discretion of the TOP. However, as mentioned, system voltage plant-level voltage may hinder testing the generator up to its maximum reactive capability (or applicable limiter settings) in some cases.

When performing a lagging (over-excited) capability test, V_{POI} voltage will typically rise. This is opposite of the operating conditions that would otherwise electrically call upon the unit to produce reactive output (a time when POI voltage is low). This inherently creates a restriction in the amount of reactive power the unit can produce without hitting limits during test. Likewise, high voltage grid conditions would cause the unit to consume (leading) reactive power. However, during testing, the change in E_T to under-excite the unit may also lower system voltage.

Figure 3.11 graphically illustrates this concept and the difference between normal operating conditions that induce changes in reactive power and the operating conditions during test that induce a change in reactive power output. The TOP is always trying to maintain E_{system} to within limits—but during testing, the changes in V_{POI} and E_T are exaggerated. These illustrations assume steady state conditions in which the operator is taking action to maintain V_{POI} to scheduled value.

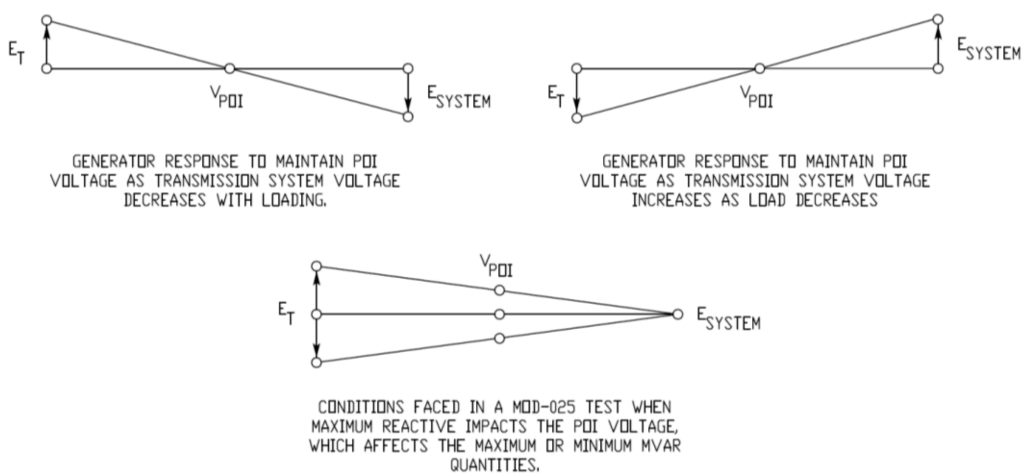


Figure 3.11: Change in Voltages during Test and Normal Conditions [Source: NRG Energy]

The TOP may elect to assist in coordinating reactive sources to aid in holding POI voltage for the generating unit under test as mentioned in Attachment 1 of MOD-025-2. However, the TOP is not required, per MOD-025-2, to coordinate other resources to support a reactive test if it is not prudent to do so. However, it is recommended that the TOP support or accommodate favorable conditions for MOD-025-2 testing. System voltage may be varied slightly, to the extent possible, such that the terminal and auxiliary bus voltages of the unit being tested remain within normal operating limits. Supplying high amounts of reactive power from the generator increases the voltage drop across the GSU, which is not an issue during actual grid disturbances when bus voltages fall and MVARs are automatically increased as the excitation system responds to the event (and vice versa for high system voltage events). However, exporting maximum reactive power during a test when system voltage is already within normal operating ranges tends to drive system voltage to above-normal levels, and this may limit reactive power output during testing (before reaching generator capability, or generator terminal or auxiliary bus voltage limits).

Figure 3.12 illustrates how system voltage level may limit the ability of the GO to get to either the field limit or UEL[35] and under what conditions for a given value of active power output (P_{max}). The left chart shows the range of reactive power at the generator terminals when the terminal voltage is adjusted between 0.95–1.05 pu with reactive power output of other units on the grid remaining relatively constant. It also shows how the system voltage will vary when the generator terminal voltage is adjusted when system voltage is at a normal value of 240 kV when the generator is at 1.0 pu. The middle chart shows how the reactive power range diminishes as the short circuit level (grid strength) decreases. The range of available testing reduces because the dV/dQ sensitivity under the weaker grid strength increases; changes in reactive power output result in larger changes of system voltage level. The right chart shows how the range is affected when system voltage is high when the unit is at 1.0 pu. The range of available testing is shifted down, allowing for testing up to or near the full under-excited capability of the machine. The same situation is true when system voltage is lower for a 1.0 pu terminal voltage, allowing for capability testing up to or nearer full over-excited range. One can observe similar results to those in the right chart when the generator transformer taps are set to a position further away from nominal.

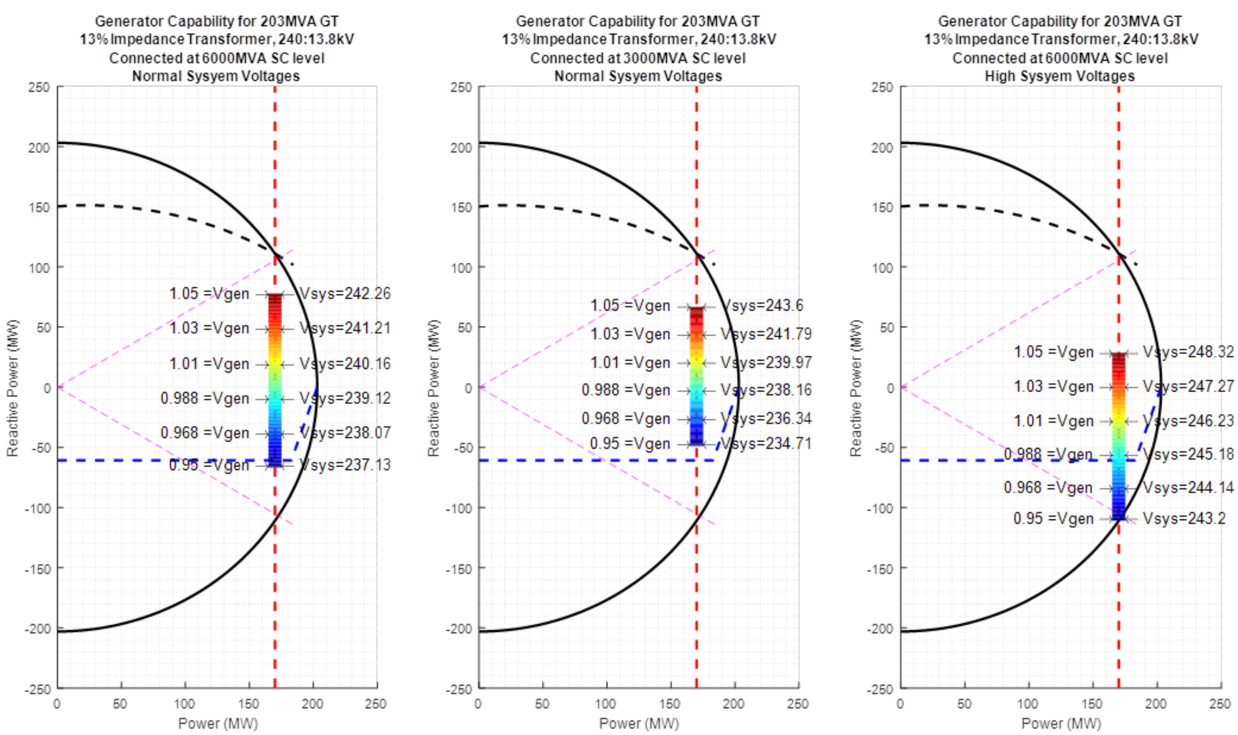


Figure 3.12: Impact of System Voltage on Capability Testing [Source: IESO]

[35] Field limit, stator limit, and UEL are only shown at 1.0 pu for figure simplicity.

Figure 3.13 shows how a unit with no degradation of reactive capability (below what is shown on the generator OEM D-curve) can be "dialed-in" to a successful MOD-025-2 test or "dialed-out" depending on the ability and willingness of the TOP to adjust system voltages if possible. In the event that conditions conducive to testing could not be achieved, the MOD-025-2 as-measured data may be adjusted using calculations to capability or limiter limits that were not restricted by system conditions (i.e., Note 2 of MOD-025-2).

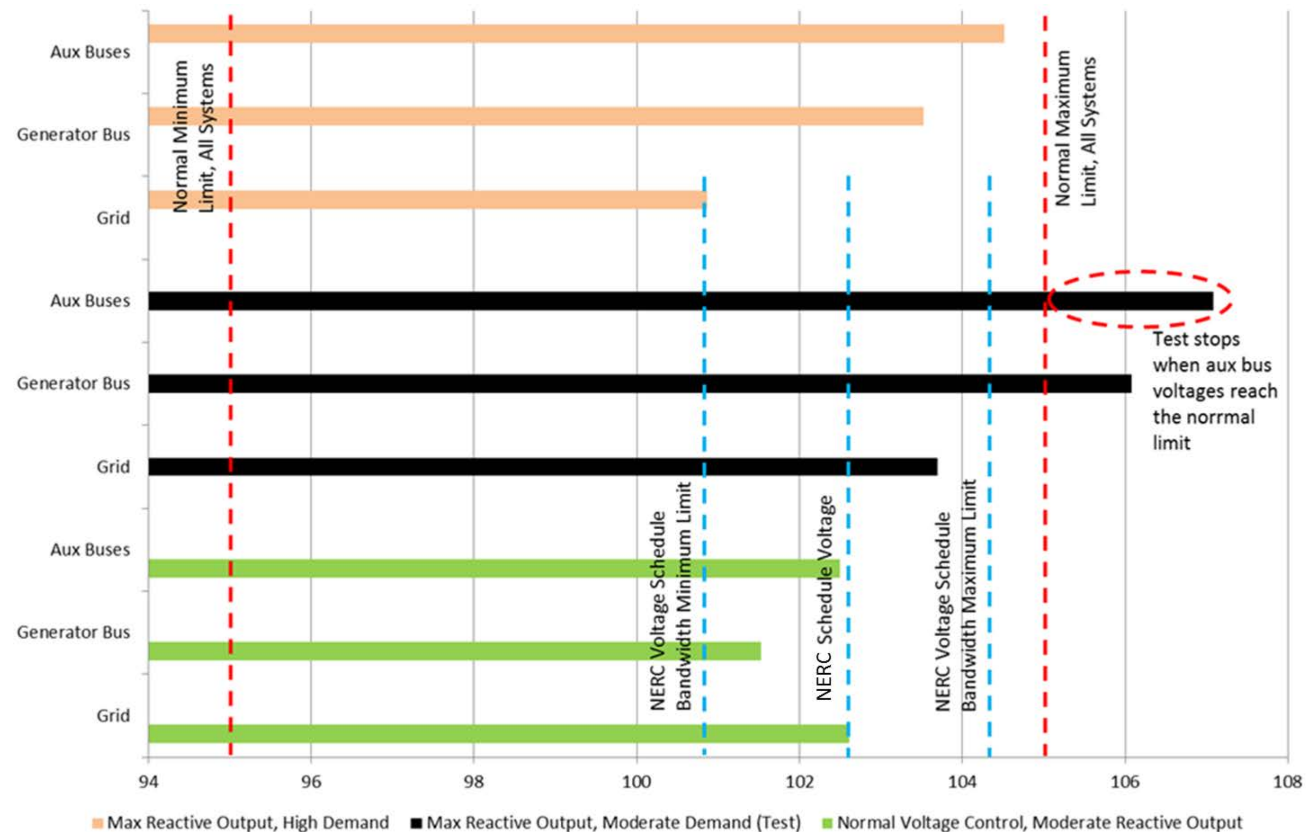


Figure 3.13: Adjustment of System Voltage for Successful MOD-025-2 Testing

Utilization of Other Units

There are electrical configurations and instances where the GO may be able to utilize units at a common station, sharing a common bus, or sharing a common transformer to maximize the opportunity that the unit under test will reach its maximum reactive power output and not be limited by other factors (e.g., terminal voltage fluctuations, system voltage limits). This is particularly useful in situations of low short-circuit ratio where the size of the unit is relatively large compared with the short circuit MVA at that interconnection point. In these cases (e.g., large units or weak grids), changes in reactive output have a larger impact on system voltage as compared with a system with very high short-circuit ratio. It is also useful to the GO in situations where system voltage is high and without the ability to utilize other units. The concept of utilizing other units' capability for the purposes of testing may be constrained by additional factors not considered here, such as fuel availability (e.g., limited reservoir capability (min head)), other plant limitations, and system operating condition limitations (e.g., dispatch of other generating units in the vicinity).

Recommendation: The GO should coordinate with the TP and PC prior to testing to ensure that the planned testing procedure and how to utilize other units' capability are adequate. Utilizing other units' capability during capability testing helps utilize additional reactive resources to ensure to the best extent possible that reactive capability is reached.

MOD-025-2 does not include requirements focusing on utilization of other units. However, to the extent possible, coordination with other resources within the plant can help enable reaching higher reactive power output levels closer to the D-curve in many cases. In addition, the TOP may have the ability to adjust the output of nearby generators and use other transmission elements (e.g., switch shunt capacitors or reactors or change set points of dynamic reactive devices). Appendix D, Cases 2 and 3 provide useful examples that illustrate how utilizing other reactive resources can help ensure to the best possible extent that reactive capability is reached. This also helps minimize the use of calculations to demonstrate presumed reactive capability under different operating conditions. It also helps capture any actual limitations that may not be expected to be reached by these calculations. Without accounting for additional nearby units (in the plant, on the common bus, or on the common transformer), the tested unit may max out at different levels of reactive output depending on the operating point of the other unit.

This process is mutually beneficial for the TOP and GOP in that system voltage fluctuations are minimized and potential violations of voltage limits within the plant are mitigated to the extent possible. The GO should coordinate with the TP and PC prior to testing to ensure that the planned testing procedure and how to utilize other units' capability are adequate.

Units that Operate at Only One Output Level

MOD-025-2, Attachment 1, Section 2.2.1 states that applicable generators should be tested "at the minimum real power output at which they are normally expected to operate." At this minimum output, maximum leading (under-excited) and lagging (over-excited) reactive values are collected as soon as a limit is reached. Some generators, although relatively rare, may be obligated (e.g., contractually) to operate at a single output level at all times other than when ramping on-line and off-line. In this case, the maximum and minimum active power output levels at which they are "normally expected to operate" are equal to each other. It may be reasonable that the generator is only tested at this single active power output level for MOD-025-2, Attachment 1, Sections 2.1.1, 2.2.1, and 2.2.2. When submitting the test information for this situation, the GO should include a technical basis and note on the test form stating the particular reason why the unit is only expected to normally operate at that single level.[36] This minimizes any extraneous information that could be provided to the TP, reduces the likelihood that the models will misrepresent the unit's capability, and clarifies what is needed for the GO. The steady-state models provided to the TP should then also reflect these conditions with $P_{max} = P_{min}$ and corresponding Q_{max} (over-excited) and Q_{min} (under-excited) for this one active power output level.

MOD-025-2, Attachment 1, specification 2.2.3 explicitly states that "Nuclear Units are not required to perform reactive power verification at minimum Real Power output"; hence, these units only need to be tested for reactive power capability at maximum active power output.

[36] Units "normally" operating at a single output level due to economic dispatch reasons do not qualify for this condition. The economic dispatch of a machine is not technical justification for it to only be tested at one level. The technical justification should be based on a contractual or regulatory limitation. Historical output data should be provided as technical justification that the plant normally operates at only one output level.

MOD-032-1 Data and MOD-025-2 Testing

MOD-025-2 and MOD-032-1 are two closely related standards for testing and reporting maximum and minimum active and reactive power of a generating unit. MOD-025-2 requires testing generating units and reporting the following results obtained during test:

- Gross maximum and minimum active power capability
- Maximum and minimum reactive power capability at active power capabilities provided above

Attachment 1 of MOD-032-1 describes the steady-state data that should be submitted by the GO for generating units, including the following:

- **Active Power Capabilities:** Gross maximum and minimum values
- **Reactive Power Capabilities:** Maximum and minimum value at active power capabilities provided above

While some tools do have the capability to represent a machine's steady-state capability curve, most tools simply model a machine by specifying these four points from both MOD-025-2 and MOD-032-1:

- **P_{max}:** The lesser of the mechanical power of the turbine and the continuous electrical capability of the generator for +/- 0.95 lead/lag power factor, measured at the generator terminals, excluding all supplemental firing capability (or any power augmentation) for ambient conditions specified by the TP
- **P_{min}:** The minimum generator output [MW], measured at the generator terminals, to ensure the generating unit does not become unstable or violate any emissions regulations
- **Q_{max}:** Maximum sustained overexcited reactive output [MVAR] at the generator terminals, at the maximum active power capability (P_{max}). These values should be based on the most limiting constraints as shown in PRC-019-2 coordination curves (e.g., overexcitation limiter), and based on 1.0 pu terminal voltage.
- **Q_{min}:** Maximum sustained underexcited reactive output [MVAR] at the generator terminals, at the maximum active power capability (P_{max}). These values should be based on the most limiting constraints as shown in PRC-019-2 coordination curves (e.g., underexcitation limiter, loss of field), and based on 1.0 pu terminal voltage.

An important consideration is whether the reported maximum and minimum capabilities from the MOD-025-2 testing should be the same as the data supplied for MOD-032-1 purposes. The answer to this question is "not necessarily" for the following reasons:

- MOD-025-2 testing provides the maximum and minimum capability (including limiters) that a unit is able to demonstrate under operating conditions at the time of the test. The test may be limited by system voltage or auxiliary bus voltage, and these conditions may preclude the unit from achieving its full capability at that time. The data reported for MOD-025-2 testing is not required to be representative of the reactive capability of the machine. However, values from these tests may be used to determine the applicable capability of a unit.[37]
- MOD-032-1 generator reactive capability data should be the maximum and minimum reactive capability that the unit can provide (including limiters). This should not be any value limited by auxiliary bus voltages or system voltages during the time of any test. In powerflow studies, for example, the reactive power will be demanded of the unit when the terminal voltage is low.

[37] MOD-025-2, Attachment 1, Note 2 states: "While not required by the standard, it is desirable to perform engineering analyses to determine expected applicable Facility capabilities under less restrictive system voltages than those encountered during the verification. Even though this analysis will not verify the complete thermal capability curve (D-curve), it provides a reasonable estimate of applicable Facility capability that the Transmission Planner can use for modeling."

Figure 3.14 shows an example of a machine capability curve with the testing results within the capability of the machine, which would get reported for MOD-025-2 testing. The test results may be limited by a number of factors as described in this guideline and not actually reflect the machine capability curve. The limits reached during testing are not necessarily equal to the specified capability limits of the machine (P_{max}, P_{min}, Q_{max}, Q_{min}) that should be provided to the TP for MOD-032-1. For Interconnection-wide modeling purposes, the TP and PC are expecting values that would be associated with the full capability of the machine for a 1.0 pu terminal voltage (i.e., the capability curve of the machine). As a distinct component in the simulation, these quantities should not be limited or restricted based on testing (other than limits associated with excitation limiters). On the other hand, MOD-025-2 capability curve testing provides actual values gathered during testing or during normal operation of the machine and may not uncover the actual machine capability if they cannot be reached due to other limitations during testing. The aforementioned Note 2 of MOD-025-2 provides an optional but highly recommended means whereby test results restricted by HV system conditions can be corrected to values usable for MOD-032-1. The same analysis will also show if limitations other than HV system voltage affected the MOD-025-2 verification, allowing correction to values measured during the test that do not reach the generator OEM D-curve boundaries (or applicable limiters that prevent reaching this capability).

Takeaway:
Machine capability data submitted for MOD-032-1 may not match the data collected during capability curve testing for MOD-025-2. The TP and PC should clearly outline the data to be supplied for MOD-032-1 reporting requirements, and should understand the limitations encountered during testing to make sure the data aligns. Engineering calculations may be used to identify the expected capability when limits are reached prior to reaching the actual capability curve during test; however, this is not a requirement of MOD-025-2. Hence why the MOD-032-1 and MOD-025-1 data for machine capability are not expected to match in all cases.

The TP, PC, and GO should not treat the MOD-032-1 capability data as necessarily the same as the MOD-025-2 as-tested capability results nor should they expect for the MOD-025-2 testing results to identically match the capability curve of the machine. If the actual capability testing reaches expected generator limitations, or calculations are used to demonstrate those limits, then the data should match closely. Otherwise, the MOD-032-1 data used for planning (and operating) cases will likely differ than the MOD-025-2 testing values.

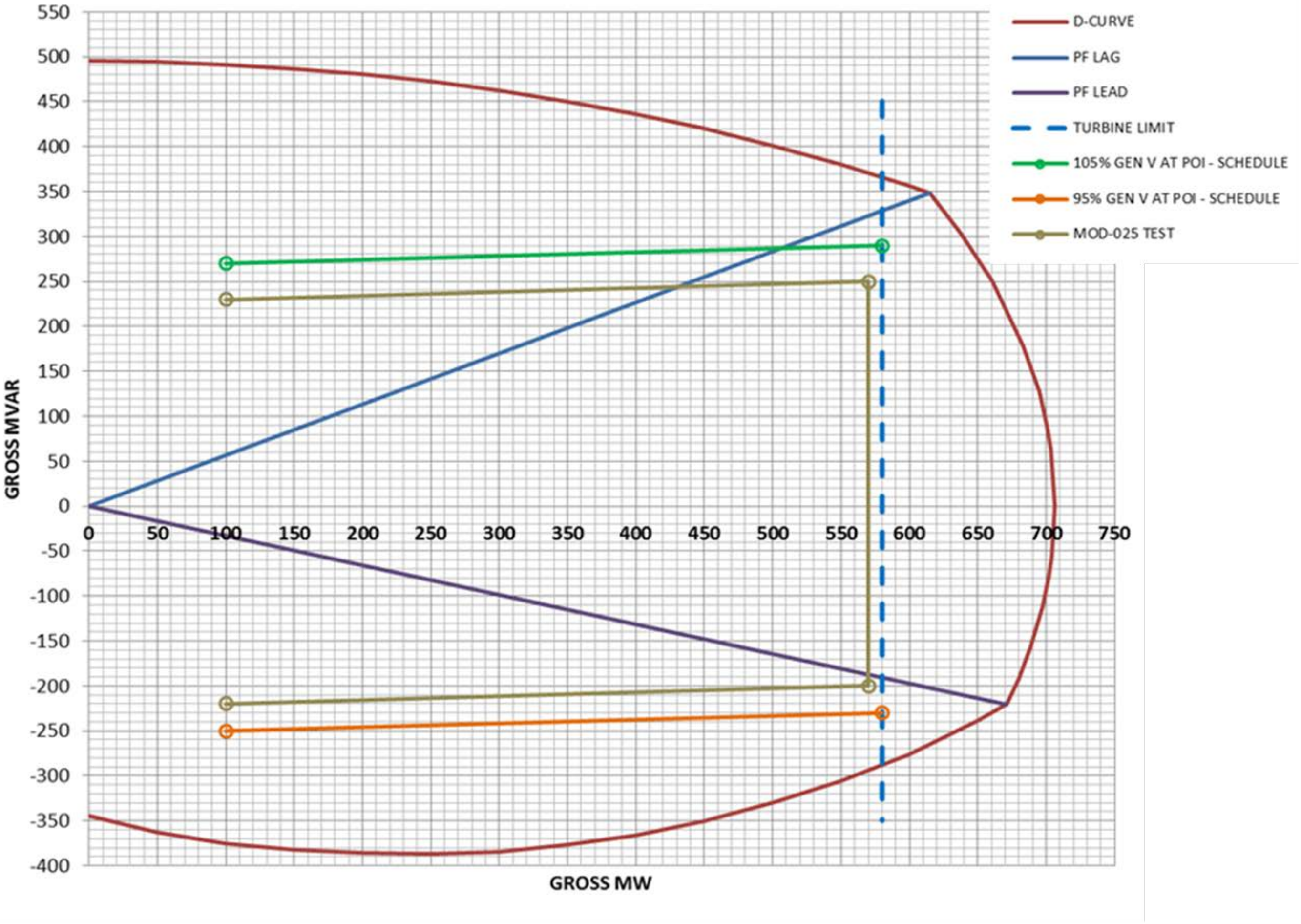


Figure 3.14: Difference between MOD-025-2 Testing and MOD-032-1 Data [Source: NRG Energy]

Chapter 4: MOD-026-1 Testing Procedures

The purpose of MOD-026-1 is to verify the generator excitation control system or plant volt/var control function dynamic models. This section describes the various tests that may be performed to develop or verify the dynamic models related to the generator excitation control system.

It is important to note that Footnote 1 of MOD-026-1, which describes the power plant elements that are considered part of the excitation control system[38] or plant volt/var control function:

> [1] "Excitation control system or plant volt/var control function:
>
> a. For individual synchronous machines, the generator excitation control system includes the generator, exciter, voltage regulator, impedance compensation and PSS.
>
> b. For an aggregate generating plant, the volt/var control system includes the voltage regulator & reactive power control system controlling and coordinating plant voltage and associated reactive capable resources."

Footnote 1 explicitly states that for synchronous machines, the generator, exciter, AVR, impedance compensation,[39] and PSS are all included as part of the generator excitation control system. Therefore, the generator, PSS, and compensation dynamic models, where applicable, should also be verified as part of MOD-026-1. The interactions of accuracy between the generator model and excitation system model (e.g., exciter masking bad generator data) should be accounted for. It is important to derive an accurate generator model prior to verifying the exciter model. This section covers the tests that may be relevant[40] to verifying a generator dynamic model as well as the exciter and PSS. As noted previously, where good OEM data exists for the generator model parameters (see Chapter 1), field testing is not likely to provide results that are deemed "better" for the generator parameters. In these cases, the emphasis of testing should be on validating the excitation system (AVR, exciter, current-compensation, and PSS).

Generator Open Circuit Magnetization (Saturation) Test

The open circuit magnetization (saturation curve) test is one of the most important verification tests since it defines the base values from which many other modeling parameters are derived from. Often, the results of the open circuit saturation curve test are iteratively refined to get a set of parameters that provide the best fit for capturing overall unit dynamic response. The machine is operating at full speed, no load (FSNL) with the generator main breaker open (i.e., not connected to the grid). Quite often, the excitation system is started under manual control at a reduced set point to start the saturation curve tests at a low value for field current and therefore terminal voltage. While maintaining excitation in manual control, terminal voltage (and obviously field current) is then increased, such that a sufficient number of samples are taken below 60 percent of rated terminal voltage and a sufficient number of samples are taken between 60 percent and up to 110 percent (generally not exceeding 1.05 pu[41]) per IEEE 115-2009. Sometimes, the test is conducted without an excitation start up (field flash). In these

[38] This echoes IEEE Std. 421.2 in defining the term, "excitation control system" as covering the combined performance of the synchronous machine, excitation system, and power system stabilizer.
[39] S. Patterson, "Cross-Current Compensation Model," WECC MVWG Meeting, October 2017. Available: https://www.wecc.biz/Administrative/Cross%20Current%20Compensation%20Model-Patterson-2017%20October.pdf.
[40] The tests described in this chapter are a suite of possible tests that may be performed under various conditions and circumstances. Not all tests are always required to verify a dynamic model; however, some tests may or may not be needed based on model performance.
[41] Typically most V/Hz limiters will be set to a value between 1.08 to 1.15 pu voltage; therefore, it may not be advisable to exceed 1.08 pu voltage in the saturation test.

cases, it is possible to perform the measurements from the highest value of terminal voltage (110 percent or, more typically, 105 percent) down to values as low as 50 percent of the rated terminal voltage or even lower. Note that some excitation systems may not allow the voltage to be reduced to below around 80 percent terminal voltage, even when the generator is off-line. To do so may require completely shutting down the unit and making temporary changes to the excitation system controls—this is typically ill-advisable as it may lead to inadvertent changes or damage to the unit or controls. Thus, whatever data can be safely and judiciously obtained from the open-circuit saturation curve test should be obtained and the best estimate of the air-gap line determined.[42]

It is critical to maintain excitation in manual control mode and take the measurements with the field current and the terminal voltage being monotonically changed in only one direction to avoid hysteresis[43] effects in the measurements. Terminal voltage and field current are recorded during the test and plotted against each other (**Figure 4.1**). Depending on the ability of the speed governor to maintain machine speed at a constant value during this test, it is necessary to record frequency (or speed) and correct the voltage measurements for deviations from nominal speed. Measurements of field voltage may also be useful and are recommended as they permit an assessment of the field resistance value and the field winding temperature during the test.

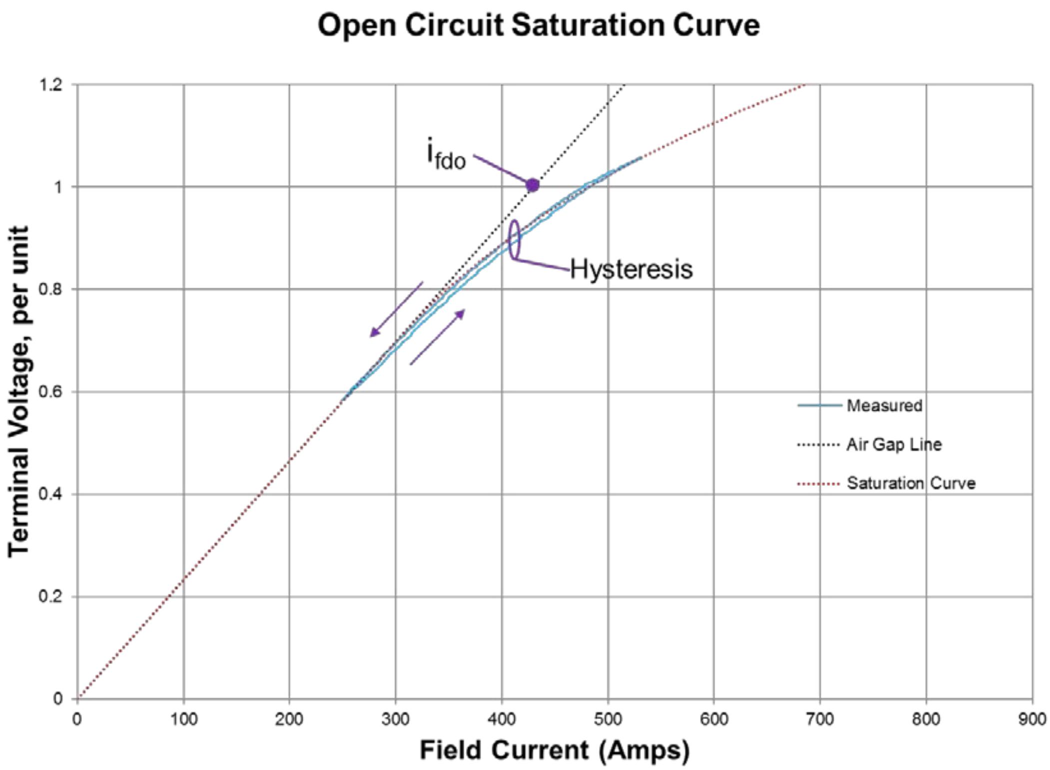


Figure 4.1: Open Circuit Saturation Curve Test Data [Source: US ACE]

The open circuit saturation curve test is used to estimate the air gap line field current at 1.0 pu terminal voltage ($i_{fag} = i_{fgbase}$ in **Figure 4.2**) and the open circuit magnetization saturation factors at 1.0 pu ($S_{1.0}$) and 1.2 pu ($S_{1.2}$) terminal voltage. A tangential line (air gap line) is drawn starting from the origin (zero terminal voltage and zero field current) through the lower voltage data points collected on the curve. Since data is generally only collected

[42] Refer to IEEE Std. 421.1 for more information.

[43] When a ferromagnetic material, such as the materials used in generators and transformers, is magnetized in one direction, it will not return back to zero or the same point it started from, when the imposed magnetic field is removed. This fact that the magnetic history of the material is not retraceable is a property commonly referred to as hysteresis. Thus, the measurements made during the saturation test must be monotonic to avoid skewing the results due to hysteresis.

between around 0.6[44] to 1.1 pu stator voltage,[45] engineering judgment is applied to get an air gap line that would be tangential to the lower voltage data if that data were available. Once the air gap line is established, a polynomial or exponential fit to the saturation curve data is established. Different software platforms may derive these curve fits differently, and this should be accounted for during model development. Existence of residual flux, which appears as an offset (positive stator voltage with no excitation applied), should be considered and adjustments made for in-service generators, compared with new units which have not been previously energized.

Figure 4.2 shows the data points needed to calculate the $S_{1.0}$ and $S_{1.2}$ values, and the equations for these values are provided below. It is important to know that these values are ratios of the difference between the air gap line and the actual measured data divided by the air gap line value. Therefore, these values should be in all but the rarest cases less than 1.0.

$$S(1.0) = \frac{I_{FNL} - I_{FAG}}{I_{FAG}}$$

$$S(1.2) = \frac{I_{F12} - I_{FAG2}}{I_{FAG2}}$$

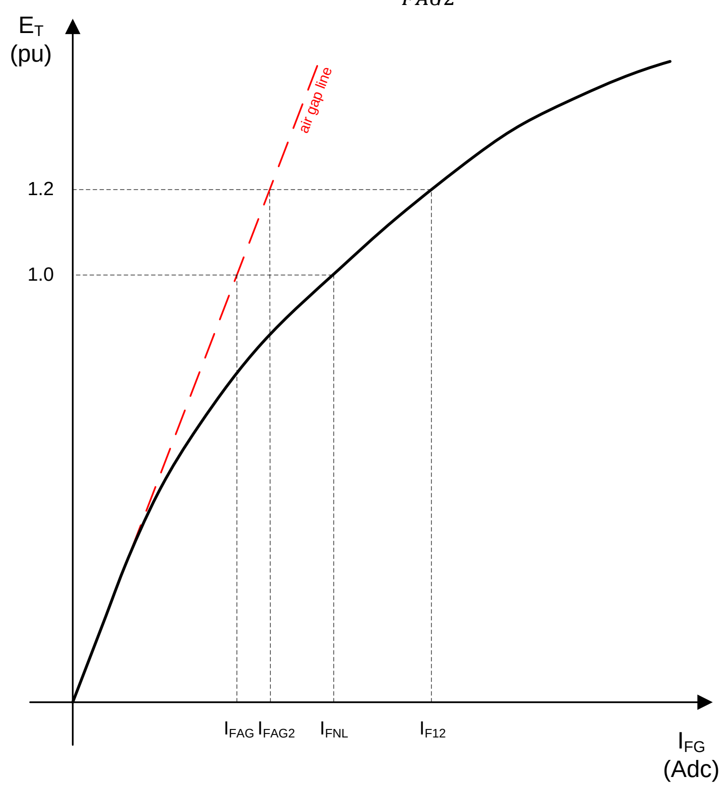


Figure 4.2: Open Circuit Saturation Curve Characteristics

The base field current is then used to find the base field voltage (E_{fgbase}) via the following equations, which is needed as a base quantity to per unitize many parameters for the excitation system (i.e., this is not possible without i_{fgbase}).[46]

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44 Some excitation systems may not be able to reach this low unless put into manual control, and some may not allow this at all. Also, residual flux in the machine may slightly skew the results of this test in real life.

45 V/Hz limiters can protect equipment from overflux, particularly when the unit is off-line. Care should be given during this test to avoid any damage to the generator and GSU.

46 The equations provided here for calculating field voltage base are from the IEEE Standards. These equations, however, do not take into consideration the fact that the rotor field resistance is not constant and varies with machine loading and rotor heating. Therefore, 1 pu

$$Efg_{base} = Ifg_{base} * R_{100°C}, for\ thermal\ units.$$

$$Efg_{base} = Ifg_{base} * R_{75°C}, for\ hydro\ electric\ units.$$

It is important to bear in mind that the open circuit saturation curve is non-linear to some degree over its entirety, and that the placement of an assumed tangent air gap line is somewhat subjective and should be considered as a starting point. The subsequent fitting of V-curve data to a model will often suggest a better fit by reconsidering the base air gap field current and perhaps the saturation function parameters (S(1.0), S(1.2)). Therefore, the definition of the open circuit saturation model and the entire steady state model of the machine can be an iterative process. Refer to the following illustrative example (**Figure 4.4**) to emphasize how E_{fgbase} is used and applied in calculations of machine parameters.

field voltage is not a constant number nor is the generator field time constant. These are facts of actual testing that cannot be captured by simple, constant parameter modeling.

Illustrative Example:
Assume a static exciter with the following:

- Excitation transformer $V_{secondary}$ = 480V, $V_{primary}$ = $V_{gen,rated}$.
- E_{fgbase} = 100 V_{DC} , from I_{fgbase} and R measurements
- Alpha min = 20, alpha max =150
- Represented by the ESST4B model

Ed0, the theoretical maximum DC voltage at the output of a 6-pulse rectifier (and this example is only applicable to 6-pulse bridges) is calculated as Ed0 = 1.35 * $V_{secondary}$.

One way to set up the model is then derived using these base values:
KP = Ed0/E_{fgbase} = 1.35*480/E_{fgbase} = 6.48 pu
VMMAX = 0.94pu
VMMIN= -0.866pu

This information can be used to determine the value of various programmable settings in the AVR and the size of the voltage reference step needed to reach the ceilings on open circuit.

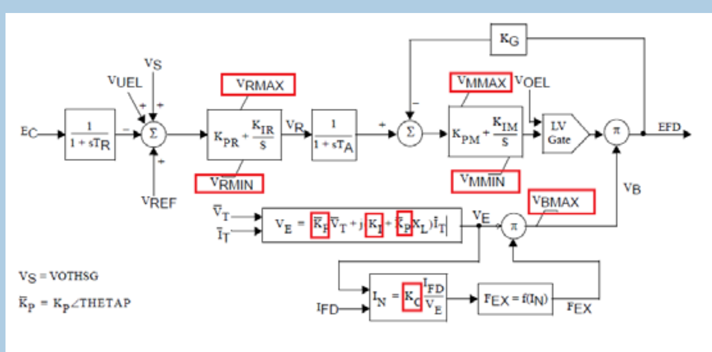

Figure 4.4: Annotated ESST4B Model [Source: Siemens PTI]

Rotating Exciters

Excitation systems that incorporate a rotating machine are typically modeled such that the machine is represented by a single time constant (T_E) and the effective non-linear gain (which includes machine saturation). If the exciter is a dc generator, this portion of the model is represented by the blocks shown in Figure 4.3.

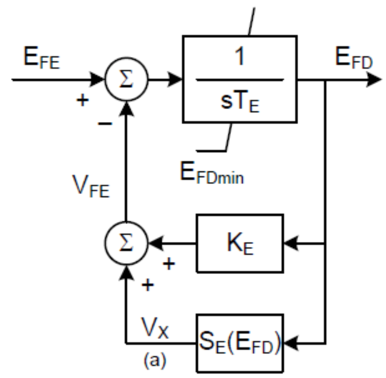

Figure 4.3: DC Exciter Representation

To properly model these systems, it is first necessary to obtain the saturation characteristic of the machine (field voltage as a function of exciter field current). If the manufacturer's data is not available, static data points taken at different load points of the unit can be used to approximate the saturation curve, since for dc machines the appropriate saturation function is with the exciter under load (i.e., supplying current to the generator main field circuit). The base exciter field current can be set either with the air gap line shown in Figure 4.5, or with a constant resistance load line drawn against the load saturation curve, akin to the air gap line as drawn against the no load saturation curve.

For rotating exciters which are an ac machine, the no-load saturation characteristic of the machine should be used to define S_E, since the loading effects are included elsewhere in the model.

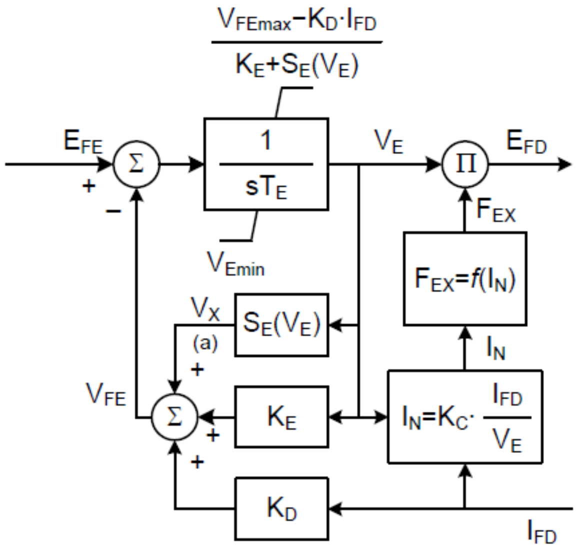

Figure 4.5: AC Exciter Representation

In this case, the manufacturer's saturation data will be necessary. The time constant of a rotating exciter (T_E) is critical to the model response and should be validated through test if the manufacturer's value is not provided (see **Figure 4.6**). For a brushless excitation system, the manufacturer's data will be the only possible source of the saturation and time constant portions of the model. If the OEM data is not available, then engineering judgment should be used to develop a reasonable estimate of the parameters.

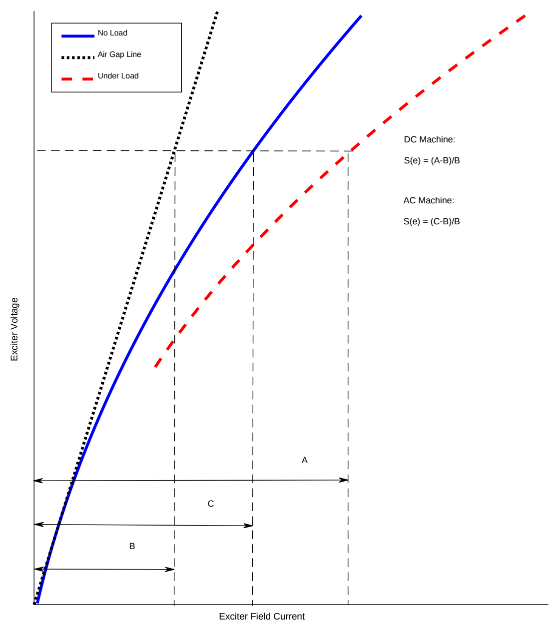

Figure 4.6: Rotating Exciter Saturation Curve

As long as both the exciter output voltage and exciter field voltage are available for measurement, the entire rotating exciter model, including T_E, can be validated using a variety of dynamic response measurements such as a frequency response as shown in **Figure 4.7**.

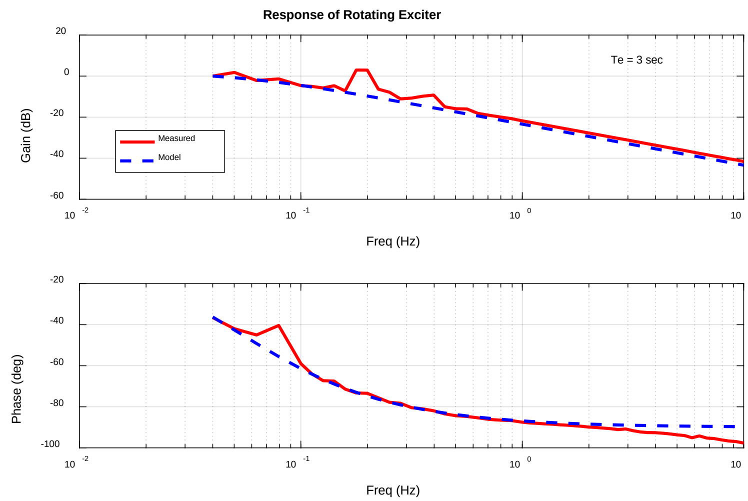

Figure 4.7: Example of Frequency Response Test for Rotating Exciter

The remaining components of the rotating exciter models are set by calculation and equipment type. Software documentation and IEEE Standard 421.5[47] should be consulted for details.

Brushless Exciters

When it is possible, [48] measuring the open-circuit saturation curve is particularly important in the case of brushless excitation systems in order to establish the base for the field current of the exciter (see Figure 4.8). In the case of a brushless excitation system, the graph is a plot of exciter field current versus generator stator voltage, and most OEM data sheets will not supply this. However, for units with static excitation systems, the measured open-circuit saturation curve will often match the OEM data sheets to within expected measurement error unless the actual equipment has defects, such as a shorted field winding. Refer to IEEE 421.5 for more information.

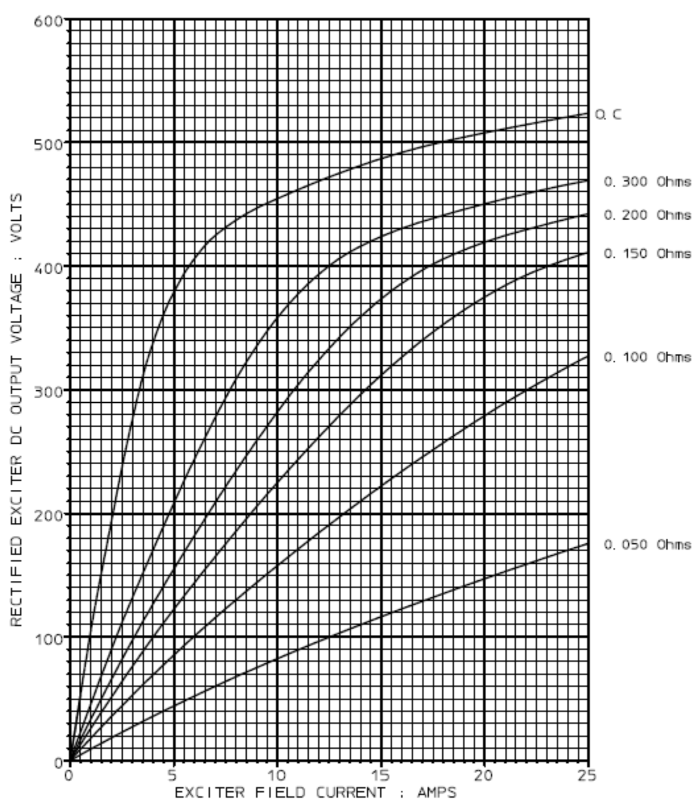

Figure 4.8: Rectified Exciter Saturation Curve [Source: Brush]

In all cases, an exciter model outputs field voltage with the assumption that the steady-state relationship between field voltage and field current is constant (fixed resistance). In reality, the temperature dependent resistance will require greater field voltage under higher running temperatures, which is not accounted for in the models. Therefore, the model should be set for the desired representation (e.g., full load temperature and the effects accounted for

[47] IEEE Std. 421.5-2016, Recommended Practice for Excitation System Models for Power System Stability Studies.

[48] A brushless rotating exciter open circuit saturation curve cannot be physically measured. In this case, it should be provided by the OEM.

accordingly in the saturation function in the dc models). In the ac models, variation in temperature can be accounted by adjusting KD. Effects, such as winding resistances being temperature-dependent, are important for matching measurements to simulations (i.e., for MOD-026-1 verification testing) but are then disregarded when these models are incorporated into the system database. This is not considered a problem for stability studies as these effects are mostly related to field quantities instead of the overall generator output.

Brushless Exciters: Determining Base Values Using Field Test

Having accurate base values for exciter field quantities is critical. They are used to determine the key parameters in ac exciter models, such as regulator output limits (V_{rmax}/V_{rmin}) and OEL pickup levels. However, vendor-provided exciter saturation curve (**Figure 4.8**) may not be available in many cases. Modelling engineers often have to determine the base values from field test data.

Figure 4.9 shows the composite saturation curve (function of the on-load saturation curve of the rotating exciter and the open-circuit saturation curve of the generator) obtained from field test for a generating unit with a brushless excitation system. Since the main generator's field circuit is not accessible, exciter field voltage and current are typically recorded and used as the base for field quantities. In this case, exciter field voltage and current base are determined as follows:

- I_{EF_BASE} = 1.8 A_{DC}
- $V_{EF\_BASE} = I_{EF\_BASE} * R_{EF}$ = 10.3 V_{DC} (R_{EF} = 5.6 Ohm)

Note that these base values do not correspond to the ac exciter's airgap field voltage/current[49] as they are taken with the ac exciter under loaded condition. Due to the demagnetizing effect of the exciter, the calculated field bases (V_{EF_BASE} *or* I_{EF_BASE}) are much larger than no-load airgap base values. To eliminate the influence of demagnetizing effect (represented by K_D in the model), base values derived from test data must be adjusted by dividing a factor of ($1+S_E+K_D$). The base values, after being adjusted, correspond to the exciter's airgap field voltage and current.

