ELECTRIC POWER
RESEARCH INSTITUTE

Generator Control Testing to Certify Reactive Power Capability, Excitation System Functions and Frequency Response

Guidelines for NERC Compliance

Generator Control Testing to Certify Reactive Power Capability, Excitation System Functions and Frequency Response

Guidelines for NERC Compliance

1014911

Final Report, November 2007

EPRI Project Manager
J. Stein

ELECTRIC POWER RESEARCH INSTITUTE
3420 Hillview Avenue, Palo Alto, California 94304-1338 • PO Box 10412, Palo Alto, California 94303-0813 • USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com

DISCLAIMER OF WARRANTIES AND LIMITATION OF LIABILITIES

THIS DOCUMENT WAS PREPARED BY THE ORGANIZATION(S) NAMED BELOW AS AN ACCOUNT OF WORK SPONSORED OR COSPONSORED BY THE ELECTRIC POWER RESEARCH INSTITUTE, INC. (EPRI). NEITHER EPRI, ANY MEMBER OF EPRI, ANY COSPONSOR, THE ORGANIZATION(S) BELOW, NOR ANY PERSON ACTING ON BEHALF OF ANY OF THEM:

(A) MAKES ANY WARRANTY OR REPRESENTATION WHATSOEVER, EXPRESS OR IMPLIED, (I) WITH RESPECT TO THE USE OF ANY INFORMATION, APPARATUS, METHOD, PROCESS, OR SIMILAR ITEM DISCLOSED IN THIS DOCUMENT, INCLUDING MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE, OR (II) THAT SUCH USE DOES NOT INFRINGE ON OR INTERFERE WITH PRIVATELY OWNED RIGHTS, INCLUDING ANY PARTY'S INTELLECTUAL PROPERTY, OR (III) THAT THIS DOCUMENT IS SUITABLE TO ANY PARTICULAR USER'S CIRCUMSTANCE; OR

(B) ASSUMES RESPONSIBILITY FOR ANY DAMAGES OR OTHER LIABILITY WHATSOEVER (INCLUDING ANY CONSEQUENTIAL DAMAGES, EVEN IF EPRI OR ANY EPRI REPRESENTATIVE HAS BEEN ADVISED OF THE POSSIBILITY OF SUCH DAMAGES) RESULTING FROM YOUR SELECTION OR USE OF THIS DOCUMENT OR ANY INFORMATION, APPARATUS, METHOD, PROCESS, OR SIMILAR ITEM DISCLOSED IN THIS DOCUMENT.

ORGANIZATION(S) THAT PREPARED THIS DOCUMENT

Kestrel Power Engineering Ltd.

Excitation System Services, Inc.

NOTE

For further information about EPRI, call the EPRI Customer Assistance Center at 800.313.3774 or e-mail askepri@epri.com.

Electric Power Research Institute, EPRI, and TOGETHER…SHAPING THE FUTURE OF ELECTRICITY are registered service marks of the Electric Power Research Institute, Inc.

Copyright © 2007 Electric Power Research Institute, Inc. All rights reserved.

CITATIONS

This report was prepared by

Kestrel Power Engineering Ltd.
112 Gilmour Avenue
Toronto, ONT M6P-3B3
Canada

Principal Investigator
L. Hajagos

Excitation System Services, Inc.
9126 N. 2150 E. Road
Fairbury, IL 61739

Principal Investigator
M. Fogarty

This report describes research sponsored by the Electric Power Research Institute (EPRI).

The report is a corporate document that should be cited in the literature in the following manner:

Generator Control Testing to Certify Reactive Power Capability, Excitation System Functions and Frequency Response: Guidelines for NERC Compliance. EPRI, Palo Alto, CA: 2007. 1014911.

PRODUCT DESCRIPTION

There is renewed interest in issues surrounding power system reliability following several major power outages that occurred on the West Coast of the North American power system in the late 1990s and in the Northeast in 2003. One area identified as requiring improvement was in the configuration and reporting of the capabilities, protection, and control of synchronous generators that form the primary source of supply. The U.S. Energy Policy Act of August 2005 contains provisions that make compliance with the North American Electric Reliability Corporation (NERC) standards mandatory and enforceable.

Accurate simulation models of power system equipment are beneficial to all power system participants in order to maximize equipment availability, minimize losses, avoid interruptions, and protect equipment, to name just a few objectives. The required level of detail, best methods to obtain data, and frequency of verification are just some of the issues encountered when trying to obtain and maintain these models. To complicate matters, there is no one method to obtain the desired information that applies to all types of equipment, schedules, and budgets. There is, however, a body of available techniques that can be used to meet these goals, and this report summarizes them and describes the benefits and drawbacks of each.

The report is organized into sections based on the draft standards that were in place as of its writing. These standards are presently in the process of being re-drafted; however, the technical descriptions and engineering approach described are relevant regardless of the final form of the regulatory requirements.

Results & Findings

For generation owners with limited experience in the areas of technical compliance with NERC requirements or with generator equipment testing and modeling, this report provides a blueprint for constructing their own compliance program. By using proven practices of other owners and consultants, readers can quickly identify techniques and organizational structures that best suit their organization. Readers will learn that many of the tools required to comply with the emerging requirements already exist in any large, modern generation company.

This report also covers some basic ambient monitoring concepts and applications. The continuation of this project and subsequent reports will address current developments and concepts in ambient monitoring (the recording of unit responses to system disturbances, rather than the use of staged testing as a means of verification of simulation models). Future work in this area should identify the recording requirements and also the minimum complement of signals required to validate various control system models.

Challenges & Objective(s)

This report has been written for generation owners and market participants who work with them on meeting technical regulatory compliance requirements. Section 5 of the report has been written to facilitate the creation of a compliance structure within an organization. Sections 1 through 4 provide a resource for engineering staff involved in analytical support, testing, or simulation of generators and their associated controls.

Applications, Values & Use

The technical regulatory requirements that apply to generation owners were being re-drafted as the report was in progress. The techniques and practices described here will need to be reviewed and updated based on any changes. Once the requirements have become entrenched and the requirements become mandatory, all generation owners will have to participate in this work, creating a market for innovative solutions and services.

EPRI Perspective

In addition to the EPRI report 1015241, *Power Plant Modeling and Parameter Derivation for Power System Studies: Present Practice and Recommended Approach for Future Procedures*, this report is a comprehensive compilation of information associated with the NERC technical requirements applied to generator owners. By drawing on EPRI's membership and resources, EPRI has been able to provide an accurate picture of the present best practices applied by the largest utilities throughout North America.

Approach

This report is based on a compilation of information obtained from generation owners, consultants, industry standards, related technical references, regional entities, and NERC. The project and report are intended to summarize the current approach and best practices that pertain to NERC generator standards while realizing that the standards are actively evolving. This was accomplished for this project through interviews and surveys, interaction with NERC and the NERC standards committees, and input from a technical advisory group that was comprised of generator owners and market participant representatives.

Keywords

Ambient monitoring
Compliance
Coordination
Excitation limiter
Excitation System
Frequency response
Governor
Model
Protective Relay
Reactive Power Capability
Real power Capability
Regulatory Requirement
Staged Test
Synchronous generator
Verification
Validation

ABSTRACT

Industry re-structuring has led to the reorganization and disintegration of traditional integrated utilities and a focusing on commercial issues. At the same time, there is renewed interest in the issues surrounding power system reliability following several major power outages that occurred on the West Coast of the North American power system in the late 1990s and in the Northeast in 2003. A general review of operating and planning procedures occurred which highlighted the need for greater consistency and standardization amongst all of the industry participants.

One of the areas identified as requiring improvement was in the configuration and reporting of the capabilities, protection and control of the synchronous generators that form the primary source of supply to the Bulk Electricity System (BES). In 1997, NERC (North-American Electric Reliability Corporation) developed a set of Operating and Planning standards for use throughout the North American industry (NERC Planning Standards, Part II System Modeling Data Requirements, approved by Board of Trustees, September 16, 1997). The Planning Standards include rules for the routine verification of generating unit capabilities.