In this example, if we assume K_D = 1.8 pu and S_E = 0 pu, then the adjustment factor is 2.8 pu. The exciter field voltage and current bases after being adjusted are shown below.

- $I_{EF\_BASE\_adj}$ = 1.8 A_{DC} / 2.8 = 0.64 A_{DC}
- $V_{EF\_BASE\_adj}$ = 10.3 V_{DC} / 2.8 = 3.7 V_{DC}

The adjusted base values for exciter field quantities can be used to per-unitize the AVR settings, such as regulator output limits and OEL pickup levels.

[49] Airgap field voltage and current is defined in IEEE 421.1 as, "the synchronous machine field voltage required to produce rated voltage on the air-gap line," and the airgap line must be taken at no load conditions.

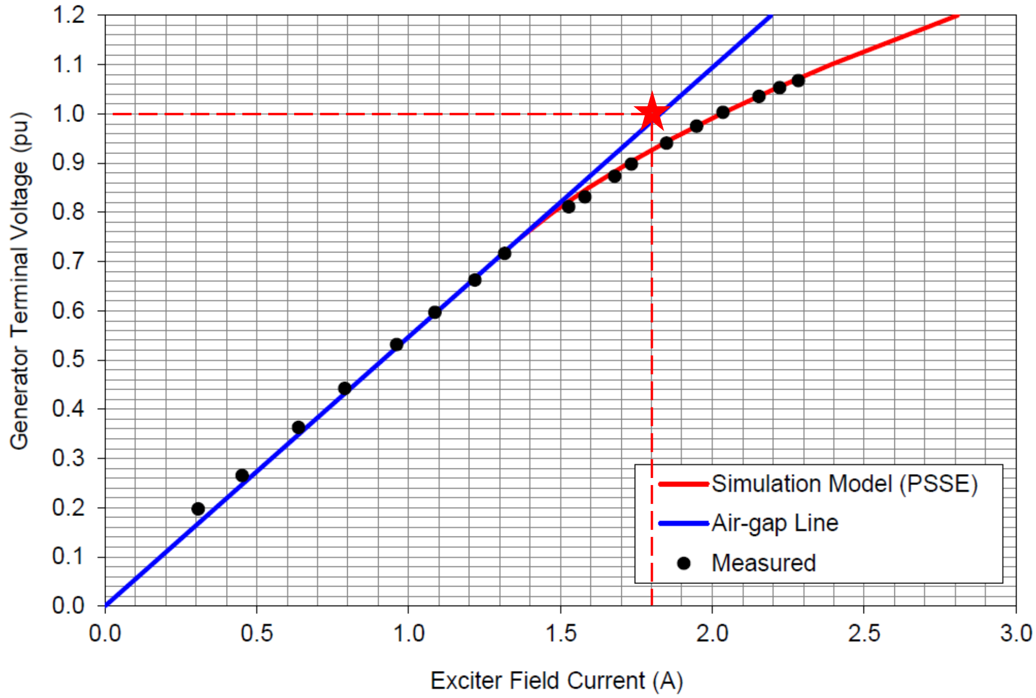

Figure 4.9: Sample Composite Saturation Curve, Unit with Brushless Exciter [Source: Powertech]

V-Curve and Reactive Limits

The V-curve test is intended to validate the d- and q-axis reactances (X_d and X_q), leakage reactive (X_l), and the saturation functions[50] of the generator model. A necessary use of this test data is in deriving the Kis parameter for the GENTPJ model. In this test, the following values should be recorded: field current, field voltage, active power, reactive power, and stator terminal voltage. It is important to monitor terminal voltage and stator current to ensure safe operation during this test. This data can be effectively collected during MOD-025-2 testing as well as to provide an economical means of gathering this information for modeling.

The V-curve test should be performed at a few different load levels on the machine. Typically these are in the range of near 0 percent, some partial load value (e.g., 50 percent or 70 percent), and near baseload (e.g., > 90 percent loading). The machine is dispatched at unity power factor (0 MVAR output). The amount of reactive power absorbed from the grid is increased slowly toward the lower limit to get steady-state measurements and stopped when a reactive limit or minimum acceptable operating state is reached. Reactive power is then incremented toward the upper limit and again stopped when a reactive limit or maximum acceptable operating state is reached. As reactive power is incremented from leading (under-excited) to lagging (over-excited) power factor, a half dozen to a dozen points are gathered along the way to record the steady-state values of MW, MVAR, kV, and field current/voltage. As with the open-circuit saturation test, it is critical that this test be done monotonically to avoid magnetic hysteresis. The reactive power is finally adjusted back to 0 MVAR output. The active power is adjusted to the new operating state, and the process is repeated at that other load levels. Figure 4.10 shows this process on a generic capability curve. Note that for nuclear units and large critical thermal units it may not be possible to perform this test at any operating condition other than at baseload. This should be sufficient in these cases. In the absence of test data at partial load, operational data during loading and unloading may be used to fill in the data gaps.

[50] NERC, "Use of GENTPJ Generator Model," NERC Modeling Notifications, Nov 2016. Available: HERE.

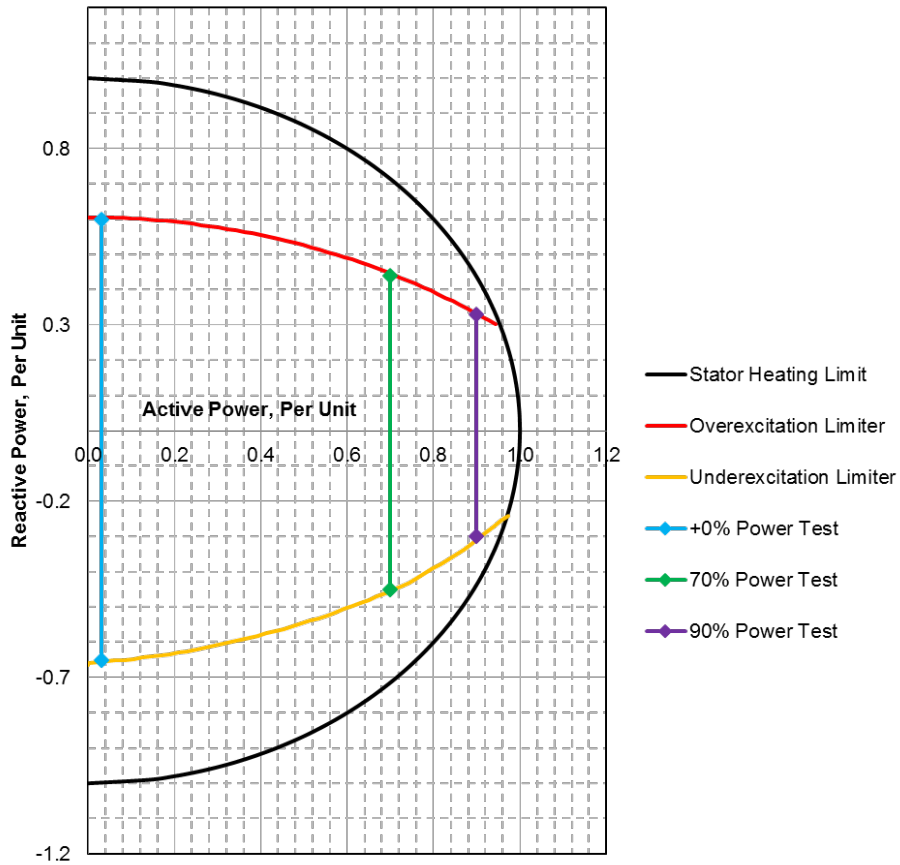

Figure 4.10: Testing Reactive Capability during V-Curve Test [Source: US ACE]

Getting an accurate V-curve and open circuit saturation curve fit (and representative parameters) includes an iterative process. First, the air gap line should be approximated from the available data. As described above, test data is obviously not collected for low voltages down to 0.0 pu, so the test data is used to fit the air gap line, which passes through the origin of the plot. The goal is to get a tangential line near the lowest terminal voltage data available since this will more accurately represent the air gap line being tangent to the remainder of the curve. Figure 4.11 shows the result of manually determining i_{fdo}. After this first step, the V-curve data between the steady-state model parameters and the actual test results are not expected to match.

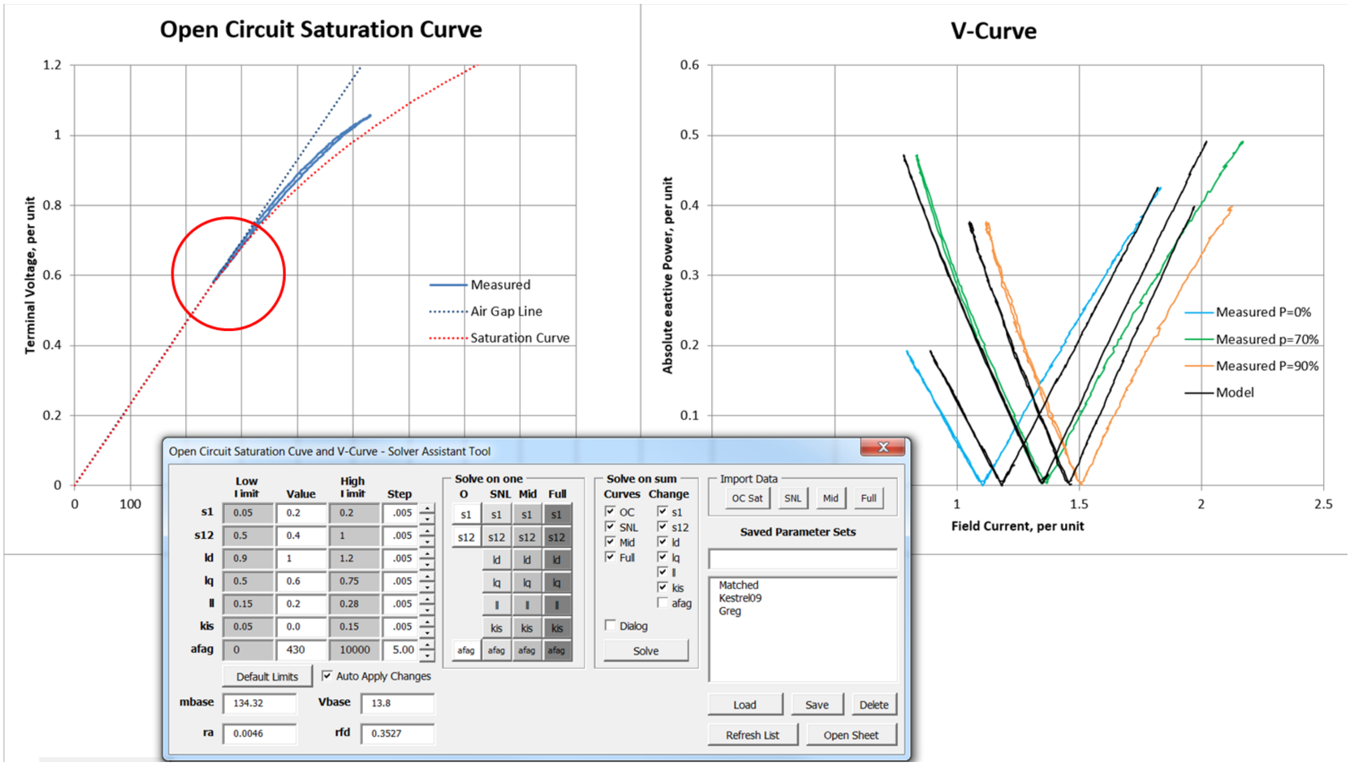

Figure 4.11: First Step in V-Curve Fitting – Determining i_{fdo} [Source: US ACE]

Next, $S_{1.0}$ is found by curve fitting to the low power output V-curve test results. This is shown in **Figure 4.12**. After this step, i_{fdo} and $S_{1.0}$ are set.

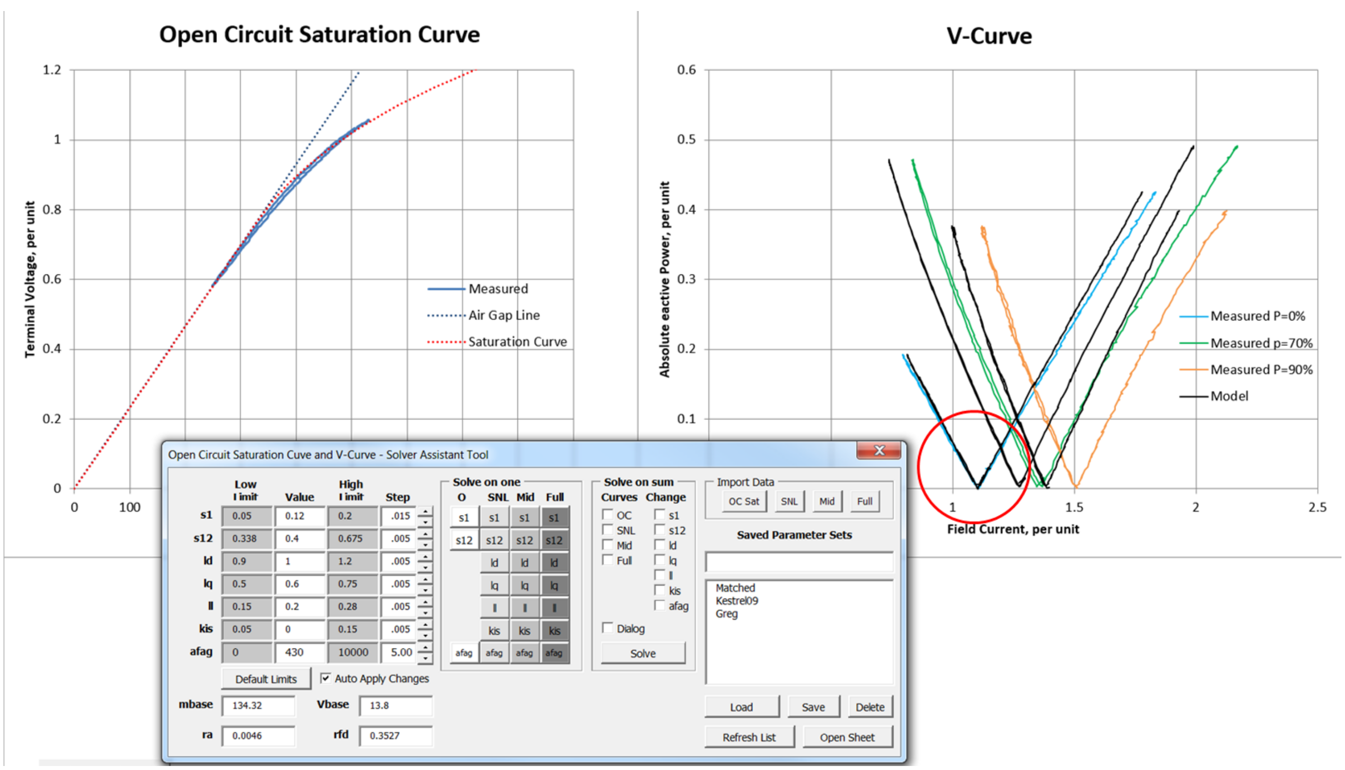

Figure 4.12: Second Step in V-Curve Fitting – Determining $S_{1.0}$ [Source: US ACE]

The final step is to iteratively estimate the remaining generator parameters ($S_{1.2}$, L_d, L_q, l_l, K_{is}) by fitting the v-curves. Often it is easier to fit $S_{1.2}$ using the v-curves because the open circuit saturation curve data does not go far enough to clearly define it. When other information is available that can confidently be used to define any of the other parameters, those parameters can be fixed and the other parameters solved for. It is important to note that the models are not perfect and theoretically correct parameters may not always give the best fit for the model being used. **Figure 4.13** shows the final result of this process. There are openly available tools[51] that can help automatically solve for the optimal parameters following the process just described. Note that there are tools that can do this in fewer steps using optimization algorithms.[52]

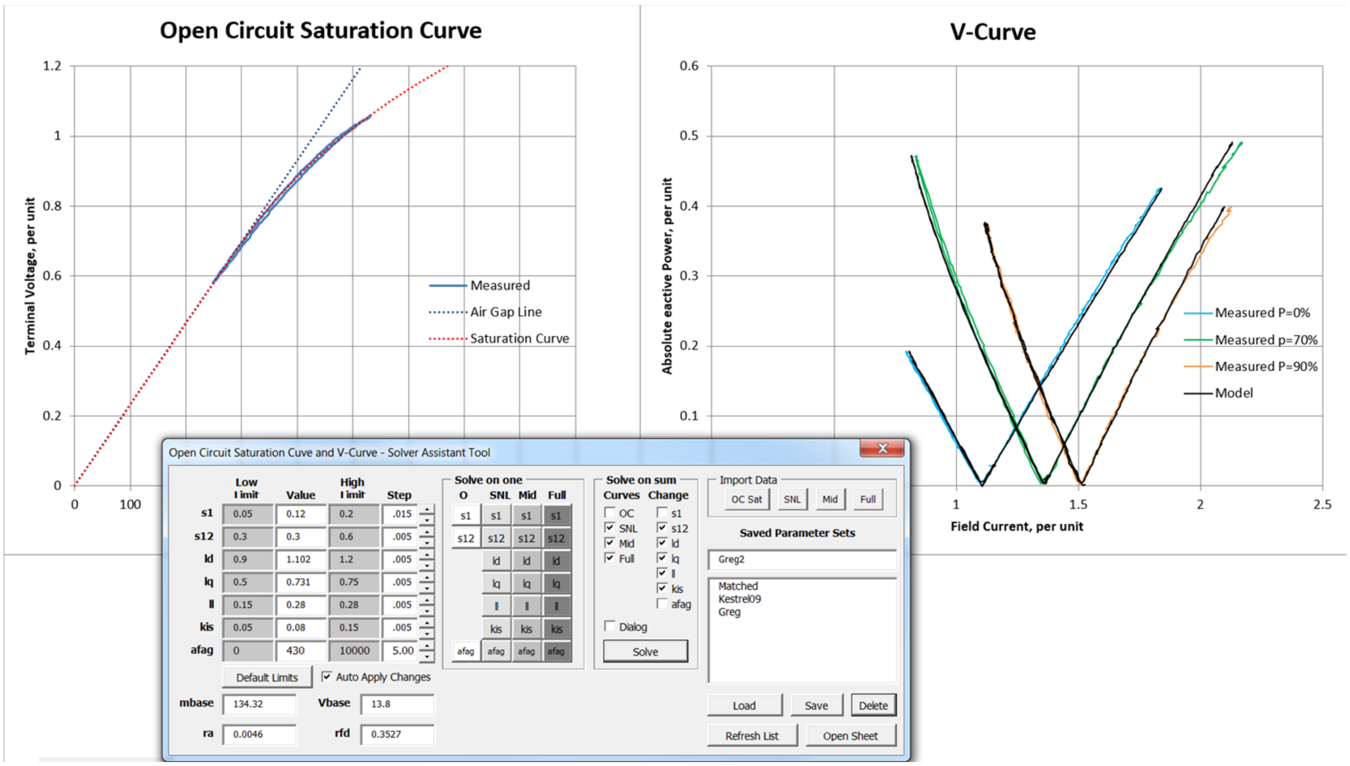

Figure 4.13: Final Step in V-Curve Fitting [Source: US ACE]

[51] An open source Microsoft Excel-based tool can be downloaded from the NERC SAMS webpage. This tool was developed by the U.S. Army Corps of Engineers.

[52] For example, EPRI's PPPD tool or U.S. Army Corps of Engineers Optimization Tool.

Load Rejection Test

The inertia constant (H) of a machine is an integral part of analyzing the stability of the interconnected BPS and it has implications on system stability assessment, unit stability performance, and reliable planning and operation of the BPS. Inaccurate values of H can lead to either conservative or optimistic results of system stability. If the modeled inertia constant is too low, conservative result (less stable) will be observed. On the other hand, an optimistic value of H, where it is modeled too high, can lead to overestimation of system stability conditions and potential instabilities during actual system operation that were unexpected during the near-term planning horizon, operational planning assessments, or real-time assessments. The inertia constant is also an integral part of tuning the PSS, and a representative estimate of H, is necessary for correct tuning. All these issues can impact transmission investments, plant performance, critical clearing times, and other issues related to the interface between generation and transmission.

> **Takeaway:** Typically the generator dynamics models used for positive sequence stability simulations include an inertia parameter that includes both the generator and turbine. Verify that the data collected from the manufacturer includes both components and compare with what is expected for the model.

The most accurate means of determining H is to review technical drawings or information supplied by the manufacturer for the generator and turbine. This is because, from a fundamental l standpoint, the best value of H is determined through detailed calculations from the exact dimensions of the turbine-generator mechanical shaft. Manufacturers use detailed finite element models of the drive-train assembly for their design and manufacturing process and thus can derive a very accurate value of H for both the electrical generator and the turbine-assembly and thus the combined total turbine-generator value of H. A machine manufacturer will always have calculated the inertia for its equipment, but the value may sometimes need to be converted to the correct basis. H is the ratio of kinetic energy to generator rated MVA, where H has units of MW-sec/MVA and WR^2 is lbm-ft^2, and is obtained from the equation.[53,54]

$$H = \frac{0.231 * WR^2 * RPM^2 * 10^{-9}}{MVA_{Gen\ Nameplate}}$$

Some OEMs may instead provide a GD^2 rotational inertia value, which must be converted from diameter to radius and from SI units to imperial units if being plugged into the formula above. Additionally, the H value must be recalculated if raising the generator nameplate MVA in a manner that leaves the rotational inertia unaffected (e.g., due to cooling system improvements). Manufacturers may also only provide H for the generator and not include the turbine or rotating exciter. The turbine inertia must be accounted for as it is often the largest portion of the inertia for large steam-turbines and heavy-duty natural gas turbines; for hydroelectric generators the turbine usually represents 5–10 percent of the total inertia. In most situations, these data points collected from the manufacturer data should be trusted as the most accurate source of data for H, since H is not meaningfully affected by manufacturing tolerances, maintenance, repair, or long-term wear and tear.

> **Takeaway:** Load rejection tests and derivation of H from these tests should not be used to derive H from scratch. In the event that no manufacturer data is available, if a load rejection test is to be used to derive H; however, there is inherent error in using this test data that result in the slope of the response not being an accurate measurement of solely the inertia of the machine.

Load rejection tests and derivation of H from these tests should not be used to derive H from scratch. In the event that no manufacturer data is available, a load rejection test may be necessary to derive H; however, there is

[53] The equation for H in SI units is $H= ½J\omega^2$, where J is the total moment of inertia of the combined turbine-generator assembly in kg.m^2, and ω is the base mechanical angular speed in rad/s.

[54] 0.5 [kinetic energy is ½mV^2] * (lbf-sec^2/32.174 lbm-ft) * (lbm-ft^2) * (rev/min)^2 * (2 * 3.14159 rad)^2/rev^2 * min^2/(60 sec)^2 * kW/(737.6 ft-lbf/sec) = 0.231 * 10^{-6} kW-sec

inherent error in using test data that results in the slope of the response not being an accurate measurement of solely the inertia of the machine. Examples include the following:

- Fast-acting fuel/steam shutoff valve action following unit breaker-trip signal
- Governor response
- Turbine damping
- Inaccuracy in drawing a tangential line to the acceleration curve near the *t = 0* point
- Friction and windage
- Mechanical load (e.g., compressor braking for single-shaft natural gas turbines)
- Measurement errors in the measured initial power/load rejected and the calculated speed of the unit after load rejection

These effects can lead to overestimating or underestimating the inertia; which may also overestimate or underestimate system stability. Load rejection tests may also impose unnecessary stresses on boilers, turbines, and other equipment and should not be undertaken at high load levels without justification.

If no alternative derivation of H is available, load rejection tests can be performed by dispatching the unit on-line carrying load at relatively low levels (e.g., 5–20 percent). Once measurement recording is started, the operator opens the main generator circuit breaker[55] and the dynamic response is recorded. The pre- and post-rejection active power output should be recorded for the test to determine the change in power output. Frequency is measured during the test and a tangential line is drawn at the point of rejection against the frequency measurement over time, typically within the first couple hundred milliseconds. Frequency is often calculated from the terminal voltage (V_t) waveform measurement (since other frequency measurements may be noisy), and any resulting voltage transient may appear in the speed measurement. **Figure 4.14**, **Figure 4.15**, and **Table 4.1** show examples of frequency measured over time for load rejection tests. The inertia constant is derived using the following equations:

$$H = \frac{\Delta P_{pu}}{2 * \left(\frac{\Delta f_{pu}}{\Delta t}\right)}$$

$$\Delta f_{pu} = f2 - f1$$

$$\Delta t = t2 - t1$$

If the test results compare reasonably well to the expected H value, supplied by the manufacturer, verification is complete. The load rejection test can be used to check the calculated H value but should not be used in determining H value directly. If the calculated H value is not confirmed by the load rejection test then it may be necessary to contact the manufacturer or obtain information to determine more accurate characteristics during a turbine overhaul. Again, it is emphasized that load rejection tests are not necessary where good vendor-calculated values of H exist.

[55] Some testing engineers may, based on their discretion, place the AVR in manual for this test, which may be able to determine inertia as well as quadrature axis reactance in one test. However, this is not required and is not recommended at higher loading since tripping a higher load at full speed with the AVR in manual will result in a high terminal voltage.

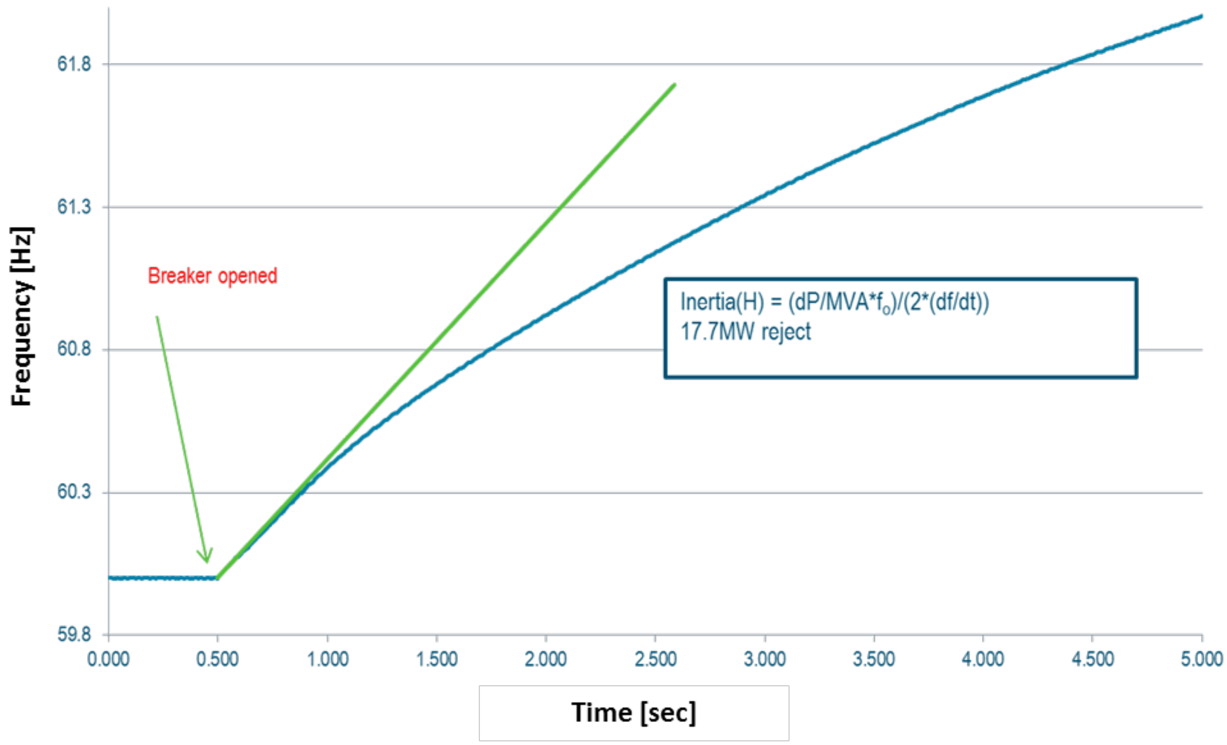

Figure 4.14: Load Rejection Test and Estimation of Inertia Constant for 156 MVA Unit

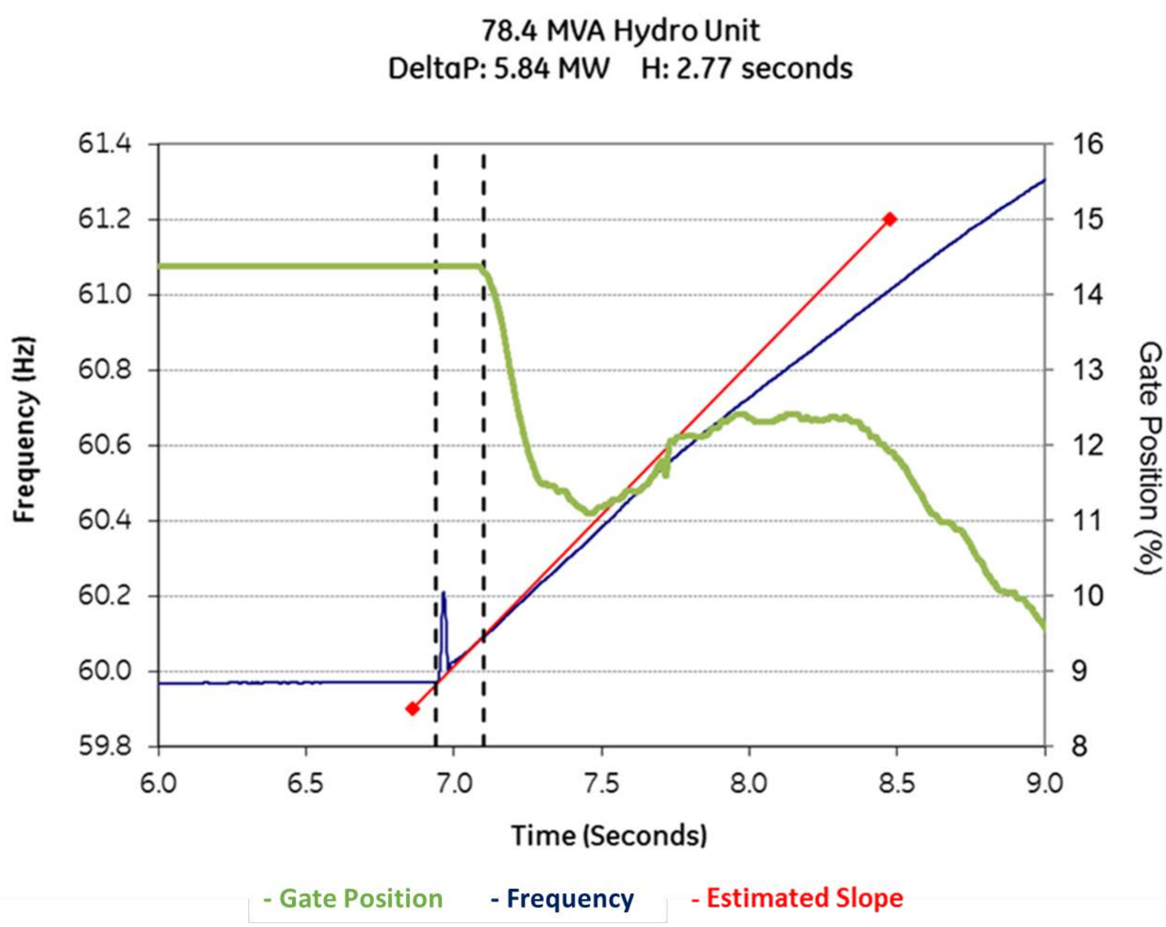

Figure 4.15: Load Rejection Test and Estimation of Inertia Constant for Hydro Unit

Table 4.1: H from Plot Interpretation	
Parameter	**Value**
Base MVA	78.4
Preseparation Power (MW)	5.84
ΔP Pre-Separation Power (pu)	0.074
Base Frequency (Hz)	60.0
Straight-Line Delta Speed (Hz)	1.30
ΔS: Straight-Line Delta Speed (pu)	0.0217
ΔT: Straight-Line Delta Time (sec)	1.615
H: Inertia Constant (sec)	2.77

Takeaway: The spike in measured frequency (speed) near the breaker opening is an instrumentation artifact due to the frequency signal being derived from the terminal voltage. When the breaker opens, the excitation level of the machine is different than what is needed open circuited, resulting in a voltage transient. It's an indicator of when the breaker opened, but it should be ignored (as best as possible) as far as the speed determination is concerned.

Stator Current Interruption Test

In instances where OEM generator design data are unavailable or the accuracy of the data is in dispute, it may be possible to perform stator current interruption tests to help determine the d- and q-axis generator model parameters.

The adequacy of d- and q-axis generator model parameters can be determined through a comparison of dynamic simulations and recorded tests. Stator current interruption tests (or breaker openings) from zero power factor and under-excited[56] can be used for the identification of the generator model d-axis parameters. Identification of the generator model q-axis parameters can be attempted through rejection tests from load conditions that establish exclusively q-axis stator currents.

This approach to dynamic generator model parameter identification makes use of time responses of generator variables. The basic techniques use time domain analysis of generator variables under disturbances, such as load rejections and field voltage changes.[57] Key variables to record for the transient response tests are stator current (or active and reactive power), terminal voltage, field current, field voltage, and frequency or speed.

D-Axis Parameters

In order to estimate the d-axis generator model parameters, the ideal initial conditions of the unit would be at zero active power, absorbing reactive power and in manual control of the excitation system. This condition guarantees that flux only exists in the d-axis. The test would consist of opening the generator circuit breaker connecting the machine to the power grid and recording the terminal voltage, frequency, field current, and field voltage response to the breaker opening. With the generator under-excited, saturation effects would not be present and the test results can be used to determine the basic unsaturated values of Xd, X'd, X''d, T'd0, and T''d0. **Figure 4.16** shows terminal voltage (blue), stator current (black), field current (green), and field voltage (red) response to a stator current interruption test designed to determine the d-axis generator parameters.

[56] Stator current interruption tests with over-excited conditions should be avoided whenever possible to avoid excessive terminal voltage condition after the unit breaker opens.
[57] F.P. de Mello and J.R. Ribeiro, "Derivation of Synchronous Machine Parameters from Tests," IEEE Transactions on Power Apparatus and Systems, July/August, 1977, pp. 1211-1218.

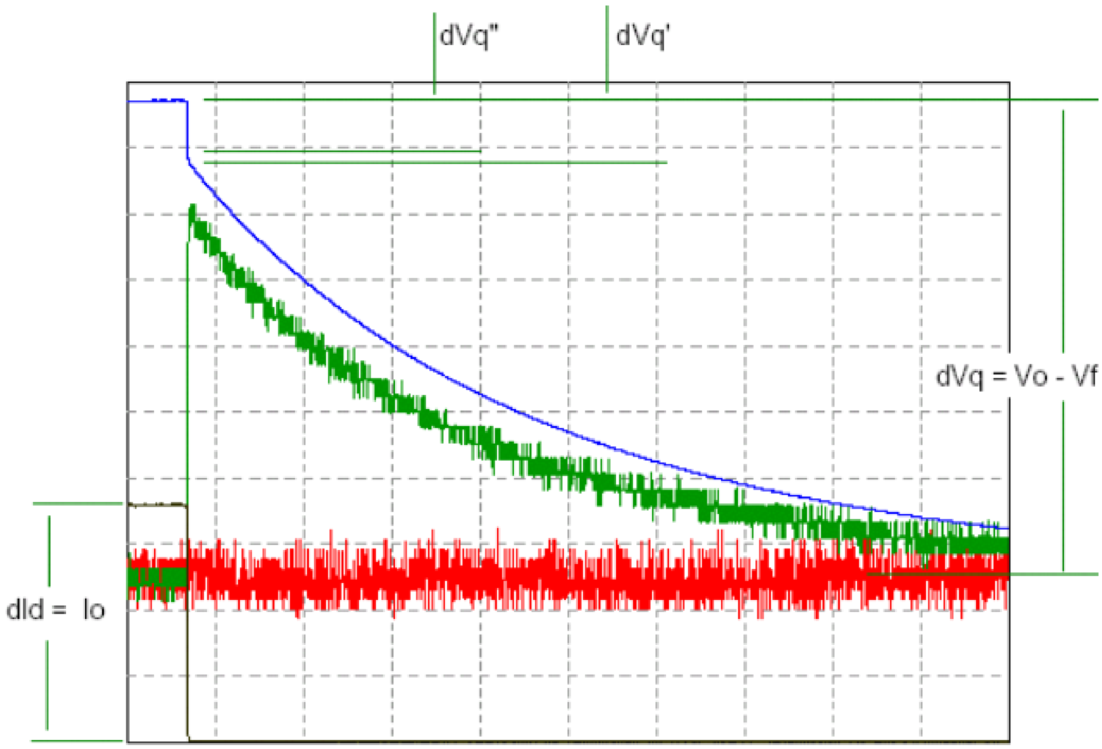

Figure 4.16: Stator Current Interruption Test Measurement Quantities [Source: J. Undrill]

Using the equations below and the values determined in Figure 4.16 by analyzing the changes in terminal voltage and stator current, an initial estimate for the d-axis impedances can be made. Simulations of the stator current interruption test can also be used to confirm or determine the generator model d-axis parameters. Note that the field current response can also be used to determine the T'd0 and T''d0 time constants as laid out in the de Mello and Ribeiro paper.

$$X_d = \frac{dV_q}{dI_d} = \frac{V_0 - V_f}{I_0}$$

$$X_d' = \frac{dV_q'}{dI_d} = \frac{V_0 - V_q'}{I_0}$$

$$X_d'' = \frac{dV_q''}{dI_d} = \frac{V_0 - V_q''}{I_0}$$

It should be noted that there are some limitations to this test when applying the ideal theory to real world applications. In many instances, it is impossible to run a synchronous generator at zero active power either due to reverse power relay action or the inability of the plant controls to successfully maintain zero or low load for any significant period of time. In these cases, reducing the generator output to less than five percent of maximum output may be acceptable in achieving a model match. In this case, recording of frequency or speed is important.

Note that the theory behind this test is that when the generator breaker is opened, the field voltage is expected to be held constant. However, most static excitation systems work in constant field current regulator mode when switched into manual[58] operation and not field voltage regulator mode. Figure 4.17 shows expected field voltage

[58] The GOP should notify its associated TOP of any status change on the AVR, PSS, or alternative voltage controlling device within 30 minutes of the change per VAR-002-4.1 Requirement R3.

regulator behavior (left) versus the unexpected field current regulator behavior (right) during a stator current interruption test. It is clear from the right plot that field voltage (red) is not held constant during the test. This impacts the terminal voltage (blue) and field current (green) response significantly when compared to the ideal response. The equations laid out in the de Mello and Ribeiro paper can no longer be determined by analyzing the plots but rather must be simulated. In addition, field voltage and frequency would need to be "played back" into the generator model in order to replicate the response accurately. Most commercial and open source software packages offer this type of play back feature.

Lastly, units that use brushless excitation systems offer even less ability to determine the generator model parameters via this method as field current and field voltage are not measurable/recordable values.

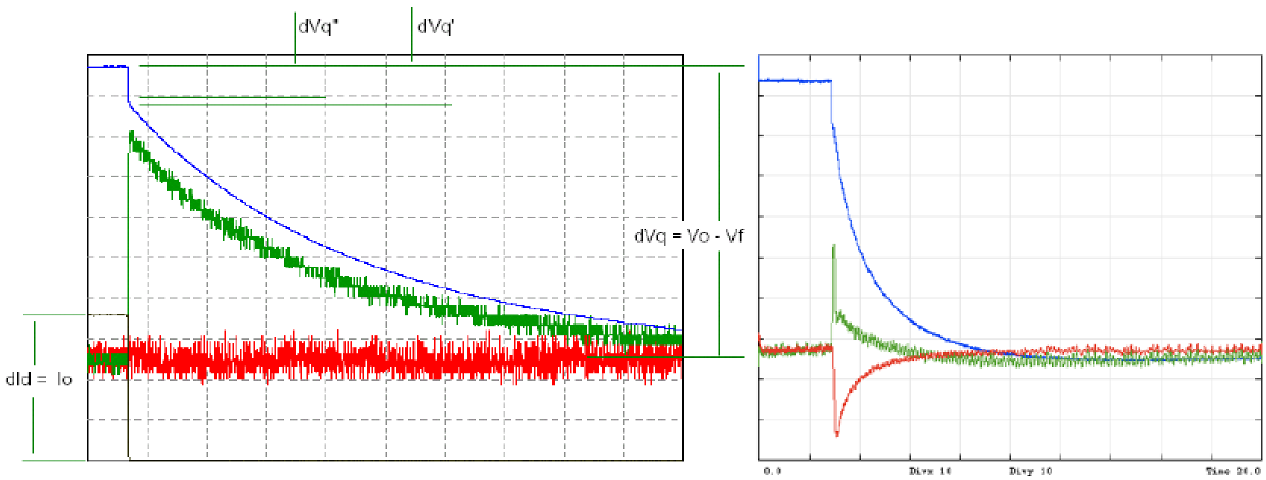

Figure 4.17: Constant Field Voltage vs. Variable Field Voltage during Interruption Test [Source: J. Undrill]

Q-Axis Parameters

In order to estimate the q-axis generator model parameters, it would be ideal to establish a loading condition on the unit where the stator current is composed only of a quadrature axis component. The desired loading condition can be arrived at by successive stator current interruption tests where the field current deviation is recorded each time. The objective is to find the ideal loading condition that results in no noticeable transient deviation for the field current. While multiple stator current interruption tests could be performed to find this location, a minimum of two various conditions, which result in transient deviation in opposite directions, can be used to locate the point where ΔI_{fd} is zero as shown in the de Mello and Ribeiro paper.

An alternative method of finding the correct q-axis loading condition is to utilize a rotor position signal and calculate the relative rotor angle between the stator current and the measured rotor position. The q-axis loading condition then can be achieved by adjusting the unit P and Q such that the relative rotor angle is 90° additional to the rotor angle measured during d-axis stator current interruption test prior opening the unit breaker. The rotor position signal can be obtained through one-pulse-per-revolution key phasor signal or laser tachometer measurement by means of placing a reflective tape on the generator shaft. Figure 4.18 illustrates the rotor angle positions during d-axis test and q-axis test. The advantage of this method is that it significantly reduces the number of load rejection tests needed to be performed on-site. The disadvantage is when one-pulse-per-revolution key phasor signal is not available, the generator needs to have a complete shutdown to allow placement of a reflective tape on the shaft.

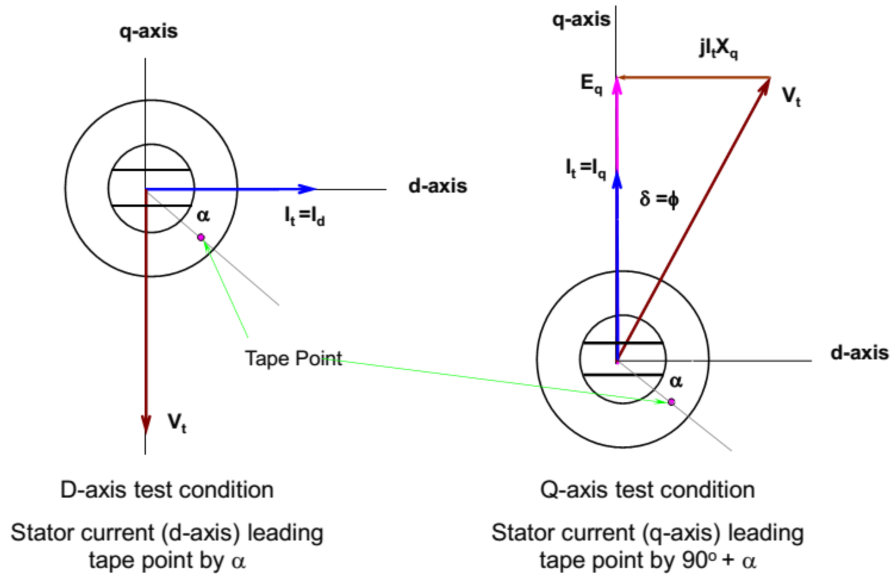

Figure 4.18: Illustration of Rotor Positions in D-Axis and Q-Axis [Source: Powertech]

Once the location is found, a final stator current interruption test, using that real and reactive power level to produce zero d-axis stator current component, will result in a transient voltage (blue) as shown in the top plot of Figure 4.19.

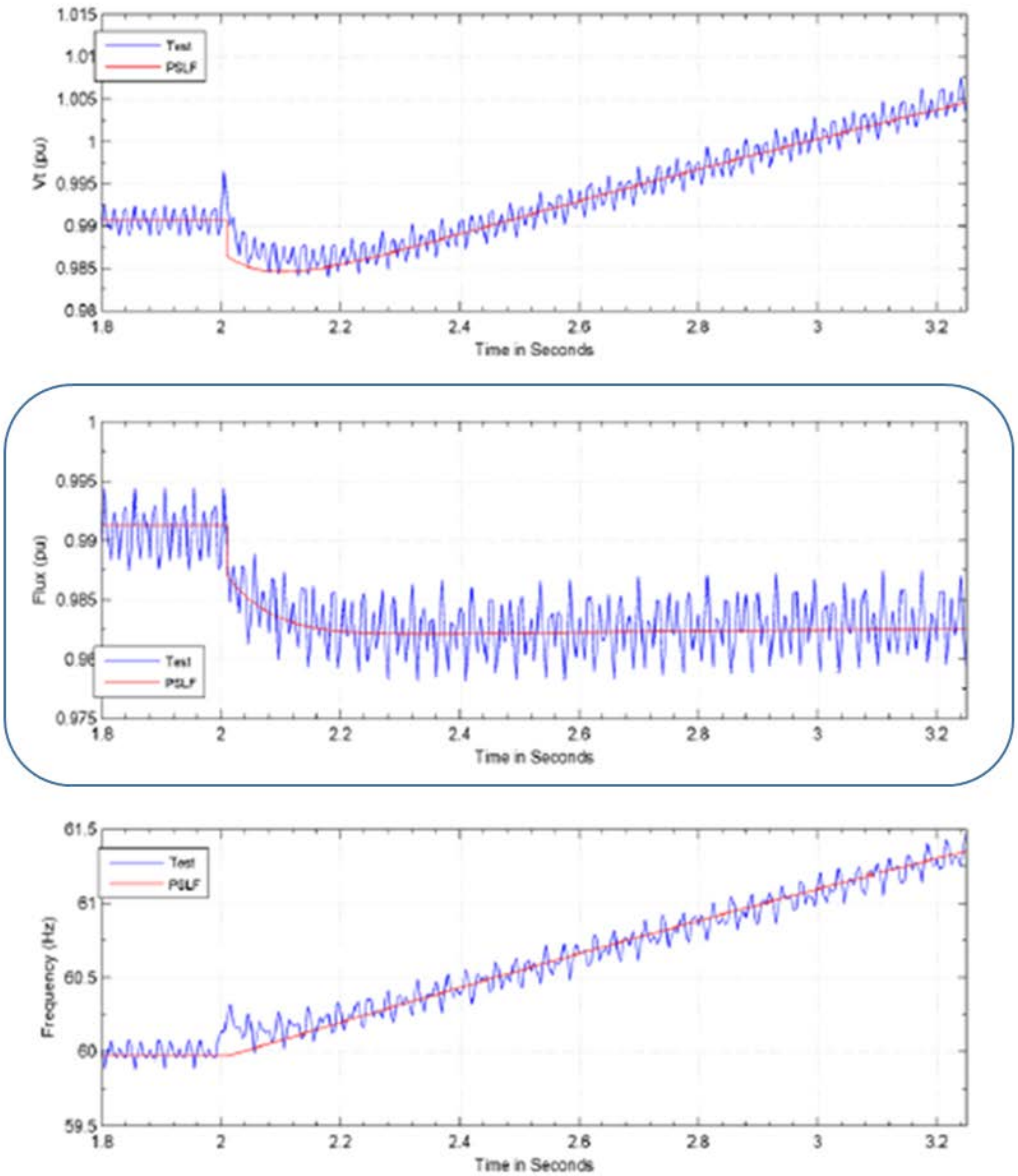

Figure 4.19: Flux Comparison to Confirm Q-Axis Data [Source: GE]

In order to determine the q-axis parameters, flux ($V_{t,pu}$/$speed_{pu}$), shown in the center plot of **Figure 4.19**, is used to eliminate any differences between simulation and test frequency, which is often caused by the inability to exactly match the governor off-line control responses.

While the q-axis stator current interruption tests can be achieved, they may not derive the exact generator model parameters and lead to additional errors. It is recommended that this test not be the sole source for determining/verifying the q-axis parameters. A combination of this interruption test along with an exciter step, an exciter impulse, and a generator synchronization can be used to confirm q-axis parameters.

Exciter Step Test

Excitation system and PSS models are typically verified using voltage reference step tests[59] with the PSS off-line (OFF) and PSS on-line (ON). PSS OFF tests verify the AVR models while the PSS ON tests help to verify PSS models. Table 4.2 shows the signals that should be captured during these tests. The step signal should be recorded or the step size should be clearly noted. If the excitation system is a static exciter, then only the field voltage and current of the generator main field need to be recorded. If the excitation system is a rotating ac exciter, both the main field of the generator and the exciter field quantities should be captured, if possible. However, only one of these is adequate, and the testing engineer may have a particular preference. For brushless excitation systems, only the field voltage and current of the exciter can be measured. Sampling rates should be at least 120 samples per second or faster. Data should be collected for at least 1-5 seconds prior to the step injection and for at least 10–20 seconds after.[60]

Table 4.2: Exciter Step Test Signals

On-line Verification Signals	Off-line Verification Signals
MW MVAR Terminal voltage Field voltage Field current Exciter field voltage Exciter field current Frequency[61] PSS compensated frequency or speed input PSS Output	Terminal voltage Field voltage Field current Exciter field voltage Exciter field current Frequency PSS compensated frequency or speed input

Table 4.3 shows some of the potential step tests that may be performed for verification purposes. Not all of these step tests necessarily need to be performed to collect sufficient data to verify the model; however, the tests typically conform to one of these options.

[59] For additional reference, see IEEE Std. 421.2-2014 "IEEE Guide for Identification, Testing, and Evaluation of the Dynamic Performance of Excitation Control Systems."
[60] The necessary duration of recorded response will vary from case to case based on the response rate of the particular excitation system. The testing engineer should evaluate this to ensure that adequate pre- and post-step data has been recorded.
[61] For most PSSs, this is compensated frequency (calculated from electrical quantities (e.g., voltage from PT and current from CT)). This is important when comparing to simulated response. Some software vendors allow for use of the compensated frequency as part of either user-written models or part of the standard models (based on software vendor).

Table 4.3: Potential Voltage Reference Step Tests				
Unit Status	**PSS Status**	**Loading**	**V_{ref} Step %**	**Step Duration (sec)**
Off-line	Off	No Load	±2-5%[62]	10-20
On-line	Off	Min Load	±2-4%	10-20
On-line	Off	Full Load	±2-4%	10-20
On-line	On	Min Load[63]	±2-4%	10-20
On-line	On	Full Load	±2-4%	10-20

The smaller reference step tests help validate AVR parameters (e.g., KPR, KIR) while the larger reference steps with the unit off-line[64] help validate the ceiling parameters in the model. Performing the larger reference steps with the unit on-line is not recommended, particularly because this could cause the unit to change from consuming a large amount of reactive power to producing a large amount of reactive power that is not ideal for grid reliability as it may violate downstream equipment limitations or local criteria. In addition, larger steps are performed off-line to avoid any interactions from components, such as the PSS, UEL, and OEL (e.g., the test targets specific aspects of the model verification).

Note that modern AVRs may have different settings depending on the status of the PSS or for unit on-line vs. off-line conditions. Verification tests need to be performed for expected operating settings (on-line settings). If a generating unit has several expected operating modes (e.g., a generating mode with PSS active and one set of AVR gains, and a condensing mode with PSS turned off and a different set of AVR gains), the verification testing should be performed for both operating modes and the test report should include models for both operating modes.

Performing the smaller steps at full load helps validate any droop or line drop compensation since this is based on current. It can be shown that droop is present by applying a two percent step off-line and observing a two percent terminal voltage change and then applying this step on-line and observing a terminal voltage change that is less than two percent and in proportion to the droop quantity. Full load testing also validates the PSS (note that the PSS is typically turned off by the controls at very low generator output levels). So the steps to verify PSS performance should be performed when the unit is loaded near rated load. The test is performed at full load rather than partial load since these conditions have the highest propensity for oscillations. The testing also confirms that the machine is well damped for these types of step changes common during grid disturbances.

[62] The V_{ref} step should be large enough to confirm the ceiling quantities. This step may be as high as 8–10 percent depending on the expected ceiling voltage and gains implemented; however, caution should be taken when performing this test to prevent the unit and its auxiliaries from operating outside their normal voltage range post-step (i.e., the pre-step voltage may need to be adjusted up or down to facilitate larger voltage steps). It is recommended to perform this test at elevated stator rms voltage (e.g., 103–105 percent and performing the step test in the negative direction of -5 to -10 percent).

[63] Ensure loading is above PSS minimum load level (i.e., PSS is on-line and active).

[64] Consider any changes in operating settings for on-line vs. off-line conditions (e.g., exciter gains).

In the case of on-line tests, these should be done as close to rated unit MW output as possible with the PSS ON and PSS OFF (or with PSS ON at rated and at low gains if turning the PSS off is not possible or not allowed). Off-line tests should be performed at rated speed. Note that the off-line tests are, as indicated above, an additional confirmation of the AVR dynamics and often a good way (by comparing off-line and on-line step tests) of verifying the current-compensation values in the AVR controls. However, the off-line step tests are not absolutely essential, particularly for digital control systems where the current-compensation values can be easily determined and verified from the digital settings. Also, the ceiling of the excitation system can also be confirmed by calculation. During the course of these tests, the GOP should notify its TOP of any status change of the PSS, per VAR-002-4.1 Requirement R3, when the PSS is turned OFF and then back ON.

Example of Step Size Required to Hit Ceiling:
Consider the ESST4B model again and assume the ceiling is set to > 200 percent rated field voltage when the unit is at rated field current and rated voltage.

To get from EFGOC to hitting the ceiling voltage, the combination of $(V_{ref}\text{-}V_{meas})$*(KPR+KIR/s)*KP needs to equal the $V_{ceiling}/E_{fgbase}$. Removing the gain from the excitation transformer, $(V_{ref}\text{-}V_{meas})$*(KPR+KIR/s) needs to be equal to cos(α_{min}).

Therefore, the size of the step to hit ceilings will depend on exciter gains. If the exciter is set up with KPR = 27.8 and KIR = 2.78, a step of at least 3.64 percent would be needed to hit the ceiling. On the other hand, if the exciter was set up with KPR = 12 and KIR = 1, a step of at least 8.3 percent would be needed to hit the ceiling.

Figure 4.20 shows the dynamic response from five percent voltage reference step test at FSNL. The terminal voltage and field voltage are matched between simulation and actual response to confirm modeled performance. In the left plot, the dynamic response is verified; in the right plot, the field voltage ceiling is verified from the step response. **Figures 4.21** and **Figure 4.22** show results from a two percent voltage reference step test with the unit on-line loaded near full load with the PSS off and on, respectively. Note the relatively close match of field voltage, terminal voltage, and reactive power for both cases.

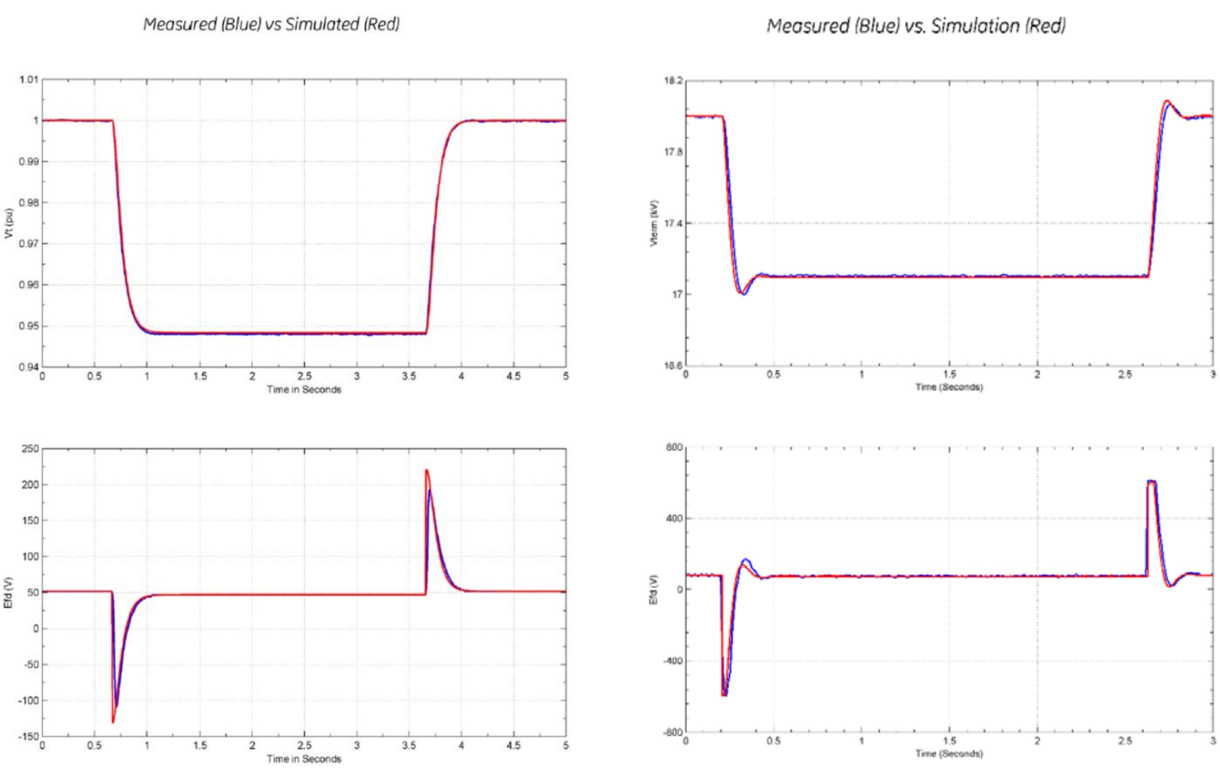

Figure 4.20: Voltage Reference Step Tests at Full Speed, No Load [Source: GE]

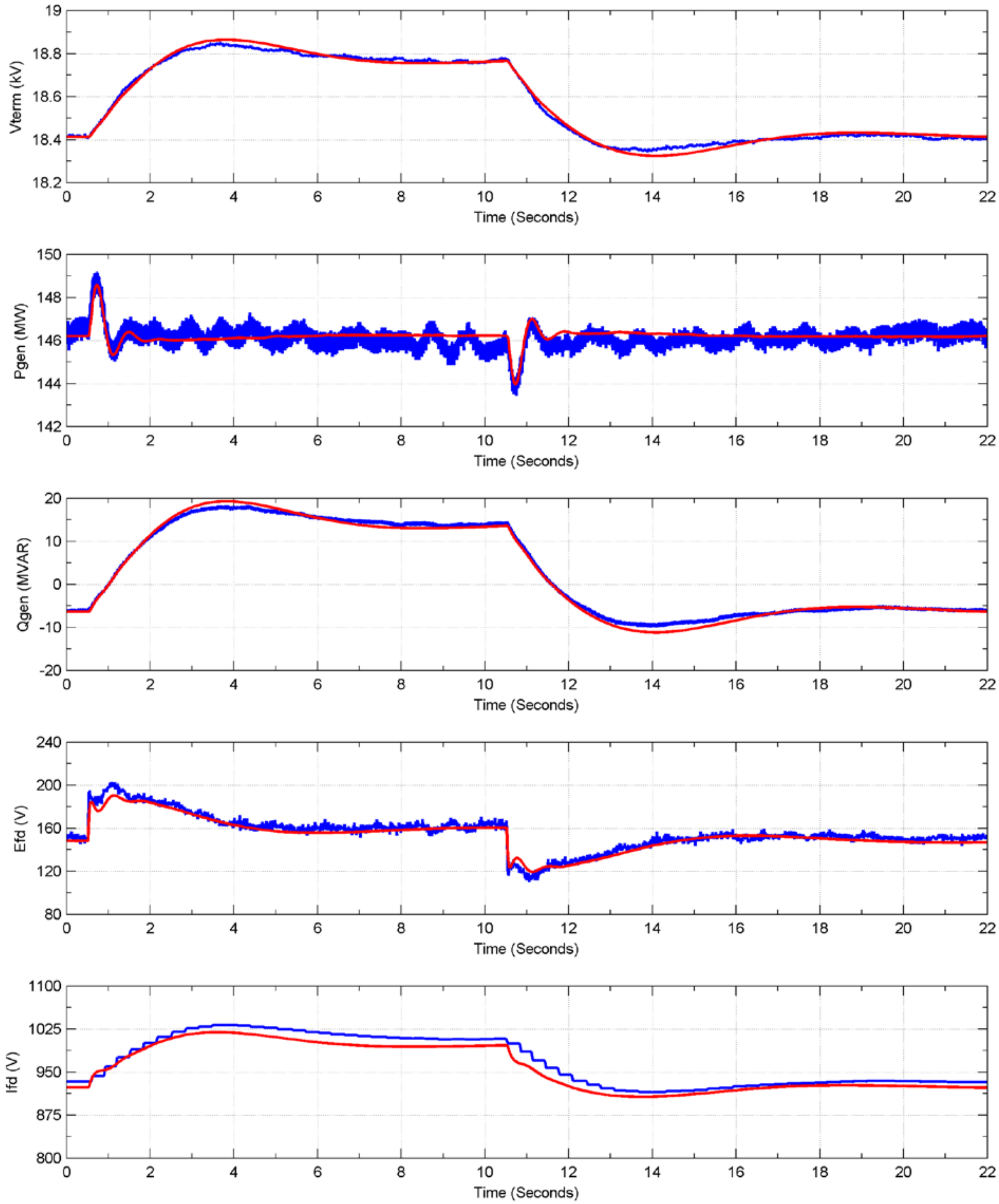

Figure 4.21: Two Percent Voltage Reference Step Test at On-line Near Full Load, PSS ON Measured (Blue) vs. Simulation (Red) [Source: GE]

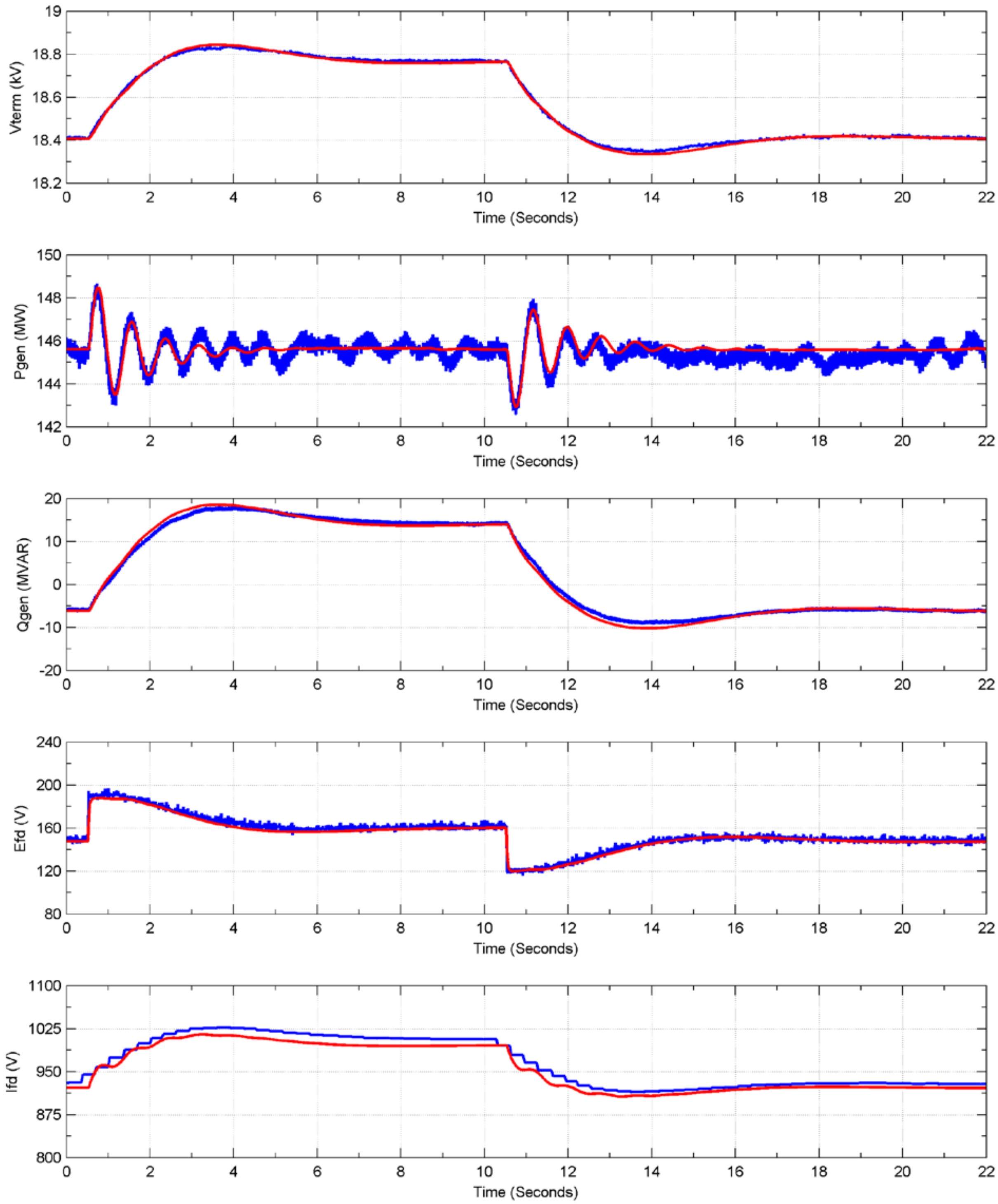

Figure 4.22: Two Percent Voltage Reference Step Test at On-line Near Full Load, PSS OFF Measured (Blue) vs. Simulation (Red)
[Source: GE]

Generating units that share a common bus at the terminals are equipped with some form of compensation that allows for stable operation through sharing of reactive load. This can be accomplished through reactive or cross current compensation.[65] For units that share a low side bus, it is easiest to simply validate one unit with all other units off-line (**Figure 4.23**). In this case, compensation can be validated in and out of service as a normal part of staged testing, if desired. If verification is performed with other units on-line, compensation cannot be removed without other units first being placed in manual mode to prevent instability. Care must be taken when performing staged testing with units connected to the same bus and excitation system in manual mode as machine limits could be exceeded. Verification of compensation settings for all parallel units can be performed simultaneously if the compensated responses of all parallel units are captured when performing staged testing on a single machine.

See **Figure 4.24** where a two percent voltage reference step test, in Auto mode, was performed in the high pressure of a cross compound machine and the low pressure data was captured at the same time. Data was then validated through a single machine infinite bus system.

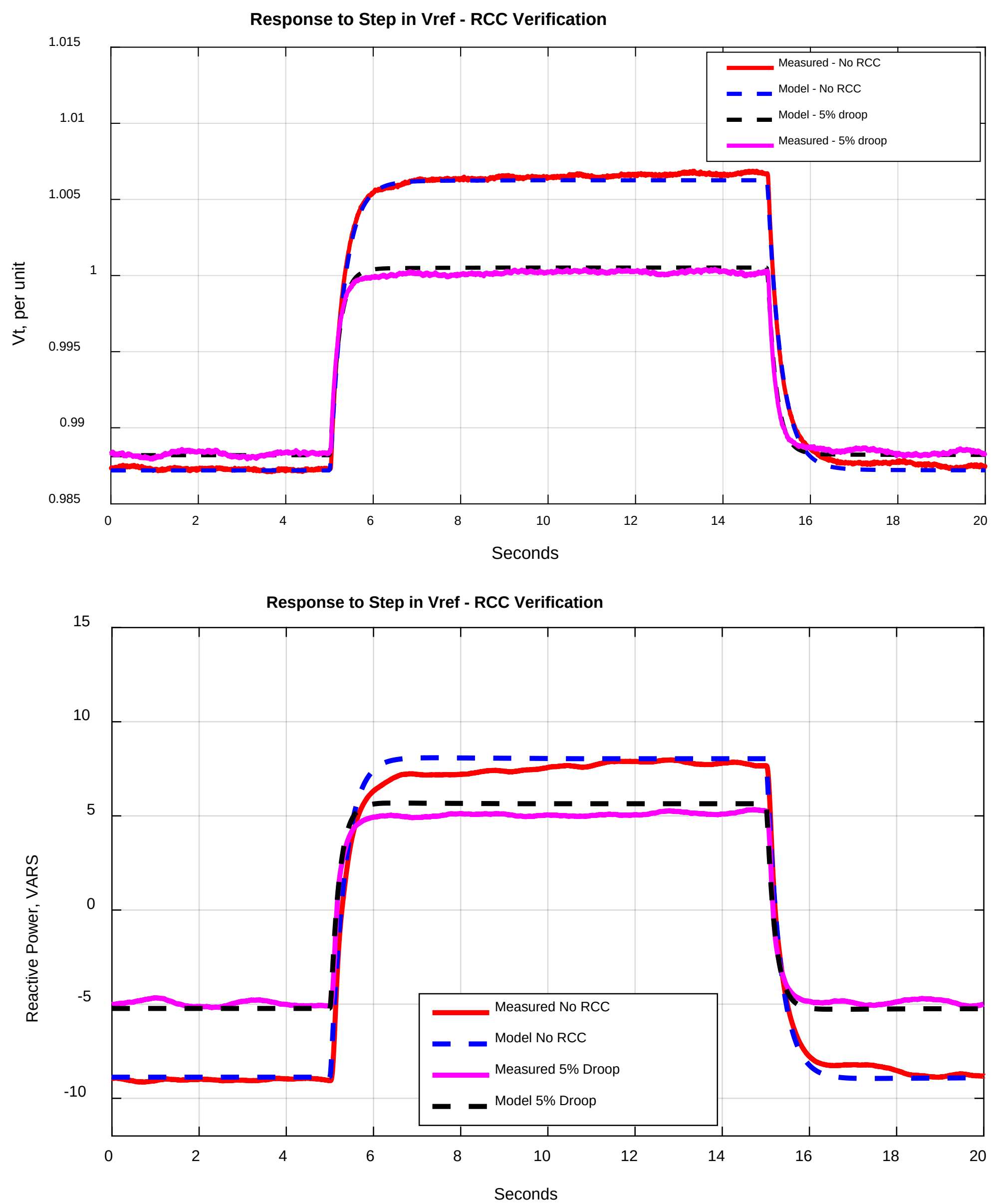

Figure 4.23: RCC Verification using Voltage Reference Step Tests [Source: USBR]

[65] Western Electricity Coordinating Council, "Cross-Current Compensation Model," WECC, Salt Lake City, Nov 3, 2014. [Online]. Available: https://www.wecc.biz/Reliability/Cross-Current_Compensation.pdf.

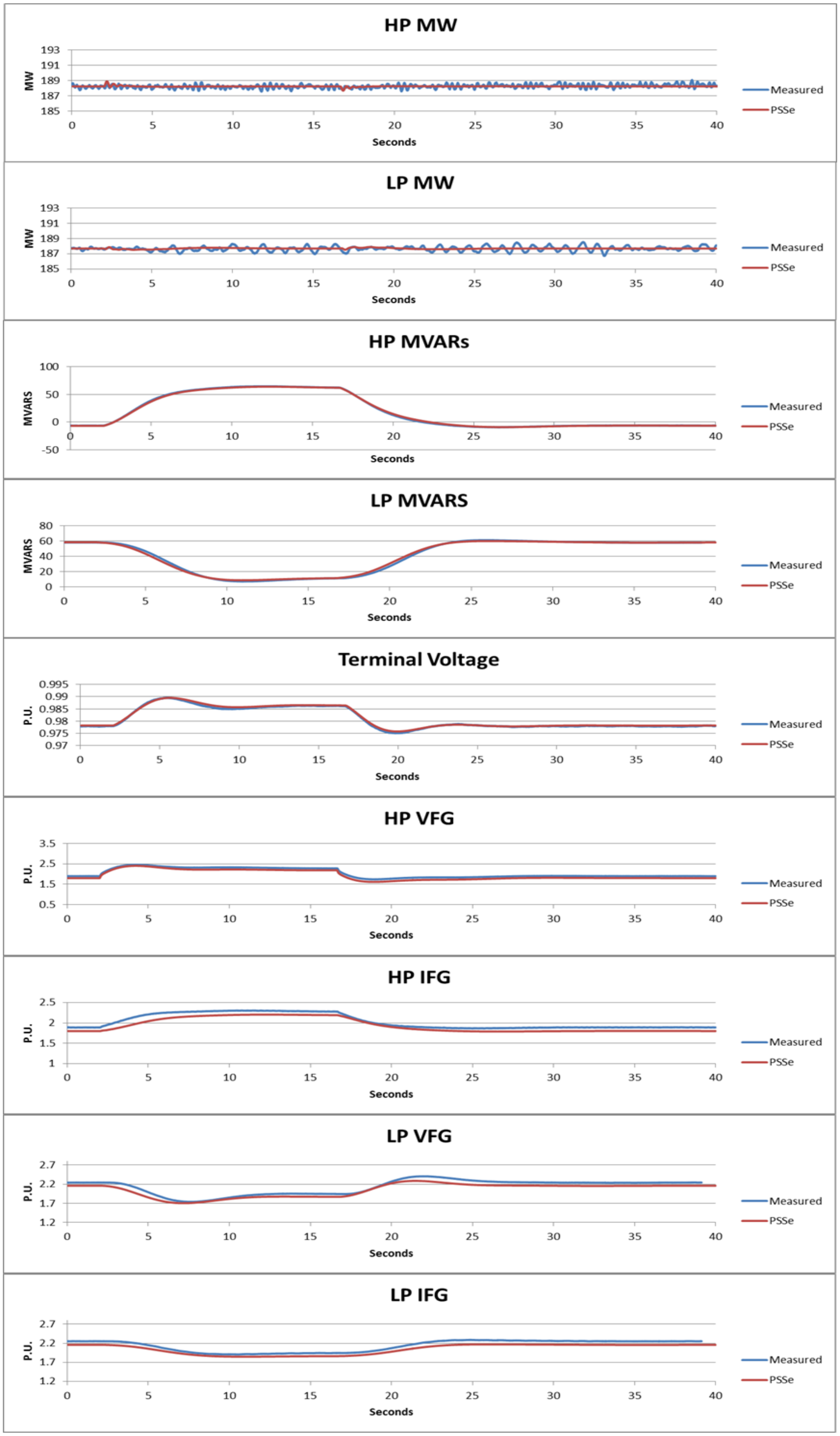

Figure 4.24: RCC Verification for Cross Compound Unit w/ Both AVRs in Auto [Source: Duke]

The effect of the reactive current compensation can also be validated by using frequency response methods (see **Figure 4.25**). The process is similar in cases when the RCC is set for line drop compensation as well or if cross current compensation is employed between two or more units. Since the reactive current output determines the compensated response, in order to properly validate the values of reactive current compensation parameters, it is necessary that the model reactive current responses very closely match the measured reactive current responses as well as the voltages. Playback methods are very effective for validating reactive current compensation models.

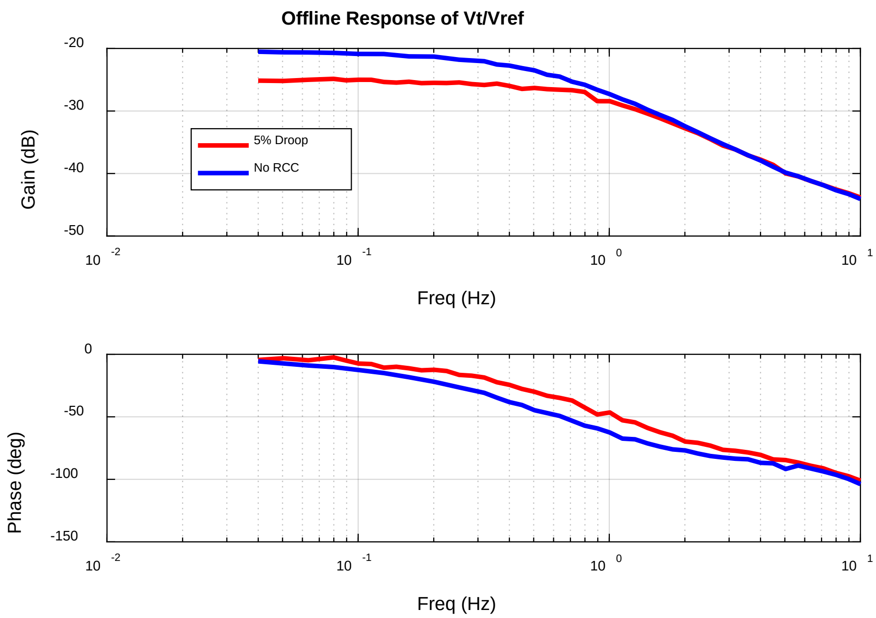

Figure 4.25: Frequency Response Verification for RCC [Source: USBR]

Power Factor and VAR Controllers

In some instances, the GOP may have been granted exemption from operating in automatic voltage control mode to a scheduled voltage value or range.[66] In those cases, the resource is allowed to operate in a power factor or reactive power (VAR) control mode. These controllers act as a secondary control loop in the AVR controls that slowly adjust the AVR reference in order to maintain a specific MVAR or power factor set point. These models can be determined from on-line AVR reference step tests with the controller active. In most cases, these outer loop controls are very slow in response and the field measurement recordings need to be longer to capture the return of the reactive power to its original set point. The time frames of these controls should be considered when determining how and if to model them. If the MVAR or power factor controls interact with the AVR in a time frame that is simulated as part of the transient stability or mid-term stability simulations (e.g., out to approximately 60 seconds), then a representative model should be provided. Otherwise, a suitable match between simulation and actual test without these additional models can be attained. In this case, the GO should still inform the TP that the plant operates in a VAR or power factor control mode.

Figure 4.26 shows an example of a relatively fast outer loop VAR controller for a 112.8 MVA generating unit. The outer loop VAR control comes from the plant-level distributed control system (DCS) rather than internal to the exciter. The DCS overrides the two percent voltage reference step test within 10 seconds. The figure also shows how the standard excitation system model was not able to accurately represent this overriding outer loop control. In this case, an additional model is needed to represent the outer loop controller, otherwise the actual response of the plant to changes in voltage cannot be accurately modeled. Dynamic models, such as *pfqrg* (reactive power

[66] See NERC Reliability Standards VAR-001-4.2 *Voltage and Reactive Control* and VAR-002-4.1 *Generator Operation in Maintaining Network Voltage Schedules*. Available: https://www.nerc.com/pa/stand/Pages/ReliabilityStandardsUnitedStates.aspx?jurisdiction=United States.

regulator/power factor angle control), can be used in conjunction with the excitation system model to capture these effects.

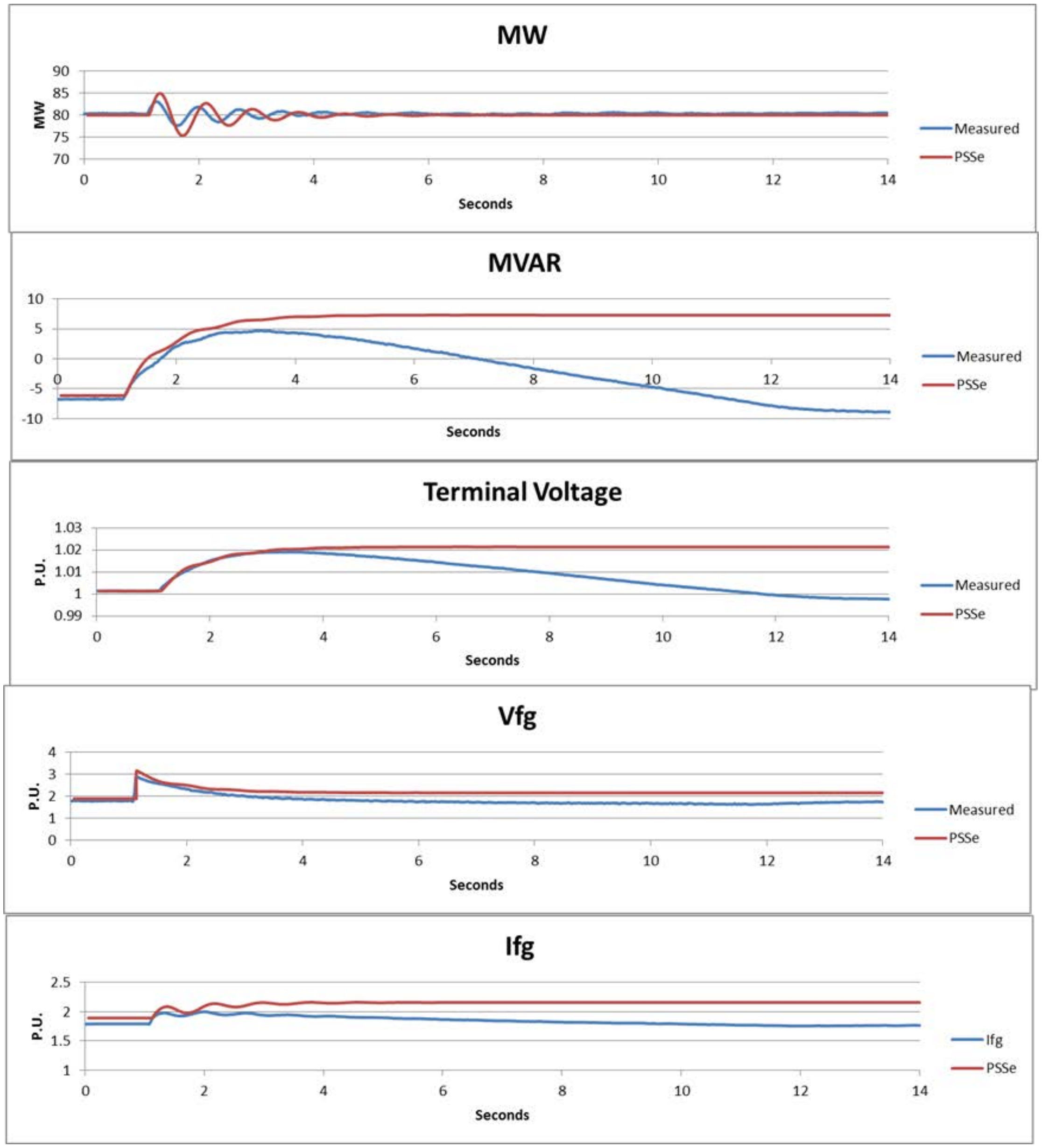

Figure 4.26: Power Factor Controller Response Compared to Simulation

Exciter Impulse Step Test

In order to provide a better local mode active power oscillation, exciter impulse tests are often performed (see Figure 4.27). While similar to the exciter step tests, the exciter impulse tests are typically larger in magnitude (five percent to 10 percent) but for much shorter durations (0.1–0.5 seconds). Exciter impulse tests are often used in analysis of PSS commissioning to determine its effectiveness in damping oscillations. This type of test can also be used as part of a collection of tests in determining/verifying generator model q-axis parameters.

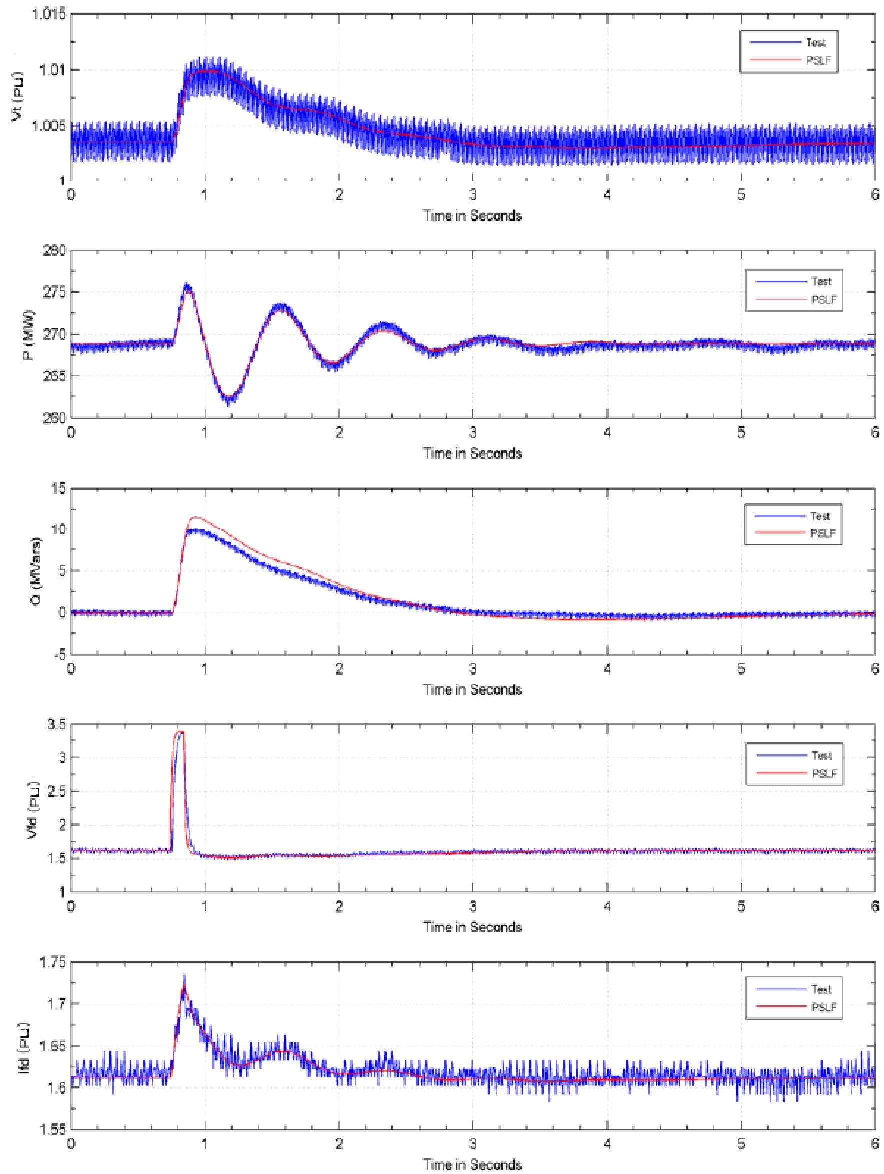

Figure 4.27: 5% Exciter Impulse Test (PSS Off) [Source: GE]

This test can be used to help confirm Xq, X’q, T’q0, and T’’q0 by a comparison of the simulation to measured active power oscillations. Assuming the inertia constant is confirmed, the magnitude and period of these oscillations are greatly affected by the q-axis parameters. Note that the two percent exciter voltage step test also offers a similar opportunity in verifying the q-axis parameters, but the active power oscillations may not be as observable.

To evaluate the damping of the PSS, the results of the exciter impulse tests with and without the PSS enabled is compared in Figure 4.28. A reduction in the “local” mode oscillation is observed with the PSS in-service.

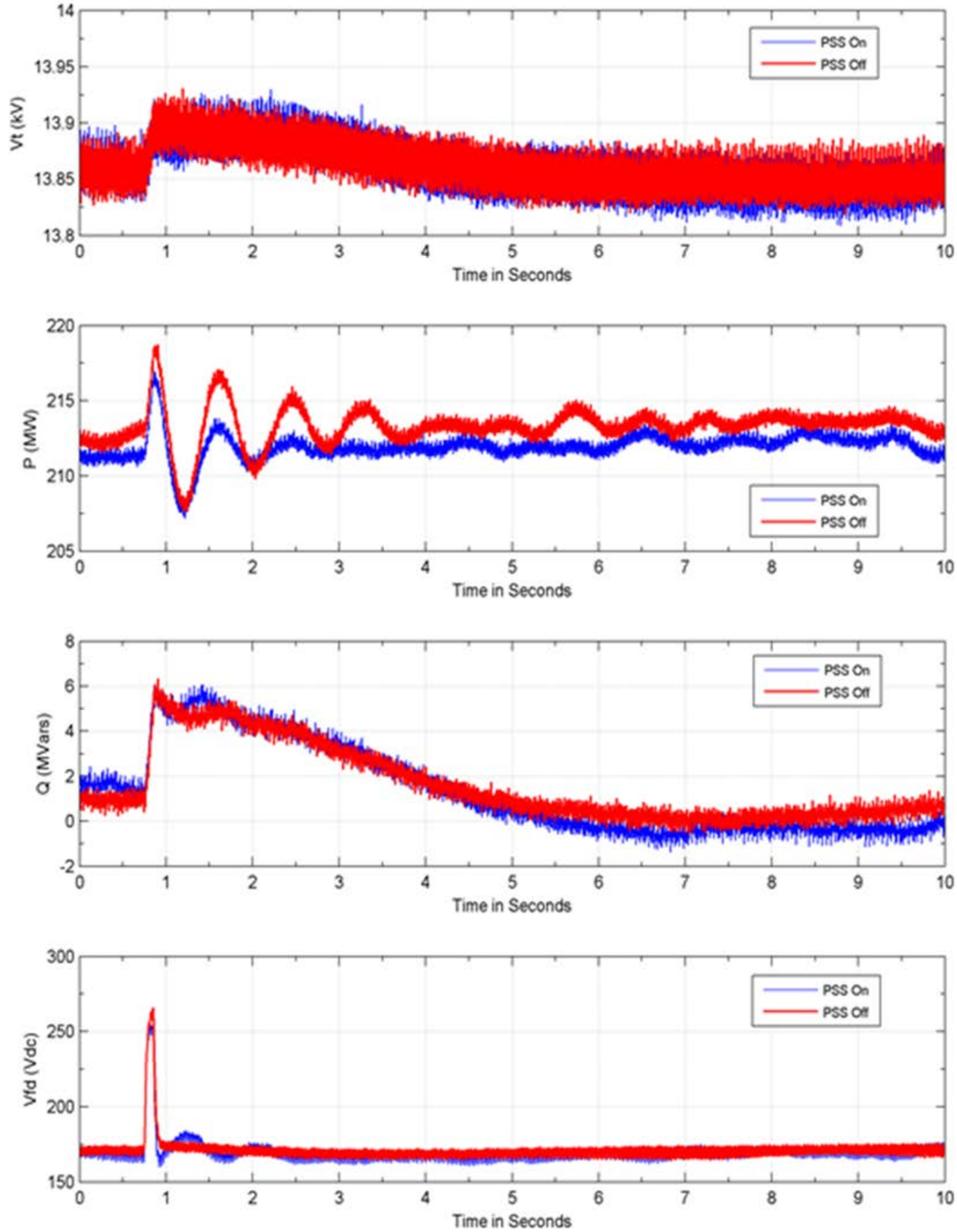

Figure 4.28: Five Percent AVR Impulse Test—PSS Off vs. PSS On [Source: GE]

To further clarify the PSS performance the MW signals of the impulse test with and without PSS are processed by using fast fourier transform to get a power spectral density of the signal as a function of the signal frequency. Figure 4.29 compares the MW with and without PSS and clearly demonstrates the reduction in signal magnitude provided by PSS around the local mode frequency (~1.25Hz).

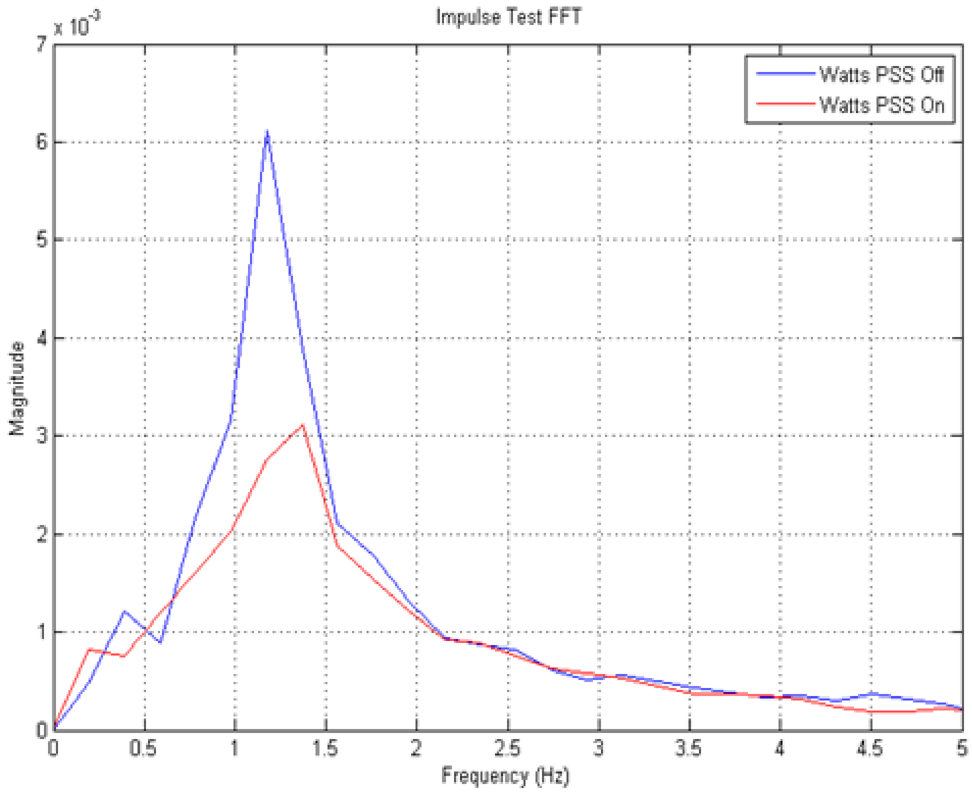

Figure 4.29: Impulse Test Fast Fourier Transform [Source: GE]

Generator Synchronization

With the unit running at FSNL, the operator will synchronize the unit to the grid. This normal event can often be recorded during a testing session. It is important to capture the active power, reactive power, terminal voltage, stator current, and generator frequency response pre- and post-synchronization. Often this recorded response is used along with a q-axis stator current interruption test, voltage reference step and impulse tests in confirming or determining q-axis reactances and time constants. Initially, the reaction of the active power response during a synchronization of the unit to the grid can be compared to dynamic model simulations as the initial active power oscillations are primarily driven by the q-axis parameters. Along with iterations with the stator current interruption test and voltage reference step tests, the data can be estimated fairly well.

In order to simulate the synchronization correctly, the pre- to post-synchronization change of speed and voltage needs to be accounted for. This type of simulation requires the use of a user-written model to adjust for any off-nominal presynchronization speed, voltage magnitude, and voltage angle (or synch angle).

Figure 4.30 shows a comparison of the active power output of a dynamic simulation model to the recorded response of the generator.