The organizations that oversee electricity reliability in North America have been in existence for decades. NERC's mission is to ensure that the bulk electric system in North America is reliable, adequate and secure. Since its formation in 1968, NERC has operated successfully as a self-regulatory organization, relying on reciprocity and the mutual self-interest of all those involved.

NERC consists of eight Regional Entities. These entities are responsible for the promotion and enforcement of the reliability management programs within their geographic territory. Each one oversees the activities of one or more utilities and control areas. In areas where an Independent System Operator (ISO) controls operation, they are responsible for meeting the Operating Standards and enforcing the Connection requirements and Planning Standards on market participants within their jurisdiction.

The U.S. Energy Policy Act of August 2005 contains provisions that make compliance with NERC standards mandatory and enforceable. As a result, the NERC standards are in the process of being re-written to reflect their new status. The various standards relevant to this report are referenced and some details are provided from the version available at the time of report writing. The reader should obtain the latest versions of the NERC and Regional standards prior to embarking on a model validation program.

CONTENTS

LIST OF FIGURES

LIST OF TABLES

1

GENERATOR STEADY STATE PERFORMANCE

This section addresses draft standards MOD-024 "Verification of Generator Gross and Net Real Power Capability" [1-1] and MOD-025 "Verification of Generator Gross and Net Reactive Power Capability" [1-2]. These standards are presently under development by the NERC Generator Verification Standards Drafting Team. This section is based on the draft standards issued in January 2007. Any significant changes to the final standards will need to be considered when reviewing the material of this section and formulating a compliance plan. Many of the concepts discussed in this Section are based on conventional industry practice and standards and will therefore not be affected by any changes to the final NERC requirements.

The primary technical requirement of the draft standard MOD-024 requires reporting of seasonal gross and net active power generating capabilities and active power requirements of auxiliary loads. The primary technical requirement of the draft standard MOD-025 requires verification of maximum generator gross and net reactive power capability (both lagging and leading) at seasonal active power generating capabilities as reported in accordance with Reliability Standard MOD-024. Reactive power limitations, such as generator terminal voltage limitations, shorted rotor turns, etc must be reported. Reactive power of auxiliary loads must be reported.

Each of these requires specification of the method of verification, including date and unit conditions. Each region is responsible for establishing acceptable data sources and supporting engineering calculations. Meeting these requirements involves both measurement and calculations.

Some aspects of steady-state performance overlap with NERC PRC-019 [1-3] as discussed in Section 2 and this report will reference each as required.

1.1 General Concepts and Issues

This section focuses on the steady-state capability and limitations of three-phase synchronous ac generators, as they represent the primary source of power on the interconnected power system. The ac generator is an electromechanical energy converter, taking mechanical power as its input and producing electrical power at its output. Utility-scale synchronous generators are also the primary form of energy storage on the power system due to the rotating inertia of the combined turbine/generator. Differences in fuel source and prime mover designs have led to vast differences in the physical size, ratings and operating characteristics of the synchronous machine. These differences result in different performance and modeling, which will be discussed. Ratings for salient-pole and round rotor generators are defined in ANSI standards C50.12 [1-4] and C50.13 [1-5], respectively. (Note that the present standard C50.13 replaces older versions of standards C50.10, C50.13 and C50.14).

In order for us to control these generators we need to understand and describe their characteristics in the form of mathematical relationships. Mathematical models of generators for stability studies are described in IEEE Standard 115 [1-6] and IEEE Guide 1110 [1-7] as well as in many textbooks and papers (see [1-8]).

Although the compliance requirements discussed in this section deal with on-line active power and reactive power capability, some steady-state modeling data should be collected to allow calculations of the relationship between generator terminal conditions. This model of the generator can then be used to supplement, and in some cases replace, testing of extreme operating points in meeting compliance requirements. The following sub-sections introduce some of the concepts and defining equations for the generator. This leads to a discussion of the physical operating limits on the generator and connected equipment and the methods used to verify these limits.

1.2 Open Circuit Characteristic (Generator Saturation)

The term open circuit is used throughout this document to refer to operation with the main circuit breaker open (i.e. generator not synchronized to the grid). During open-circuit operation the relationship between the dc current flowing through the field winding and the three-phase ac voltage, is given by: $E_t = X_{ad}I_{fg}$ where X_{ad} represents the d-axis mutual reactance at 60 Hz. This relationship would be linear, if it were not for the fact that the mutual reactance is subject to magnetic saturation. Additional field current is required to produce incremental increases in the terminal voltage. Representing this relationship correctly over the full operating range of the generator is crucial to establishing the relationship between field and ac terminal quantities for both open-circuit and on-line conditions.

A typical open-circuit saturation curve is shown in Figure 1-1. The lower portion of the curve (region I) is a straight line representing the relationship between excitation and output voltage below the point at which the rotor and stator iron becomes saturated. This line, extended to higher currents and voltages, is referred to as the air-gap line.

As the excitation is increased, the actual open-circuit characteristic deviates from the air-gap line by an amount equal to the additional field current required to overcome saturation (region II). At very high levels of excitation, outside of the allowable voltage range of the unit, the iron is fully saturated and the relationship is once again linear (region III).