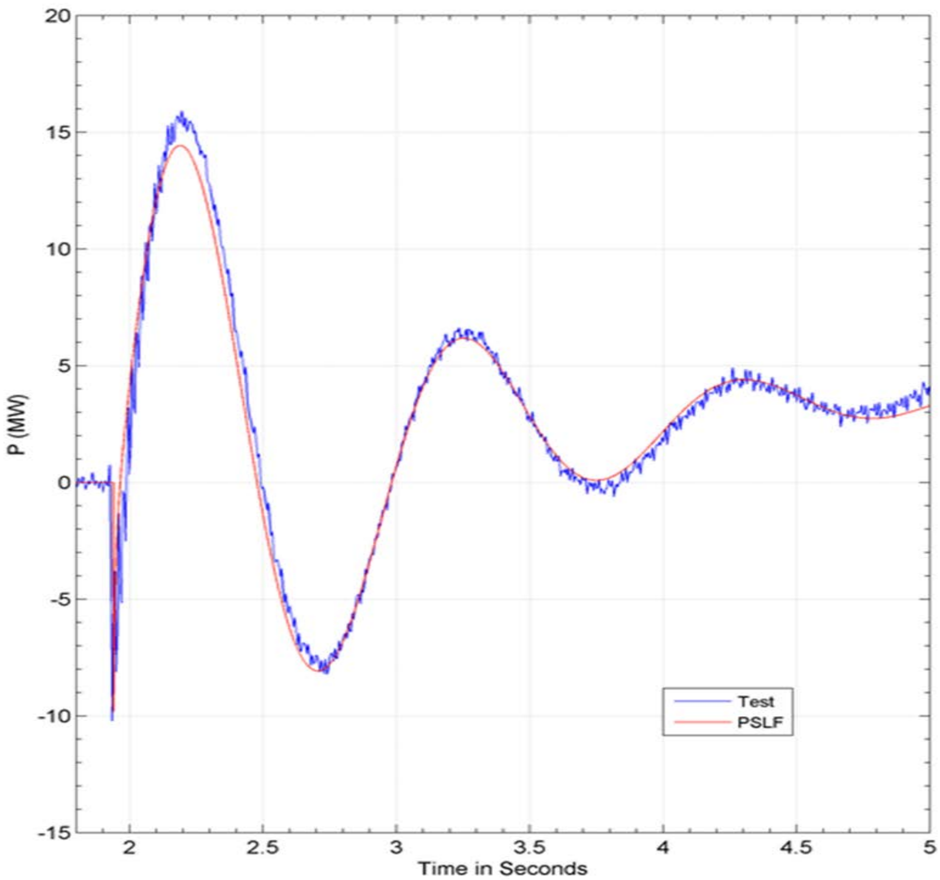

Figure 4.30: Active Power during Synchronization [Source: GE]

Frequency Response Test

The mathematical representation of generator control systems (e.g., excitation control systems, speed governors) is based on block diagrams of these systems expressed in the Laplace domain. This representation lends itself most naturally to consider these systems in terms of transfer functions in the Laplace (s) or frequency (jω) domain. While it is most common to consider model verification test methods that are easily replicated in time domain simulation (e.g., step response tests), there are situations where it is more appropriate or even necessary to consider the verification of the block diagram models with respect to their native frequency domain transfer function form.

Although there are several methods that can be used to measure the control system response as a function of frequency, the level of noise in the electrical signals from the generator measurements of interest makes most of these methods ineffective. A simple and effective way to measure the frequency response of these systems is by using a variable frequency sine wave input and measuring the response of each frequency over the range of interest (see **Figure 4.31**). The output signal for one or more exact periods of a single frequency is compared to the input signal and the differences in amplitude and phase angle are used to calculate the magnitude and phase responses. The injection of the sine wave input and reading of the output signals can be performed in simulation identical to how it is performed during testing at the plant. Commercial analyzer equipment and modeling software are available for this type of analysis, although many practitioners develop their own tools. The compiled results of the test are then plotted on a Bode plot. The exact same test performed in simulation is then used and model results are compared against the measured responses.

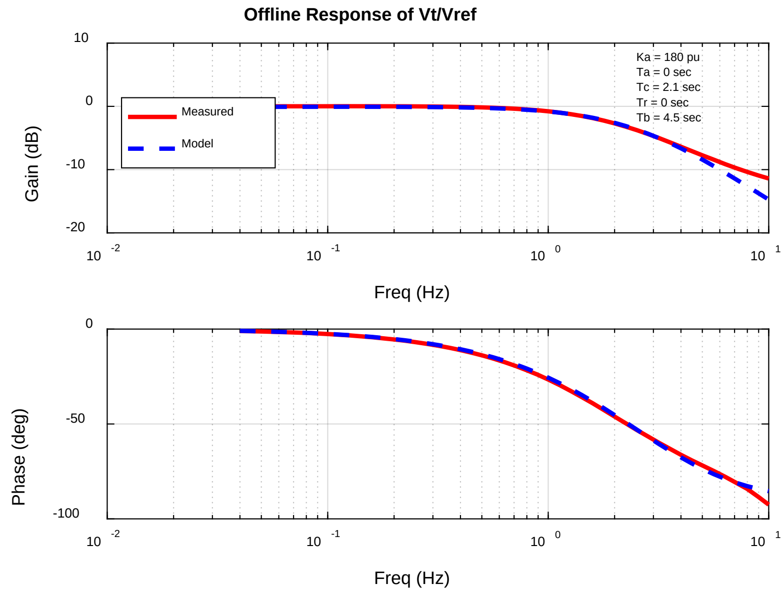

Figure 4.31: Frequency Response Test Plots [Source: USBR]

In this case, the responses of Vt/Vref as a function of frequency prove to be a valuable and effective verification of the excitation control system model. Frequency response measurements are necessary to validate PSS tuning and the model. The minimum load measurement of Vt/Vref is used to tune the phase compensation of the stabilizer as shown in **Figure 4.32**. This method of analysis can also be used to measure the response of the governor control loops (see **Figure 4.33**).

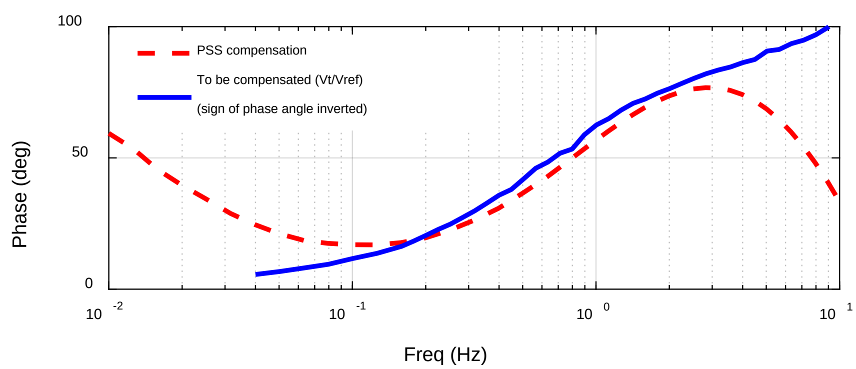

Figure 4.32: Tuning of Phase Compensation Plot [Source: USBR]

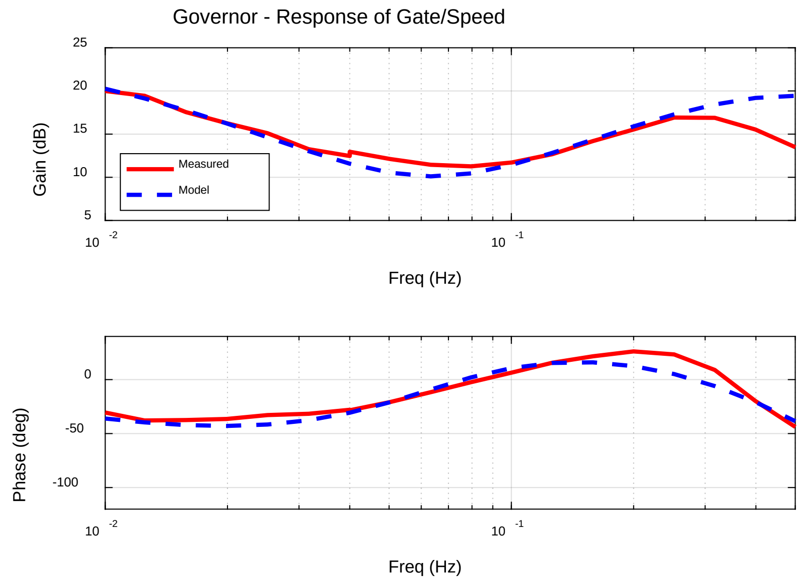

Figure 4.33: Turbine-Governor Frequency Response Test Plot [Source: USBR]

Frequency response analysis is valuable for accurate baseline model development as it not only verifies the model over the entire frequency band of interest but can also be used to identify the characteristics of individual components or subsystems of the control systems. **Figure 4.34** is a verification of a subsystem of the governor system in the **Figure 4.31** above.

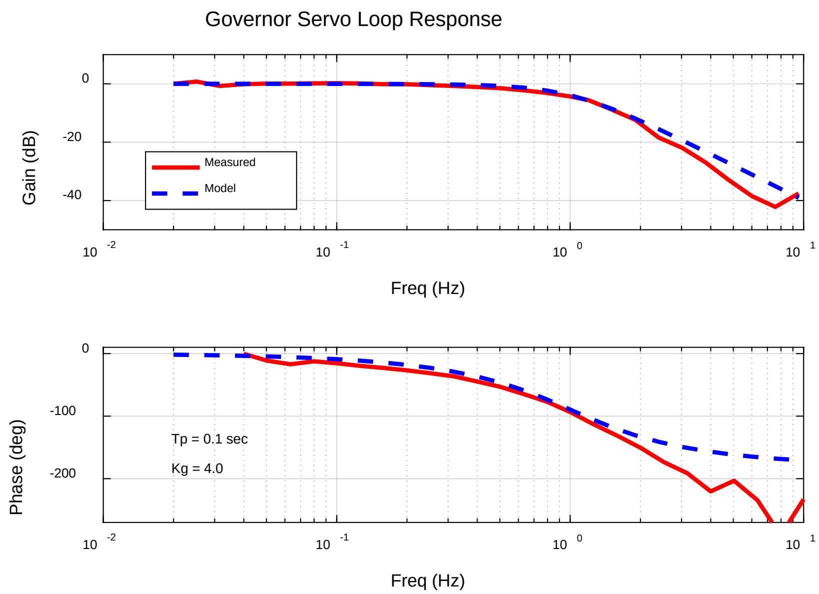

Figure 4.34: Turbine-Governor Subsystem Frequency Response Test Plot [Source: USBR]

PSS Verification Testing

A PSS modulates an AVR input to produce field voltage changes in order to provide a component of electrical torque in phase with rotor speed deviations (damping torque) to reduce both low frequency and local mode power oscillations. It is fairly standard practice for interconnection agreements[67] to require a PSS on new units, which is tuned during commissioning. A PSS can improve stability during abnormal grid conditions, enabling a wider range of allowable system conditions (e.g., forced or planned outages) that may not be studied in the long-term planning horizon. For existing units, AVR upgrades may be a good time to add a PSS. Requests by the TP/PC for adding a PSS to specific units should occur early in the process of upgrades to minimize costs and impacts to GOs. However, the GO should engage with the TP/PC, who typically performs studies to identify if adding a PSS provides reliability benefit to the unit and the BPS.

Modern high-gain AVRs, while significantly improving first-swing transient stability by providing increased synchronizing torque, may contribute to system oscillations due to decreased damping torque in some cases. While detection systems, alarms, and operator action may offer some protection, PSSs are developed specifically for the purpose of protecting the grid against unexpected oscillations by providing increased damping torque. Therefore, TPs should consider requiring PSSs at all large generating plants to ensure that oscillations remain well damped for both known oscillation issues as well as situations where oscillations are unexpected. In addition, excitation systems for many newer generators include an installed PSS as part of the AVR upgrade yet they may not be activated. TPs should consider requiring an operable PSS for units that may be involved in a potential oscillatory situation or issue.

Key Takeaway:
TPs should consider requiring PSSs at all large generating plants to ensure that oscillations remain well damped for both known oscillation issues as well as situations where oscillations are unexpected. In addition, excitation systems for many newer generators include an installed PSS as part of the AVR upgrade yet may not be activated. TPs should consider requiring an operable PSS for units that may in any way be involved in a potential oscillatory situation or issue.

Regardless of the design or vintage, a PSS consists of phase compensation (including washouts and a ramp tracking filter), signal limiters, and gain settings. Unlike most of the plant models, the models of PSSs can be nearly identical representations of the actual equipment. The block diagram shown in **Figure 4.35** represents what is now the de facto industry standard and the required design in some jurisdictions. This dual input design is often a completely digital implementation, which is convenient for the purposes of model verification since if the implementation has been verified and properly calibrated in the equipment, then the digital settings file can be trusted as the source of the model parameters. If this is not the case, or if the PSS consists of analog electronics, then determining the PSS parameters and model verification should be performed in an open loop configuration with the unit shut down or off-line and the model or its components considered separately.

[67] Ensure that any regional requirements, standards, or interconnection agreements are adhered to.

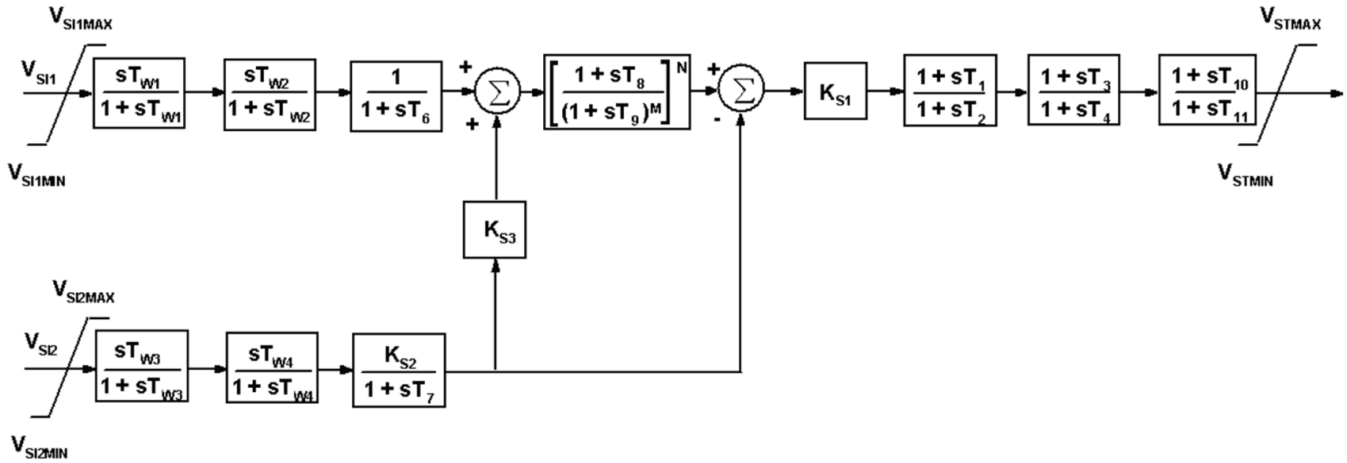

Figure 4.35: PSS Block Diagram

The phase compensation, which includes the lead-lag and the washout blocks, can be most easily verified using frequency response measurements over a large bandwidth (can range from 0.01 Hz to 100 Hz, but more typically 0.1 to 10 Hz). This measurement (or calculation) is a necessary step in tuning the PSS. In the dual input design, proper measurement of the phase compensation can be accomplished using the frequency input path only with the ramp tracking filter and the power input path nullified.

The proper tuning of a PSS for high initial response excitation systems often leads to phase lag time constants on the order of 0.01 seconds, typically the minimum setting allowed in digital systems. However, the typical time steps used in performing large scale stability studies do not allow time constants set this short, so it should be kept in mind that the resulting response of such a PSS model might in effect not match the measured response (see Figure 4.36). This caveat also applies to the generator and excitation system and their models as well. Model fidelity should not be expected beyond 3 Hz.

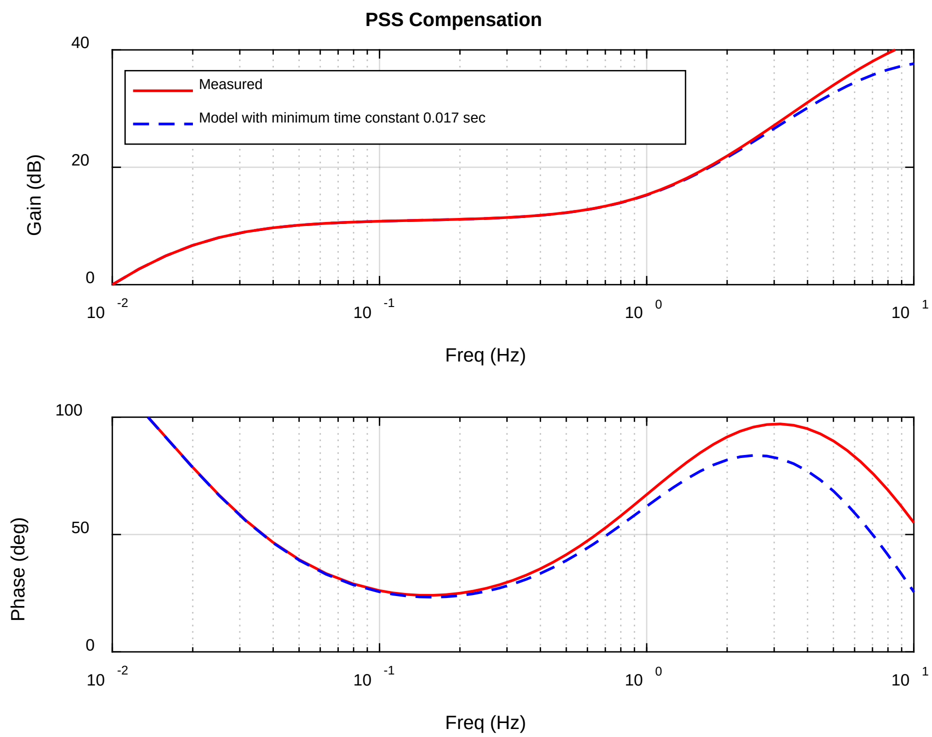

Figure 4.36: PSS Compensation Test – Measured vs. Simulated [Source: USBR]

Verification of PSS limiting functions can be carried out by measuring the output voltage at which they operate. An input signal or the gain KS1 can be increased until the PSS output signal is clipped. The calibration of the output limiter should be verified as the maximum per unit frequency change. Other important limits (i.e., the voltage cutoff and low power cutoff points), although not currently represented in the models, should be documented.

Verification of the overall gain (KS1) is perhaps the most difficult part of the PSS to verify, and unfortunately is the most important. In analog systems, each portion of the circuitry can contribute to the overall effective gain, and the calibration of the gain dial setting must be known accurately, preferably measured. Verification of the overall frequency/volt (or volt/volt) gain through the PSS should be measured using a small low frequency input signal to check the resulting df/dv signal gain of the PSS output signal. If frequency response testing of the governor is performed, the resulting low frequency oscillations in the measured frequency input to the PSS can provide such an input for the PSS, which will also verify the calibration and effective gain of the PSS frequency transducer. In units where rotor frequency is calculated by compensating measured terminal voltage with an adjustable reactance value X_{comp}, (which is not presently represented in PSS simulation models) error in the estimation of the value for X_{comp} can lead to considerable error in the PSS input signal as the computer models use the simulated generator rotor frequency as the input signal.

Since the main intent of requiring PSS throughout Interconnections is to contribute damping to low frequency, inter-area mode oscillations, the PSS model should be verified in this frequency range as best as possible. While it is normal practice to tune the PSS based on local mode oscillations that can be stimulated with inputs into the AVR, the frequency range of the local mode oscillation for most units is in the 1–4 Hz range. However, the local mode oscillation behavior depends not only on the PSS, but the exciter, generator, and external system as well. Depending on the equipment, tuning, and accuracy of individual generator, excitation system, and external power system models, the correspondence between measurements and model performance of local mode behavior is likely to be noticeably imperfect, and may not be the best evidence for verification of the PSS model. In the best cases, the behavior in this frequency range is approximate. The model accuracy will likely degrade further at higher frequencies, which if used as evidence of "maximum PSS gain" in a PSS tuning study, and should be taken with the proper consideration.

Compensated Frequency Signal

There are differences between the actual PSS inputs and the model interpretation. Most PSSs use a compensated frequency rather than the actual measured rotor speed deviation. Compensated frequency is a calculated frequency signal derived from the PT and CT signals and a compensation reactance. The PSS also includes a user selectable quantity sometimes referred to as Xq* (or X_{Qslip} or X_{comp}). Depending on the software platform, the model may or may not allow for the user to use compensated frequency (as compared with rotor speed deviation).

If the compensated frequency nearly matches the rotor speed deviations, then it would not matter significantly from a modeling standpoint. On the other hand, sometimes the measured and actual responses do not match as closely, and this may be attributable to the input signals being used between the actual implementation and the modeled representation. The PSS models in commercially available software that do not have PSS2A where the user can select compensated frequency as the input, and an additional parameter Xq* may have this issue where different inputs will result in different output when comparing with reality.

Modelers should be aware of the fact that there is a difference between the types of input signals to the PSS, which may cause a difference in simulation vs. measurements if the compensated frequency is different than that of rotor speed deviation. In the absence of a one-to-one correspondence between the PSS input structure and the available simulation model, the model gains and sometimes time constants should be selected to match the in-service damping at full load so that transmission operator's simulation studies are not optimistically stable. The users of the simulation software should contact the software provider and request the implementation of the compensated frequency as an available input to the PSS models, which would eliminate this source of discrepancies between the actual equipment response and the simulated responses given the currently available models. All commercially available software vendors should include this feature to select compensated frequency as an input in the PSS models.

Other Considerations

Modern PSSs may have a low power cutoff threshold where the PSS will toggle on and off. It may be useful to implement a hysteresis on this low power cutoff threshold so the PSS does not chatter or toggle on and off if the unit is operating around this range (although this is rare, it has occurred in the past). In addition, some units may have different PSS operating modes where different gains may be used in rough areas of operation (e.g., min loading conditions for natural gas turbines, hydro rough zone operating ranges). These are typically not modeled since the unit is not intended to operate in this range; the TP should know where these ranges are to avoid dispatching the unit there in simulations.

Also, some older legacy PSS designs (some of which are still in service on generating units) were poorly designed, such as to not afford adequate lead/lag compensation blocks and range to allow for proper tuning. These legacy PSSs are likely ineffective and grandfathered into the system. Moving forward, if the excitation systems associated with such PSSs are retrofitted, the opportunity should be taken to replace the PSS with a modern digital PSS2B or PSS2A as appropriate.

Chapter 5: MOD-027-1 Testing Procedures

The purpose of MOD-027-1 is to verify the turbine/governor and load control or active power/frequency control function dynamic models. This chapter describes the various tests that may be performed to develop or verify the dynamic models related to the turbine/governor and load control or active power/frequency control functions.

It is important to take note of Footnote 1 of MOD-027-1, which describes the power plant elements that are considered part of the turbine/governor and load control (synchronous generation) or active power/frequency control function (inverter-based generation). It is described below:

> [1] "Turbine/governor and load control or active power/frequency control:
>
> a. Turbine/governor and load control applies to conventional synchronous generation.
>
> b. Active power/frequency control applies to inverter connected generators (often found at variable energy plants)."

As well as the turbine/governor, any outer loop or plant-level controls that interact with the active power response of the plant should also be verified as part of MOD-027-1 and modeled in stability studies.[68] The following section first lists the tests relevant to verifying turbine/governor dynamic models and model parameters, then lists tests relevant for testing the outer loop or plant-level controls.

Turbine-Governor Verification

The active power-frequency controls of the machine should be verified as part of MOD-027-1, including the turbine-governor model as well as any plant-level control systems that may interact with the governor. First, the turbine-governor model should be verified, and then any additional controls can be overlaid on this model to represent the overall plant active power response and that should also be verified.[69] In the case of large thermal units, the turbine-governor models used to represent these controls in power system simulation programs are far simpler as compared to the actual turbine controls in a large thermal plant (e.g., as compared with the relationship between excitation system models and actual controls). For example, there is a single valve modeled in a typical model for a steam-turbine (IEEEG1) whereas there is an arc of valves around each turbine stage in an actual steam-turbine. The goal is to develop a model that reasonably represents the droop, deadband, and response time of the turbine-governor such that the model is able to emulate the active power response of the unit for a given frequency deviation.[70]

Governor Droop and Deadband Test

The turbine-governor droop (permanent droop for hydro units) should be tested for all expected types of feedback—electrical output, valve position, gate position, etc. If gate or valve position is used as the feedback signal instead of power, droop is calculated based on this signal. It is important to know the power base used for defining the permanent droop. For example, hydro units use gate feedback[71] rather than power feedback for

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[68] Assuming these controls interact in the time frames relevant to dynamic simulations, as stated previously, these times are generally out to 60 seconds following a disturbance.

[69] Most tests will not require switching off the PSS. However, certain dynamic tests (e.g., frequency response tests for hydro plants) may require the PSS switched off such that electrical power provides a suitable proxy for mechanical power. The GOP should notify its TOP of any status change of the PSS per VAR-002-4.1 Requirement R3.

[70] IEEE Task Force on Turbine-Governor Modeling, *Dynamic Models for Turbine-Governors in Power System Studies*, *IEEE Technical Report PES-TR1*, January 2013. Available: http://sites.ieee.org/fw-pes/files/2013/01/PES_TR1.pdf.

[71] Gate feedback may be less convenient to plant operators than power feedback. However, when power feedback is used, the watt transducer output is generally filtered so that the governor does not instantaneously respond to electric power variations that would result

improved control stability; therefore, droop as well as other settings are based on the turbine rating MW.[72] In general, for all turbine types (i.e., hydro, natural gas, or steam), it is better practice to per unitize the model on the MW rating of the turbine.

Droop (or permanent droop for hydro units) can be tested through various means. One method that can be used with various OEM turbines is to measure the steady-state parameters (speed, speed/load reference, and active power output) over a wide operating range of the unit.

If speed/load reference signal is not available, the application of changes in frequency or speed reference in either or both directions at different operating points may be possible. When applying the speed reference steps, they should last long enough for the unit to reach a new steady-state operating condition to record speed deviation and output power.

Figure 5.1 shows an example of data points collected during a test. The unit was loaded to several different operating levels from minimum power output to base load. The steady-state parameters (active power and speed reference minus speed) were recorded at each operating point. These values were then plotted against each other in order to determine the droop.

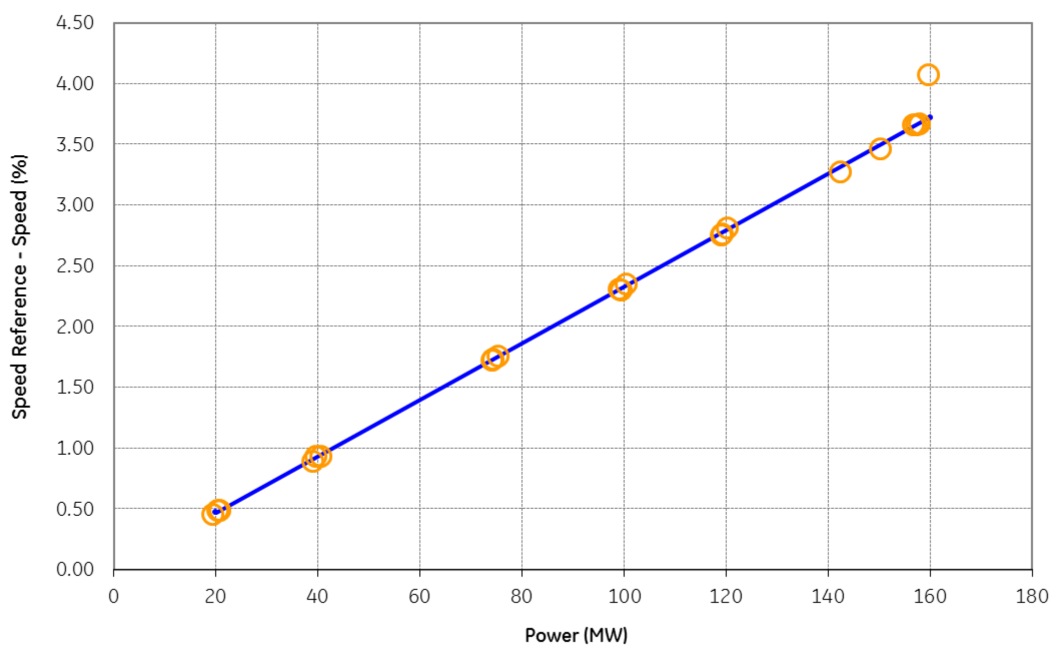

Figure 5.1: Estimation of Droop Test [Source: GE]

Droop can then be calculated as the following:

$$Droop = \frac{\left(\frac{\Delta f}{f_{nom}}\right)}{\left(\frac{\Delta P}{P_{nom}}\right)} = \frac{\left(\frac{\Delta \omega}{\omega_{nom}}\right)}{\left(\frac{\Delta P}{P_{nom}}\right)}$$

in driving the gate/valve servomotor in the opposite direction to what it should be. The equivalent time constant of power feedback should be validated correctly as applicable.

[72] Generator MVA should not be used for per unitizing droop for hydro generators. All per unitized values in the turbine-governor are based on turbine ratings and converting them to the generator base needlessly complicates calculations (e.g., known settings cannot be used, droop settings may be flagged as not within acceptable ranges, power-gate curve data may not be correct or useable).

In this example, the calculation can be made using discrete data points along the linear estimate:

$$Droop = \frac{(3.72\% - 0.47\%)/100\%}{(160MW - 20MW)/172.8MW} = 0.0401 = 4.01\%$$

It should be stressed that this test is not necessarily a measurement of the droop setting in the governor. This is a measurement of the sum total of the signal gains throughout the turbine-governor system, including gate or valve non-linearity, turbine efficiency, effective head (on hydro units), etc. These can drastically affect the net regulation. However, for modern natural gas turbines, this test typically yields an accurate and close correspondence to the digital droop setting since the fuel valves are quite linear.

Overall deadband consists of two components:

- **Intentional Deadband:** An intentional deadband setting in the turbine-governor programmed to minimize dithering on digital controls and movement of valves, gates, etc.
- **Unintentional Deadband:** The unintentional range of speed deviation for which due to the mechanical systems (e.g., backlash) may result in little to no movement of the turbine-governor.

The intentional deadband should be determined and explicitly modeled. Unintentional deadband, due to mechanical effects, is difficult to consistently measure and characterize. It varies over time or operating point, is not consistent or linear, and is generally not considered "deadband" in many situations. Rather, these are combinations of backlash, friction, saturation, looseness, tightness, leakiness, etc. In many natural gas turbines, the unintentional physical deadband is relatively small to negligible while in steam and hydro units this may be more prevalent and quite significant. The model should represent this type of unintentional deadband when consistent mismatch in model verification tests demonstrate that the deadband exists and reasonable adjustment to the deadband addresses the mismatch. The model representation of the deadband may be a combination of the verified intentional deadband as well as the measured unintentional deadband.

Governor Deadband Modeling:
Engineering judgment should be used when representing deadband in a governor model (example in Figure 5.2). Some models do not include a deadband, or the deadband location in the model may not relate with actual implementation.

Incorrect deadband modeling can have consequences for system-wide studies. Primary frequency response from each unit may be over- or under-estimated, affecting model fidelity. Past experience has shown an overestimation of primary frequency response, and incorrect deadband modeling is one contributing factor.

Software vendors should review the implementation of each turbine/governor model and include a deadband in those models that do not have one modeled.

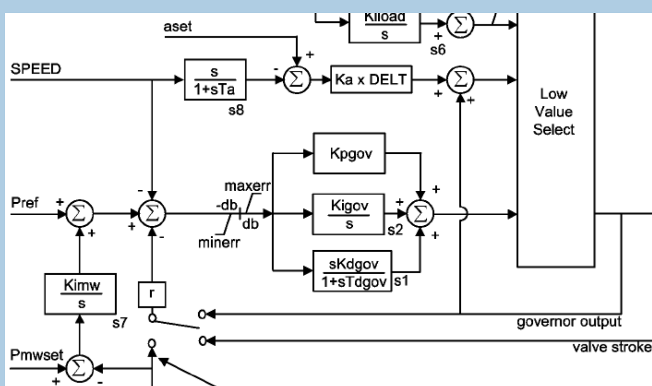

Figure 5.2: Governor Model Diagram

Plant operators may not be aware of frequency control requirements or recommendations put forth by their respective BA or by NERC and may enable a governor deadband to minimize any undesirable servomotor or power oscillations. Deadbands should be minimized to the extent possible, and appropriate settings of governor PID controls or transient gain droops can help minimize these undesirable oscillations. This minimizes a "frequency dead zone" for primary frequency control and provides an overall more stable power system. If deadband is to remain enabled, then it should be tested and modeled appropriately in the dynamic model. It is understood that some minimal level of intentional deadband (e.g., 15 to 30 mHz) is likely, in most cases, necessary to minimize constant movement in turbine valves, gates, etc.

The governor deadband can be tested via two different methods; frequency disturbance recording or introducing a frequency step. Each method has its benefits, drawbacks, and practical limitations; however, either test is suitable to confirm the unit provides primary frequency response and can be used to estimate the deadband and droop for modeling purposes provided the test is run with the governor in its normal mode of operation (refer to the section "Representation of Typical Operating Mode(s)"). For digital control systems, intentional deadband can be confirmed by extracting the setting from the controls.

Verification using Steady-State Methods

Turbine/governor models include a number of parameters that can be derived through measurement of steady-state operating conditions. These steady-state conditions may be part of a set of tests or may be captured during normal operating conditions depending on the circumstances[73] at the plant. Typically some form of steady-state test (e.g., load ramp test) is performed to collect a number of steady-state parameter values. The following sub-sections illustrate how capturing this data can be used to derive the parameter values.

No Load Fuel Flow and Turbine Gain Test (Natural Gas Turbines)

For natural gas turbines, no load fuel flow (w_{fnl}) and turbine gain (K_{turb}) can be determined by operating the unit at different power output levels and comparing power versus fuel valve position (e.g., fuel stroke reference). Figure 5.3 shows an example of these operating points and how the two parameters are derived. A line is drawn between the operating points that crosses through the no load point. The fuel stroke reference at the no-load point defined as w_{fnl} (e.g., 14.2 percent = 0.142 pu). The turbine gain is determined as the slope of the line in per unit as shown in the figure below.

[73] Collection of data should be performed under relatively the same operating conditions (e.g., ambient temperature) to ensure consistent data.

$$K_{turb} = \frac{P_{2,pu} - P_{1,pu}}{FSR_{2,pu} - FSR_{1,pu}}$$

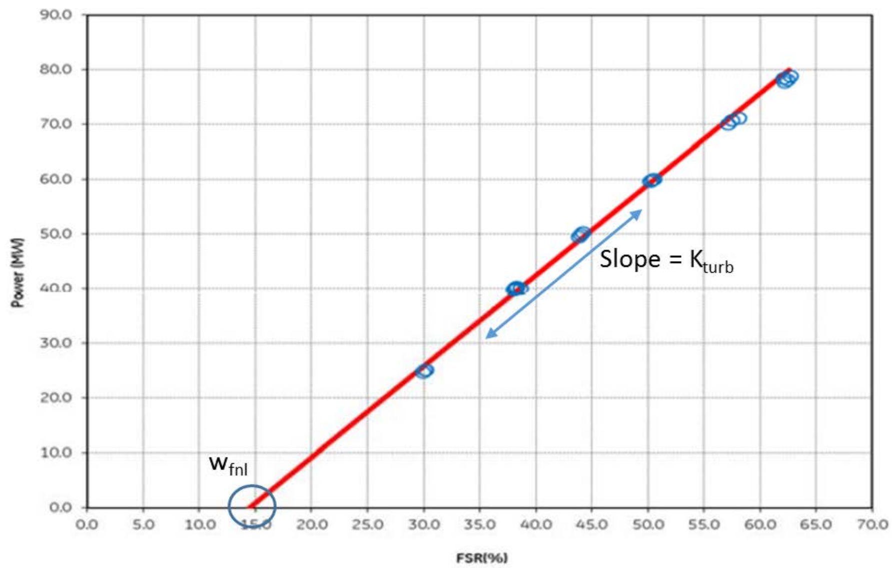

Figure 5.3: Turbine Gain and No Load Fuel Flow Determination [Source: GE]

Load Limit Model Verification and Simulations

It is important to understand that the maximum amount of active power that a natural gas turbine may produce is based on ambient compressor inlet temperature conditions. GOs should provide a temperature-output relationship (see **Figure 5.4**) typically available from the manufacturer as part of the test results. This can also be used to show that there is no material change in equipment from previous testing. The temperature/generator output relationship provides necessary information for the GO to provide appropriate powerflow and dynamic model parameters specified by the TP or PC based on the specific operating conditions being studied. These changes may affect the simulated response of the unit and are important for the TP to consider. TPs who receive a dynamic model with *ldref* < 1.0 pu should ensure they understand at what ambient conditions this value represents and how to scale it appropriately. TPs should also understand that studies not accounting for a decrease in *ldref* under higher ambient temperatures may provide an optimistic response of the natural gas fleet. The natural gas turbine model should be per unitized on the ISO MW rating of the turbine. Then *ldref* = 1.0 for this condition (i.e., ISO 59°F, 14.70 psia). For example, if a heavy summer condition is being modeled where ambient temperature is 35°C, then the maximum power achievable by the natural gas turbine for this condition per the manufacturer-supplied curve may be 80 percent of its ISO MW rating—thus *ldref* = 0.8.

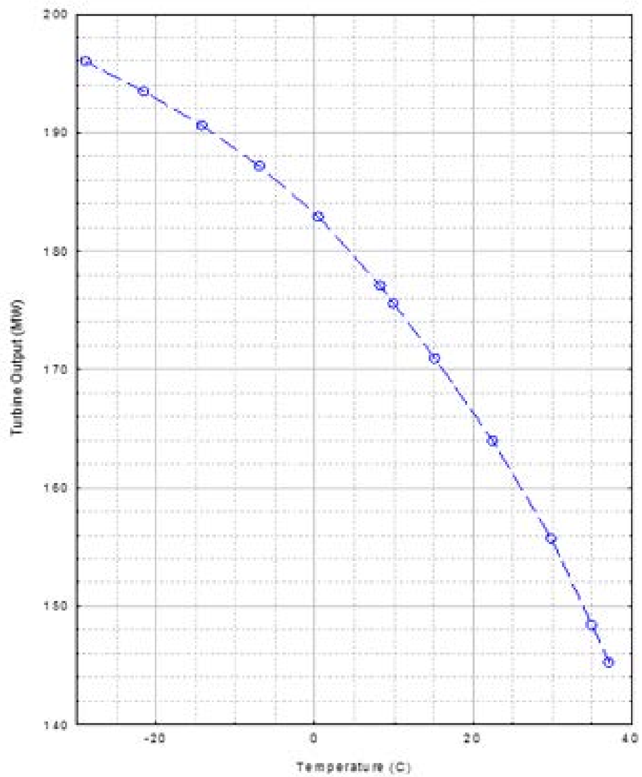

Figure 5.4: Power Output vs. Ambient Temperature Relationship of Natural Gas Turbine [Source: IESO]

Power-Gate Test (Hydro Units)

For hydro units, gate position is adjusted across its allowable range and active power is monitored (see **Figure 5.5**). Usually, water flow vs. gate servomotor opening and active power vs. water flow data are collected as the gate position is adjusted across its allowable range. Values are corrected to account for the rated vs. actual head value to be used as the reference for the computation of the water starting time. The water starting time can also be calculated using penstock dimensions. A common error is using the rated active power of the generator as the per unit base. The reference values[74] that should be used for correctly modeling the turbine output power are as follows:

- Turbine output power at rated head and 1 pu gate servomotor opening
- Generator output power at rated head and 1 pu gate servomotor opening if stator resistance is to be neglected
- Water flow at rated head and 1 pu gate servomotor opening (i.e., "$Q_{flow,ref}$")
- 1 pu base for the gate servomotor opening should be the same as the reference value used in the PID controller and in the transient and permanent gate droop functions

[74] Test result analysis can be challenging and difficult to resume when there is confusion as to which reference values were used by the technicians setting the speed governor and the power system engineers using the dynamic models. The reference values used should be clearly documented to enable effective test results analysis.

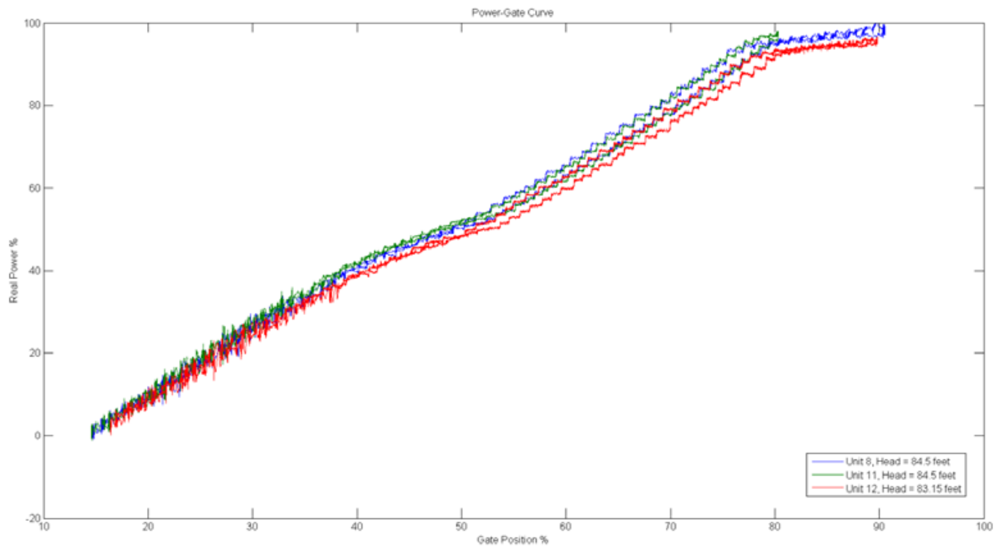

Figure 5.5: Power-Gate Response [Source: US ACE]

Data previously collected (e.g., at commissioning) should be periodically validated. Whenever water flow measurements are unavailable, at least steady-state power vs. gate data (including corrections according to actual net head values) should be collected. The typical translation from power data collected at different net head from the rated value is as follows:

$$P\text{ (G, Rated Head)} = P\text{(G, measured)} * \text{(Rated Head}/H_m)^{1.5}$$

If water flow happens to be measurable, the translation for water flow vs. gate servomotor is as follows:

$$Q_{flow}\text{(G, Rated Head)} = Q_{flow}\text{(G, measured)} * \text{(Rated Head}/H_m)^{0.5}$$

Where G is the gate servomotor stroke, Rated Head is the head value used to compute the water starting time coefficient Tw in the turbine model (generally the designed rated head on the turbine nameplate), H_m is the net head (or approximated net head) value at the moment of the measurement, and Q_{flow} is the water flow through the turbine wheel.

Hydro turbine models should account for the non-linear characteristics of water flow vs. gate servomotor stroke and power vs. water flow (see **Figure 5.6**). Most of the simulation programs use look-up tables[75] to represent this; however, a third order polynomial will provide the best fit. Software vendors and subject matter experts should consider model improvement to enable polynomial representation. **Figure 5.7** shows a non-linear water column available in common power system stability software. This model is adequate for a typical hydro plant with one equivalent penstock and no surge tank. There is no need to model the whole water adduction system if the surge tank is large enough to be considered as an infinite reservoir. Linear turbine-water column models should not be used.

[75] For example, this is available in the WEHGOV model.

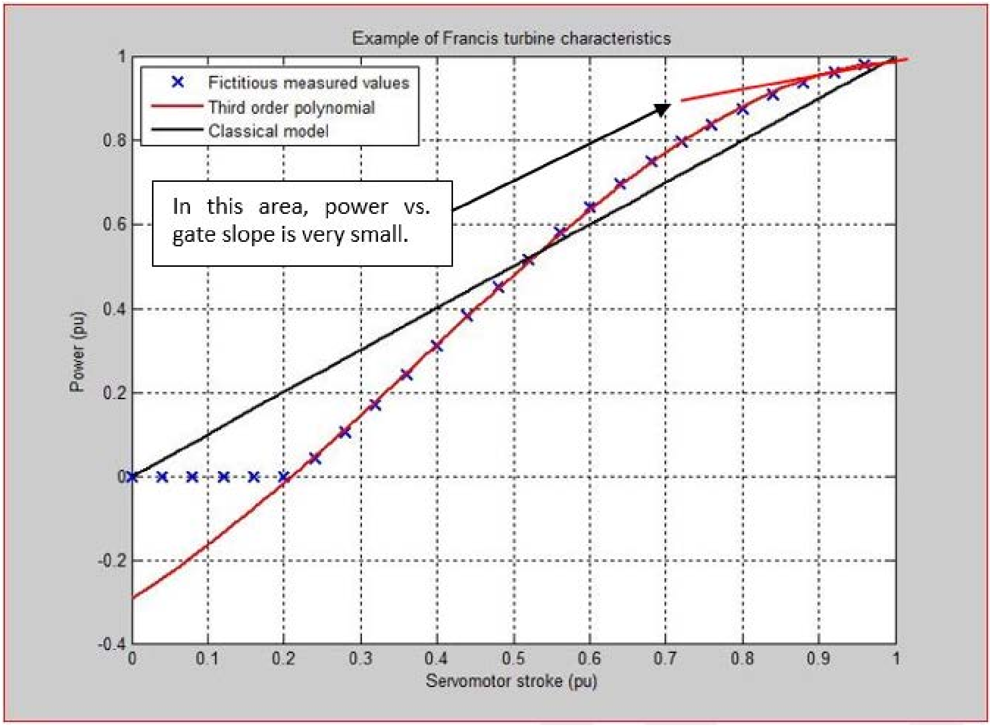

Figure 5.6: Power vs. Gate Servomotor [Source: OPAL-RT]

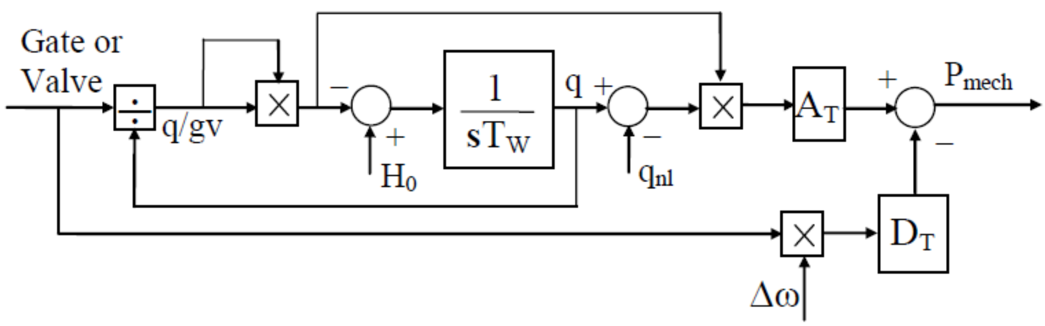

Figure 5.7: Francis Turbine Model with One Equivalent Penstock [Source: IEEE PES-TR1]

Blade-Gate Test (Hydro Units)

This test is the same as the Power-Gate test with blade position also recorded for Kaplan turbines. The unit output is gradually raised from 0 MW to maximum MW. Head, power, blade, and gate are recorded. Steady-state measurements are taken at increments (e.g., five percent) as power is raised. This can also be done while lowering power; however, the control input (speed or power setting in load control mode) should only be adjusted in one direction until the maximum (or minimum) is reached to avoid backlash. Data is then used to create characteristic curve data points as defined by the model being used (see **Figure 5.8**).

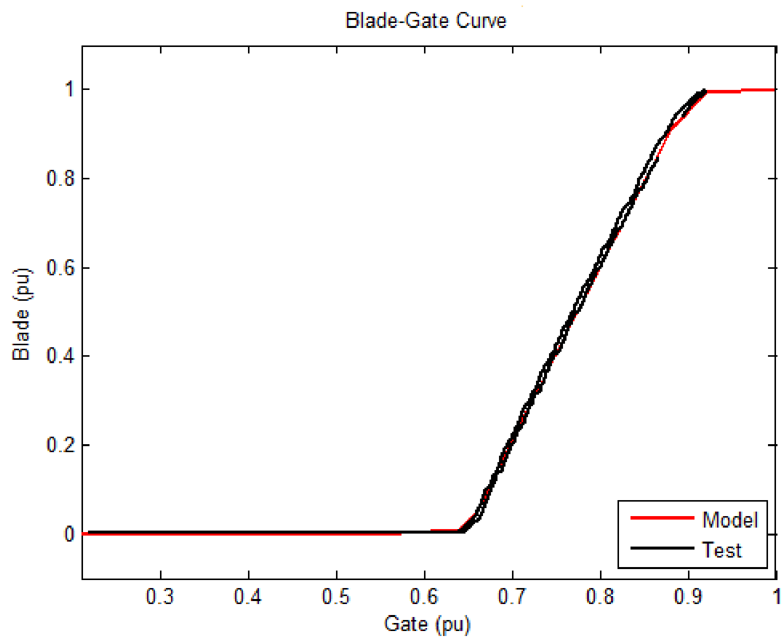

Figure 5.8: Example of Blade vs. Gate Data Collected During Test

Verification using Disturbance-Based Methods

Data collected during grid disturbances when the unit is on-line and operating in its normal operating mode can be used to verify dynamic model parameters. The overall plant response can be verified as described in previous sections. In addition, specific aspects of the turbine/governor model can be verified and these are discussed here.

Deadband can be observed by a generating unit's response to grid disturbances. System frequency excursions, such as generation or load tripping events, occur fairly regularly within an Interconnection and these conditions are suitable to drive frequency outside the governor deadband for reasonable[76] deadbands (e.g., ± 36 mHz). This method is the only approach for mechanical governors used on older hydroelectric turbines. Some type of disturbance recorder needs to be installed to capture this data. Frequency or speed and active power are recorded[77] when the unit is in its normal operating mode between minimum and full load.

Figure 5.9 shows an example of a frequency deviation event and the actual and simulated response of the unit to that frequency excursion. The red plot shows the actual response and the grey, blue, and yellow response show various modeled responses with different deadband settings to try to match. The deadband was tested at 0 mHz and this clearly proved incorrect since the unit does not respond to small changes in frequency throughout. Deadband was tested at 33 mHz, and this also proved incorrect since the initial match is good and the transient response is good, but the return to pre-event output was not captured. As the frequency began to recover, the actual unit response reduced to match this increase in frequency. The 33 mHz deadband setting did not capture this until frequency reached outside the upper deadband. In this case, the planning engineer tested the position of the deadband and determined that the deadband was not located in the correct location in the model. Upon moving the deadband (e.g., from speed deviation to speed error, or vice versa), they were able to obtain an excellent match (yellow plot). Plotting time synchronized measured unit MW output and frequency against simulated response provides a useful verification of the overall dynamic turbine-governor model for the unit.

[76] NERC Reliability Guideline on Primary Frequency Control, December 2015. Available: HERE.
[77] It may be useful to record other quantities such as gate position (hydroelectric turbines), valve position (natural gas and steam turbines), or controller output where available.

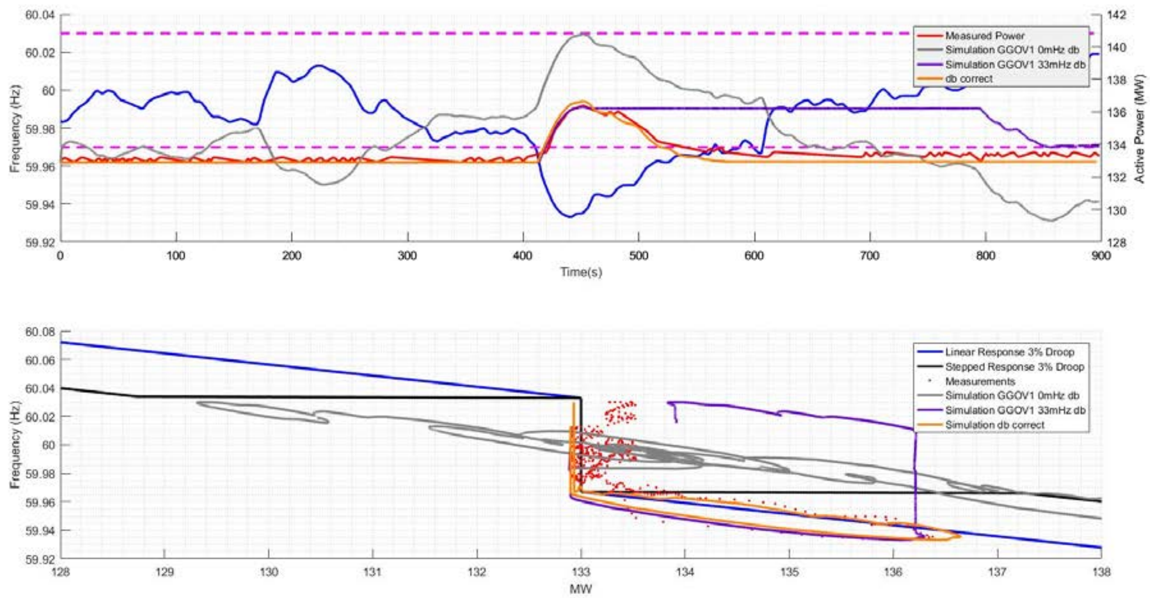

Figure 5.9: Disturbance Measurement for a 225MVA Natural Gas Turbine [Source: IESO]

Figure 5.10 shows that the number of opportunities to capture data diminishes with the size of the deadband, and there is a practical limit to the size of the deadband that can be confirmed via this method. For example, 10 percent of the hours in a year will have at least a minimum frequency value of ≤ 59.95 Hz as compared to 75 percent of the hours in a year will have a minimum frequency ≤ 59.97 Hz.[78] For expected deadbands in the range of ± 36 mHz, there are ample opportunities to confirm the deadband setting. Large deadbands outside the expected, reasonable range may not be practical to test with this approach since frequency may not reach lower limits.

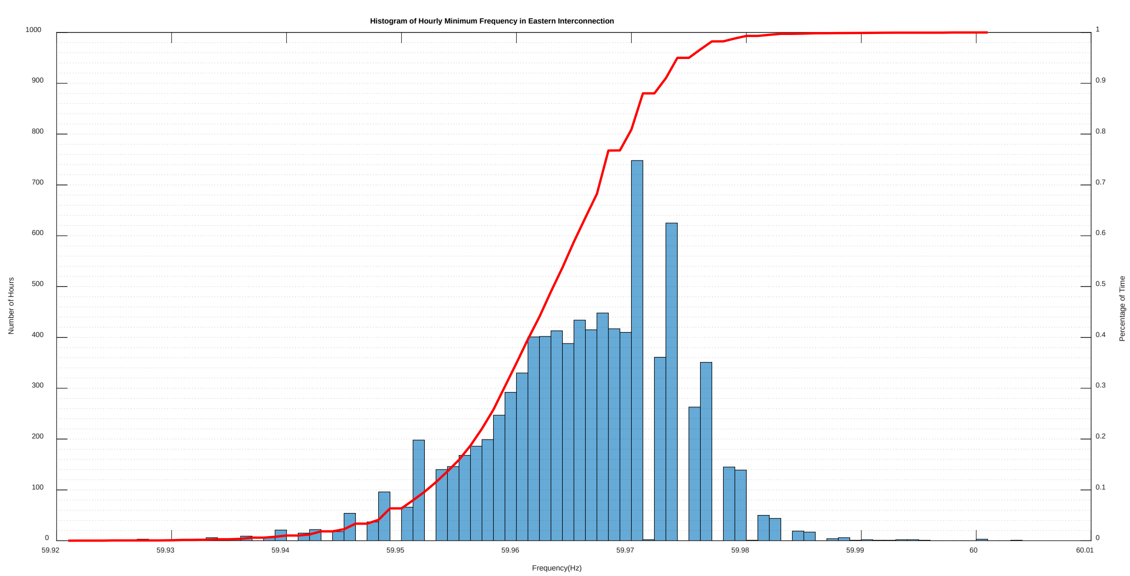

Figure 5.10: Hourly Minimum Frequency—Calendar Year 2016 [Source: IESO]

As mentioned above, it may be beneficial to measure quantities, such as gate or valve position, when either the droop is based on gate or valve position rather than electrical power or when the electrical power measurement

[78] Minimum frequency events include loss of generation and normal frequency deviations from nominal.

has low resolution or accuracy. Figure 5.11 provides an example where the resolution of the electrical power measurement was too low to determine the hydroelectric turbine deadband of ±5 mHz. However, when the gate position is plotted rather than electrical power, the deadband of 5 mHz can be confirmed.

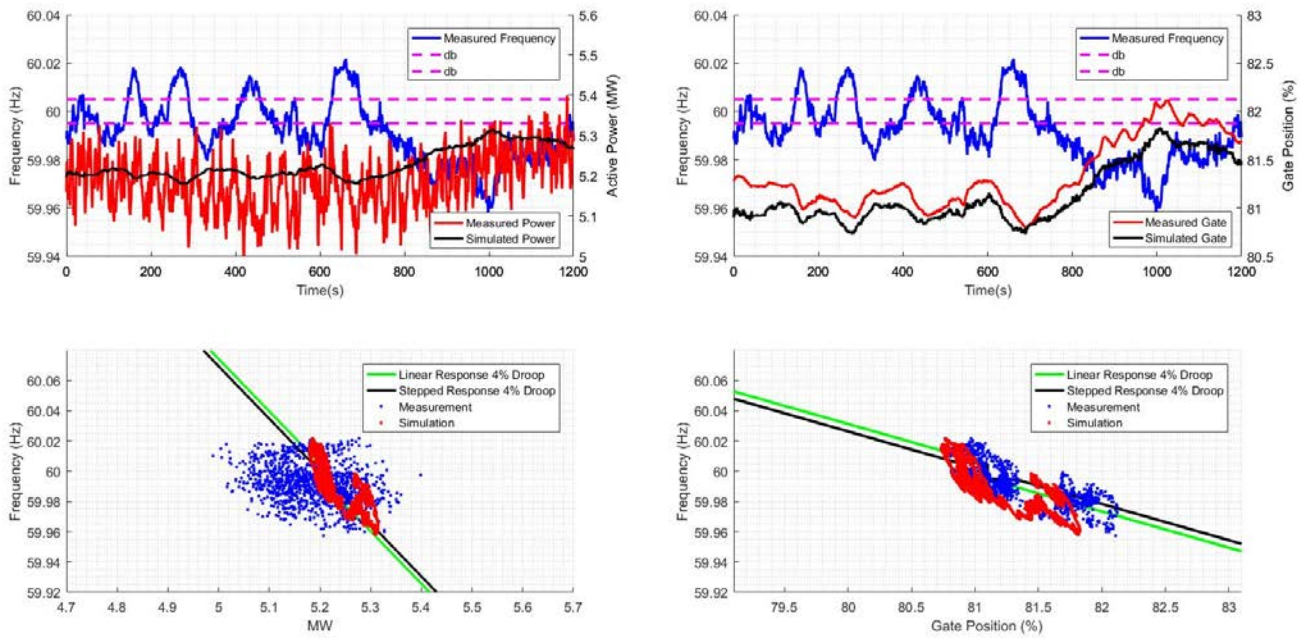

Figure 5.11: Measured Power and Gate during Ambient Measurements for 6.9 MVA Hydroelectric Generator [Source: IESO]

Model Verification and Capability Testing for Nuclear Generation:
The suite of potential tests that may be performed for nuclear generation is similar to other synchronous resources. The same tests can be used for verifying the generator, excitation system, PSS, and turbine-governor parameters. Nuclear resources are not required to test reactive power capability at minimum active power output as part of MOD-025-2 capability testing. Refer to the relevant standards for specific details regarding the requirements for nuclear generation related to model verification and generator capability testing.

Staged Testing

Governor model verification is often performed using staged tests involving a step change injected into the turbine-governor controls. Frequency, speed, power output, and feedback signals (e.g., gate position, valve position) are collected to verify performance. The unit is operated in its normal mode of operation and at an operating point between minimum and maximum load (i.e., capable of providing governor response). The following subsections describe the various tests that may be performed.

Speed/Frequency or MW Load Reference Step Test

The turbine-governor response (controller PID gains, droop, and deadband) to perceived changes in system frequency can be verified by using speed/frequency reference step tests into the governor or MW load reference steps into the plant load controller. The type of test performed is highly dependent on the capability of the unit/plant controller's ability to inject an additive component into the appropriate speed, frequency, or load reference location. This is a controlled test of speed/frequency change perceived by the governor or MW change perceived by the plant controller, and testing engineers can quickly observe response and make any necessary changes or correction following a test run. These tests may also be used to verify other elements of the model, such as rate limiters if applicable.

Figure 5.12 shows three locations where a step may be applied in the model—perceived speed/frequency, unit speed/load reference, or plant load controller reference. These points relate to some degree to actual points in the physical equipment and this should be verified during testing. It should also be verified that the step input is applied before the intentional deadband used in the governor (if any) so that this control component can also be verified during the test.

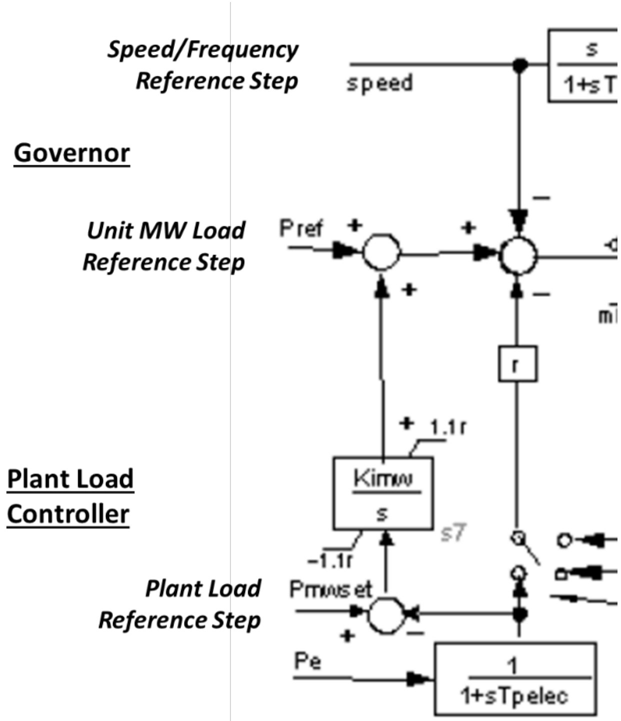

Figure 5.12: Load Reference Step Input [Source: Duke]

Typically, for hydro turbines where mechanical stresses are not as concerning, a 0.5 percent and one percent[79] change in speed reference is applied and removed with the unit on-line with sufficient governor headroom to prevent reaching the maximum output conditions (e.g., gate or stator output limit). Active power, gate position, and blade position are typically monitored on a hydro unit. If possible for hydro units, tests should be performed with permanent droop on gate instead of power for easier verification of control gains. The verification tests should, to the extent possible, use the actual operating conditions and control modes used by the equipment during normal operation and controls should not be adjusted specifically for testing purposes. This minimizes any discrepancy between the modeled response and actual response for system reliability studies. For steam and natural gas turbines, typically a speed reference change of the order of 0.1 percent up to 0.2–0.5 percent may be applied. Larger steps are rarely used. For a natural gas turbine in addition to active power, the fuel stroke position may also be monitored. For a steam turbine the valve position(s) are likely not easily monitored and do not necessarily have a one to one correspondence in the simple planning models used. For steam turbines, use flow reference or flow demand, which linearizes the valve response (valve curves).

For hydro units, if the non-linear gain characteristic between gate position and power is modeled by a piecewise linear function (Figure 5.13), the continuous gain change in power output for changes in gate position that will be measured will not be reproduced in the simulations with these models. In these cases, the power output responses may match adequately during some portions of the response but not typically throughout. The problem will be most acute near the most abrupt transitions in the characteristic. In most cases, the gate responses are the best signals for response comparison, and some error in the power signal should be acceptable (Figure 5.14). Since

[79] Sometimes a larger step may be required to confirm gate rate limiters (maximum opening and closing rates).

the unit will normally be operated near the top part of the curve, it is recommended to define as many points as possible at the top in this case, typically the most curved part of the power vs. gate characteristic.

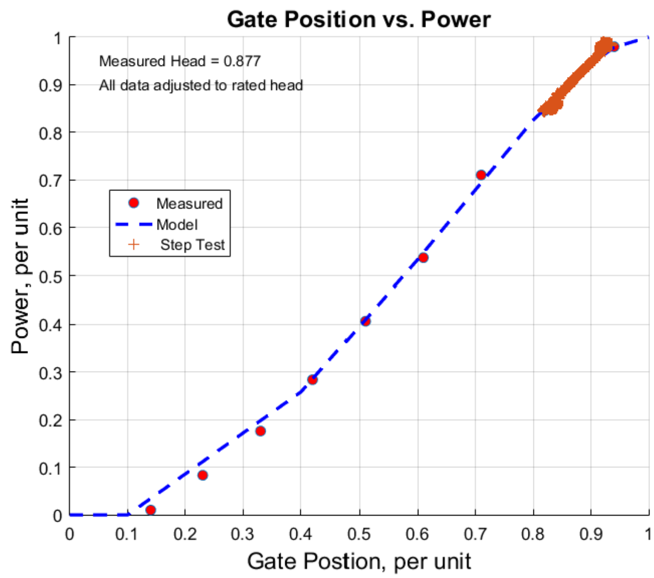

Figure 5.13: Piecewise Linear Power-Gate Characteristic Representation [Source: USBR]

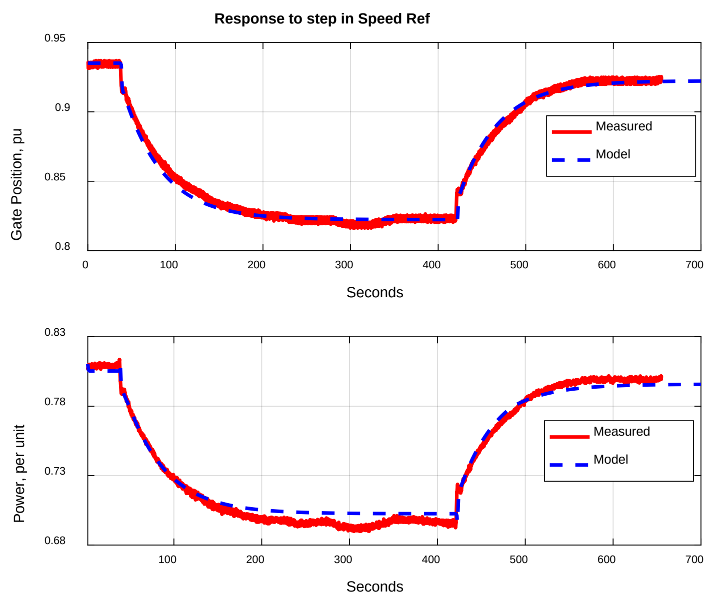

Figure 5.14: Load Reference Step Input [Source: USBR]

Figure 5.15 shows the perceived speed/frequency steps for a Pratt & Whitney aeroderivative natural gas turbine using a Woodward controller test function. The perceived speed to the governor is held to 3,600 RPM and injections of +6, +12 and -12 RPM where made at various times during the test.

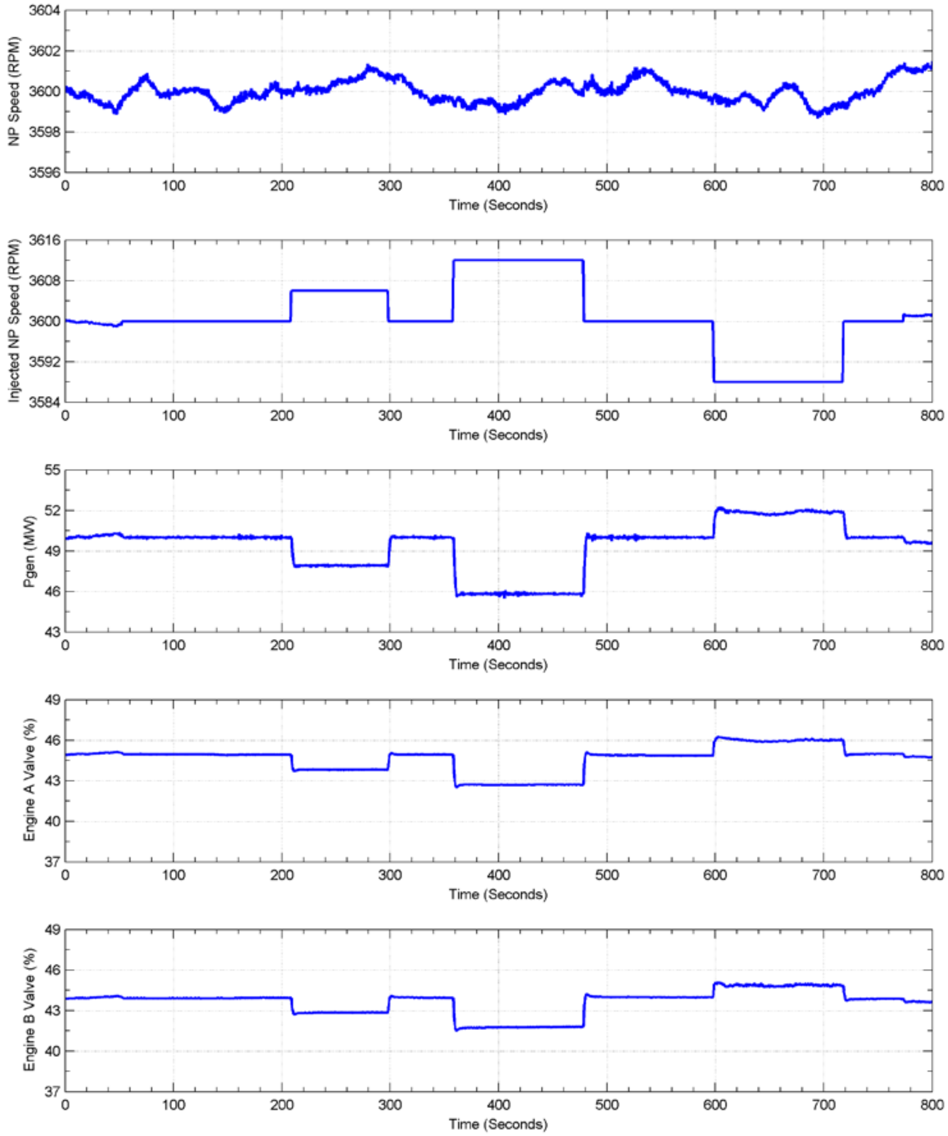

Figure 5.15: On-line Governor Speed Reference Step Test [Source: GE]

The first two speed injections (+6 and +12 RPM) allow for the speed governor controls to be simulated. Figure 5.16 shows the simulated response by "playing back" the perceived speed into the simulation. This corresponds to injecting a signal into the governor speed/frequency reference point in Figure 5.12. The blue line represents the measured values while the red line represents the simulation response.

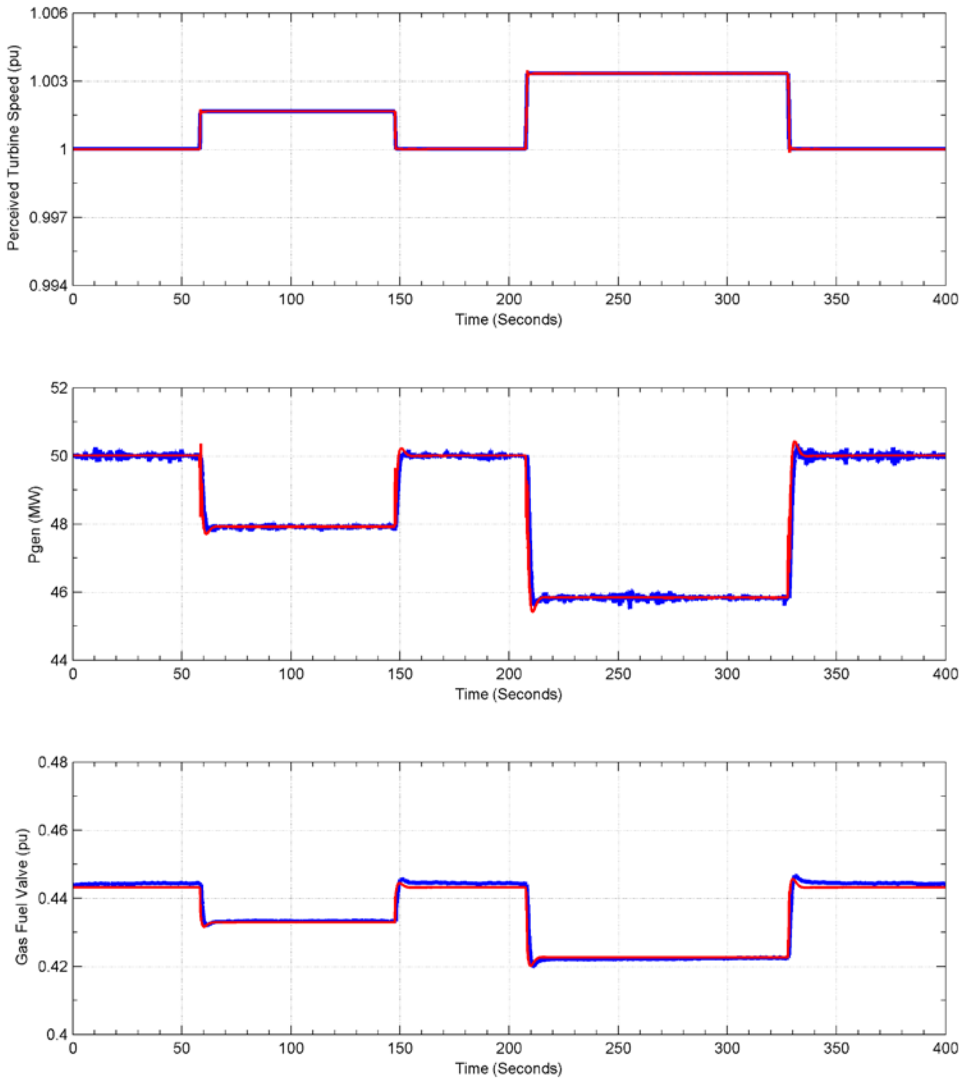

Figure 5.16: On-line Governor Speed Reference Step Test versus Simulation Determination of Speed Governor Controls [Source: GE]

The third speed injection (-12 RPM) allows for the exhaust temperature controls to be simulated. **Figure 5.17** shows the simulated response by "playing back" the perceived speed into the simulation. Once again, this corresponds to injecting a signal into the governor speed/frequency reference point in **Figure 5.12**. The blue line represents the measured values while the red line represents the simulation response.

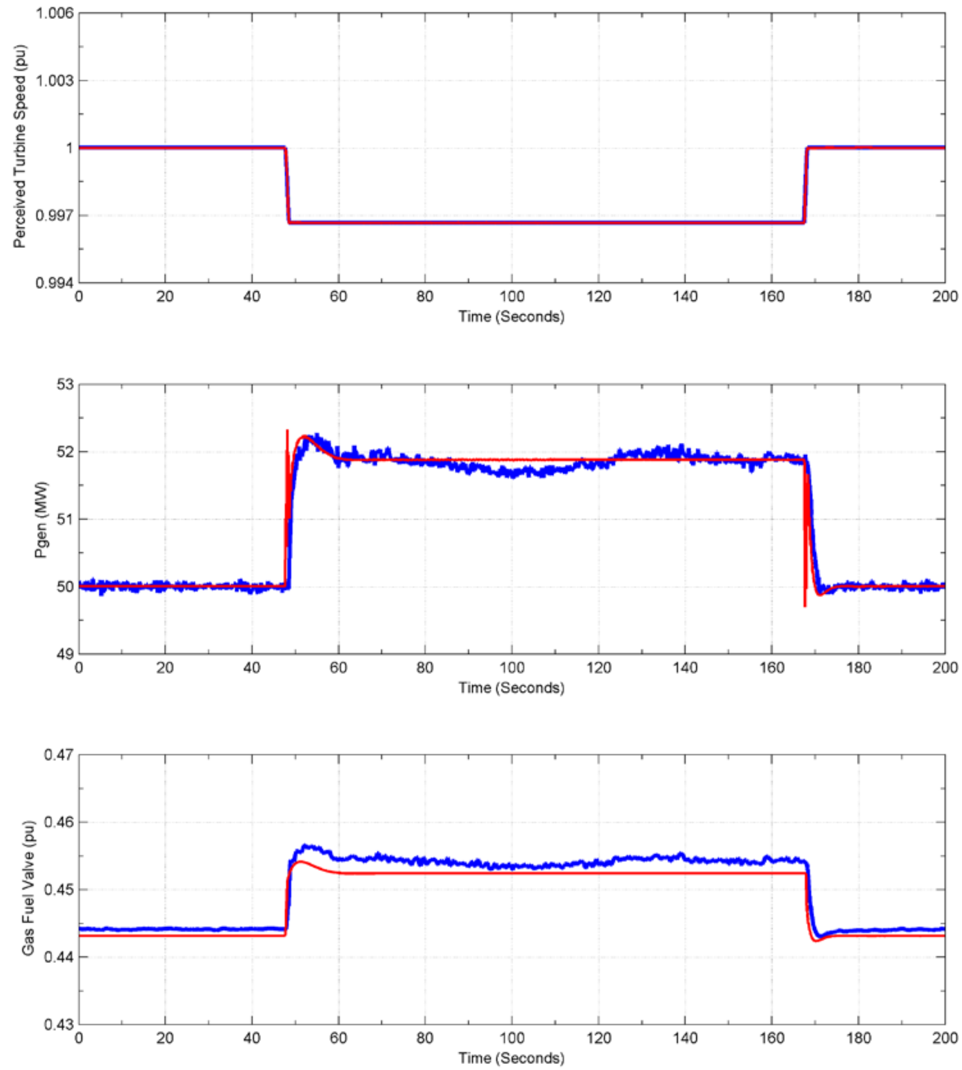

Figure 5.17: On-line Governor Speed Reference Step Test versus Simulation Determination of Exhaust Temperature Controls [Source: GE]

Figure 5.18 shows the speed/load reference steps for a GE natural gas turbine using Mark VI controls. The natural gas turbine controls see the grid frequency during the event but also experience a deliberate change to the speed/load reference injected by the test engineer. The perceived speed to the governor is "played back" while speed/load injections of (-0.2 percent, -0.4 percent and +0.4 percent) where made at various times during the test. These steps are equivalent to a -120 mHz, -240 mHz, and +240 mHz frequency reference changes.

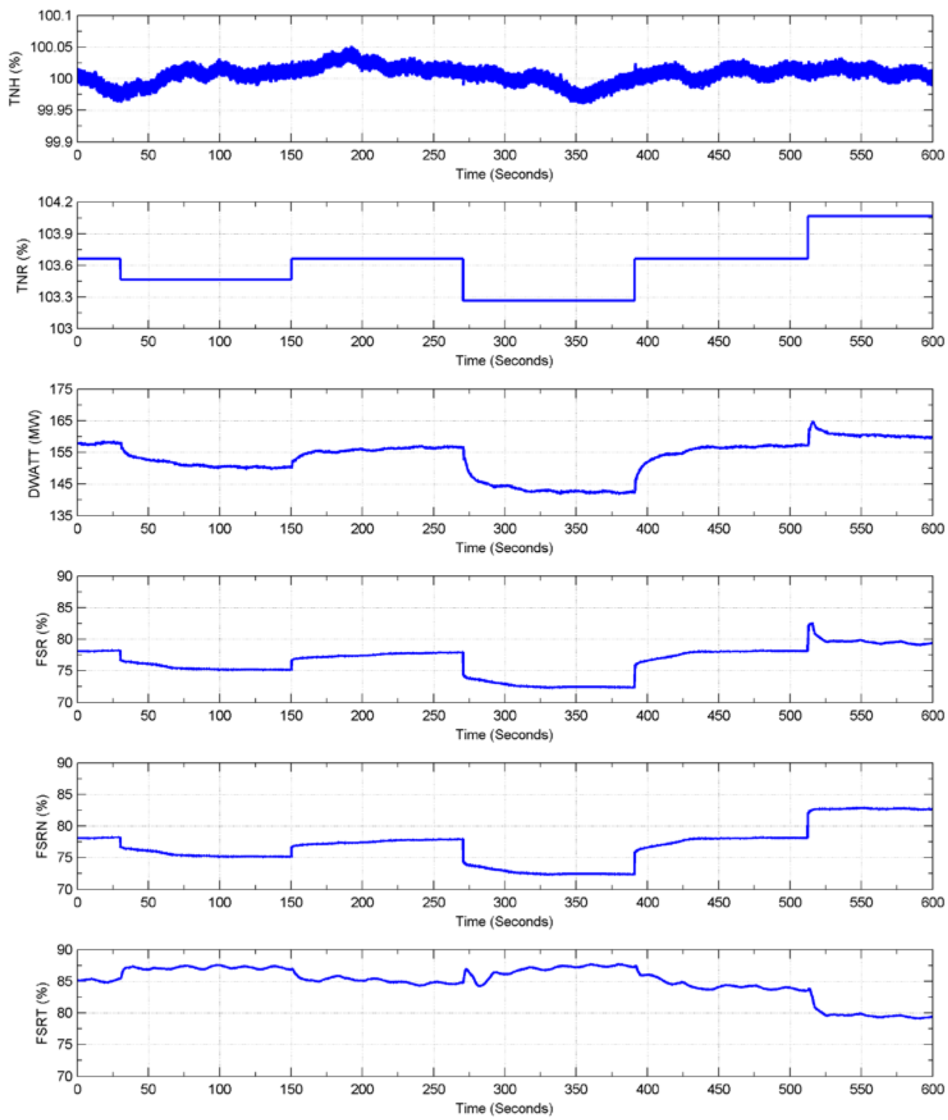

Figure 5.18: On-line Governor Speed/Load Reference Step Test [Source: GE]

The first two speed/load injections (-0.2 percent and -0.4 percent) allow for the speed governor controls to be simulated. **Figure 5.19** shows the simulated response by "playing back" the perceived speed into the simulation and injecting a speed/load reference change. This corresponds to injecting a signal into the governor unit MW load reference point in **Figure 5.12**. The blue line represents the measured values; the red line represents the simulation response.

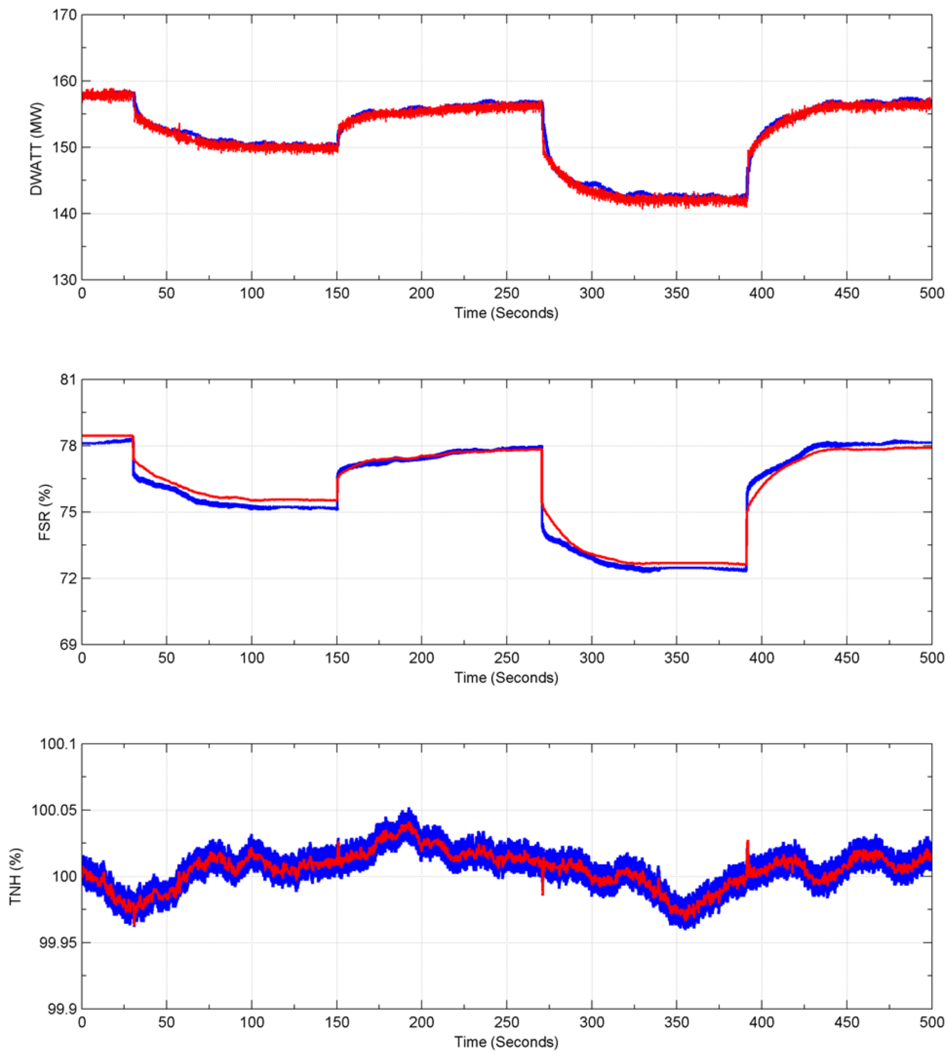

Figure 5.19: On-line Governor Speed/Load Reference Step Test versus Simulation Determination of Speed Governor Controls [Source: GE]

The third speed/load injection (-0.4 percent) allows for the exhaust temperature controls to be simulated. **Figure 5.20** shows the simulated response by "playing back" the perceived speed into the simulation and injecting a speed/load reference change. Once again, this corresponds to injecting a signal into the governor unit MW load reference point in **Figure 5.12**. The blue line represents the measured values; the red line represents the simulation response.

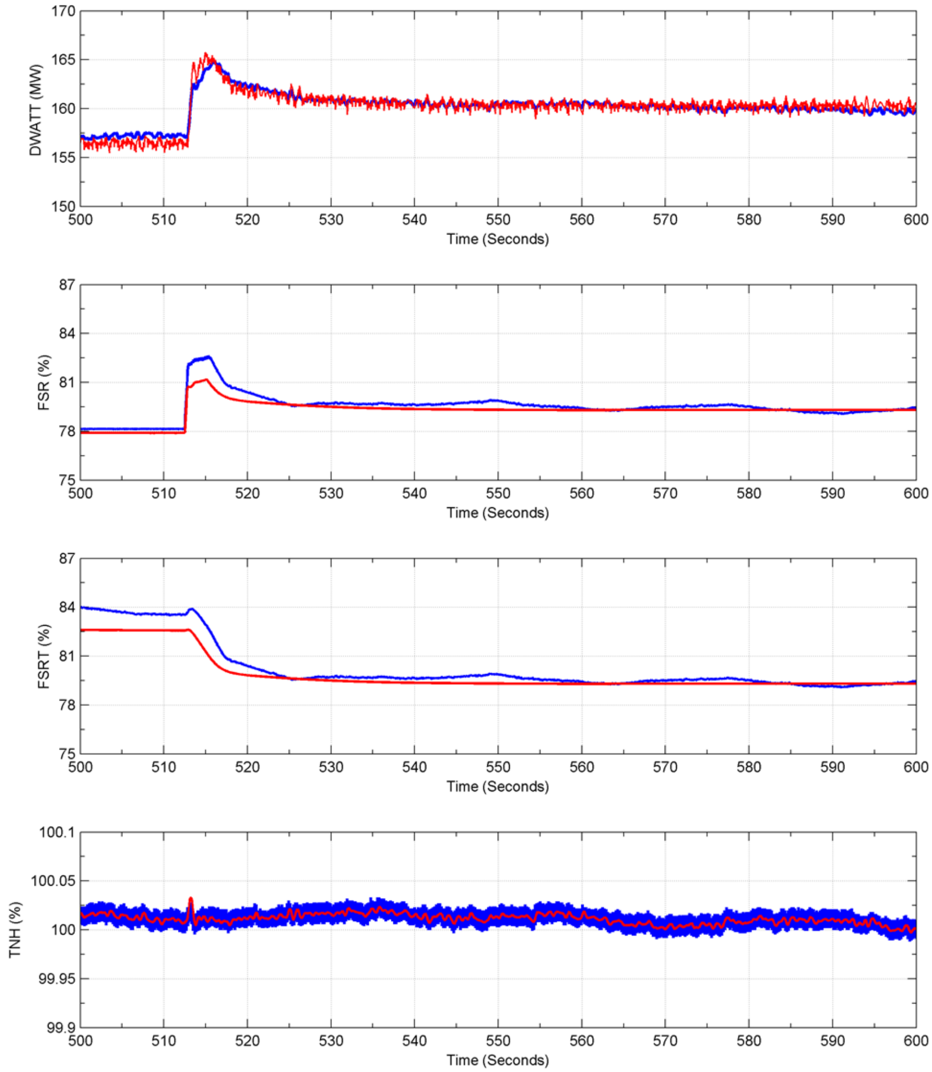

Figure 5.20: On-line Governor Speed/Load Reference Step Test versus Simulation Determination of Exhaust Temperature Controls [Source: GE]

Frequency Sweep (Hydro Units)

Frequency sweep tests involve injecting an oscillation into the speed/frequency meter or the speed reference entry port and monitoring the available signals (gate servomotor and power output signals, at a minimum). For example, **Figure 5.21** shows gate servomotor position over time as the test is performed. An oscillation ranging from near 0 Hz up to 5 Hz is overlaid on the rated frequency signal. The frequency of oscillation is continuously increased ("swept"), linearly or not. The frequency value is computed in such a way that it will increase slowly enough for detecting resonances but fast enough not to generate damage on the equipment. Once the maximum oscillation frequency is reached, the oscillation is removed from the system. Focusing on frequencies that generate some resonance or unsuspected behaviors enables quick identification of any deficiencies (e.g., "dead times" or delays that could occur when the speed governor is driven by speed/frequency oscillations) in the system or discrepancies between reality and expected model.

These tests often require the PSS to be turned off to avoid interactions between the PSS's frequency response and the test result. The GOP must inform the TOP of any status change of the PSS per VAR-002-4.1 Requirement R3.

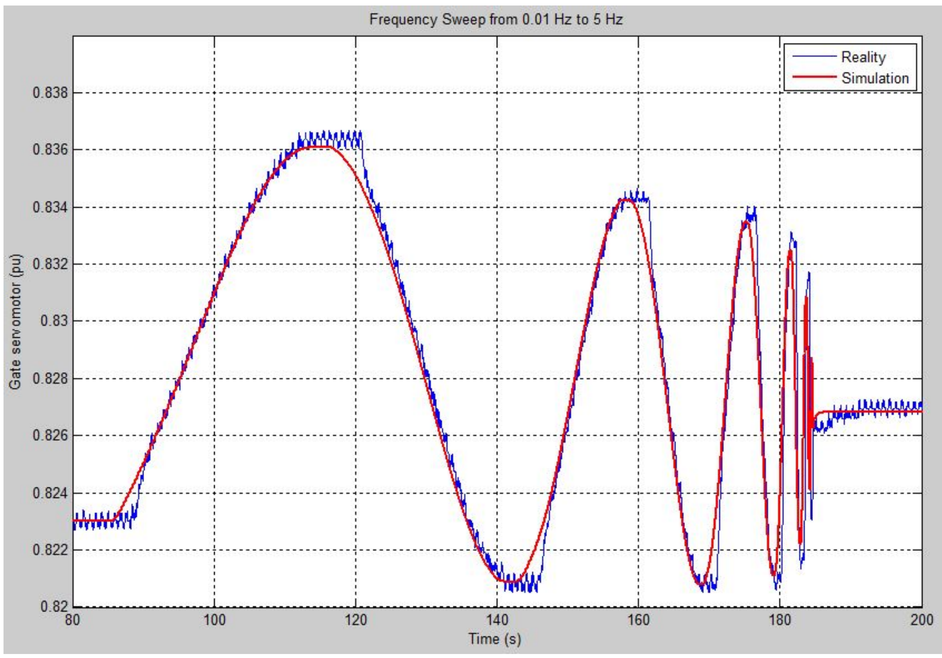

Figure 5.21: Frequency Sweep Test [Source: Opal-RT]

Servomotor characteristics (Hydro Units)

The inherent servomotor deadband is usually very small and can be neglected, but, if substantial, it can contribute to deteriorating the stability of an islanded system and should be included in the model. Many models represent the servo system as a gain and time constant with the integrator of the main servo, resulting in a second order system, which is the proper representation of this part of the system.

Accurately modeling the turbine-governor for stability studies requires the servo system be modeled with both a gain and time constant in addition to the integrator as shown in **Figure 5.22**. For electronically controlled governor systems, the response of the servo control system is easily obtained through small signal testing—step or swept frequency response (see **Figure 5.21**). In mechanical-hydraulic systems, the gain and time constant can be obtained with the dashpot disabled as part of normal maintenance measurements. Gate rate limits and temporary droop measurements should also be determined at this time. A mechanical engineer responsible for the governor adjustment and maintenance should be consulted.[80]

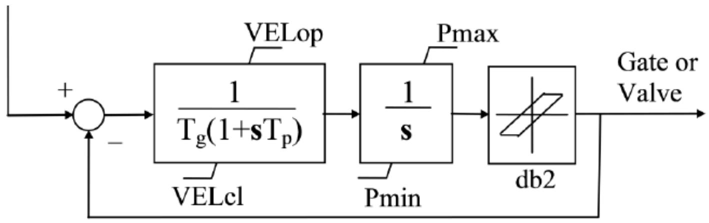

Figure 5.22: Gate Servomotor Model Representation

Water Starting Time Constant (Hydro Units)

T_w (or T_{turb}) is referred to as the water starting time or water time constant. It represents the time required for a head H_0 to accelerate the water in the penstock from stand still to the velocity U_0. The equations below represent the "classical" transfer function of the turbine-penstock system. It shows how the turbine power output (P_m) changes in response to a change in gate opening (G) for small perturbation (prefix Δ) about a steady-state operating point (subscript '0') for an ideal lossless turbine.

$$\frac{\Delta P_m}{\Delta G} = \frac{1 - T_w s}{1 + \frac{1}{2} T_w s}$$

where

$$T_w = \frac{L U_0}{a_g H_0}$$

Where L = length of conduit, m
a_g = acceleration due to gravity, m/sec^2
U_0 = velocity at a given operating point
H_0 = water head at a given operating point

It should be noted that T_w varies for different operating points based on this equation. Typically, T_w at full load lies between 0.5 seconds and 4.0 seconds. The transfer function represents a "non-minimum phase" system. This special characteristic of the transfer function may be illustrated by considering the response to a step change in gate position. The time domain response is given by the following:

$$\Delta P_m(t) = \left[1 - 3e^{-\left(\frac{2}{T_w}\right)t}\right] \Delta G$$

Figure 5.23 shows that the mechanical power actually decreases by 2.0 pu per unit immediately following a unit increase in gate position. It then increases exponentially with a time constant of $T_w/2$ to a steady state value of 1.0 pu per unit above the initial steady state value.

[80] US Bureau of Reclamation, "Mechanical Governors for Hydroelectric Units," Facilities, Instructions, Standards, and Techniques, vol. 2-3, Denver, CO. Available: https://www.usbr.gov/power/data/fist/fist2_3/vol2-3.pdf.