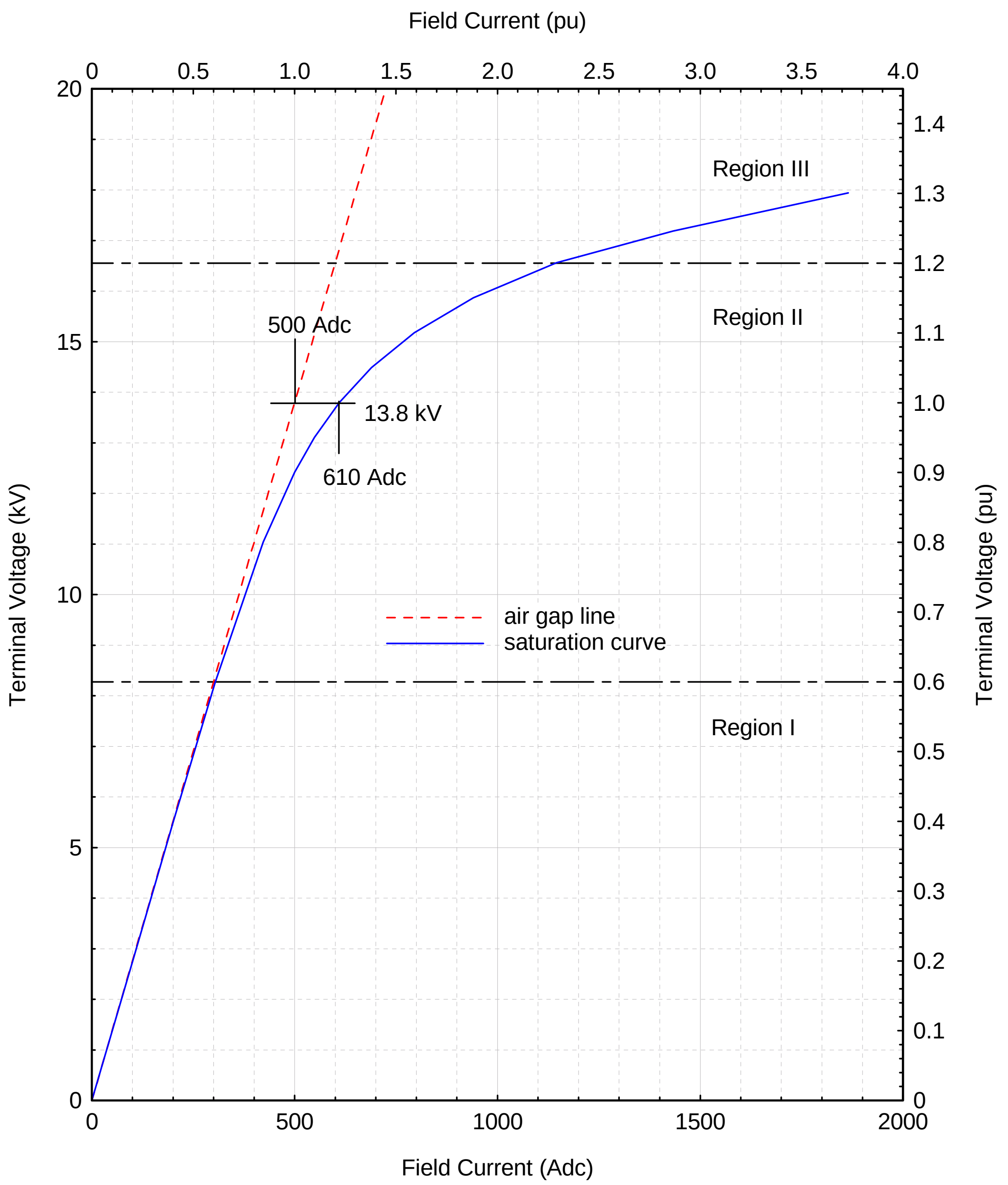

Figure 1-1
Generator Open Circuit Saturation Curve

Although it is a simplification, most commercial simulation programs represent the effect of magnetic saturation for on-line conditions using the open-circuit relationship. Alternative methods of representing saturation are discussed in detail in IEEE Std. 1110 [1-7]. For simplicity, saturation may be represented mathematically as follows [1-8]:

Region I - no saturation (linear)

$$I_{fg}(pu) = E_t(pu)$$ **Equation 1-1**

Region II - normal operation, saturated

$$I_{fg}(pu) = E_t(pu) + fn(E_t(pu) - E_L(pu)) \qquad \textbf{Equation 1-2}$$

where E_L is the point at which the saturation curve becomes non-linear (typically 0.5 to 0.8 pu voltage). Various functions (fn) may be used to represent the field current vs. terminal voltage as excitation is raised slowly from near zero to above rated (but below the over voltage protection setting of the unit).

Region III - full saturation

The relationship is usually modeled mathematically as a linear extension of the end of region II, which is defined by the ratio of slopes of region I/region III (usually 5-10).

Many simulation programs use an approximation of the above relationships based on two points defined as S1.0 and S1.2 where:

$$S1.0 = \frac{(I_{fg}(saturated) - I_{fg}(air\_gap))}{I_{fg}(air\_gap)} \text{ at } E_t = 1.0 \text{ pu (e.g. rated)} \qquad \textbf{Equation 1-3}$$

$$S1.2 = \frac{(I_{fg}(saturated) - I_{fg}(air\_gap))}{I_{fg}(air\_gap)} \text{ at } E_t = 1.2 \text{ pu} \qquad \textbf{Equation 1-4}$$

Generator manufacturers normally supply open-circuit saturation characteristics for their units. Confirmation of this characteristic is often done by measurement during commissioning. Periodic re-testing is recommended to identify problems such as shorted turns and confirm the calibration of instrumentation. This measurement is done by gradually increasing excitation from Region I into the saturated regions. The measurement is normally only performed to voltages of 1.05 pu to stay within the generator continuous capability with higher values obtained from manufacturer's data or through extrapolation of available measurements.

1.3 On Line Characteristics (Reactive Capability)

Once the generator is synchronized to the power system, its analysis becomes considerably more complex. Changes in power from the turbine will no longer change the generator's steady-state speed, as this is determined by the power system as a whole. Instead, changes in input mechanical power will change the rotor's position with respect to the stator MMF wave, resulting in changes in the electrical counter torque and active (real) power output. Changes in field current continue to produce changes in the ac terminal voltage. However, the open-circuit relationship no longer applies due to the flux created by the flow of reactive current in the stator windings (armature reaction).

The goal of developing a model of the generator for on-line operation is to permit prediction of operating points that might not be accessible during staged tests or normal operation. The discussion below is a simplified account of the process used to derive the relationships between the field and terminal quantities that can be solved based on selection of independent and dependent variables. These relationships may be used in one of two ways:

- Calculate reactive power as a function of active power, terminal voltage and field current in order to plot the generator V-curves or capability curves
- Calculate field current as a function of active power, reactive power and terminal voltage to confirm the V-curves or capability curves based on measured data

The basic steps for calculating the field current from the other variables are listed below. Calculation of reactive power as a function of the other variables is described in Section 1.3.3. The steady state relationships between the field and terminal quantities are described in Section 1.3.1.

- Obtain generator saturation curve and synchronous impedances
- Calculate stator current and power factor from stator voltage, active and reactive power
- Calculate air-gap voltage behind leakage reactance and stator resistance
- Calculate saturation level
- Adjust mutual reactances for saturation
- Calculate rotor angle
- Calculate field current
- Compare with measured values

1.3.1 Defining Equations

Figure 1-2 is a phasor diagram depicting steady-state conditions for a synchronized generator operating with armature voltage and current of Ea, and Ia respectively. Lagging power factor conditions (power factor angle = θ) have been depicted, and the projection of the phase quantities onto the direct (d) and quadrature (q)-axis reference frames has been shown. The equations relating the d and q-axis components of the terminal quantities and the rotor angle, δ, and power factor angle are as follows ([1-6], [1-7], [1-8], [1-9], [1-10]).

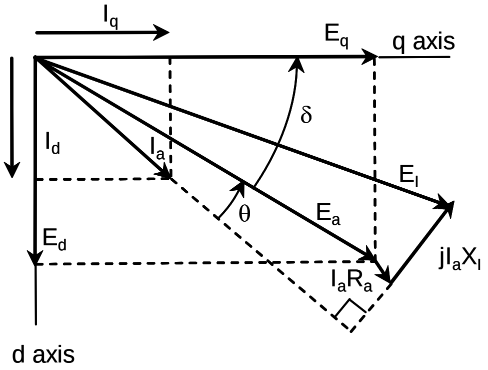

Figure 1-2
Steady-State Phasor Relationships of Voltage and Current in a Synchronous Generator

In terms of the dq reference frame, the steady-state (also referred to as synchronous) reactances, X_d and X_q, for the machine are defined as follows:

$$X_d = X_{ad} + X_l$$

Equation 1-5

$$X_q = X_{aq} + X_l$$ **Equation 1-6**

Where:

X_l = leakage reactance associated with paths of leakage flux which do not couple the field and stator windings

X_{ad} = mutual reactance representing flux paths along the polar axis which link the two sets of windings

X_{aq} = mutual reactance representing flux paths along the inter-polar axis which link the two sets of windings

The mutual reactances are affected by saturation and must be evaluated at each operating point in order to relate the field and ac terminal quantities.

$$E_d = E_a \sin\delta = -jX_q I_q$$ **Equation 1-7**

$$E_q = E_a \cos\delta = -jX_{ad} I_{fg} - jX_d I_d$$ **Equation 1-8**

$$I_d = I_a \sin(\delta + \Theta)$$ **Equation 1-9**

$$I_q = I_a \cos(\delta + \Theta)$$ **Equation 1-10**

Where the power factor angle is defined as:

$$\Theta = \tan^{-1}(Q/P)$$ **Equation 1-11**

$$I_a = \frac{|P + jQ|}{E_a}$$ **Equation 1-12**

In Table 1-1, generator terminal measurements are compared with field current and rotor angle values calculated from the generator model as described above, using the validated open circuit saturation characteristic and saturated impedance values.

Table 1-1
Example On Line Steady State Generator Measurements

Active	Reactive	Terminal	Field	Field Current		Rotor Angle		Limit
Power (pu)	Power (pu)	Voltage (pu)	Voltage (Vdc)	Measured (Adc)	*Calc (Adc)*	Measured (Degrees)	*Calc (Degrees)*	Reached
0.6	-0.25	**0.95**	177	1590	*1583*	54	*58*	**95% kV**
0.61	0.41	**1.05**	376	3176	*3137*	26	*23*	**105% kV**
0.89	**-0.21**	0.96	258	2247	*2224*	60	*64*	**UEL**
0.90	0.44	1.03	449	**3720**	*3711*	33	*30*	**Field**

The limitation reached in each of the measurements is listed in the table. At lower power levels, the generator voltage reached its maximum continuous limits (95% and 105% voltage) before any other limitations were reached. The relationship between voltage and reactive capability is discussed below in section 1.3.4. At higher load, the operational limits reached were the under excitation limiter (UEL). Excitation limiters are discussed in detail in Section 2 and Section 3. At maximum load, overexcited, the field current limit was reached in this case. The stator current limit was never reached in the measurement example shown. The field and stator limits are discussed in Section 1.3.3.1. Because of the inherent accuracy and calibration limitations of the measurements, agreement between the measured and calculated values within 2-5% is considered adequate for validation of the model. Measurements and transducers are discussed in another section.

1.3.2 'V' Curves

The field current required to maintain specified levels of reactive power, at different active power outputs, is often supplied by the manufacturer as a set of compounding curves or 'V' curves. These curves depict the steady-state relationship between armature current and field current for active power levels, with the terminal voltage maintained at rated value. These are often combined on a plot with the compounding curves, which depict the relationship between armature current and field current for constant power factor. Example curves for a round rotor generator are shown in Figure 1-3. The V-curves are shown for three different active power levels (0.5, 0.7 and 0.85 pu MVA). The compounding curves show how field current must be adjusted to maintain constant power factor (assuming constant terminal voltage) as stator current is increased. The letter designations are used in the discussions below.

The field current is plotted in terms of per-unit of rated field current; i.e. the field current required to produce rated-MVA output and power factor. Note that this is not equal to the field current denoted I_{fgbase}, which corresponds to the air-gap line, open circuit field current which is used in all mathematical generator models.

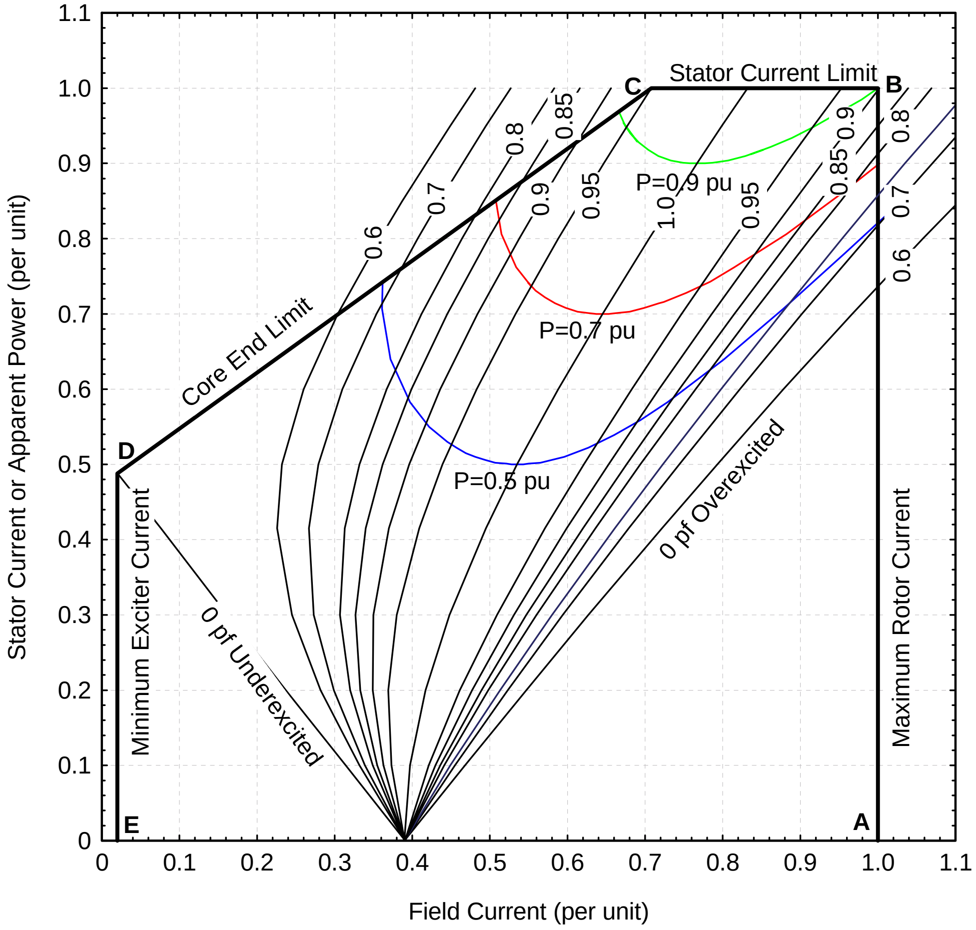

Figure 1-3
V-Curves and Compounding Curves

These curves are useful in assessing the rating of an exciter in relation to the required field current at various loads. It is important to remember that they represent the requirements based on rated terminal voltage conditions, and that the field current requirements of the unit are strongly dependent on the actual operating voltage.

1.3.3 Capability Curves

The generator's capability curve provides a quick summary of the generator's output capability, by plotting the boundary of permissible active and reactive power combinations. With reference to Figure 1-4, the generator's physical output limits are normally a function of the following: stator current limit (segment B-C), field current limit (A-B), end-region heating limit (C-D). The steady-state stability limit (SSL) is also often drawn on the capability curve even though it is a function of both the generator capability and system connection strength, and is therefore dependent on the transmission system. Each of these limits is discussed below.

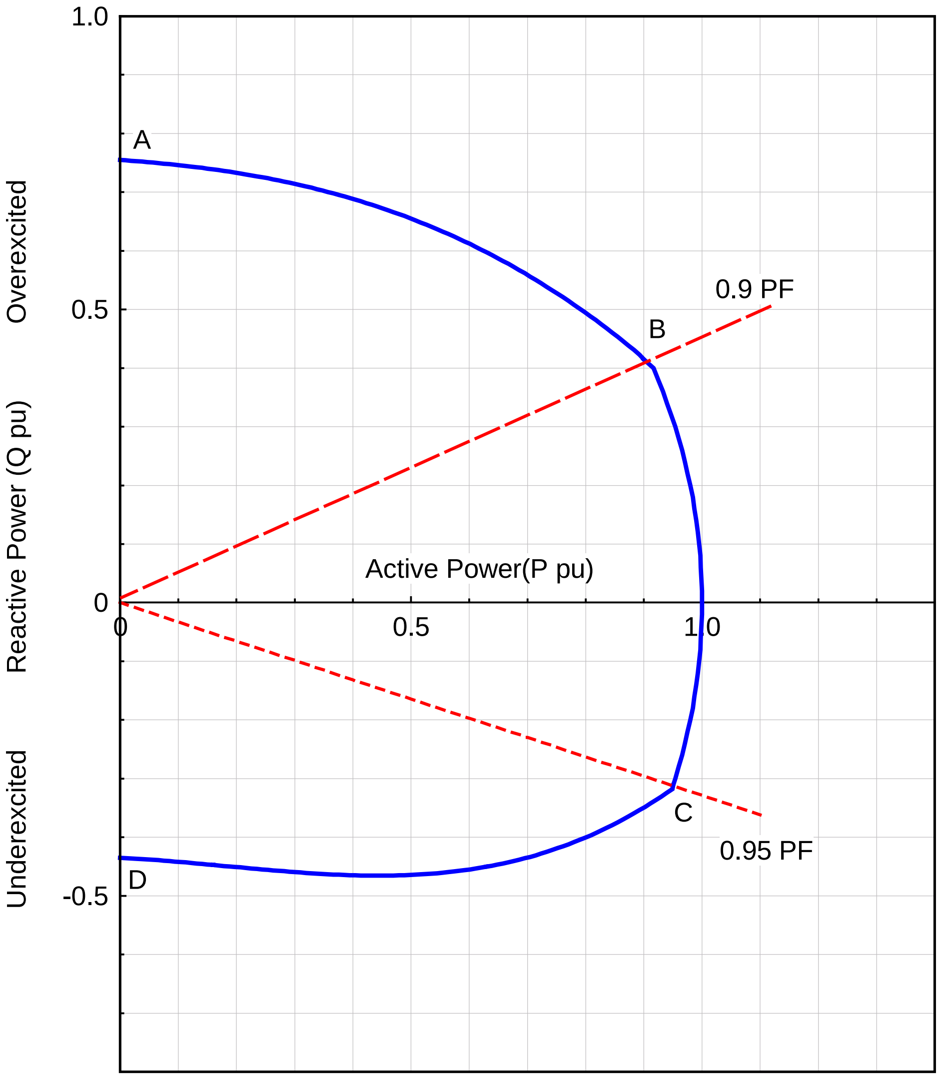

Figure 1-4
Example Cylindrical Rotor Generator Capability Curve

1.3.3.1 Copper Limits

The relationship between the stator and rotor current ratings and temperature is a function of the winding insulation class as defined in ANSI C50.13 [1-5].