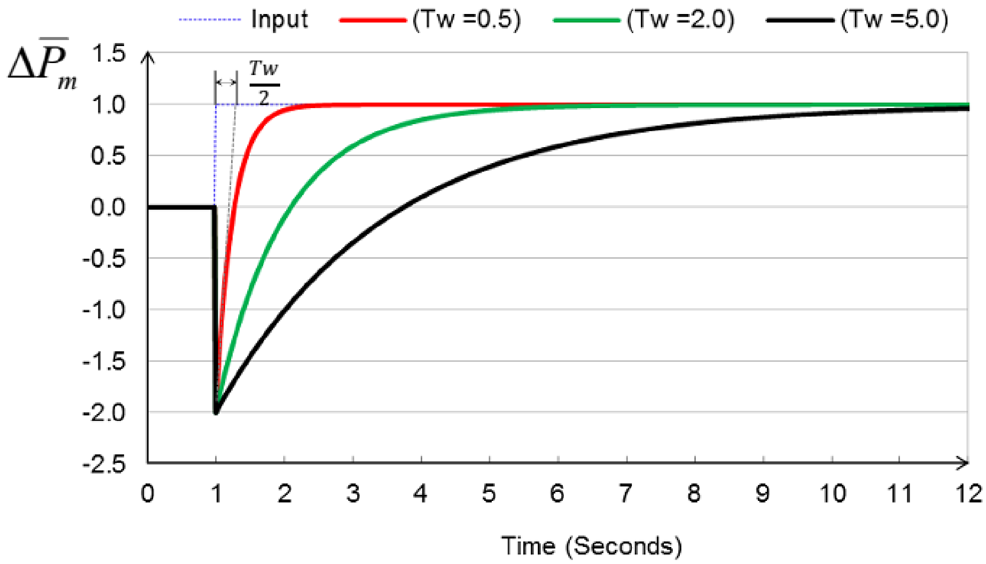

Figure 5.23: Hyde Turbine Mechanical Power in Response to 1.0 pu Gate Step Change

The initial power surge is opposite to that of the direction of change in gate position. This is because when the gate is suddenly opened, the flow does not change immediately due to water inertia; however, the pressure across the turbine is reduced, causing the power to reduce as well. With a response determined by T_w, the water accelerates until the flow reaches the new steady value, which establishes the new steady power output. Similarly, Figure 5.24 shows the hydraulic turbine mechanical power response to a 0.1 pu gate ramp down change.

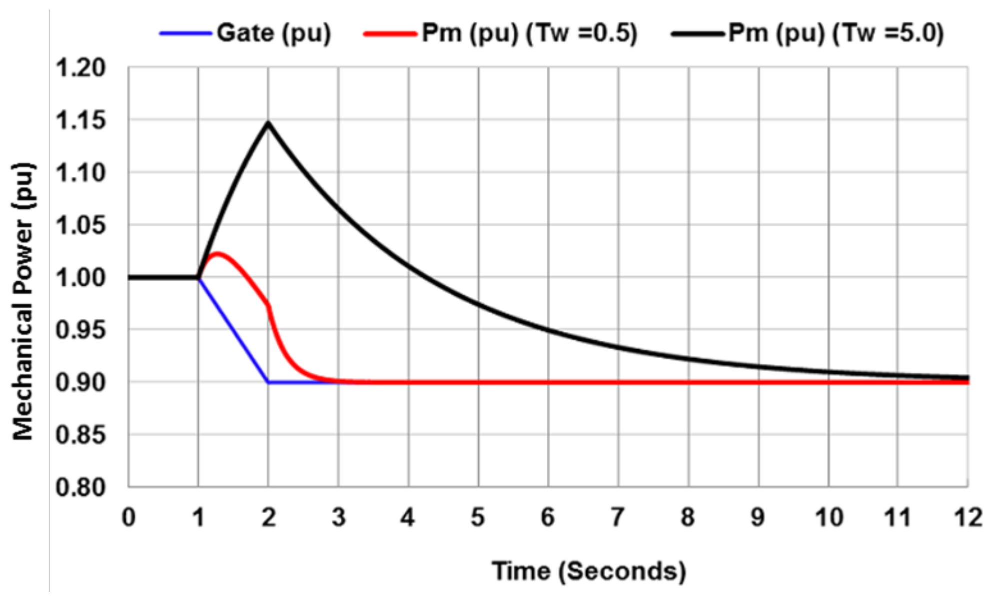

Figure 5.24: Hydro Turbine Mechanical Power in Response to 0.1 pu Gate Ramp Change

The linear model given by the equation above represents the small-signal performance around a certain operating point. A non-linear model is required where speed and power changes are large, such as in islanding, load rejection, and system restoration studies. Figure 5.25 shows a block diagram of the complete per-unit equations representing the water column and turbine characteristics. In this model, T_w refers to the water starting time constant at a rated load and with the gate fully open (G=1.0), which is given by the equation below.

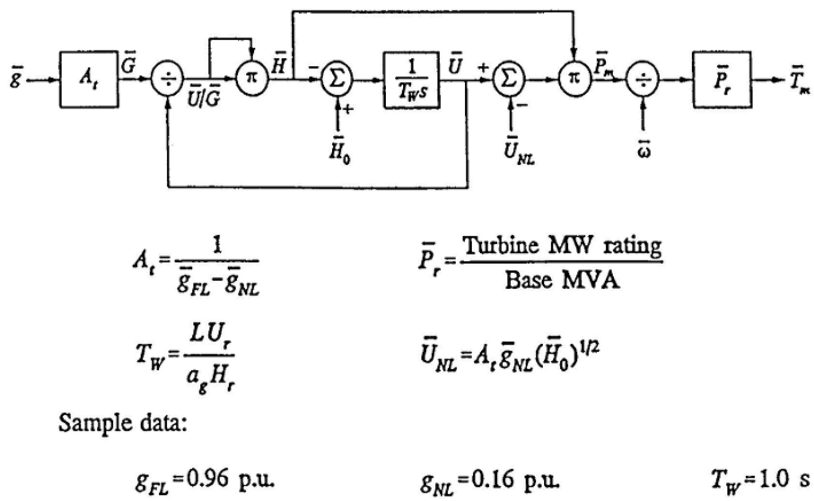

Figure 5.25: Complete Per Unit Equations Representing Water Column and Turbine

$$T_w = \frac{LU_r}{a_g H_r}$$

where L = length of conduit, m
a_g = acceleration due to gravity, m/sec^2
U_r = velocity at rated load
H_r = water head at rated load

The water starting time constant can be verified by on-site testing by applying a quick change to the wicket gate position using speed adjuster motor (gate limiter), causing a large step change in unit output. Figure 5.26 shows the curve matching result of the water starting time constant test by “playing-back” the measured gate position to the model.

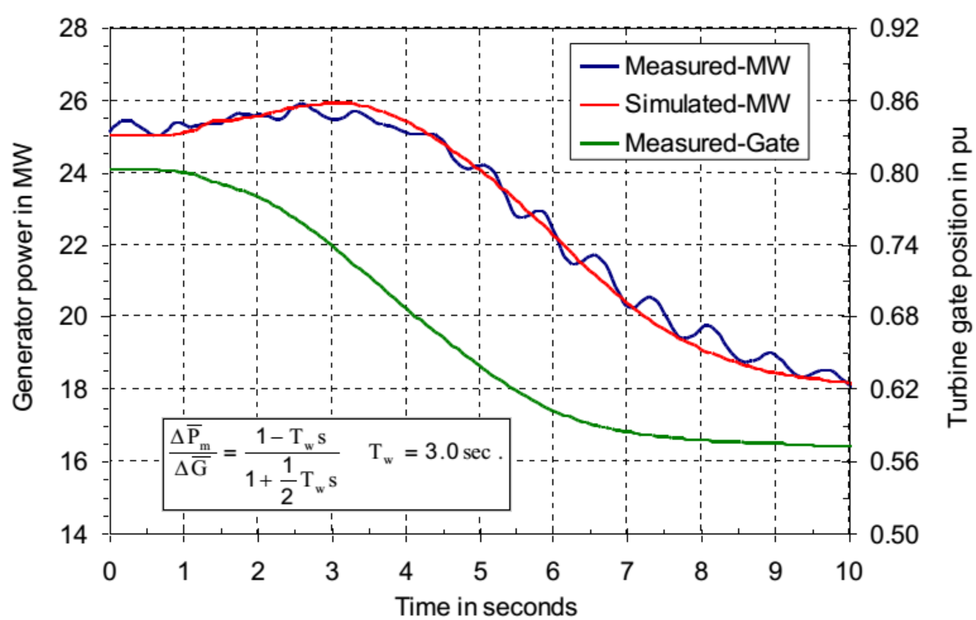

Figure 5.26: Water Starting Time Constant Verification Test for 37.5 MVA Hydro Unit

Plant-Level and Outer Loop Controls Verification

Once the model of the turbine-governor has been validated (for example, the lower part of Figure 5.27), any plant-level or outer loop controls should also be validated (for example, upper part of Figure 5.27) to ensure the overall simulated dynamic response of the plant matches the actual plant performance. Staged tests can be performed to verify outer-loop controls, but this can be more complex and caution should be exercised to avoid interactions between the turbine-governor controls and the outer loop controls. The outer-loop controller, in many cases, may be from a different vendor than the turbine-governor and in the plant's DCS. Therefore, the access point for the outer-loop controller may be different than the turbine-controls. For a staged test, a small load reference step is injected at the input of the outer-loop controller ("Load reference step input" in Figure 5.27), while the outer-loop controller and turbine-governor are both active. The turbine should not be near base-load for this test to allow it room to move. The step change in load should be small (e.g., ≤ five percent of the rated turbine MW) to avoid undue stress on the turbine. Some outer loop plant controllers include a frequency bias that disables the outer-loop controller for typical system-wide frequency excursion events. In these situations, if disturbance monitoring of significant system-wide frequency events show that the outer-loop controller does not come into play, then modeling the outer-loop controller may not be necessary for system planning studies (the GO should confirm this with data and coordination with their TP/PC). If the outer-loop controller is modeled in these cases, the frequency bias must also be properly modeled.

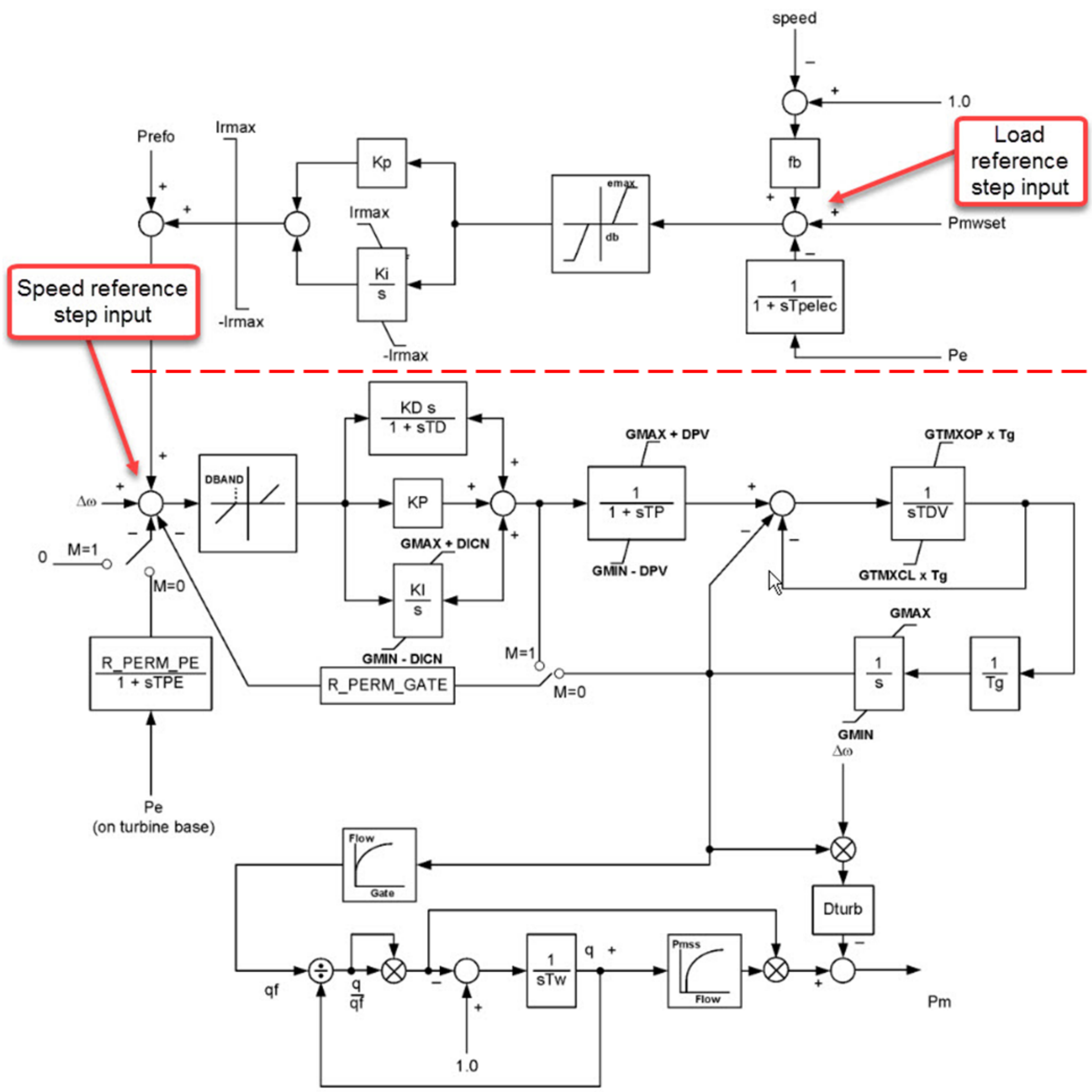

Figure 5.27: Load Reference Step Input [Source: Duke]

Disturbance-based model verification is perhaps the best approach for doing both these tasks and will best capture the overall plant response to an actual system event.[81] As an example of disturbance based verification, Figure 5.28 shows verification of a large steam turbine generator during a system under-frequency event. In this case, the governor model and the outer loop load control model were both verified. Basically, by measuring the total power output of the plant and frequency at the generator, one can play-back the measure frequency into the model and then compare the simulated and measured power output of the plant.

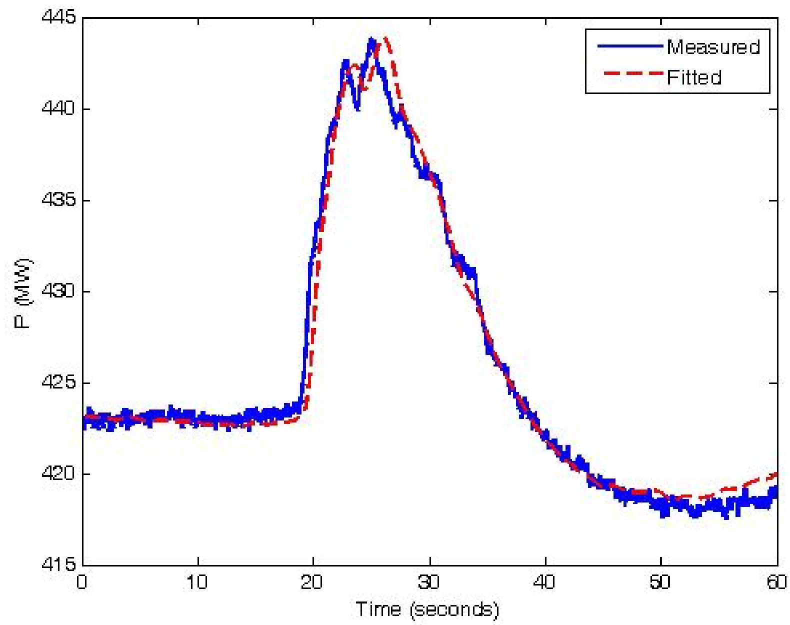

Figure 5.28: Large Steam Turbine Generator Model Verification [Source: © IEEE 2011][82]

[81] However, where such data is not available, staged testing may also be possible.
[82] P. Pourbeik, C. Pink and R. Bisbee, "Power Plant Model Validation for Achieving Reliability Standard Requirements Based on Recorded On-Line Disturbance Data", Proceedings of the IEEE PSCE, March 2011.

Chapter 6: Recommended Usability Testing

An integral part of the process for developing representative and useable models for planning and operating the BPS is the usability testing of these models within the Interconnection-wide base cases created for each Interconnection. This section describes the expected testing performed by the TP to ensure a sufficient level of usability of the models supplied. These tests may be adapted or modified by the TP as deemed appropriate for their system. TPs should have a clearly defined process for testing the usability of these models so that they can provide this information to the GO if necessary. This will help the GO understand the types of tests and simulations for which this model is suitable. The GO, working with any applicable model developer and manufacturer, should understand how the model will be tested and used so they can ensure it meets the usability tests performed by the TP. An ideal approach would have the GO, TP, and model builder all coordinating throughout the process to maximize efficiency and minimize any potential modeling issues or errors. The requirements in MOD-026-1 and MOD-027-1 do not prescribe such coordination. Given the time lines associated with these requirements, one entity has deadlines to complete some tasks while the other entity might not have an obligation (at least as part of the requirements in the standard(s)) to support that effort in a timely manner or even have the budget and man-power to support the effort. However, this is a recommended approach, to the extent possible. The following discussion is limited to positive sequence dynamic models used for stability analysis; however, the concepts may also be applied other types of models, such as electromagnetic transient models.

Takeaway: It is suggested that, whenever feasible, the GO, TP, and model builder coordinate throughout the model verification process, particularly during the model usability steps, to maximize efficiency and minimize any potential modeling issues or errors.

The NERC MOD-026-1 and MOD-027-1 standards generally outline the types of tests that can and should be performed by the TP to ensure usability and numerical stability of the models provided by the GO. The accuracy of these models is also part of the standards but rely on the TP to provide the technical justification for questioning the accuracy of models provided by the GO to meet the requirements in these standards. It is important to differentiate between how and when these tests are most appropriate. There are two distinct time frames for testing usability and accuracy of models—(1) precommissioning during the interconnection process (e.g., System Impact Studies phase) and (2) on-line operation either during grid events or during the reverification process pursuant to the NERC MOD standards.

- **Precommissioning:** Models provided during the interconnection process are used to study the impact that a newly interconnecting generator will have on the BPS performance from a steady-state and dynamic standpoint. Typically, a detailed model of the expected dynamic behavior of the plant is required during the System Impact Study phase of this process. Since the unit is not yet commissioned, the most representative data available for the expected type of generator should be used for creating a model, but the submitted models are expected to not exactly match the actual settings and performance since they are only expected models and not under the purview of MOD-026-1 or MOD-027-1. This generally requires the GO to work with the manufacturer to provide a model that reasonably represents the class and type of machine expected to be installed. During this phase, the TP can only test usability of the model since no actual on-line measurement data is available. Expected usability tests are discussed in the next section.
- **On-line Performance and Reverification:** Once the plant is on-line and operational, NERC MOD-026-1 or NERC MOD-027-1 require the GO to provide verified models, and the TP is required to check and document usability of the models within 90 days of receiving this verified model (see requirement R6 of MOD-026-1 and requirement R5 of MOD-027-1). Accuracy of the models can be assessed by the TP in two ways: technical concerns identified during review of the verification documentation provided by the GO, or documented mismatches between actual recorded disturbances and simulation results for a given transmission system event. During a grid disturbance, unit or plant electrical quantities (POI voltage,

current, frequency, phase angle) can be measured and disturbance-based power plant dynamic model verification can be performed.[83] This enables the TP to assess model accuracy and establish a degree of confidence in model accuracy as compared with actual unit response. The TP can then prepare technical justification, as described in R5 of MOD-026-1, or the written comments and supporting evidence mentioned in the last bullet of R3 of MOD-027-1. The documentation prepared by the TP is required in order to initiate the process with the GO on rectifying any discrepancies identified during the verification.

Once the plant in on-line and operational during grid disturbance, unit, or plant electrical quantities (POI voltage, current, frequency, phase angle) can be measured and disturbance-based power plant dynamic model verification can be performed. This enables the TP to assess model accuracy as compared with actual system disturbances.

These concepts are captured in Requirement R3 of MOD-026-1 and MOD-027-1. The sub-bullets of R3 describe three situations where the TP tests either the usability or the accuracy of the model provided by the GO:

- **Model Usability:** R3 sub-bullet #1 describes that the TP may test the model to ensure it is usable. Examples of usability tests are provided below. Requirement R6 in MOD-026-1 and requirement R5 in MOD-027-1 provide the TP 90 calendar days from the date of receiving the verified models from the GO to send a written response regarding the usability of the models.
- **Verification Documentation:** R3 sub-bullet #2 describes that the TP may review the verification documentation and model provided by the GO. The TP may request additional information or clarification if it is determined that insufficient or incorrect information is provided in a test report or verification document. The TP will also provide written comments identifying the technical concerns with the data and information supplied.
- **Model Accuracy:** R3 sub-bullet #3 describes that the TP can perform disturbance-based model verification using dynamic measurement data to ensure that the performance of the model under grid disturbances is reflective of the actual response of the unit or plant under those same disturbances. The TP can provide written comments and supporting evidence that the models do not match recorded response following a transmission system disturbance.

Requirement R6 or MOD-026-1 and Requirement R5 of MOD-027-1 outline the requirements on the TP to inform the GO that the model is usable within 90 days of receiving the validated models from the GO. Three sub-requirements describe the specific tests that, at a minimum, must be performed by the TP. The GO should supply a powerflow and dynamic model for the unit(s), which should pass the following usability tests:

- **Initialization:** The model, when added to an Interconnection-wide or more localized system model, should initialize properly for the dynamic simulation. The dynamic model(s) provided by the GO should be added to this case and tested to ensure initialization is successful. The model should be dispatched within active power, reactive power, and terminal voltage limits prior to initialization. Initialization should occur with no error and the TP should provide the initial conditions from the initialization to show that no errors occurred and reasonable machine conditions were achieved. The log file should also be checked to ensure the added model(s) does not initialize outside any limits. If so, the TP should check to ensure the unit is dispatched within MW capability, temperature limits (e.g., *Idref*), head level (e.g., hydro units), voltage limits, etc. **Figure 6.1** shows an example of a screenshot of machine initial conditions during successful initialization of a dynamic simulation.

[83] See NERC Reliability Guideline on Disturbance-Based Power Plant Dynamic Model Verification. Available: HERE.

```
INITIAL CONDITION LOAD FLOW USED  1 ITERATIONS

---------------------------- MACHINE INITIAL CONDITIONS ----------------------------

 BUS# X-- NAME --X BASKV ID  ETERM   EFD    POWER    VARS   P.F.  ANGLE   ID     IQ

 6441          ›1   20.000 1  0.9751 1.6319  262.00  -32.47 0.9924  55.55 0.5837 0.5010
```

Figure 6.1: Example of Machine Initial Conditions during Initialization [Source: SOCO]

- **No-Disturbance Flat Run:** A successfully initialized dynamics case should be able to remain at equilibrium during a dynamic simulation when no contingency is applied. A no-disturbance "flat run" simulation is performed to ensure negligible transients occur due to the new model or interactions with other models. This simulation is typically run for at least 20 seconds[84] to capture any potential small signal or control interaction instabilities that could arise over this time period. Worst channel deviations for the entire case should be analyzed (**Figure 6.2**). The angle and power output of the unit being assessed can be plotted to show that the no-disturbance simulations results in negligible transients (**Figure 6.3**).

```
 LIST OF 10 CHANNELS WITH MAXIMUM DEVIATION FROM  INITIAL TIME=    -0.0083
            FROM TIME      0.0000 TO TIME     30.0000

CHANEL IDENTIFIER                      INITIAL VALUE    DEVIATION         TIME (SECONDS)
 1595  ANGL BUS 315233 MACH '2 '         27.23         -0.2081E-02       0.7000
 1551  ANGL BUS 315116 MACH '1 '         30.21         -0.1356E-02      28.2233
 2767  ANGL BUS 630687 MACH '1 '        -98.27         -0.8850E-03      29.9945
 1403  ANGL BUS 300273 MACH '1 '        -99.83         -0.7553E-03      29.8694
  936  ANGL BUS 235625 MACH '1 '        -111.0         -0.7477E-03      29.5777
  785  ANGL BUS 213740 MACH '1 '        -6.237         -0.6680E-03      26.2020
 1523  ANGL BUS 315048 MACH 'F '         13.96         -0.6342E-03      29.8278
 1601  ANGL BUS 315260 MACH 'A '        -5.665         -0.6337E-03      29.8278
 1602  ANGL BUS 315261 MACH 'B '         2.195         -0.6299E-03      29.8069
 1603  ANGL BUS 315262 MACH 'C '         2.367         -0.6287E-03      29.8069
```

Figure 6.2: Maximum Channel Deviations during No-Disturbance Simulation [Source: SOCO]

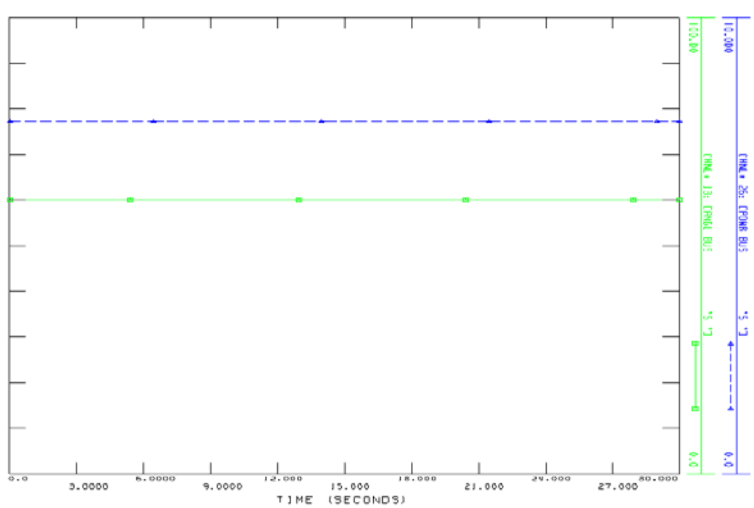

Figure 6.3: Machine Power and Angle during No-Disturbance Simulation [Source: SOCO]

[84] This is recommended in the NERC Procedures for Validation of Powerflow and Dynamics Cases. Available: HERE.

- **Positive Damping:** Testing for positive damping when adding a new model to the case requires an understanding of the stability of the case prior to adding the model. TPs may use this test as a usability test as well as a stability screening tool (see **Figure 6.4**). For example, applying a three-phase, normally cleared fault at the high side of the GSU or POI can test for both unit stability and positive damping of the model. If no issues arise, then both topics can be addressed. If stability or damping issues are identified, then the TP will need to do additional analysis to determine if the instability or poor damping is due to an actual stability issue on the system or due to issues with the new model being added to the case. Other types of damping tests can be used by the TP, such as reactor/capacitor switching, line switching, and other simulated events to ensure positive damping. The selection of these events are left to the discretion of the TP; however, the TP is recommended to test using at least a three-phase normally cleared fault since those are the majority of stability contingencies that are simulated. The goal is to test for worst case conditions that the model may be subjected to, and to mitigate the potential for numerical issues to arise with the model at a later time in the planning process. It is recommended to perform a 60-second simulation[85] to capture any potential small signal or control interaction instabilities that could arise over this time period. It is also advisable to include at least one unbalanced fault simulation in the verification process. Planning studies now incorporate unbalanced faults (specifically in TPL-001-4), and while unit response is not as stressed as during a 3-phase fault, it can help reveal issues with the sequence model of the unit.

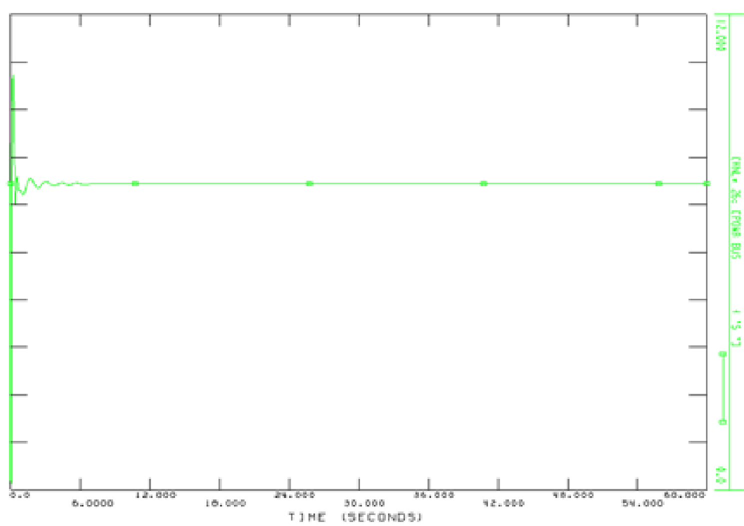

Figure 6.4: Positive Damping of Excitation System for Fault on GSU [Source: SOCO]

The TP should use a powerflow and dynamics case that is known to be numerically stable and free of any initialization errors. When a new or updated dynamic model is provided by the GO, the TP should ensure that the GO provides an updated powerflow model as well if applicable. The TP should also ensure that any required updates to the system-wide case are also implemented, to avoid any simulation issues. The GO should provide models in the format specified by the PC or TP according to the NERC MOD Standards. Any modifications of ratings (e.g., generator MVA, generator or turbine limits, temperature limits, reactive capability limits) should be properly incorporated into the model used for testing. The initial simulation case used by the TP to evaluate the GO model should exhibit constant states during a flat run and positive damping during a disturbance prior to adding any new or modified model. Furthermore, the addition of the model should not significantly degrade system dynamic performance either during initialization, flat run, or reasonable contingency events.

[85] This is recommended in the NERC Procedures for Validation of Powerflow and Dynamics Cases. Available: HERE.

In particular, any modifications of ratings (e.g., generator MVA, generator or turbine limits, temperature limits, reactive capability limits) should be properly included in the system-wide power flow case. The initial case should simulate a flat run and should exhibit positive damping prior to adding or updating any model, and the addition of the model should not significantly degrade performance of the model either during initialization or a flat run.

It is important that the TP select a case that is reasonable for testing model performance as opposed to system planning. The model under test should be dispatched within actual operating limits and set up for intended operating conditions (e.g., within verified temperature, voltage, and MW limits). Planning cases may be intentionally overstressed to identify stability or transfer limits. These cases may exhibit poor damping, initialization issues, etc., and may not be suitable for testing usability of new models. While TPs should be cognizant of this issue, it is up to the discretion of the TP to determine which case (or set of cases) is most suitable for testing the models.

If the model is not usable for any of the reasons outlined in MOD-026-1 Requirement R6 or MOD-027-1 Requirement R5, the TP is required to provide a technical description of why the model is not usable, so the GO can correct any issues identified. This technical description should include a printout of the selected powerflow conditions (initial generator dispatch), dynamic models and parameters used in the simulations, any warning or error messages from the simulation software, and a description of the simulation(s) (disturbances) leading to the conclusion that the model(s) is not usable.

Appendix A: Combined Cycle Power Plants

A combined cycle power plant (CCPP) consists of one or more gas turbine and a steam turbine. The exhaust heat from the gas turbine(s) is fed into a heat-recovery steam generator (HRSG), which then supplies the steam for the steam turbine. This can be done in various configurations, but generally falls into two main categories:

- Single-shaft combined-cycle units where the gas turbine, steam turbine, and electrical generator are all in tandem on a single rotating mechanical shaft (**Figure A.1**), and
- Multi-shaft units where one or more gas turbines, each typically with its own HRSG, feed steam to a single steam turbine with all the units being on separate mechanical shafts (**Figure A.2**).

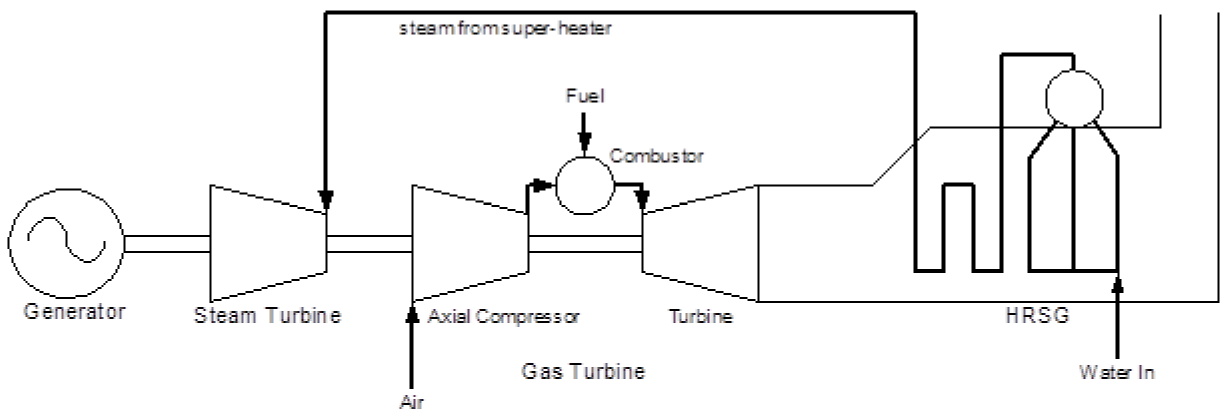

Figure A.1: Single-shaft combined-cycle power plant (IEEE© 2003[86])

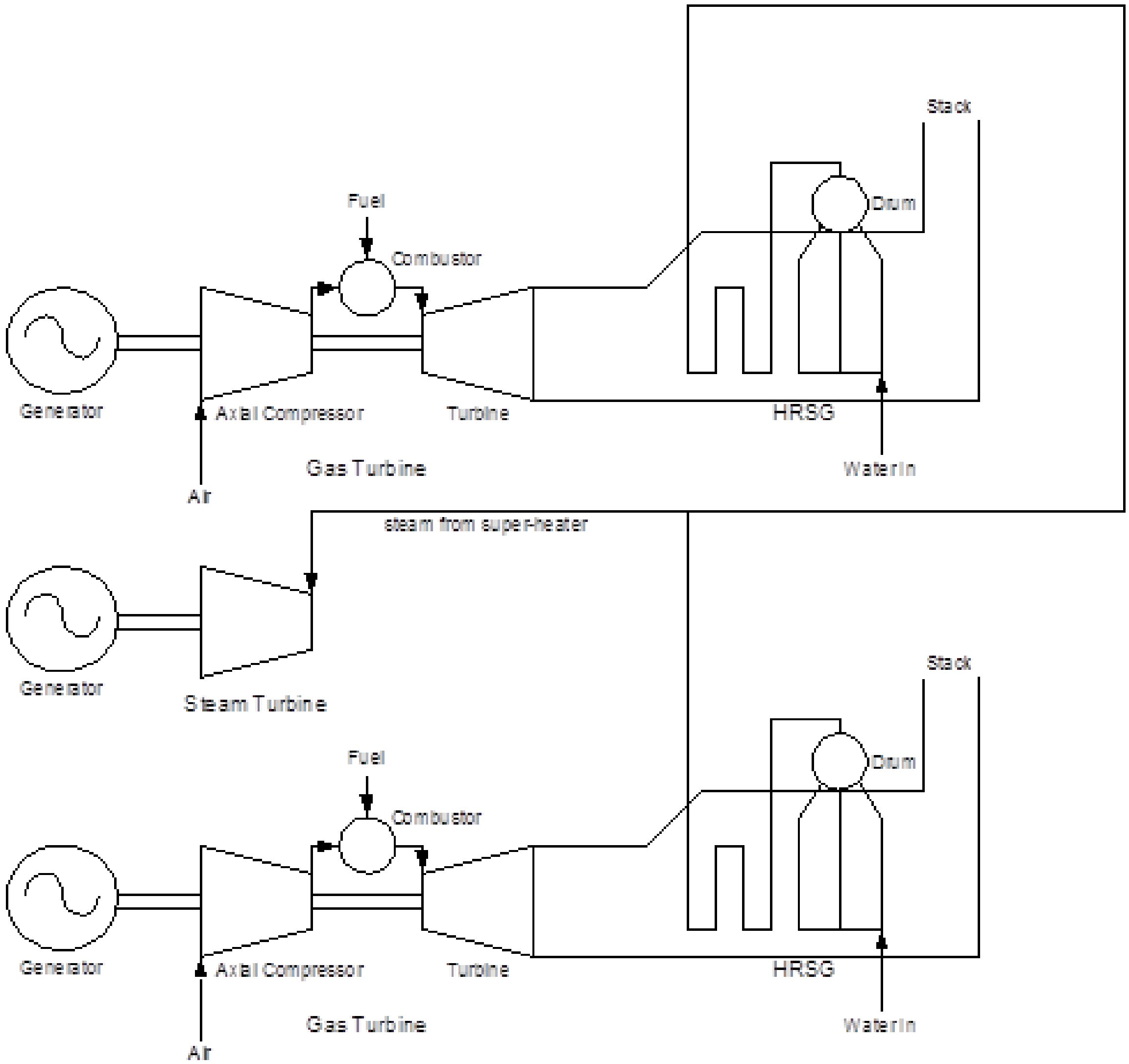

Figure A.2: Multi-shaft combined-cycle power plant (IEEE© 2003[86])

The natural gas turbine(s) in a CCPP are typically no different than those in simple-cycle operation; the main difference is in the way they are operated. In a CCPP, typically the GT inlet-guide vanes are modulated at partial load.[86, 87] The airflow through the GT compressor and turbine can be adjusted by changing the angular position of the variable inlet guide vanes (VIGVs), which are essentially the first few stages of stator blades of the axial-compressor. By keeping the VIGVs at their minimum angle and slowly opening them as the unit it loaded, the exhaust temperature is kept high at lower loading levels to maintain the desired level of the heat transfer into the HRSG and maintain an overall higher plant efficiency. When the natural gas turbine is loaded close to baseload, the VIGVs are wide open. The airflow is a function of the VIGV angle, ambient temperature at compressor inlet, atmospheric pressure, and the shaft speed. For the purposes of power system studies, the GT in a CCPP and simple-cycle GT plant are modeled using the same models.[87, 88]

[86] P. Pourbeik, "Modeling of Combined-Cycle Power Plants for Power System Studies", Proceedings of IEEE PES General Meeting, July 2003.
[87] CIGRE Technical Brochure 238, *Modeling of Gas Turbines and Steam Turbines in Combined-Cycle Power Plants*, December 2003 (free download here: http://www.e-cigre.org/Order/download.asp?ID=238.pdf)
[88] IEEE Task Force on Turbine-Governor Modeling, *Dynamic Models for Turbine-Governors in Power System Studies, IEEE Technical Report PES-TR1*, January 2013. (download here: http://sites.ieee.org/fw-pes/files/2013/01/PES_TR1.pdf)

In a CCPP, the steam turbine (ST) is typically operated in one of two different mode: (1) sliding pressure or (2) fixed steam inlet pressure control.[86, 87] A combination of these operation modes is common over the operating range of a CCPP.

When in sliding pressure control, the valves that control the flow of steam entering the steam turbine are wide open. Steam pressure is a function of the steam mass flow entering the steam turbine. Since power output of the ST depends on the steam mass flow it is not directly controlled (as the valves are wide open), and thus the power output of the ST can only be increased by increasing steam flow. This involves generating more steam in the HRSG and generally requires an increase in heat from the natural gas turbines or supplemental firing[89] if present. Therefore, the ST simply follows the output of the GTs. The ST will provide an increase in MW output when the amount of steam from the HRSG is increased from the increased waste heat from the GT(s); however, this takes many minutes due to the HSRG steam production process.

Figure A.3 shows a simulation of a multi-shaft combined-cycle power plant using the generic models developed by CIGRE.[87, 88] The load/speed reference set point of the GT was increase by a small step. The results show what would be the expected behavior of a typical CCPP connected to a large power grid where system frequency would remain effectively unchanged due to such a step increase in the plant output. The GT output increases until it is limited by the temperature control loop, transiently over-shooting its steady-state maximum power limit. The ST, operating in sliding pressure mode, follows the gas turbine output with a delay of several minutes. The ST will change its response at different rates depending on the number of GT(s) providing response. This affects the time constants, droop parameters, and needs to be accounted for with a link between the GT(s) and ST in the model.

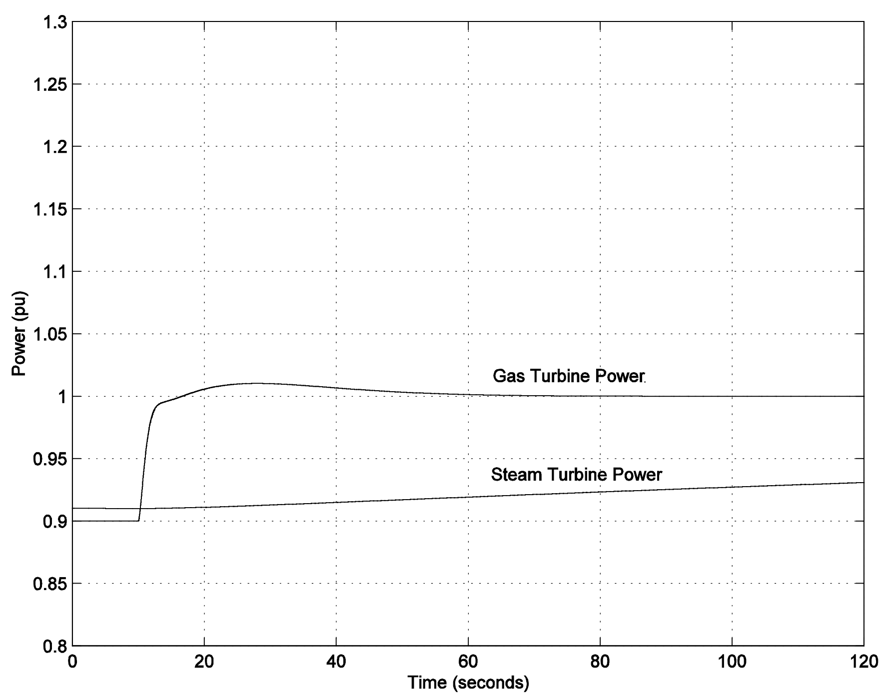

Figure A.3: Simulated Response of a Multi-Shaft Combined-Cycle Power Plant to a Step-Change in Natural Gas Turbine Power Reference (IEEE © 2003[86])

[89] In some applications, additional capacity is provided for the ST by introducing a supplementary process, such as firing duct burners. These supplementary processes require operator action, which is not captured in standard stability models. Without supplemental firing, typically the ratio of the maximum power output of the ST to the total maximum power output of the GTs is roughly 1:2. That is, 2/3 of the total plant output comes from the GTs and 1/3 from the ST.

Figure A.4 shows a real-life example of this with measured and simulated active power at a 3-on-1 CCPP. A speed reference step is applied to one of the three GTs to illicit governor response from the GT. At time *t = 250 s*, GT speed is dropped by approximately 80 mHz. The ST takes approximately 1000 s (*t = 1250 s*) to reach its new output level after steam pressure has increased and stabilized. This can be modeled using the CIGRE models, (available in certain simulation software programs); however, typical transient stability studies are usually run for no longer than 60 seconds, and more commonly 30 seconds, and this response is not significant during this time frame.

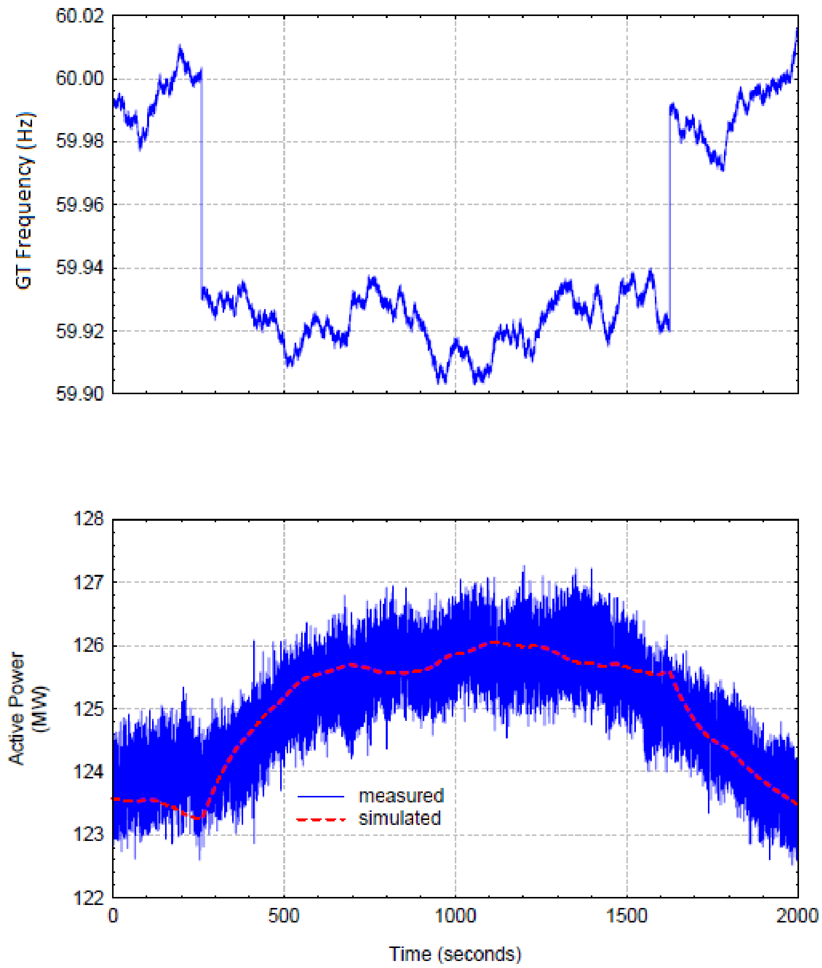

Figure A.4: Change in Active Power for a 574 MVA ST as a Result of GT Governor Action

Based on the explanation of CCPP operation above, and clear recommendations in the CIGRE[87] and IEEE[88] Task Force reports, the following recommendations are presented as guidance for modeling CCPPs in power system studies:

- **Transient Stability Analysis:** When data is provided that confirms the ST is operated with valves wide open (i.e., sliding pressure), it should be acceptable to provide a governor model for the ST that represents constant mechanical power. That is, no governor model is used for the steam turbine, and the GO should notify the TP accordingly.[90] The TP should accept this modeling approach since the ST power output will

[90] MOD-027-1, Attachment 1, Row 7 states that if the "unit is not responsive to both over and under frequency excursion events," then Requirement 2 can be met with a written statement to that effect transmitted to the TP. The written statement should include a description of why the unit does not respond. In this case, it is due to the constant mechanical power on the steam turbine during the time frame of study for dynamic simulation models (e.g., 30–60 seconds). Disturbance data should also be provided to supplement this written statement demonstrating that the ST does not respond. Note that measurement resolution of around 1–2 samples/second is sufficient for these purposes of constant output during 30–60 seconds (not for capturing dynamic response).

be relatively constant during the time frames studied for transient stability analysis, changing output slowly over several hundred seconds. It is adequate to use a representative generic model for the GT(s) (e.g., GGOV1, or the CIGRE models). For single-shaft combined-cycle units, a model such as shown in the CIGRE report,[87] may need to be used. However, single-shaft units are fairly rare in North America.