Armature current results in an I^2R power loss, which must be removed by cooling to limit the temperature of the stator core, stator windings, and nearby components. Since stator current varies directly with apparent power, this limit appears as a semi-circle centered on the origin with radius equal to the unit MVA rating, as described in Equation 1-12.

Some utility-scale generators are capable of operating at rated MVA and power factor for voltages within the range of 95% to 105% subject to the allowable temperature rise on the stator windings based on the insulation system [1-4, 1-5]. It is important to note that the standards only require rated apparent power capability for rated voltage conditions. An observed temperature rise below the insulation system's thermal rating under these service conditions does not imply that operation at higher levels is permissible. On the other hand if observed temperature rises are higher at the stated current level the manufacturer should be consulted for guidance on whether de-rating is necessary.

Field winding heating will limit the output capability of the unit for lower power factors. Most manufacturers provide continuous field current and voltage ratings as part of their nameplate data. Rated continuous generator rotor field current should be specified by the manufacturer as the excitation current required for full load operation at rated voltage and power factor including suitable margin [1-5]. This level of field current should result in observable temperature rises (measured by average field winding resistance method) equal to or below the limits for the insulation system in question. It is worth noting that there is some uncertainty in the calculation of this field current level and that operation within temperature limits is often guaranteed at the rated point even if it later turns out that the generator needs slightly more excitation than predicted [1-11]. It is also important to note that margin is often included in this value to accommodate the increased field current required to operate at rated apparent power over the entire allowable voltage range down to 95% of rated. Observed temperature rises below the thermal rating does not imply that operation at higher levels is permissible. On the other hand if observed temperature rises are higher at the stated current level the manufacturer should be consulted for guidance on whether this limit can still be used.

The relationship between field current and operating points in the power plane are derived from the following two equations.

$$P = \frac{X_{ad} I_{fg}}{X_s} E_t \sin \delta_s$$

Equation 1-13

$$Q = \frac{X_{ad} I_{fg}}{X_s} E_t \cos \delta_s - \frac{E_t^2}{X_s}$$

Equation 1-14

These equations describe a circle in the PQ plane with origin along the P-axis and offset on the Q-axis by E_T^2/X_S. These equations are simplified since they do not account for saliency or saturation effects. The stator and field current limits can be visualized in the simple sketch of Figure 1-5.

In the past the Manufacturers often plotted the capability curve graphically. The machine's apparent power rating and power factor was used to establish the intersection with the field winding limit. Curves drawn in this manner do not necessarily reflect the locus of PQ points for constant, rated field current.

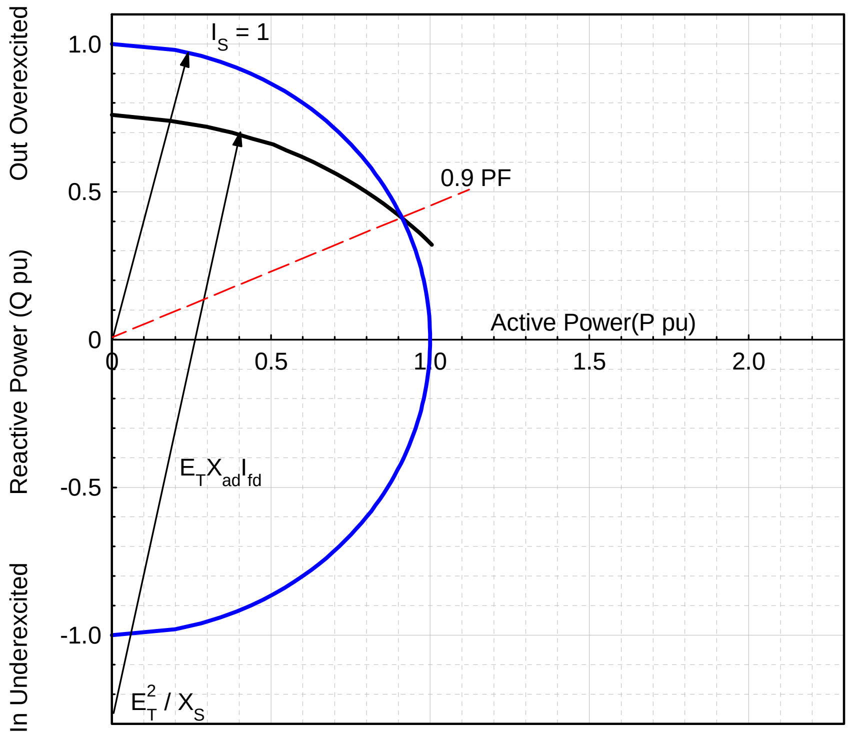

Figure 1-5
Copper Heating Limits

1.3.3.2 End-Region Heating Limit

Under-excited operation on utility-scale generators can be restricted by a number of factors but the only one solely associated with the generator is core-end overheating. The leakage flux at the end of the stator laminations is usually limited by saturation caused by overexcited operation. For extreme under excited conditions increased armature leakage flux in the end-region can produce large eddy currents since the flux is perpendicular to the stator laminations. This can impose a very significant limitation on under-excited operation on older round-rotor machines where the structural materials used to maintain pressure on the core ends and stator teeth were constructed of magnetic material [1-12]. Even on newer round-rotor machines this phenomenon is normally the limiting factor on operation in the under-excited region depicted by segment CD of Figure 1-4.

Due to their construction, salient-pole generators are normally not constrained by core-end overheating in this region. Other factors, discussed in later sections normally determine the practical limits of operation.

Generators constructed along the guidelines of C50.12 and C50.13 are normally capable of operation to at least 0.95 power factor leading.

Vendors do not provide a mathematical relationship to describe a unit's core-end limitations, but provide the limit graphically on their capability curves. Two common representations of the core-end limitation are shown in Figure 1-6 (segment C-D). In case (1), the vendor has explicitly shown the self-excitation or minimum exciter current curve (D-E), and has provided a core-end limit curve which intersects with this limit, and with the stator current limit at 0.95 pf leading. In case (2), the vendor has provided a smooth curve which corresponds to a straight-line segment on the corresponding V-curve diagram, which provides some margin to the self-excitation limit and again intersects with the stator curve at the 0.95 pf leading operation point.

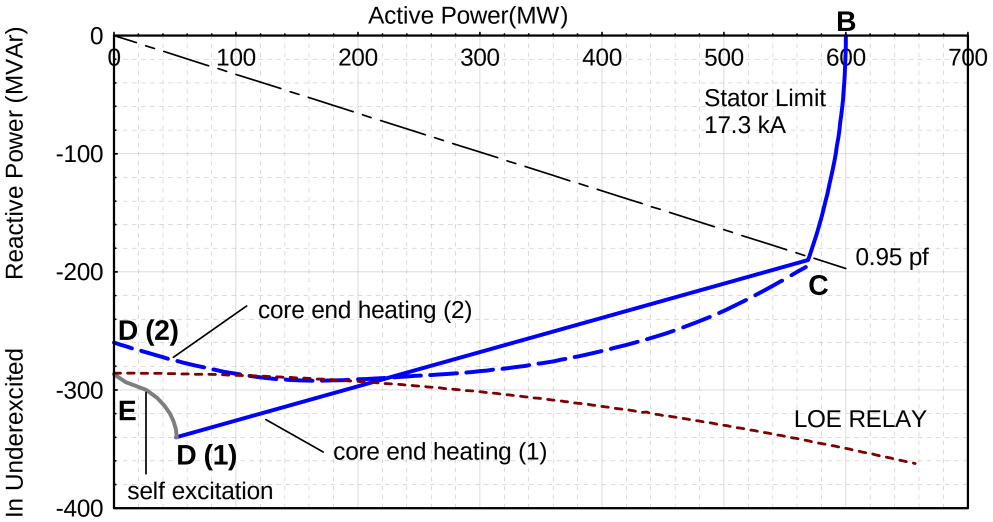

Figure 1-6
Different Representations of Core-End Limits in a Round-Rotor Generator

1.3.3.3 Steady-State and Small Signal Instability

For operation with fixed excitation (i.e. manual control), the generator tends to become unstable as excitation is reduced, because of the reduction of synchronizing torque. Many manufacturers include a curve in the under-excited region based on the calculated steady-state stability limit under the following assumptions:

- unit operating with fixed field voltage
- saliency ignored
- saturation effects ignored
- external impedance estimated or guessed.

The most common method of presenting the steady-state stability limit is graphically. The limit is presented as a semi-circle plotted on the capability curve with the following characteristics:

$$\text{Center: } P = 0;\ Q = \frac{E_a^2}{2} * \left(\frac{1}{X_E} - \frac{1}{X_D} \right) \quad \text{Radius: } R = \frac{E_a^2}{2} * \left(\frac{1}{X_E} + \frac{1}{X_D} \right)$$

Equation 1-15

where

X_E = the total external reactance from the machine terminals to an estimated “infinite bus”;

X_D = the generator synchronous impedance and all quantities are expressed in per-unit.

The value of X_E cannot be known for all possible system operating conditions so the curve is often drawn for either normal or worst-case conditions. When drawn for normal transmission conditions, the steady state stability limit is outside the generator capability curve, and does not restrict generator operation [1-13]. This is discussed further in Section 2.

The Transmission Operator must be notified and approve operation on manual control, making this limitation an operational, rather than control concern. The use of modern, high-gain automatic voltage regulators and power system stabilizers, alleviates most practical constraints on generator reactive loading based on transient, small-signal and steady-state instability. Even if these limits were to be plotted, the manufacturer has no way of knowing the external reactance of the network in advance and the simple relationship based on internal and system reactance is not accurate in a multi-machine situation. Only the System Operator can accurately establish stability limits during real-time operation and as a result, calculated stability limits are often omitted on modern capability curves.

1.3.3.4 Impedance Based Relays

The other characteristic that appears in many generator capability curves in the under-excited region is the Loss of Excitation (LOE) Relay operating region. LOE relays will be discussed in more detail in conjunction with excitation limiters in Section 2.

1.3.3.5 Effect of Cooling Conditions

Some generators have multiple ratings depending on cooling conditions, including coolant temperature (e.g. ambient air) or coolant pressure (e.g. hydrogen). Most generation owners report reactive capability based on rated cooling conditions. In cases where permanent de-ratings exist, the actual operating conditions are used to define the output capability. The cooling conditions assumed during calculations or encountered during measurements should always be specified along with the data. In present simulation models, the effect of cooling on turbine output is modeled with the maximum output limit or thermal limit parameter, which should be set to match the conditions expected during the study (e.g. summer peak, winter peak...). No such facility exists in the simulation models to modify the reactive limits or rotor limits, although these may indeed change in some units with cooling.

1.3.4 Effect of System Voltage

There is often confusion about the actual reactive capability of generators and the relationship between voltage and reactive power limits during staged testing and during actual power system disturbances.

Utility-scale generators supplied in North America are typically designed in accordance with C50.12 and C50.13 to operate continuously within the confines of their reactive capability curves between 95% and 105% of the nameplate voltage [1-4, 1-5] subject to allowable temperature rises. Sustained operation at higher voltages is to be avoided to prevent premature ageing of insulation. Sustained operation at lower voltages is permissible with appropriate de-rating of the output to keep core and winding temperatures within limits. Thus, staged tests should not be conducted beyond these limits.

Station and unit service loads fed from the generator should be capable of continuous operation at voltage levels corresponding to this range of generator terminal voltage. If a unit is not capable of operating within the 95% to 105% range because a station service voltage level restriction is reached first, the ISO or Region may require the generator owner to correct this in order to be compliant with local regulations.

If the original Manufacturer's capability curve is being used, the unit can be operated within the plotted active and reactive power characteristic for voltages in the range of 95%-105% subject to allowable observed temperature limits. If, however, a utility has re-rated their units based on heat run data [1-6] then the limit imposed by field winding heating is often drawn for the full range of allowable continuous terminal voltage. This effect is more pronounced for a salient pole generator because of its lower synchronous impedances. An example plot showing the effect of terminal voltage on the field current limit (A-B) is shown in Figure 1-7.

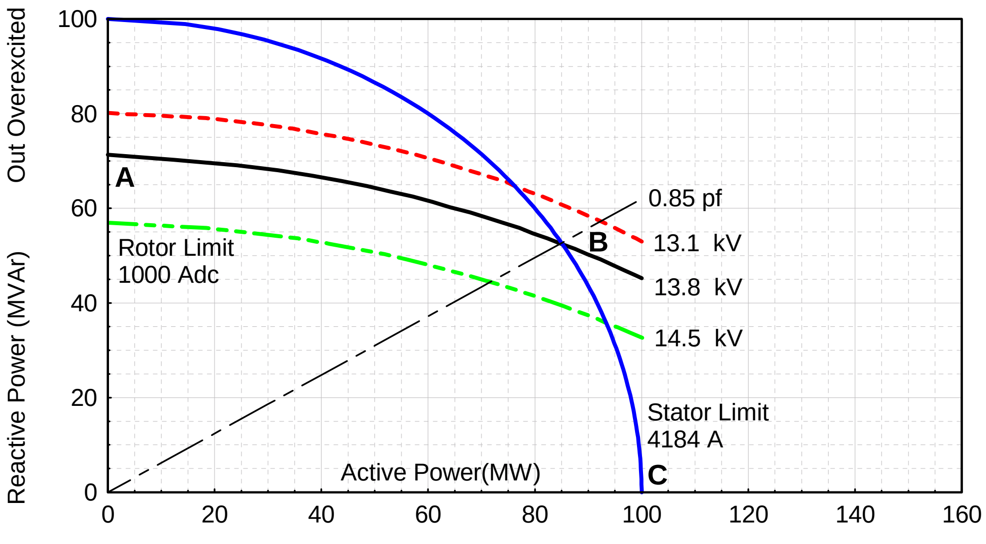

Figure 1-7
Effect of Terminal Voltage on Field Current Limit

For a given stator current limit, the apparent power of the generator will increase or decrease with voltage, however manufacturers do not guarantee operation at higher apparent power for voltages between 100% and 105%. Capability curves are normally plotted as a single characteristic curve regardless of voltage. During operation at reduced voltages the stator limit, as plotted in MVA (B-C) may have to be reduced as dictated by observable temperature rise. Reducing reactive power to accomplish this is not desirable since it will lead to lower voltages, exacerbating the problem.

Voltage limitations also impact on the ability to test reactive capability. In actual operation, reactive power output from the generator to the grid normally results from low system, and consequently generator, voltages. During staged testing, generator reactive output is increased by raising the exciter's voltage reference, resulting in high generator voltage with normal system voltage. As a result, the generator's 105% voltage limitation, or other bus voltage limitation is usually reached well before the generator's field current or stator current limit is reached. This is a function of stiffness of the transmission system and transformer impedance.