- **Mid-Term Time-Domain Analysis:** Mid-term time-domain stability studies include simulations over several minutes following a system disturbance. These simulations are often performed in relation to voltage stability. If such studies involve disturbances that result in generation/load imbalance, then the CIGRE or IEEE Task Force models may be needed to represent the HRSG and ST dynamics. Note: models like IEEEG1 or TGOV should not be used when modeling the behavior of the ST in a CCPP since these models do not have a direct link between the ST and GT. On the other hand, the CIGRE models do represent the direct link between the GT(s) and the ST through a simple model of the HSRG.
- **Small-Signal Analysis:** Small-signal stability analysis involves linearizing the power system model equations at a specific operating condition to form the state-space representation of the system. Thus, inherent in this analysis is the assumption that system perturbations are small and should not invoke any non-linearities. Therefore, if the CCPP is baseloaded at its peak output, then the GTs are on their temperature limit and the ST at its maximum output with valves wide open, therefore small perturbations in electrical power and or system frequency will most likely have little to no effect on the mechanical power output of either the GTs or ST, so they should be modeled at constant power. Under partial-load conditions, a linearized version of a simple GT model (e.g. GGOV1) should typically be adequate, and once again since the ST is most likely in sliding pressure mode, constant mechanical power (i.e. no governor model) should be assumed for the ST.
- **Islanding Studies or Other Detailed Studies:** There are several detailed models that may be appropriate for more detailed studies, particularly where islanding and other conditions may apply. Such detailed models should be used with guidance from the equipment vendor and where deemed necessary and appropriate.
- **Software Implementation:** Software vendors should adopt the CIGRE models for potential future use, as necessary, for special studies in the time frames discussed. Due to the reasons listed above, this is not considered an urgent modeling improvement issue.

Takeaway: The steam turbine of a CCPP can be modeled a number of different ways. The following recommendations are made:

- Not including a dynamic model for the ST should be considered adequate for normal transient stability simulations on the order of 30–60 seconds, since this can represent constant mechanical power, which is a reasonable representation of this time frame. However, a written explanation from the GO to the TP and PC should be provided explaining why no model is provided.
- For the purposes of dynamic model verification related to MOD-027-1, it can be shown that the unit does not respond within the transient stability simulation time frame; hence, not including a dynamic model to represent the ST should be acceptable. Again, a written explanation should be provided by the GO.
- If a governor model is deemed necessary or required by the TP or PC, inform the GO so that they are aware of this supplemental request and can then consult the CIGRE/IEEE reference material for further information. These governor models may not be part of the standardized model libraries of some commercial software programs and that should be considered by the TP or PC setting the modeling requirements.
- Software vendors should adopt the CIGRE models as part of their standard model library for potential future use and ensure uniform implementation of these models across software platforms.

Appendix B: Verification of Equivalent Units

MOD-026-1, Attachment 1, Row 4 describes the Verification Condition and associated required action for testing. If the verification conditions are satisfied, then the verification can be met by a written statement and inclusion of the other equivalent unit.[91] The verification condition states as follows:

> *"Existing **applicable unit that is equivalent to another unit(s) at the same physical location**.*
> *AND*
> *Each applicable unit has the same MVA nameplate rating.*
> *AND*
> *The nameplate rating is ≤ 350 MVA.*
> *AND*
> *Each applicable unit has the same components and settings.*
> *AND*
> *The model for one of these equivalent applicable units has been verified."*

While MVA nameplate rating, size threshold, and "same components and settings" are relatively straightforward, the concept of equivalency is bit vague. Generating unit equivalency to another unit(s) at the same physical location should be carefully considered, and this determination should be made on the basis of factual measurements and engineering judgment. For units to be considered equivalent, they should have the following:

- The same manufacturer and model for the electrical turbine, mechanical turbine, excitation system, and governing system
- These components should have the same electrical characteristics, settings in the AVR and governor, the same mechanical and civil characteristics of the governing system, etc.

During commissioning, adequate baseline testing should illustrate that the units are in fact equivalent from the point of view of modeling the response for use in simulation software. Over time, any of the above characteristics may change as a result of the following:

- Equipment wear
- Intentional or unintentional settings changes during maintenance practices
- Component replacement

Engineering judgment should be used first to consider the unit's history, generator rewinds, length of service, etc. Documentation should be provided to back up assertions regarding equivalent units. In situations where unit equivalency is under question, testing[92] can be used to demonstrate that the units are still in fact equivalent. For example, **Figure B.1** shows the measured open circuit saturation curves for two hydroelectric units with the same equipment and at the same facility. The two units were commissioned one after another and have been operating with over 50 years of service. The first unit requires more field current to achieve the same terminal voltage as the other unit, indicating that there is a possibility of shorted turns in the rotor winding of G1. From this test result, it is clear that S(1.0), S(1.2), and I_{fgbase} will be different between the two models. As a result, one can no longer conclude that these units are equivalent and model reverification should be performed for each unit.

[91] A different equivalent unit then needs to be tested during each 10-year verification.

[92] To the extent possible, testing to compare unit equivalency should be performed under similar operating conditions (e.g., ambient temperature) so as not to affect comparison of test results.

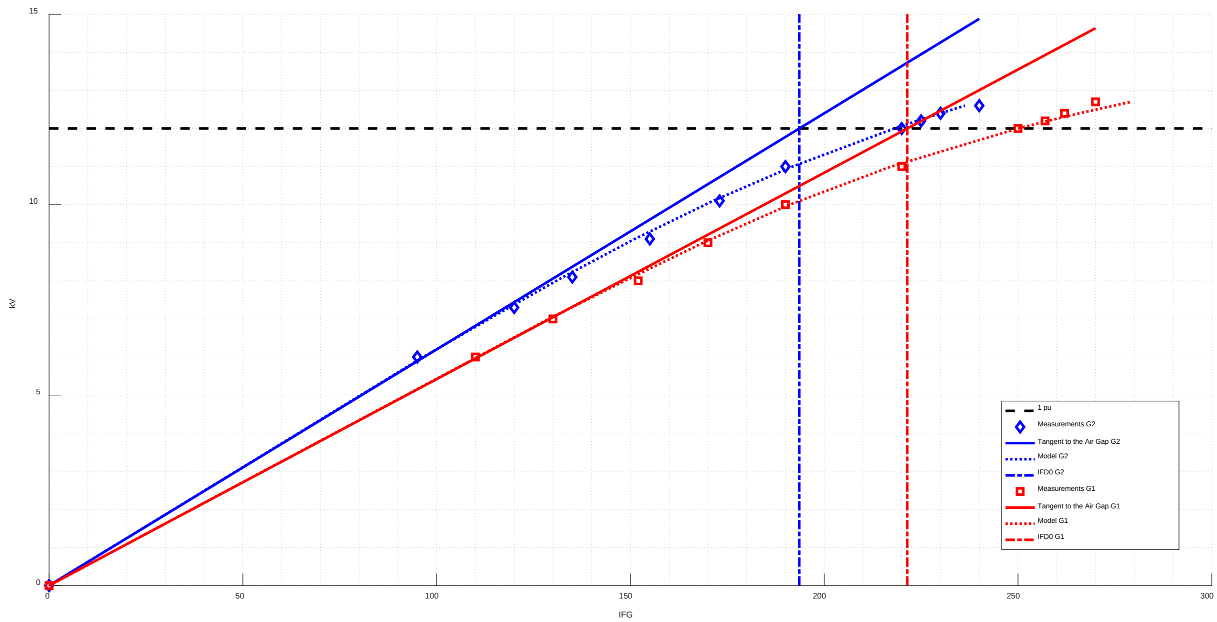

Figure B.1: Two Open Circuit Saturation Curves for Units Once Considered Equivalent

On the other hand, **Figure B.2** shows two other units (G3 and G4) where the open circuit saturation curves are much closer. While not identical, they also have a similar history and identical equipment and settings, but also exhibit relatively similar saturation effects as well. The air gap line estimates are nearly identical (as opposed to G1 and G2 comparison) and the associated S(1.0), S(1.2), and I_{fgbase} parameters will be very close. For these reasons, these units could be considered equivalent. **Figure B.3** shows another example of two units considered identical that have less than a five percent variation in airgap current—note the slight differences in test data collected, air gap line estimates, and I_{fgbase} estimates.

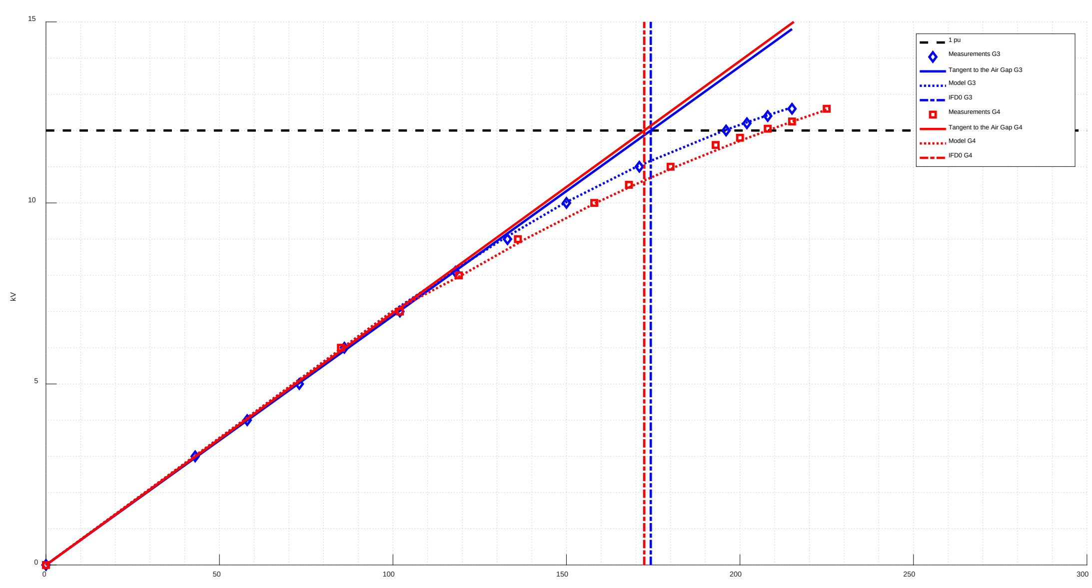

Figure B.2: Two Open Circuit Saturation Curves on Units Considered Equivalent

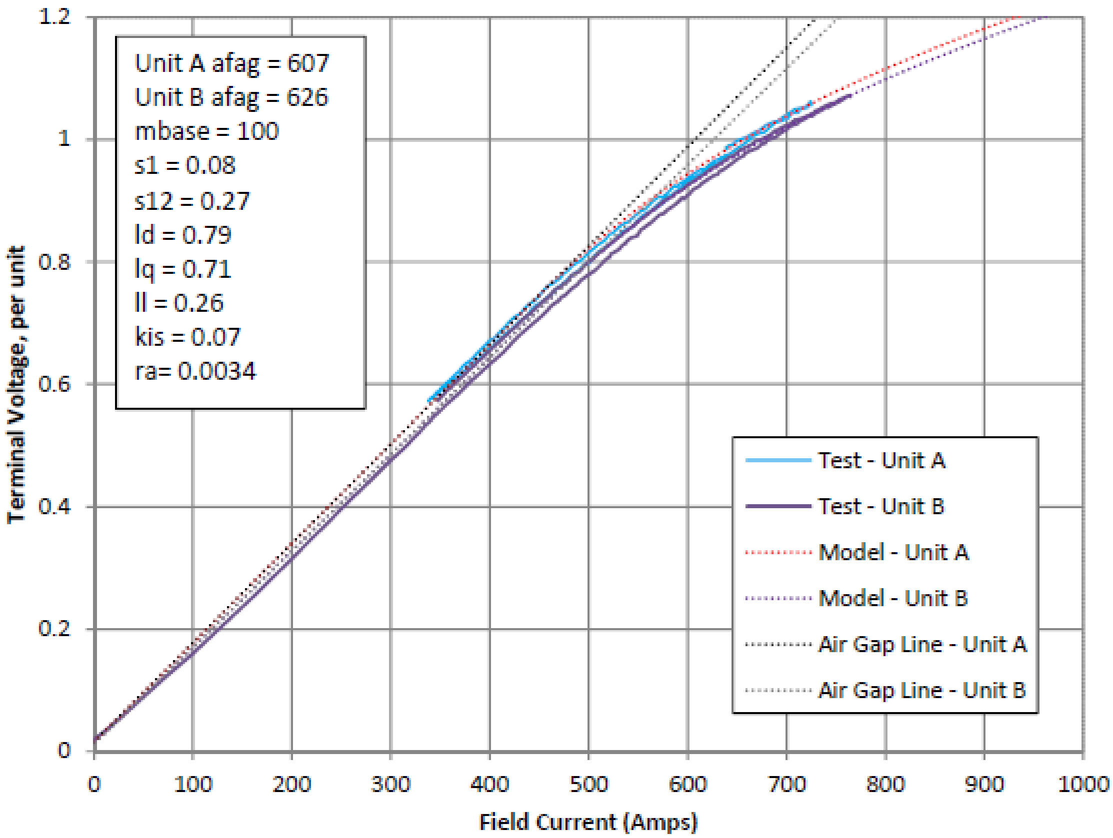

Figure B.3: Two Different Open Circuit Saturation Curves on Units Considered Equivalent

Appendix C: Specialized Testing

In addition to the tests outlined in this guideline, more specialized testing may be performed in some situations to identify modeling parameters or verify the response of controls or protection. This section briefly describes some of these tests.

V/Hz Limiter Test

Testing of the V/Hz limiter may occur during AVR commissioning, following changes to AVR settings, or during excitation system upgrades. The test can be used to demonstrate stable response of the limiter action, and also enables determining when the limiter will operate and when it will not operate; hence, it proves that the limiter is properly coordinated with any V/Hz protection relays. Many V/Hz limiters will limit the terminal voltage set point with a given slope starting from a maximum terminal voltage as shown in **Figure C.1**.

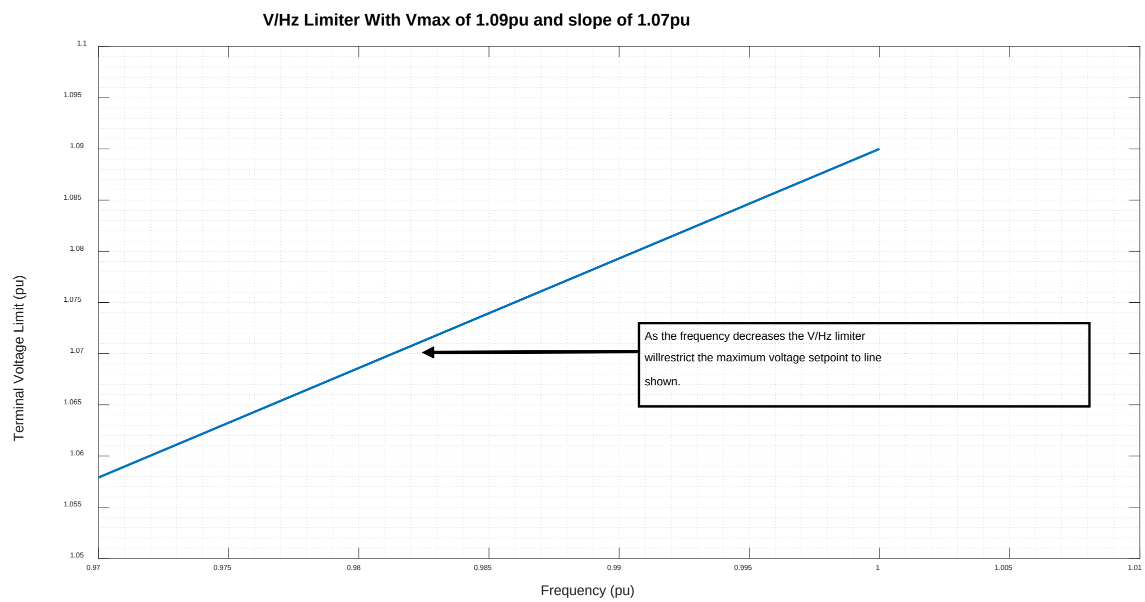

Figure C.1: Example V/Hz Limiter Settings

In most cases, the settings will be such that it will not be practical to test the unit at the voltages and frequencies to illicit a limiter response. Therefore, the recommended method of testing the limiter is to temporarily lower the V/Hz limiter settings while the unit is off-line (open circuit) and either introduce a positive voltage step or a negative speed reference step. This may depend on the implementation of the V/Hz limiter as some limiters may only operate on declining frequency.

Figure C.2 shows a V/Hz limiter test where the unit is off-line at rated voltage and rated speed. V_{max} was temporarily lowered to 1.0 pu and a negative speed reference change was introduced at 35 s. Terminal voltage and frequency were recorded to show stable V/Hz limiter operation. As the unit was slowing down, terminal voltage was lowered to limit the flux in the unit per the V/Hz limiter implementation. In this case, the terminal voltage was limited to 0.995 pu. Following the test, the value of V_{max} was placed back at its normal value of 1.09 pu.

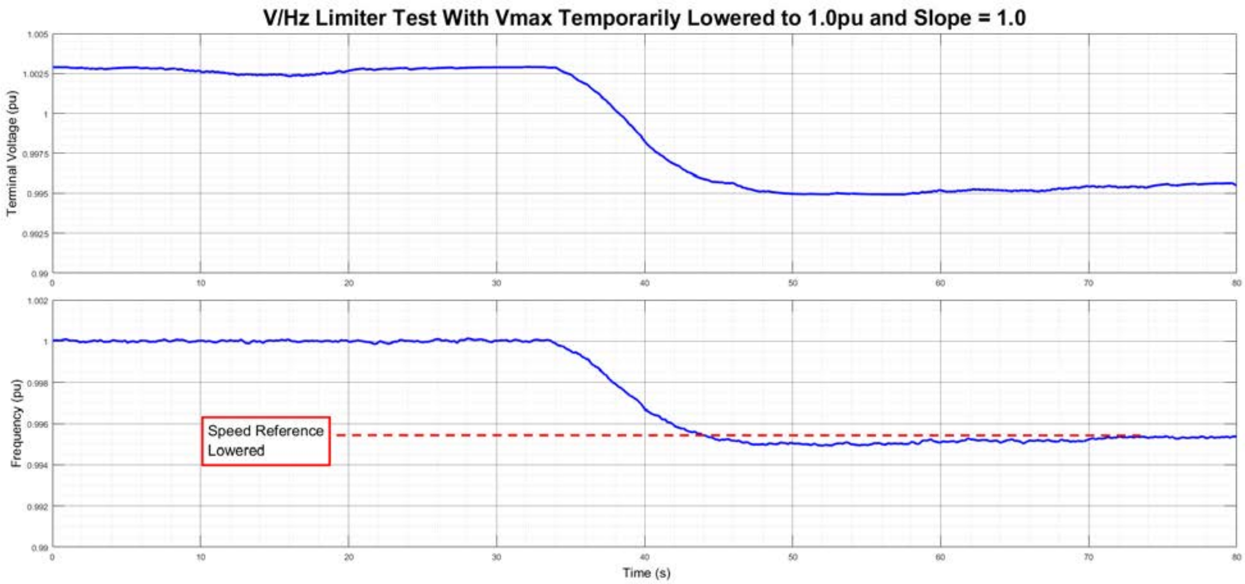

Figure C.2: V/Hz Limiter Test for a 156MVA Steam Turbine

The outcome of this test is not generally used for modeling purposes unless a V/Hz limiter model is provided to the TP or required by the TP.

Overexcitation Limiter Test

Testing of the OEL also may occur during AVR commissioning, following changes to AVR settings, or during excitation system upgrades. The test can be used for model verification where OEL models are required to demonstrate stable response of the limiter action and also to predict when the limiter will operate and when it will not operate. Hence, the test proves that the limiter is properly coordinated with any protection relays. OEL limiters will limit the AVR output such that the field winding current is inside the trip curve and damage curve as specified by IEEE C50.13. This is shown in Figure C.3 where 1.0 pu current represents a value of greater than rated field current.

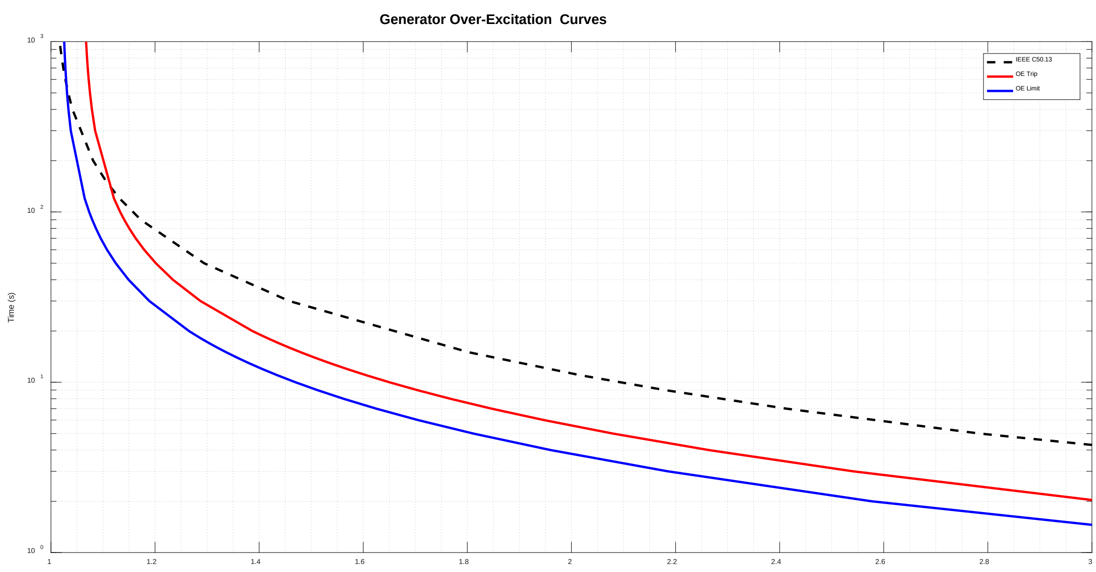

Figure C.3: Representative OEL time inverse curves

In many cases, it may not be possible to operate at the values of rotor current for the times specified in the inverse-time OEL curve due to system conditions (i.e., it may not be possible to operate a unit at full load and rated power factor due to voltage constraints). As such, this test should be conducted by temporarily lowering OEL pickup settings and applying a voltage step change while the unit is on-line and lagging (over-excited). The temporary OEL setting must be a value greater than the prestep field current and must not be so high that it cannot be reached with an appropriately sized voltage reference step. An example of such a test is shown in **Figure C.4.**

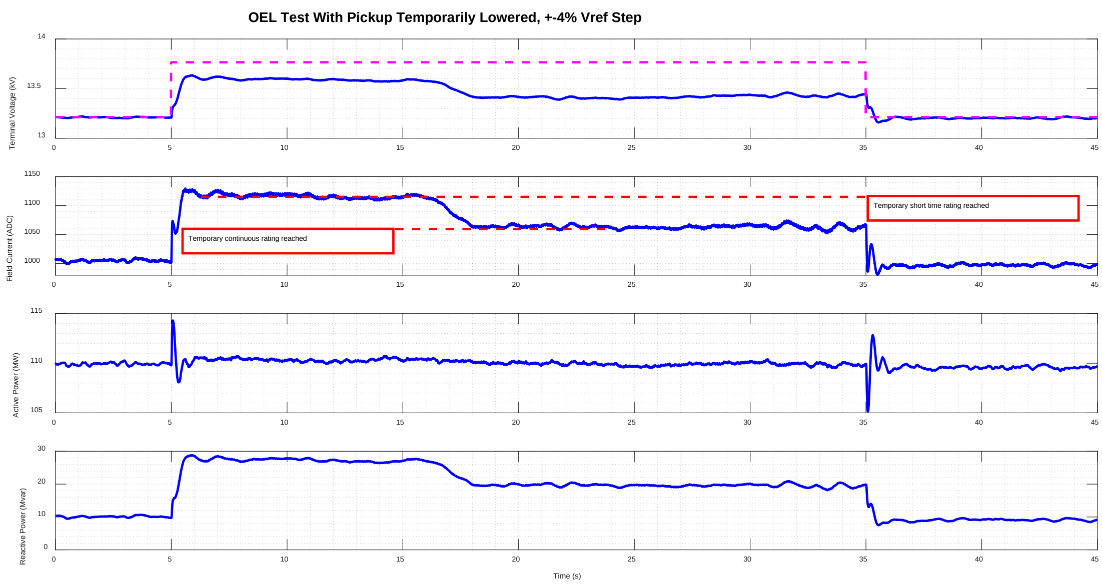

Figure C.4: OEL Test for a 135MVA Hydroelectric Turbine

At time *t = 5 s*, a plus four percent voltage reference step is introduced. As observed in the measured terminal voltage, field current, field voltage, power, reactive power, and PSS output, the machine did not reach the new terminal voltage (represented by the magenta line) because the field current hit the lower temporary limit. At *t = 17 s*, the field current is limited further by the inverse-time characteristic, and this can be see seen by a reduction in both terminal voltage and reactive power. At *t = 35 s*, the plus four percent step was removed. Following the test, the pickup value was placed back at its normal value. These results show that the unit is stable when the OEL is reached, and provides measurement for which a model can be developed (where required by the TP), including model structure. For example, if the output of AVR summing junctions can be recorded, then this would provide confirmation of model parameters (e.g., excitation system OEL flag parameter).

Underexcitation Limiter Test

Similar to OEL testing, testing of the UEL also may occur during AVR commissioning, following changes to AVR settings, or excitation system upgrades. The test can be used for model verification where UEL models are required to demonstrate stable response of the limiter action and also to predict when the limiter will operate and when it will not operate. Hence, proving that the limiter is properly coordinated with any protection relays. UEL limiters will limit AVR output within the field winding current above core end heating limits or minimum excitation limits as shown on the capability curve and damage curve. Many AVRs implement this as a series of (P, Q) pairs that decrease with the square of the terminal voltage.

In many cases, it may not be possible to operate at the values of real and reactive power specified by the UEL (P, Q) pairs due to system conditions (i.e., it may not be possible to operate a unit at full output and rated power factor due to voltage constraints). As such, this test can be conducted by temporarily raising UEL (P, Q) pairs and applying a negative voltage step change while the unit is on-line and leading. The temporary UEL setting should be a value less than the prestep values and must not be so low that it cannot be reached with an appropriately sized voltage reference step. An example of such a test is shown in **Figure C.5**.

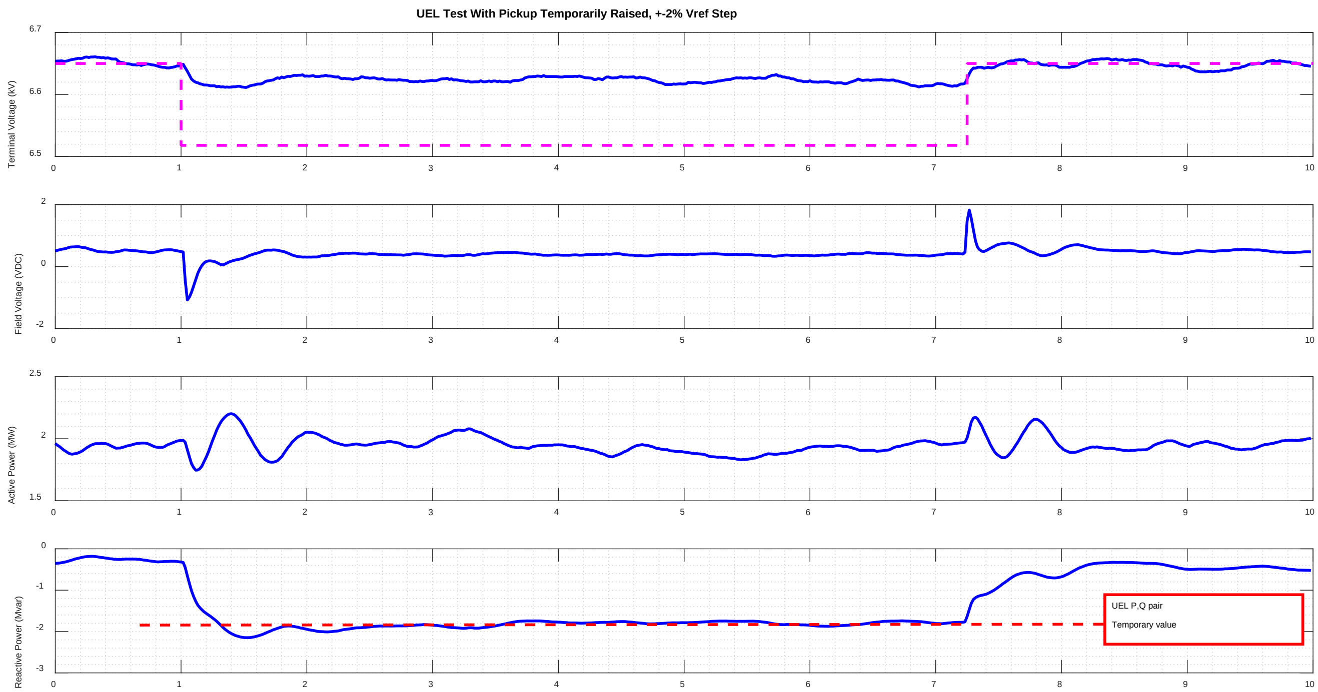

Figure C.5: UEL Test for a 5MVA Hydroelectric Turbine

At time *t* = 1 s, a negative two percent voltage reference step is introduced. From the measured values of terminal voltage, field current, field voltage, active power, reactive power, and PSS output, one can see that the machine did not achieve the new terminal voltage (represented by the magenta line) because the UEL temporary limit was reached. At *t* = 7.25 s, the negative two percent step was removed. Following the test, the pickup value is placed back at its normal value. These results show that the unit is stable when the UEL is reached and provide measurements for which a model can be developed (where required by the TP), including model structure. For example, if the output of AVR summing junctions can be recorded, then this would provide confirmation of model parameters (e.g., ESST1A UEL flag position).

Closed Loop Tests Emulating Islanded Mode of Operation

In some situations, closed loop tests may be used to estimate the turbine-governor response, meaning that the speed/frequency error signal injected into the governor controller is computed in real-time as a result of the imbalance between mechanical torque and electrical torque rather than predefined. A closed loop test can emulate generator islanded mode of operation. This test may be useful to validate the open loop test results. See the "Tests by simulated isolation" section of IEC Std. 60308 on hydraulic turbine testing for more information. **Figure C.6** shows a setup for conducting a closed loop test for a turbine-governor.

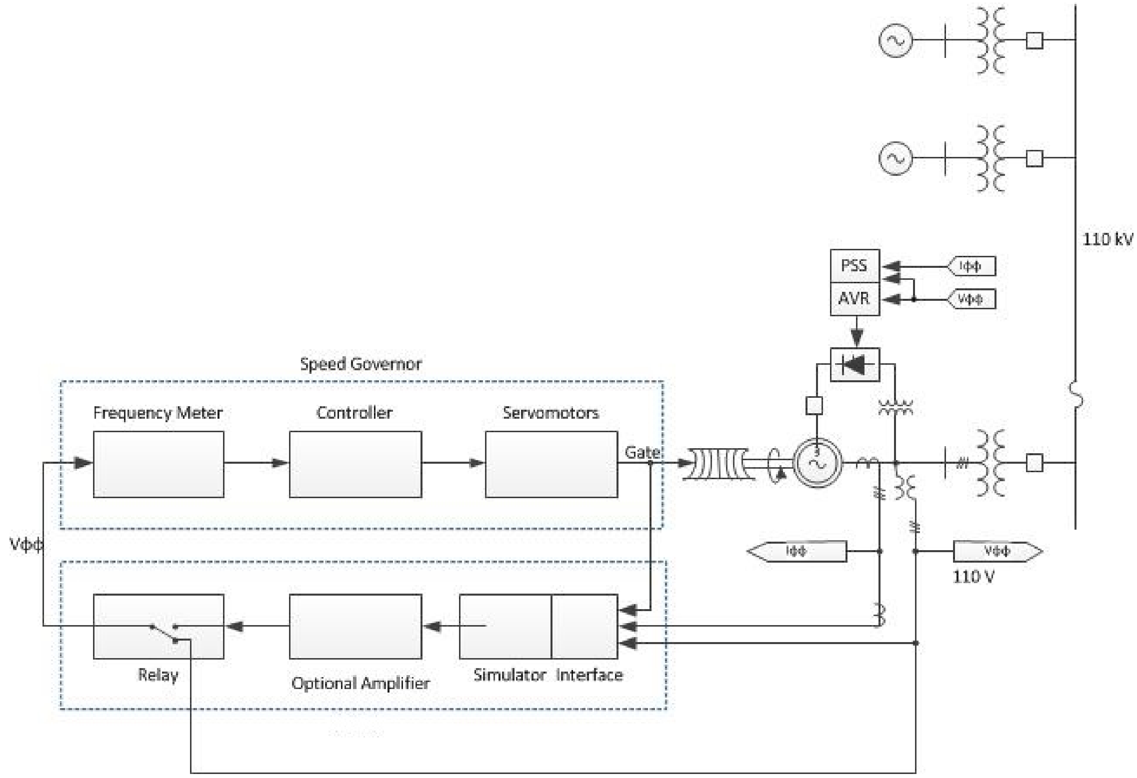

Figure C.6: Setup for Closed Loop Tests of Speed Governor [Source: Opal-RT]

Figure C.7 shows a comparison of results from a closed loop test and two off-line simulations. Following a negative five percent load step disturbance, the actual behavior appears to be unstable. However, the off-line simulation using a dynamic model and parameters derived from an open loop frequency step test show stable behavior.

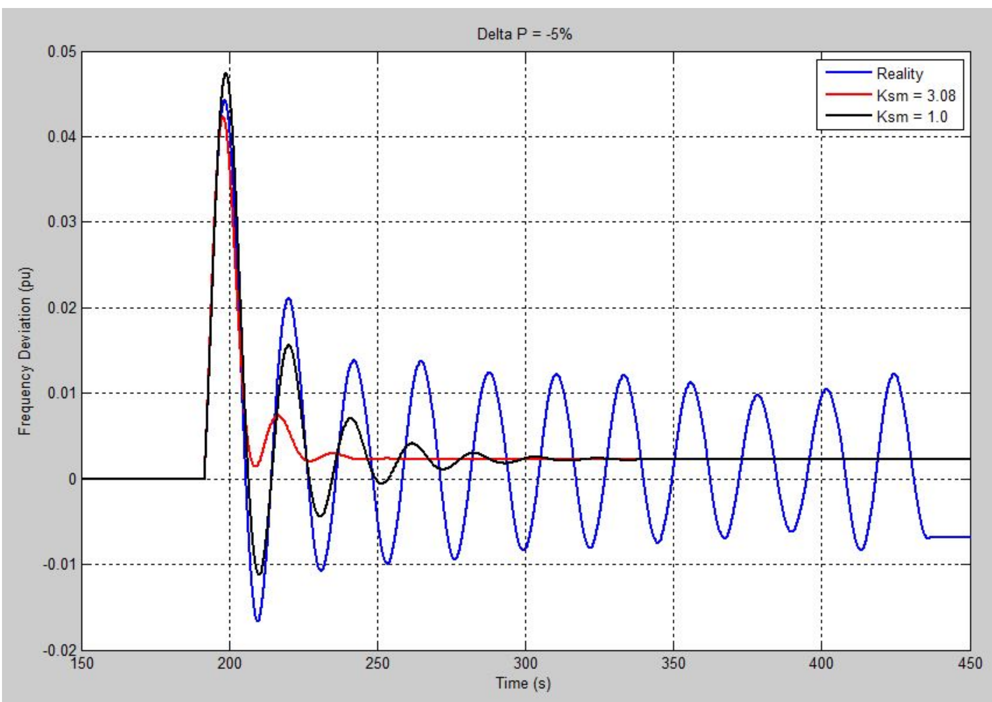

Figure C.7: Closed Loop Test Emulating Generating Unit Operating in Islanded Mode [Source: Opal-RT]

Appendix D: MOD-025-2 Testing and Calculations Example

Table D.1 shows the ratings of the synchronous generator considered in this example. The GSU is represented by a reactance (expressed in percent of given MVA base, depending on the example) and an off-nominal tap at the high-side of the GSU. Rated voltages of the GSU match the rated voltage of the generator (16.5 kV) and the rated voltage of the grid to make the example as simple as possible.[93] These differences are mostly related to properly defining the tap ratio of the GSU model, but might also impact the calculation of the GSU impedance as it should be reflected to a common per unit base. Thus, this example (although simplified to avoid these issues with per unit system calculations) is still representative of the process and results that can be obtained via calculations to support the analysis of the actual field test results.

Takeaway: It is important to determine limits for the operation of all equipment under test, including the GSU. Documentation of voltage ranges for the operation of the GSU is essential, particularly in situations where the GSU windings are rated at different voltages than the equipment connected to them.

For actual testing, operational limits for every piece of equipment under test should be understood, including the GSU. Proper documentation of voltage ranges for operation of the GSU is essential, particularly in these examples where the GSU windings are rated at different voltages than the equipment connected to them. For instance, could a GSU with a LV winding rated at 13.2 kV operate at 105 percent of the generator terminal voltage, when the generator is rated at 13.8 kV? If not, the limit of 105 percent of the GSU rating becomes a limitation to the maximum voltage of the generator, and that will have to be restricted to 105 percent of 13.2 kV (just 100.4 percent of the generator rated voltage 13.8 kV). On the other hand, if the generator is operated at 105 percent of its rated voltage, the LV winding of the GSU will have to operate at 105 percent of 13.8 kV, or 109.8 percent of the LV winding rating of 13.2 kV.

Table D.1: Example Generator Ratings

Description	Parameter	Value	Units
Generator Base MVA	MBASE	203	MVA
Turbine Maximum Continuous Rating	MCR	182.7	MW
Generator Stator Base Voltage	E_{Tbase}	16.5	kV
Rated Power Factor	pf	0.90	–
Rated Field Current (rated MVA and pf)	$I_{FGrated}$	1272	A_{DC}
Base Field Current	I_{FGbase}	498	A_{DC}

Capability curves for this unit are shown in **Figure D.1.** The top curve is associated with rated field current (ampacity of the rotor field winding) and the lower curve corresponds to the core-end heating characteristic typical of round rotor machines (over-heating conditions at the core ends due to localized over-fluxing).[94] The core-end heating curve is thus a thermal limit but not directly related to a winding current. This is usually provided by the OEM, and unless temperature transducers are properly located at the core ends, it is a difficult limit to be

[93] It should be noted that it is a common practice to have GSU transformers with windings rated at different voltages than those of the associated equipment (e.g., 13.2 kV low-voltage winding rating of the GSU connected to a 13.8 kV generator, or a 354 kV high-voltage winding rating of the GSU connected to a 345 kV substation).

[94] IEEE Std. C50.13-2014, "IEEE Standard for Cylindrical-Rotor 50 Hz and 60 Hz Synchronous Generators Rated 10 MVA and Above," 2014. [Online]. Available: https://standards.ieee.org/findstds/standard/C50.13-2005.html.

tested and verified through field tests. The right-hand side of the curve is associated with the rated stator current (ampacity of the stator windings); this is related to the rated MVA of the machine (a thermal limit associated with the stator current I_T, not apparent power).

Typically, the OEM provides capability curves similar to **Figure D.1**. These curves are usually presented for rated terminal voltage conditions (E_T = 1.0 pu). It is imperative to understand that these curves are, in reality, associated with thermal limits and, as such, to currents on the windings of the synchronous machine. Therefore, the curves in **Figure D.1** change with changes in generator terminal voltage, and thus the capability curves cannot be considered constant and independent of the generator terminal voltage.

Takeaway: The capability and limiter curves change with changes in generator terminal voltage. Thus, the capability curves cannot be considered constant and independent of the generator terminal voltage.

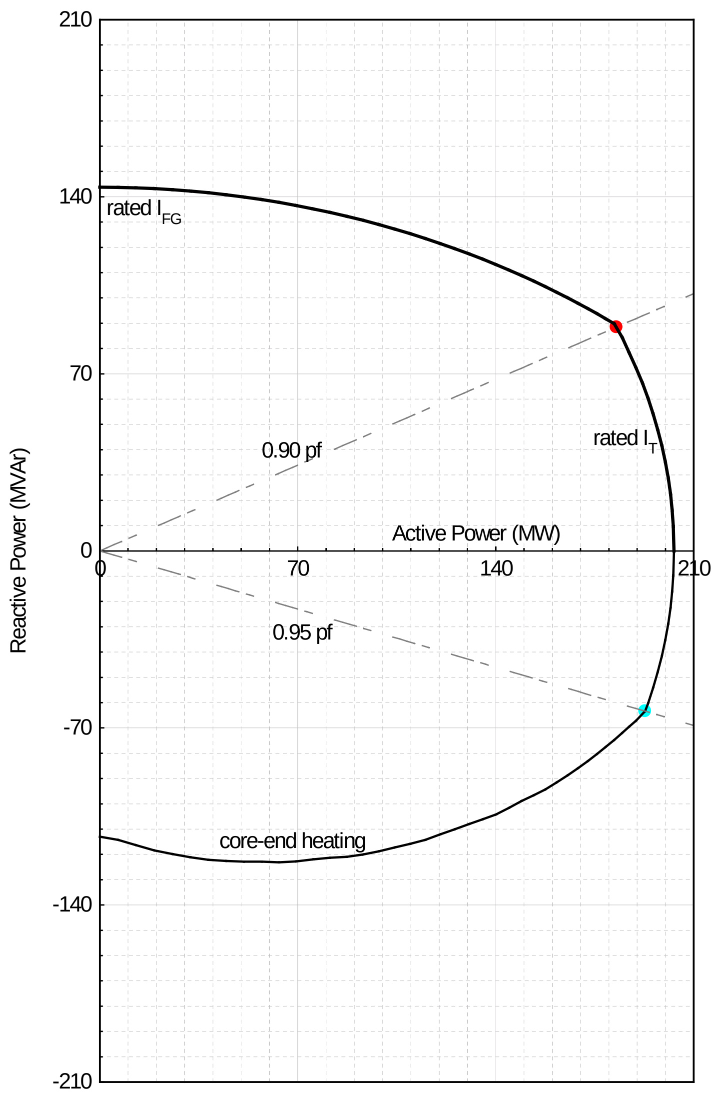

Figure D.1: Example Generator Capability Curve

Considering the requirement from MOD-032-1 to provide steady state (power flow) limits for the reactive power output of the generator, it is tempting to use, for instance, the points marked by the colored circles in **Figure D.1** to determine Q_{min} and Q_{max}. This is a simplified example, and it ignores the turbine capability, which might limit the generator output to a given maximum value of active power (P_{max}). This example assumes that the prime mover capability matches generator capability and is therefore capable of delivering a continuous rating (MCR) of 182.7 MW, equal to the generator MVA multiplied by the rated power factor. Under these assumptions, the values for Q_{min} and Q_{max} can be calculated as follows:

$$Q_{max} = 203\sqrt{1 - 0.90^2} = 88.5 \text{ MVAr}$$
$$Q_{min} = -203\sqrt{1 - 0.95^2} = -63.4 \text{ MVAr}$$

The question is whether these values for Q_{min} and Q_{max} can be reached during reactive capability testing.

The generator model is used to calculate generator field current based on the generator terminal conditions (Et, P, and Q) given by the power flow solution.

Case 1: Single Generator and GSU

The first case corresponds to a single generator connected to the BPS through its own dedicated GSU transformer. This is a single-generator plant, or the configuration of one generator on a multi-machine plant if it is going to be tested individually.

Figure D.2 represents the initial generator operating conditions at the beginning of the test, at maximum active power output. In this case, the GSU tap position is at 100 percent with 10 percent GSU reactance on the same MVA base as the generator (203 MVA). The reactance between the high-side of the GSU (POI of the plant) and the infinite bus is eight percent, on the same MVA base.

This dispatch is somewhat arbitrary, corresponding to a system voltage of approximately 101 percent. In practice, the initial dispatch will be related to the system voltage set point and system conditions at the time the test is initiated. Without coordination with the TOP, system voltage may be significantly modified by this single generating unit. In this example, the system is considered as an infinite bus, so the system voltage is considered constant.

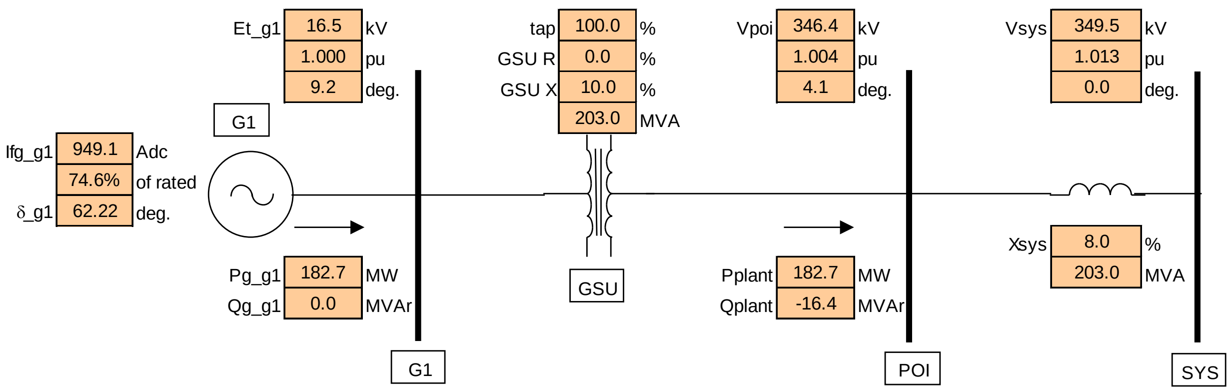

Figure D.2: Initial Generator Dispatch Conditions (Case 1)

To perform the over-excited reactive capability test, the plant operator raises the voltage set point of the generator excitation system until a limitation is reached. This is a simplistic example that does not consider plant auxiliary loads, which could become a limiting factor. In this example, the limiting factor is the generator terminal voltage reaching 105 percent as shown in Figure D.3.

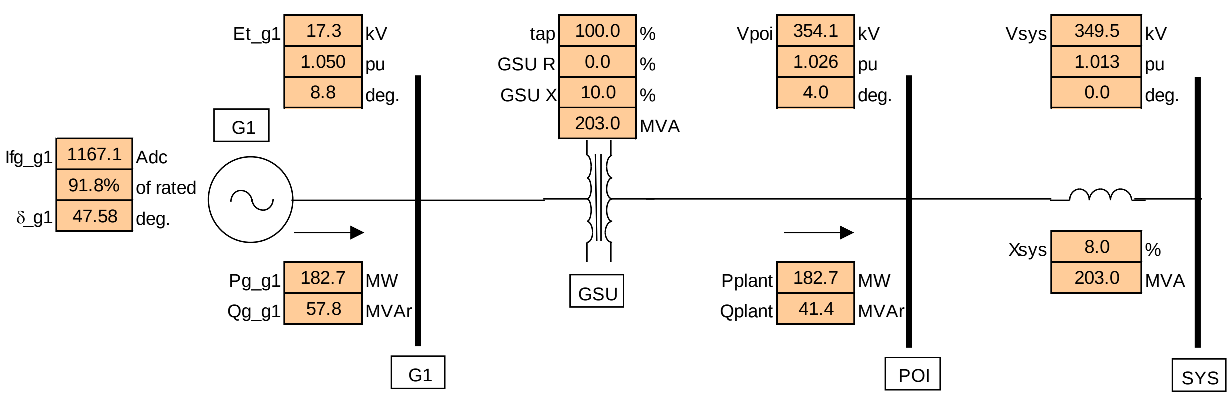

Figure D.3: Case 1 Generator Dispatch Conditions for Over-Excited Test without System Support

The generator terminal voltage raised by five percent, while the voltage at the POI changed by approximately two percent. The generator reached 91.8 percent of its rated field current and the reactive power output reached 57.8

MVAR, approximately 30 MVAR less than the value for Q_{max} = 88.5 MVAR calculated before (for these operating conditions). Thus, without support from the TOP to slightly adjust POI voltage, the values shown in **Figure D.3** would be the conditions reported in the form in Attachment 2 of MOD-025-2 for the over-excited test of this unit.

Assume that the TOP is able and willing to adjust dispatch and the POI voltage slightly to accommodate this test. This could enable a further increase in the excitation level of the generator under test. **Figure D.4** represents the new conditions for the test. Generator terminal voltage is still at its limit (105 percent) but in this case the generator field current reached its rated value (1272 A_{DC}). This was possible with a slight reduction of POI voltage by roughly two percent, which may or may not be achievable since it depends on system conditions and availability of other local reactive power resources that could be adjusted.