The converse is true when operating under-excited. There may be additional constraints, for instance due to currents in auxiliary bus loads, when the generator voltage is reduced under test conditions. This is discussed further below. As a result, engineering calculations are required to extrapolate from the measured conditions to confirm the limitations which will apply during system events.

1.4 Excitation System Ratings and Capabilities

The primary function of an excitation system is to provide the field current required by a synchronous generator to meet a specified range of power system operating conditions. Excitation system operating ratings are discussed in detail in IEEE Std. 421.4 [1-14]. Standard terminology is found in IEEE Std. 421.1 [1-15].

The exciter's continuous current rating should be equal to or larger than the maximum current required by the synchronous generator field under any allowed continuous operating conditions. In some cases, the exciter current rating may be less than that of the generator field, and become the limiting factor for over-excited operation. This can happen if a generator has been rewound with a higher capacity insulation or improved stator cooling, resulting in a higher stator current and hence MVA rating. The continuous voltage rating of an excitation system should be such that the voltage is sufficient to supply the necessary continuous current to the synchronous generator field, with the field at its maximum temperature at rated MVA and within ±5% of rated terminal voltage including all voltage drops up to the field winding terminals [1-14]. This rating should not be restrictive as each type of excitation system has additional voltage capability for field forcing as described in Section 3.

Often an over excitation limiter is utilized to limit thermal overload of the synchronous generator field winding and/or the excitation system. The minimum pickup of the excitation limiter must be determined prior to establishing the reactive capability at low power factors. Coordination of the excitation limiter, protection and capability are discussed in Section 2.

1.5 Station Equipment Ratings and Capabilities

The generator capability curve is drawn based on the gross capability of the generator itself. The generator, however, may not be the limiting element for voltage or current. The most limiting element must be considered when determining the actual unit capability. Some of the equipment which must be considered is discussed below.

- series-limiting elements (e.g. cables, buses, breakers, step-up transformers, disconnects)
- station auxiliary loads
- station-service supply buses

The effects of auxiliary bus voltage limitations are discussed in [1-16]. The paper and a follow-up [1-17] discuss the practical limitations reached during measurements and provides practical advice on selecting optimum auxiliary transformer taps for a given range of generator terminal voltage as does reference [1-18]. The authors of this EPRI report have had similar experiences with plants which required auxiliary bus motor load changes or tap changes in order to alleviate auxiliary motor trips during normal system voltage excursions. In references [1-16, 1-17], these limitations are plotted on the capability curve, however this is not recommended as variations in system voltage and auxiliary loading will affect the final limitations, and these are not properly part of the generator capability. Further, a distinction must be made between system conditions which require generator reactive output (e.g. low system voltage requiring generator lagging output), versus test conditions, where generator reactive output is raised in order to measure unit and auxiliary bus conditions. Other limitations of the method are mentioned in the discussion of [1-17].

Issues for non-utility generators (NUGS) are discussed in [1-18]. One of the key issues is sizing of the generator step-up transformer. Two common problems are the assumption that the NUG will operate at full turbine output and unity power factor (e.g. provide no reactive support), and the use of a shared transformer between gas and steam units in a cogeneration facility, which is not sized for full rated plant output. The connection voltage determines the generator owner’s requirements; embedded generation (i.e. the grid connection point is within a plant’s facilities) is different from a stand-alone generator connected through a transformer to the utility high-voltage grid. These rules are specified by the local ISO. In the present utility market, all generators are required to provide reactive support and the transformers may limit the available active power output in order to meet market rules for power factor when called upon by the system operator. [1-19] provides detailed guidelines for properly sizing the key parameters of a generator step-up transformer.

1.6 Validating Active and Reactive Power Capabilities

It is an accepted industry practice to use collection of operating data accompanied by in-service testing and appropriate engineering evaluations and studies to evaluate the condition and capability of equipment to continue to perform as intended [1-20].

Operational measurements rarely exercise the extremes of reactive capability (especially under-excited) and typically need to be either replaced or supplemented with engineering calculations and/or staged tests. They are however effective for establishing the real power seasonal capability.

Engineering calculations are discussed above and in Section 2 on coordination. The remainder of this section will discuss the performance of reactive capability testing.

1.6.1 Reactive Capability Testing

MOD-025 requires that generation owners confirm maximum levels of lagging and leading reactive capability at seasonal real power operating limits and identify the physical operating limits of the unit. These tests are required regularly since the reactive capability of each generator is critical to power system reliability and can be affected by many different factors within the plant.

1.6.1.1 Preparation

The flowchart of Figure 1-8 summarizes the prerequisites leading up to a verification of the capability by tests.

The manufacturer's generator capability curve is used as the starting point for measuring the sustained reactive capability of the unit. The capability curve should be reviewed to confirm that the operating limits are based on the present unit's condition and that each limit is clearly identified (e.g. field current limit, core-end heating limit,…). If recent operational data is available it should be reviewed to determine whether there is sufficient data to demonstrate compliance with the requirements. If this is the case, or if the available data can be supplemented with engineering calculations then no further work may be required.

If operational data is not adequate and testing is required, the first prerequisite is to establish the required measurement points. Regional or ISO guidelines may dictate the quantities that should be monitored during the performance of the reactive capability and voltage operating range tests. Not all measurements will be required or available on all units. Calibrated station metering is an acceptable means of measurement. The source of each measurement should be documented. The following is a typical list of points to be measured during the test.

- ac generator terminal voltage
- active and reactive power (generator gross and net)
- unit service load levels (MW, MVAr)
- generator field voltage and current (excitation system)
- exciter field voltage and current (rotating excitation system)
- generator stator winding temperatures (average and maximum)
- generator core-end temperatures (core-end, flux shields, etc.)
- station ambient temperature (air cooled units)
- cooler inlet/outlet temperatures (water/hydrogen cooled units)
- auxiliary bus voltages if they are fed from a Unit Service Transformer and are therefore subject to change during the course of the test
- excitation limiter status (UEL/OEL or other limiters that become active)
- other limits (gas turbine temperature limits, stator current limit, etc.)
- system high side bus voltage

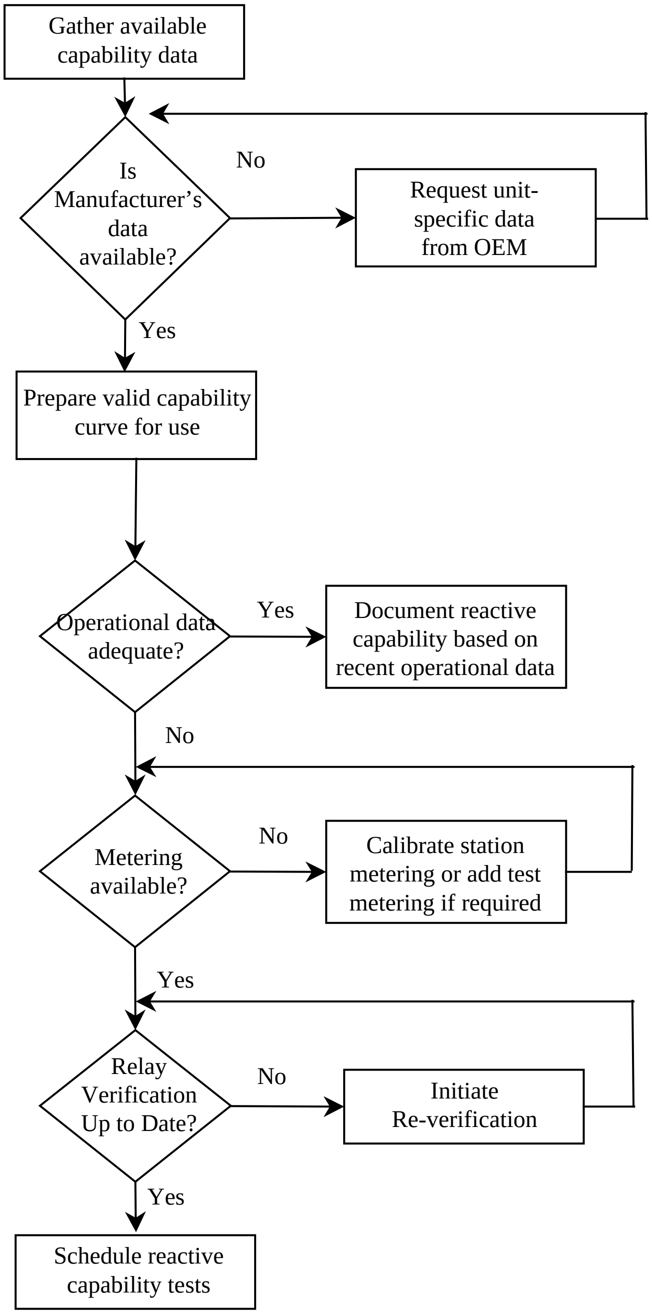

Figure 1-8
Reactive Capability Verification

Hydroelectric units normally require fewer measurements since unit service voltage issues stator core-end heating are rarely a factor.