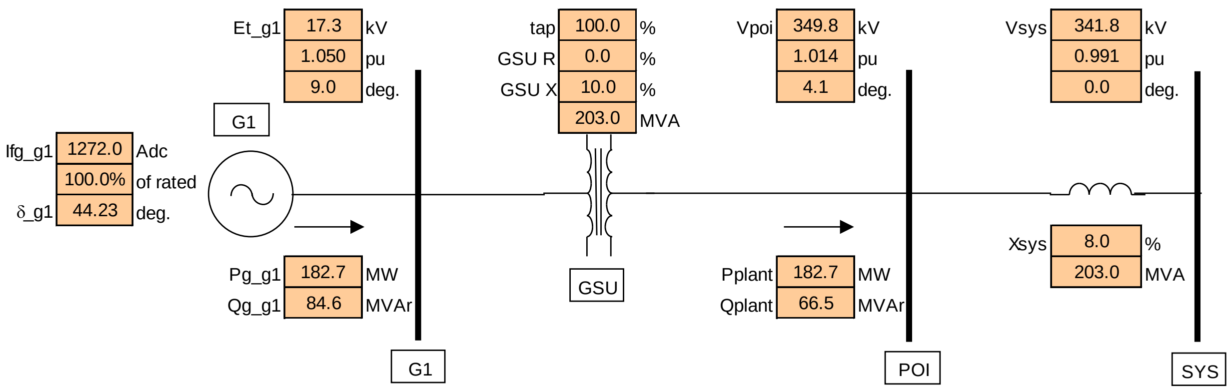

Figure D.4: Case 1 Generator Dispatch Conditions for Over-Excited Test with System Support

Even considering the full system support to bring the generator field current to its rated value, it is important to note that the reactive power output of the machine did not reach Q_{max} = 88.5 MVAR as this value for Q_{max} is calculated for generator terminal voltage equal to 100 percent. To reach the Q_{max} calculated above, it is necessary to hold the generator field current at its rated value and reduce the generator terminal voltage to 100 percent, which is only possible (in a theoretical sense) through adjustment of the system voltage. **Figure D.5** shows the system conditions that would be necessary, and it can be seen that the system voltage is impractically low, below 95 percent.

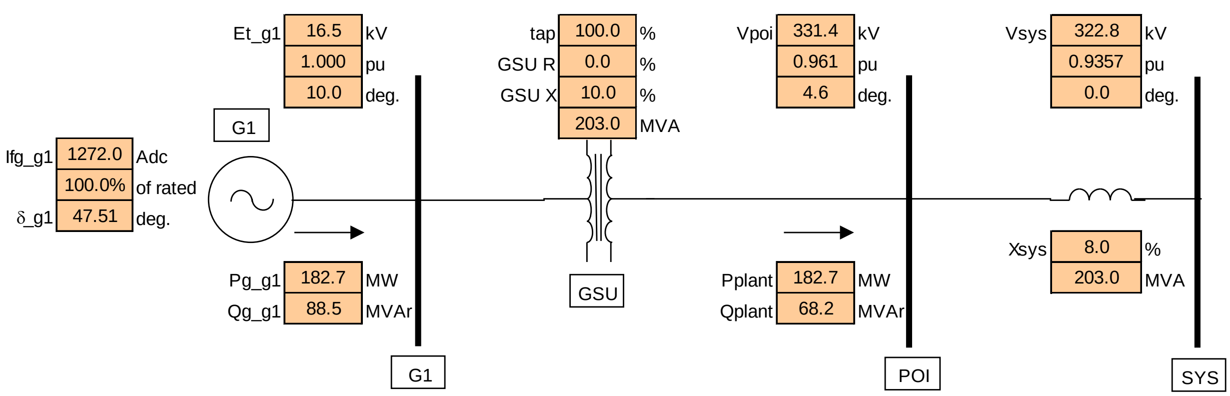

Figure D.5: Case 1 Generator Rated Dispatch Conditions with 100% Percent Terminal Voltage

This case illustrates the steps for reactive capability testing, the interactions of generator terminal voltage, system POI voltage, field current, and reactive power output (excluding any other limitations or auxiliary equipment for simplicity).

Case 1A: Single Generator and GSU (tap = 105 Percent)

Quite often, the tap position of the GSU is selected and adjusted (see IEEE Std. C57.116-2014)[95] to help support system voltage, so the tap position at the high-side of the GSU is raised to 102.5 percent or even 105 percent. Figure D.6 represents the operating conditions (compared to Figure D.2) when the exact same dispatch is used at the generator (182.7 MW, unity power factor, 100 percent terminal voltage). It can be seen that the system voltage would have to be higher to allow for this system dispatch.

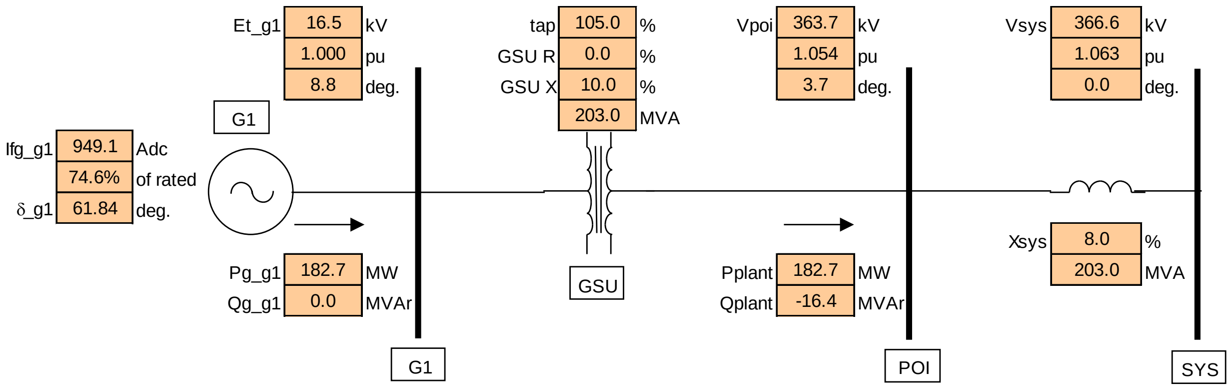

Figure D.6: Case 1A Generator Rated Dispatch Conditions with 1.0 pu Terminal Voltage

If the MOD-025-2 over-excited test is conducted starting with the conditions shown in Figure D.6, the plant operator would raise the voltage set point of the unit until reaching a limit. Similar to the previous example, that limit corresponds to 105 percent terminal voltage (ignoring the high voltage profile seen at the grid) and the conditions given in Figure D.7 would be reached.

Figures D.7 and Figure D.3 have comparable generator terminal conditions, but the generator was able to get closer to its capability, reaching field current of 1177 A (92.5 percent of rated) as compared to 1167 A (91.8 percent of rated) when the GSU tap was set to 100 percent. The GSU tap position impacts the system side, resulting in a higher system voltage and a larger reactive power flow from the generator into the grid measured at the POI. The GSU tap position affects, primarily, the net reactive power measured at the POI but has no impact on the capability of the generator, which is entirely related to the generator's limits and ratings. Nonetheless, in terms of the test conditions for MOD-025-2, the generator could get closer to its rated field current (and higher reactive power output) with the GSU tap at 105 percent, compared to what was possible with the GSU tap at 100 percent.

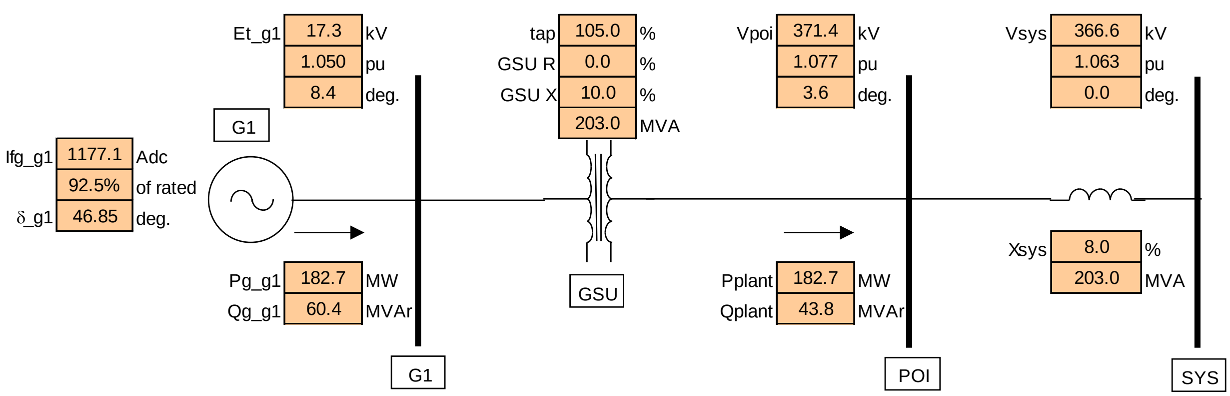

Figure D.7: Case 1A Conditions for Over-Excited Test without System Support

[95] IEEE Std. C57.116-2014, *IEEE Guide for Transformers Directly Connected to Generators*, 2014. [Online]. Available: https://standards.ieee.org/findstds/standard/C57.116-2014.html.

On the other hand, the higher voltage profile on the system might make it more acceptable for the TOP to support the test and adjust the system voltage profile as required. Figure D.8 presents the results considering a system voltage adjustment to bring the generator field current to its rated value with the generator terminal voltage still at its limit (105 percent). Once again, the system voltage had to be reduced by approximately two percent, but at this point starting from a higher initial voltage so it might be less disruptive to the normal operation of the BPS.

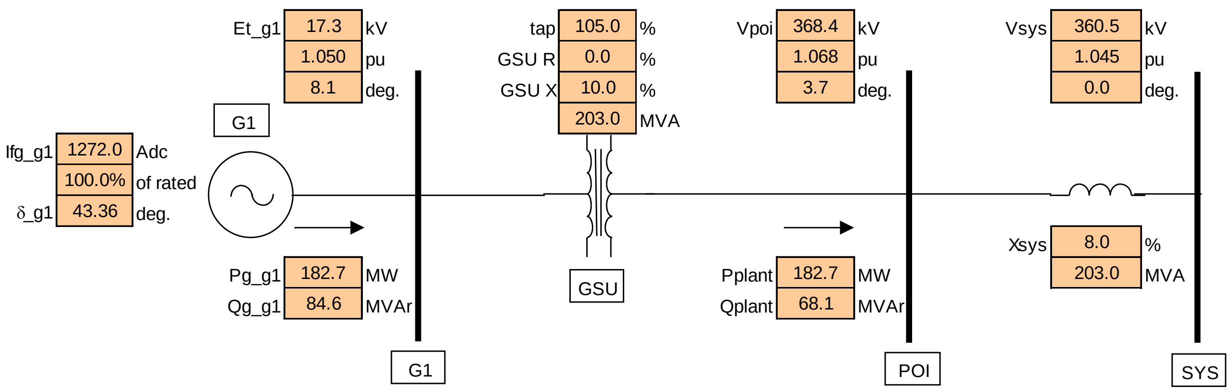

Figure D.8: Case 1a Generator Dispatch Conditions for Over-Excited Test with System Support

Case 1B: Single Generator and GSU (Tap Change without System Change)

Case 1A corresponds to a change in GSU tap compared to Case 1 without adjustment on the generator terminal conditions. In other words, it assumes that the system voltage profile was changed. The other way to look at the impact of changing the GSU tap position is considering that the system voltage profile does not change when the tap position is modified. This case corresponds, for instance, to the action of an on-load tap changer (OLTC) on the GSU.

Figure D.9 shows the impact of changing the tap position from 100 percent to 105 percent without changing the voltage at the system (infinite bus) and without changing the terminal voltage at the generator. Comparing initial dispatch for Case 1B (Figure D.9) and initial dispatch for Case 1 (Figure D.2), the change in tap position resulted in an increased voltage at the HV side of the GSU (plant POI) and required an increase in the reactive power output of the generator. In other words, the generator is operating further overexcited than in Case 1.

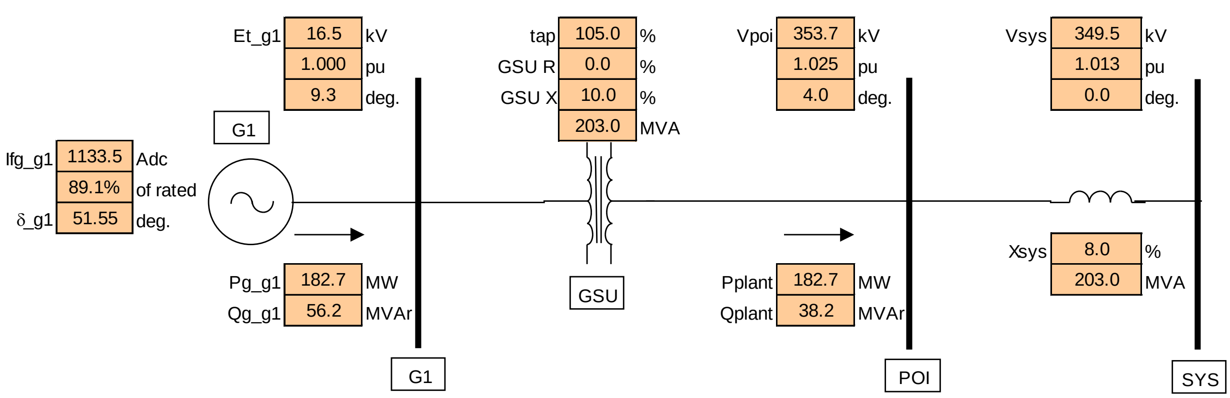

Figure D.9: Initial Generator Dispatch Conditions (Case 1B)

To perform the over-excited reactive capability test, as before, the plant operator raises the voltage set point of the generator excitation system until a limitation is reached. Figure D.10 shows that, if the terminal voltage of the machine could be raised to 105 percent, the rated field current of the machine would be exceeded. In other words, the rated field current limit of the generator can be reached with a generator terminal voltage between 100 percent and 105 percent (estimated 102.6 percent in this example).

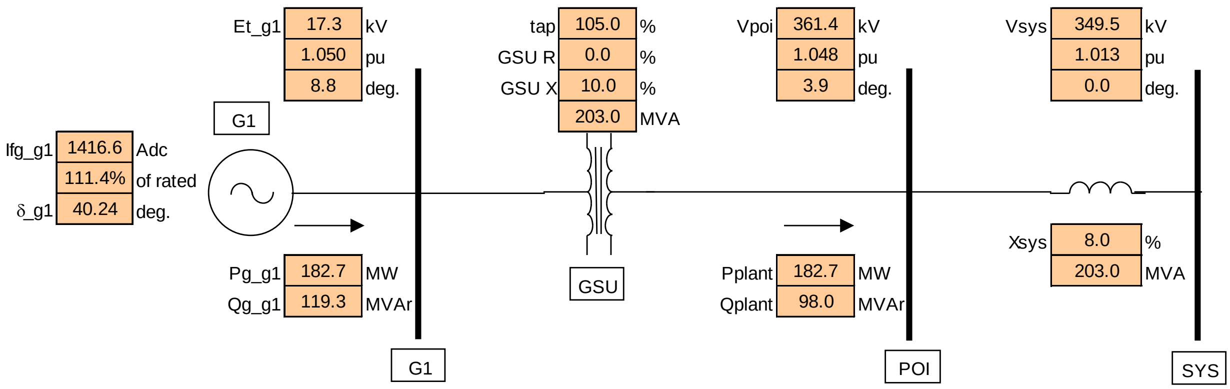

Figure D.10: Case 1B Generator Dispatch Conditions for Over-Excited Test without System Support

There would be an impact on the underexcited reactive capability test as shown in **Figure D.11**. The generator terminal voltage would reach 95 percent, and the generator would be barely under-excited, absorbing just 1 MVAR. Once again, support from the system would be required (in this case by raising the system voltage profile) to help the outcome of the test and get the generator further into its under-excited capability.

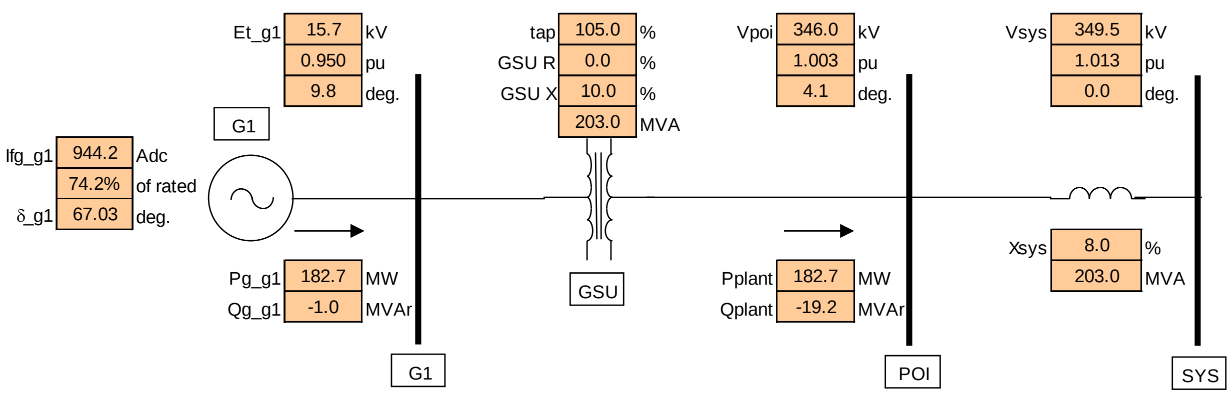

Figure D.11: Case 1B Generator Dispatch Conditions for Under-Excited Test without System Support

Summary Cases 1, 1A, and 1B

Table D.2 presents the summary of the results for Cases 1 and 1A for both over- and under-excited (not shown above) cases. The GSU and the system impedances are intentionally represented as reactances (no resistive part), so there are no active power losses in these calculations. Therefore, the generator active power output (182.7 MW) is also the net active power output of the plant as seen from the POI (no losses in the GSU). Thus, the active power is not explicitly shown in **Table D.2**.

As explained previously, the generator capability curve is usually presented for rated generator terminal voltage and thus the value for Q_{max} = 88.5 MVAR can only be obtained (for rated field current of 1272 A_{DC}) when the generator terminal voltage is equal to 100 percent. In practice, this is a condition that will seldom be possible when testing an individual machine as it would require low system voltages. These results are shown in the rows labeled “Rated.”

The selected arbitrary starting point for the MOD-025-2 reactive capability test corresponded to rated terminal voltage (100 percent voltage) and unity power factor as shown in the rows labeled “Base Case.” When the GSU tap position is changed from 100 percent (Case 1) to 105 percent (Case 1A), the generator terminal conditions are not changed, but the POI and system voltages are modified. For the same generator terminal conditions, the system voltages are higher when the GSU tap position is at 105 percent. When the GSU tap position is changed from 100 percent (Case 1) to 105 percent (Case 1B), the generator terminal conditions and the system voltages are not modified. This is similar to the expected outcome of using an OLTC, if available, to move the tap positions in the GSU. In this case, the POI voltage is raised and the reactive power output of the generator also increases, so the machine is initially operating at a higher field current (more overexcited) than the corresponding initial conditions for Case 1.

If the GSU is equipped with an OLTC, different tap positions could be used for the overexcited and underexcited reactive capability tests for MOD-025-2. On the other hand, changing GSU tap positions on a GSU without an OLTC is not a trivial task and is generally not considered reasonable solely for conducting MOD-025-2 tests; the generator has to be shut down to allow changes in tap position, which poses an undue burden on the overall test procedure and is not part of the requirements in MOD-025-2. Furthermore, for GSUs with fixed tap positions, the reactive capability tests should be conducted at the tap position that will be used for on-line operation, particularly if operational data will be used in the future to meet the requirements of the standard.

To represent the MOD-025-2 test conditions without the support from the system, the infinite (system) bus voltage is held constant while the generator terminal voltage is raised (or lowered) via the excitation system. It can be seen that the over-excited test did not reach Q_{max} and the under-excited test did not reach Q_{min} as the generator terminal voltage become the limiting factor (± five percent range). More significantly, the generator field current did not reach its rated value (1272 A_{DC}) in the over-excited test.

Generator terminal conditions (voltage, active power, and reactive power) were exactly the same and independent of the GSU tap position. In a way, this result is related to the adjustment of the system conditions rather than the generator initial condition for the different GSU tap positions. The system voltage profile is higher for the results with the GSU tap at 105 percent. On the other hand, for a given generator terminal voltage and generator active conditions are the same (e.g., 105 percent voltage, same active power output).

Table D.2: Summary of Cases 1 and 1A

	Description	Generator				POI		System
		Voltage Percent (16.5 kV)	δ (deg)	Q (MVAR)	I_{FG} (A_{DC})	Q (MVAR)	Voltage Percent (345 kV)	Voltage Percent (345 kV)
Case 1 (GSU tap = 100%)	Rated (over-excited)	100.0	47.5	88.5	1272	68.2	96.1	93.6
	Rated (under-excited)	100.0	78.4	–63.4	806	–81.8	103.5	106.9
	Base Case	100.0	62.2	0.0	949	–16.4	100.4	101.3
	Over-Excited	105.0	47.6	57.8	1167	41.4	102.6	101.3
	Under-Excited	95.0	80.8	–52.0	839	–71.7	98.2	101.3
	Over-Excited with Grid	105.0	44.2	84.6	1272	66.5	101.4	99.1
	Under-Excited with Grid	95.0	83.1	–60.0	828	–80.2	98.6	102.0
Case 1A (GSU tap = 105%)	Rated (over-excited)	100.0	46.5	88.5	1272	68.2	100.9	98.5
	Rated (under-excited)	100.0	78.1	–63.4	806	–81.8	108.7	111.9
	Base Case	100.0	61.8	0.0	949	–16.4	105.4	106.3
	Over-Excited	105.0	46.9	60.4	1177	43.8	107.7	106.3
	Under-Excited	95.0	81.1	–54.4	835	–74.3	103.2	106.3
	Over-Excited with Grid	105.0	43.8	84.6	1272	66.5	106.5	104.2
	Under-Excited with Grid	95.0	82.7	–60	828	–80.2	103.5	106.8
Case 1B (GSU tap = 105%)	Rated (over-excited)	100.0	47.1	88.5	1272	68.2	100.9	98.5
	Rated (under-excited)	100.0	78.1	–63.4	806	–81.8	108.7	111.9
	Base Case	100.0	51.6	56.2	1133.5	38.2	102.5	101.3
	Over-Excited	102.6	45.1	88.7	1272	69.4	103.7	101.3
	Under-Excited	95.0	67.0	–1.0	944.2	–19.2	100.3	101.3
	Over-Excited with Grid	Not necessary: rated field current reached in the over-excited test						
	Under-Excited with Grid	Similar to Case 1A, but requiring a larger change in the system voltage						
	Color Legend							
	Generator rated conditions							
	System voltage for generator rated conditions							
	System voltage held constant (no grid support)							

Case 2: Two Generators Sharing a Common GSU

This case corresponds to two generators connected to the BPS through a common (shared) GSU transformer. Figure D.12 represents the initial operating conditions of the generators at the beginning of the test. Both units are dispatched at their maximum active power output and the units are represented as sister units with the same parameters and ratings as presented above. To make the results comparable to those for Cases 1 and 1A (single generator and single GSU), the GSU and the system impedance base have been changed to double the original ratings (from 203 MVA to 406 MVA). In this configuration, the two units combined (total 406 MVA) are connected to the grid with the same external impedance (10 percent for the GSU and 8 percent for the system transfer impedance) when expressed in the total combined MVA base. It can be seen that the initial generation dispatch of each unit is equal to the base case conditions used in Case 1. The POI and system voltages are also the same, despite transferring twice as much power to the grid, due to the adjustment to the GSU and system impedances.

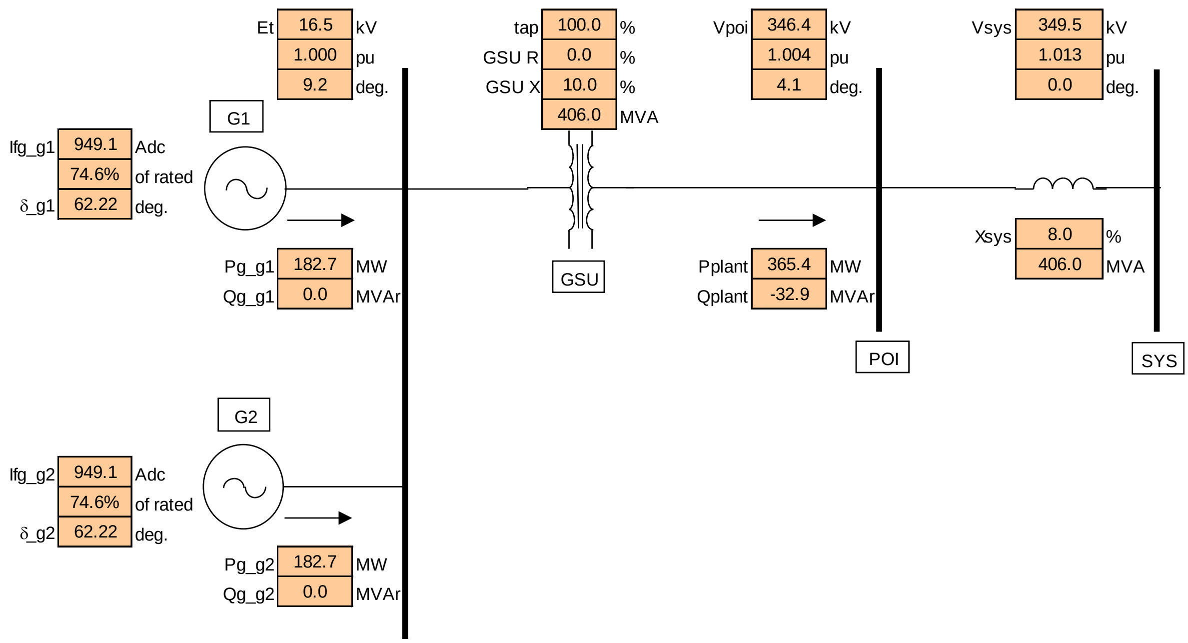

Figure D.12: Initial Generator Dispatch Conditions (Case 2)

Figure D.13 presents one possible scenario for the over-excitation test of unit G1 without calling for support from the system operators. This condition was established by using unit G2 to maintain its excitation level (same field current as in Figure D.12) while the voltage set point for unit G1 was increased. This is somewhat equivalent to the operation of unit G2 on manual control (constant field current), which might not be a practical approach for these tests. On the other hand, it is possible to adjust the field current in unit G2 by adjusting the voltage set point for the AVR on that unit.

However, the most important aspect is that unit G1 reached its rated field current (1272 A_{DC}) for a generator terminal voltage below 105 percent, so it wasn't necessary to coordinate and require additional support from the system.

On the other hand, TPs and PCs should understand that these test conditions match the requirements from MOD-025-2 (considering that Unit G1 is being tested individually), but these conditions are not to be expected in any practical operational conditions. The operation of the plant will, most likely, have both units at more or less the same voltage set point and therefore similar reactive power outputs. Thus, if a system event happens that would bring the system voltage down, both units are expected to respond following their AVR characteristics and raise their field current (and therefore their reactive power output) simultaneously.

Therefore, the reactive power losses in the GSU transformer during the MOD-025-2 test conditions shown in Figure D.13 will be quite different than what would be expected if both units are responding together and trying to push as much reactive power as possible towards the grid. As such, the determination of the plant net reactive power capability, as seen from the POI, should not be performed based on the MOD-025-2 test conditions from Figure D.13. The combined (net) reactive power output of the plant, at the POI, would have to be calculated based on the results of the MOD-025-2 tests of each unit at the plant as they would be tested individually per the requirements in MOD-025-2.

If the units are supposed to be tested as a group (all units on the same GSU), then the same issues observed in Case 1 above would apply. These units would not reach their rated field current without support from the system operators adjusting the system voltage accordingly.

It should also be noted that an angular separation between units G1 and G2 will occur, and it increases as more reactive power is transferred from one unit to the other. This angular separation between the units might impact the damping of the intra-plant electromechanical oscillation mode and might also have an impact on the transient stability of the plant. Thus, it is important to recognize that the generator dispatch associated with the MOD-025-2 test conditions in Figure D.13 has reduced stability margins when compared to the usual dispatch of these plants with both units having approximately the same excitation levels (approximately the same reactive power output).

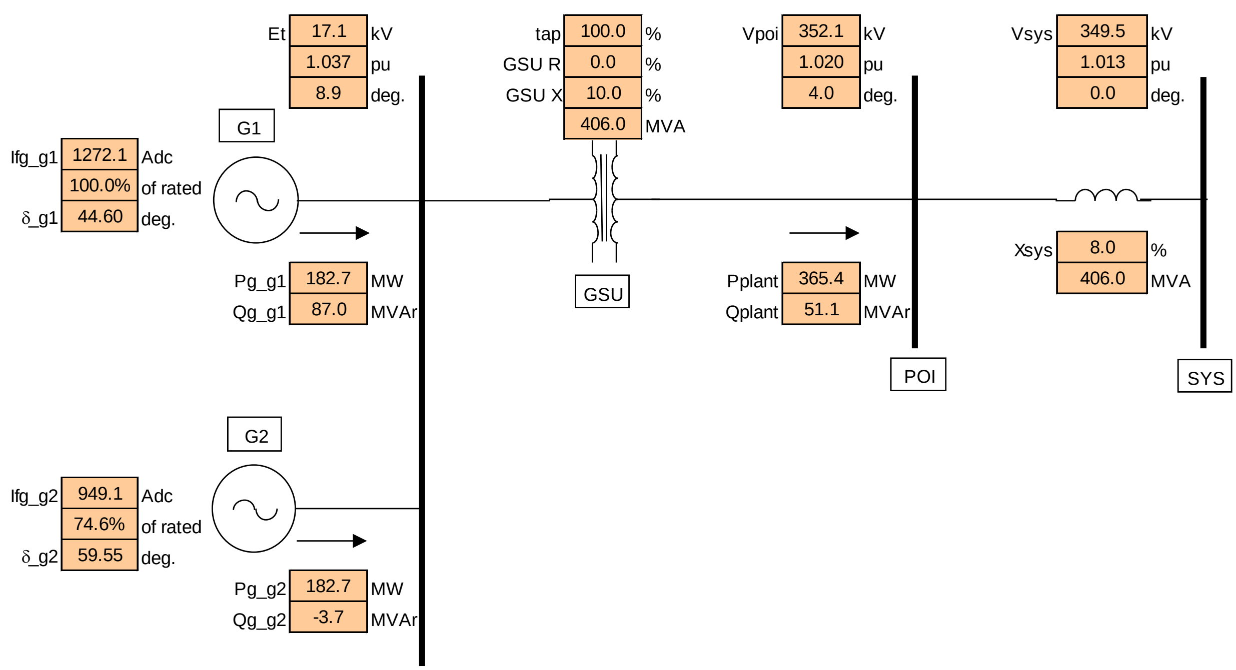

Figure D.13: Over-Excited Test on Unit G1 without System Support

Case 3: Two Generators with Separate GSUs

This case corresponds to a plant with two machines where each machine has its own GSU transformer. This is a single-generator plant or the configuration of one generator on a multi-machine plant if it is going to be tested individually.

Figure D.14 represents the initial operating conditions of the generators at the beginning of the test. Both units are dispatched at their maximum active power output and the units are represented as sister units with the same parameters and ratings as presented above. To make the results comparable to those for Cases 1 and 1A (single generator and single GSU), the system impedance base has been changed to double the original ratings (from 203 MVA to 406 MVA). It can be seen that the initial generation dispatch of each unit is equal to the base case conditions used in Case 1. The POI and system voltages are also the same, despite transferring twice as much power to the grid, due to the adjustment to system impedance.

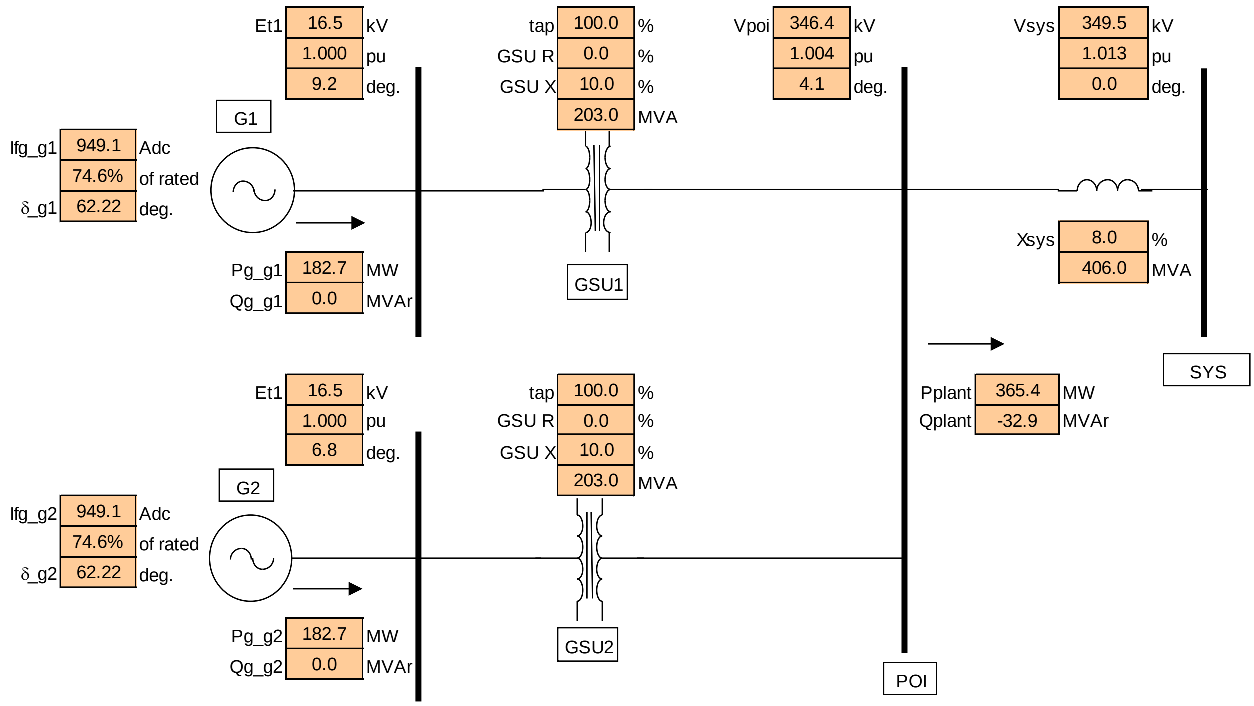

Figure D.14: Initial Generator Dispatch Conditions (Case 3)

Figure D.15 presents one possible scenario for the over-excitation test of unit G1 without calling for support from the system operators. This condition was established without changing unit G2 excitation level (same field current as in **Figure D.14**) while the voltage set point for unit G1 was increased. This is somewhat equivalent to the operation of unit G2 on manual control (constant field current), which might not be a practical approach for these tests. On the other hand, it is possible to adjust the field current in unit G2 by adjusting the voltage set point for the AVR on that unit.

Since units G1 and G2 are now connected through the HV bus of their GSUs (POI), the support from unit G2 for the test at unit G1 is different than what was calculated for case 2 with both units connected to the same terminal (LV) bus. Nonetheless, unit G1 reached its rated field current for a terminal voltage higher than 105 percent while unit G2 maintained the same field current as in the initial dispatch. The terminal voltage of unit G2 was raised due to the adjustment in terminal voltage at unit G1. There is a small difference in the POI voltage as compared to Case 2, but the biggest difference is the net reactive power output of the plant as measured at the POI. In practice, unit G2 can support the test on unit G1 as shown in **Figure D.16**. A relatively small change in voltage reference on unit G2 (compared to the initial conditions in **Figure D.14**) allows unit G1 to reach its rated field current with a terminal voltage equal to 105 percent.

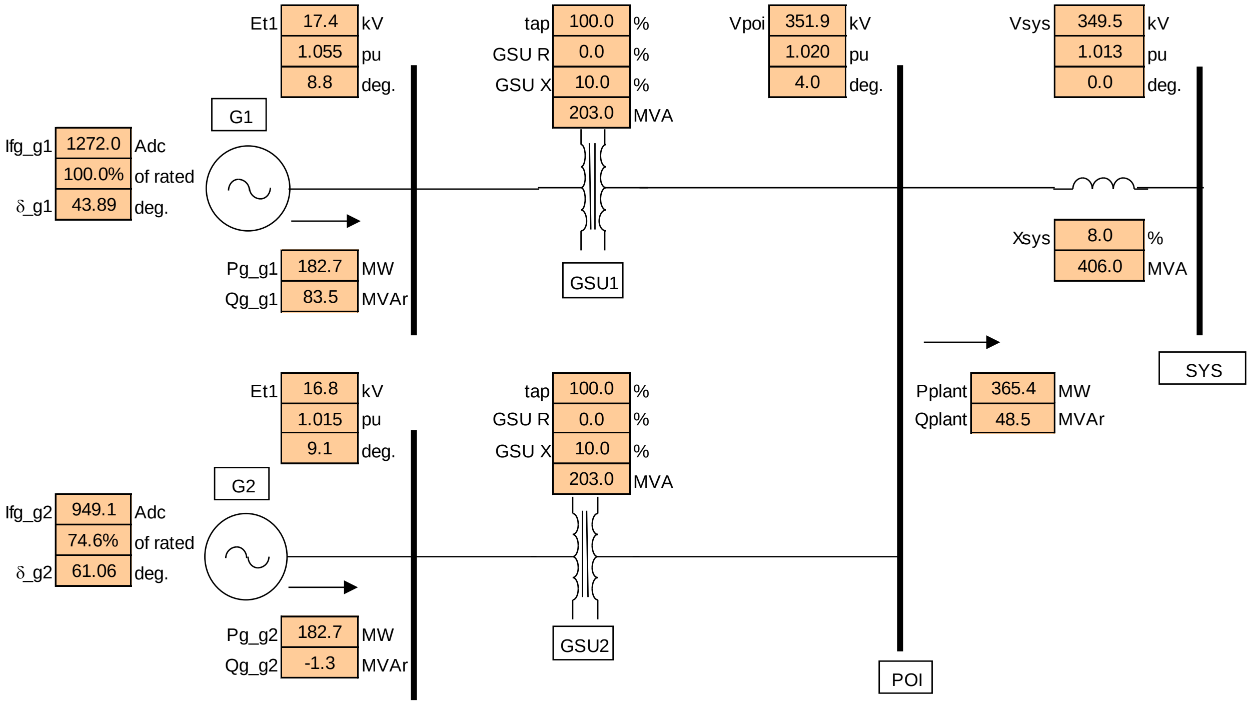

Figure D.15: Over-Excited Test on Unit G1 without System or Unit G2 Support

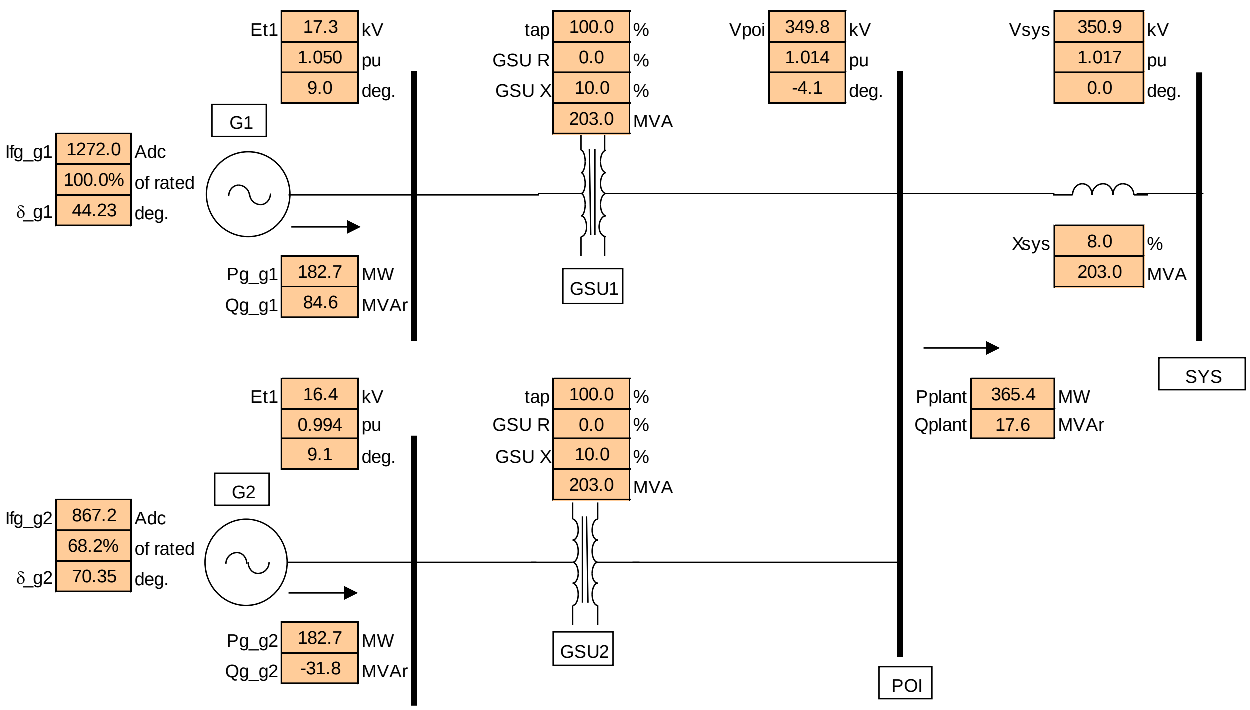

Figure D.16: Over-Excited Test on Unit G1 with Unit G2 Support

Appendix E: MOD-032-1 Data Request Examples

MOD-032-1 requires each PC and each of its TPs to, "jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the PC's planning area." Each TP and PC may need to collect MOD-032-1 data slightly differently based on the specific studies being performed, their planning case selection, their modeling assumptions, etc. It is not feasible for all TPs and PCs to use the same reporting procedures or formats. However, it is recommended that TPs and PCs review their modeling data requirements and reporting procedures for MOD-032-1 to ensure they are consistent with those of other TPs and PCs, as applicable, to aid in the data gathering and submittal by GOs and other entities.

For this reason, a list of MOD-032-1 modeling data requirements and reporting procedures are provided here for reference:

- NATF MOD-032-1 document:
  http://www.natf.net/docs/natf/documents/resources/natf-modeling-data-request-mod-032-reference-document.xlsx
- IESO:
  http://www.ieso.ca/-/media/files/ieso/document-library/registration/facility/online_facility_registration_help.pdf
- PJM:
  http://www.pjm.com/planning/rtep-development/powerflow-cases/mod-032.aspx
  http://www.pjm.com/-/media/planning/rtep-dev/powerflow-cases/20150630-mod-032-ss-dynamics-sc-data-requirements-reporting-procedures-v1.ashx?la=en
- MISO:
  https://cdn.misoenergy.org/MOD-032%20Letter%20of%20Notice%20of%20Data%20Submittal%20Duty105062.pdf
- WECC Data Preparation Manual:
  https://www.wecc.biz/Reliability/WECC-Data-Preparation-Manual-Rev-7-Approved.pdf
- ISO New England:
  https://www.iso-ne.com/static-assets/documents/2015/06/iso_new_england_compliance_bulletin_mod_032.pdf

Appendix F: List of Terms and Acronyms

Table F.1: List of Acronyms

Acronym	Description
AC	Alternating Current
AVR	Automatic Voltage Regulator
CCPP	Combined Cycle Power Plant
CT	Current Transformer
DC	Direct Current
DCS	Distributed Control System
DDR	Dynamic Disturbance Recorder
DFR	Digital Fault Recorder
FFT	Fast Fourier Transform
FSNL	Full Speed No Load
FSR	Fuel Stroke Reference
GSU	Generator Step-Up (Transformer)
GT	Gas Turbine
HRSG	Heat-Recovery Steam Generator
HV	High Voltage
LV	Low Voltage
LVDT	Linear Variable Differential (Displacement) Transformer
OEL	Over-Excitation Limiter
OEM	Original Equipment Manufacturer
OLTC	On-Load Tap Changer
PID	Proportional-Integral-Derivative
PLC	Programmable Logic Controller
PMU	Phasor Measurement Unit
POI	Point of Interconnection
PPMV	Power Plant Model Verification
PSS	Power System Stabilizer

Table F.1: List of Acronyms	
Acronym	**Description**
PT	Potential Transformer
SSSL	Steady State Stability Limit
ST	Steam Turbine
STATCOM	Static Synchronous Compensator
SVC	Static Var Compensator
UEL	Under-Excitation Limiter
VIVG	Variable Inlet Guide Vanes

Appendix G: References

The following documents are referenced throughout this guideline:

- NERC, Reliability Standard MOD-025-2: *Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability*, Atlanta, GA, March 2014.
- NERC, Reliability Standard MOD-026-1: *Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions*, Atlanta, GA, November 2014.
- NERC, Reliability Standard MOD-027-1: *Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions*, Atlanta, GA, November 2014.
- NERC, Reliability Standard MOD-032-1: *Data for Power System Modeling and Analysis*, Atlanta, GA, May 2014.
- NERC, Reliability Standard MOD-033-1: *Steady-State and Dynamic System Model Validation*, Atlanta, GA, May 2014.
- NERC, Reliability Standard PRC-019-2: *Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection*, Atlanta, GA, May 2015.
- NERC, Reliability Standard VAR-001-4.2: *Voltage and Reactive Control*, Atlanta, GA, 2017.
- NERC, Reliability Standard VAR-002-4.1: *Generator Operation in Maintaining Network Voltage Schedules*, Atlanta, GA, May 2017.
- NERC Modeling Notifications, NERC System Analysis and Modeling Subcommittee. Available: HERE.
- NERC List Acceptable Models, NERC System Analysis and Modeling Subcommittee. Available: HERE.
- NERC Procedures for Validation of Powerflow and Dynamics Cases. Available: HERE.
- NERC Reliability Guideline on Primary Frequency Control, December 2015. Available: HERE.
- NERC Reliability Guideline on Disturbance-Based Dynamic Model Verification using PMUs. Available: HERE.
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- USBR, "Mechanical Governors for Hydroelectric Units," Facilities, Instructions, Standards, and Techniques, vol. 2-3, Denver, CO. Available: https://www.usbr.gov/power/data/fist/fist2_3/vol2-3.pdf.
- Western Electricity Coordinating Council, "Cross-Current Compensation Model," WECC, Salt Lake City, Nov 3, 2014. [Online]. Available: https://www.wecc.biz/Reliability/Cross-Current_Compensation.pdf.

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Contributors

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Name	Entity
Steve Barnes	General Electric
Kent Bolton	Western Electricity Coordinating Council
Brandon Bouwman	US Army Corp of Engineers
Greg Brooks	US Army Corp of Engineers
Sean Brosig	US Army Corp of Engineers
Tom Carpenter	Tennessee Valley Authority
Rob Clemence	IESO
Terry Crawley	Southern Company
Richard Dennis	Emerson
Daniel Hansen	NRG Energy
Tao He	PJM Interconnection
Shih-Min Hsu	Southern Company
Dennis Kane	We Energies
Marc Langevin	Opal-RT
David Lemmons	Xcel Energy
Sam Li	BC Hydro
Leonardo Lima	Kestrel
Donald Lock	Talen Energy
Shawn Patterson (PPMVTF Chair)	US Bureau of Reclamation
Pouyan Pourbeik	PEACE
Randhir Singh	PSEG
John Undrill	Consultant
John Zong	Powertech Labs Inc.
Steve Yang	Bonneville Power Administration
Mohamed Osman	North American Electric Reliability Corporation
Ryan Quint (PPMVTF Coordinator)	North American Electric Reliability Corporation