Prior to testing the all quantities monitored during the test on the station Human Machine Interface (HMI) should be checked to verify that they accurately represent the quantities measured from the primary sources. Spot checks should be conducted using a calibrated meter of each station service bus voltage and the current levels on any critical load. In some cases station metering is supplemented with selected transducers and displays to allow monitoring of critical quantities that are either not available or are displayed with inadequate resolution or accuracy. Field current and field voltage indications often require calibration. These signals are not typically included in regular calibration procedures and are usually fed from 4-20 mA transducers provided for operator use in the control room. For detailed tests, raw signals e.g. mV signal from generator field current shunt, should be used for these measurements or at least to check the calibration of station metering.

Additional steps that are performed prior to tests include:

- Ensure that recent calibration records are available for protective relays (O/C, O/V, U/V) on any critical loads and unit service buses.
- Calibrate any relays that do not have recent calibration records.
- Calibrate any excitation limiters and protective devices that do not have recent calibration records.
- Note any restrictions imposed by protective relays either on the capability curve or in terms of monitored voltages and currents.

Performance of a coordination study (Section 3) will normally provide all of the required information to satisfy these steps.

1.6.1.2 Measurements

In order to meet NERC requirements, reactive capability is measured for full-load operating conditions. Some Regional Entities require reactive testing at several different active power levels. This can be useful at identifying any issues at lower output levels where they can more easily be managed and provide a better confirmation of the complete range of reactive output capability of the unit. This test may be performed during a run-up as part of the on-line testing conducted on the generator controls. Although these tests can be very straightforward to perform, care must be exercised to ensure that the generator and all associated auxiliary equipment are operated within continuous limits. On thermal and nuclear units it is especially important to monitor the station service voltage levels (4 kV and 600V) supplying the major induction motor loads to ensure that they do not trip as a result of under or over-voltage. Additional details on the tests and precautions are provided in [1-20] and [1-21].

Prior to performing reactive capability tests it is important to understand the difference between the conditions that exist during staged tests and those that exist during actual system events when the generator may be called upon to operate at the extremes of its reactive capability. During normal operation under Automatic Voltage Regulator (AVR) control, the Operator sets the AVR reference to achieve a specific reactive power or terminal voltage level. If a generator is operating at unity power factor and the power system voltage drops, the AVR control will respond by boosting excitation resulting in reactive power output from the unit to the system (i.e. lagging power factor operation). The converse is true if the system voltage rises. If the generator voltage is maintained near rated by AVR action, then the limits to be respected will be those shown on the capability curve.

Under test conditions, the situation is different. Unless the Utility can intentionally lower nearby system voltage levels, over-excited operation is normally achieved by raising the unit's voltage set point. Reactive power will then flow from the unit to the system. The limits shown on the capability curve must still be respected, however, it is most probable that the generator or auxiliary bus voltages will reach their maximum allowed values before the stator or rotor capabilities are reached for either over-excited or under-excited operation and possibly for both.

For typical transformer reactance levels and constant system voltage conditions it will normally not be possible to measure both the lagging and leading reactive power limits if these correspond to typical levels of 0.9 pf lagging and 0.95 pf leading. In some cases the Transmission Operator will be able to adjust other reactive resources sufficiently to allow the full range of testing but this is not typical. It may also be possible to change the reactive power dispatch of other units within the same plant to obtain the desired range. This is most effective when multiple units are connected together at their low-voltage terminals, sharing a common Generator Step-Up transformer.

It must be stressed that just because a voltage limit is reached during a test this does not mean that a limit should be marked at that active and reactive power point on the capability curve and called the capability limit. The capability curve reflects the operating limit on the unit ***if system voltage conditions were such that the unit was operating at that point at rated voltage***. Where voltage limits are reached before actual reactive capability limits can be confirmed it is necessary to perform calculations to assess the actual limits for rated voltage conditions as described above.

Regardless of which limits are reached the Utility should be prepared to supplement these measurements with calculations based on the steady-state representation of the generator. These can be used to establish the actual reactive capability of the generator over the full operating voltage range. The results are presented on a plot of the unit's capability. Unit stator and rotor capabilities as well as any excitation and protection limits are shown in the (P,Q) plane for different voltage conditions.

Appendix B provides an overview of the procedures to be followed in verifying reactive capability. Example measurements are shown in Table 1-1 along with a discussion of the limitations reached during the measurements.

1.6.2 Industry Experience

Over 70% of those companies that responded to the survey conduct real and reactive power capability testing on a cyclical basis.

Large base loaded thermal units typically utilize operational data to compute real power capability and sometimes reactive power capability. While staged testing in combination with calculation is used by the majority of the remaining generator operators.

Almost all of the organizations surveyed utilize engineering or other support staff within the organization combined with operators to perform the real and reactive power verification.

Adequate reactive support is essential for power system voltage stability and the prevention of voltage collapse. Generators are the best dynamic source of reactive power and voltage control in the bulk power system [1-22]. This reference describes one utility's experience in maximizing its generating units' reactive capability as well as the experience gained in educating dispatchers, plant operators and engineering personnel on the subjects of voltage collapse phenomenon and reactive power scheduling. Latent defects were corrected, and substantial cost savings were achieved in the process.

The reactive capability tests which were performed identified limits that prevented the generators from producing the reactive power output as defined by the manufacturers' capability curves. These limits were a consequence of minimal emphasis that has been placed on generators' reactive capability over many years. As a result, some perceived limits had developed which are common for many utilities.

Some of the limitations discovered are listed below:

- Most generator step-up transformers, unit auxiliary transformers, start-up transformers, and load center transformers required adjustment of their tap settings.
- Most generators had limited reactive output due to excessively high or low station service voltages.
- For some units, the stator or field winding temperature alarms were set lower than the manufacturer's suggested values and thus limited the reactive power and, in some cases, active power production.
- Some generator meters were out of calibration, causing either under-utilization of reactive capability or, at the other extreme, potential damage to the unit.
- The exciter Maximum Excitation Limiter and V/Hz Limiter (and in some cases protection) settings were found to be lower than required to allow full utilization of the generator's lagging capability.
- Some exciter reactive current compensation settings were found to be restrictive while in one case were set to over-compensate the step up transformer leading to instability.
- Operation of the generators with leading power factor was unusual, leading to a common, deeply entrenched fear and a misconception that under excited operation of the generators must be prohibited. Under excitation limiter circuits were in service, but the settings were very conservative.

The paper identifies common usage of operating limits which were either a reflection of old operating practices that were not applicable to the current system conditions or misconceptions on the part of the plant personnel. By way of example, the authors noted that generator voltage and current meters were found with "red marks" drawn on them as a warning to the plant operator not to exceed these values. Some generators were restricted to operation below the nameplate rated voltage. As per ANSI standards, each generator may operate continuously at voltages between 95% and 105% of nameplate at rated MVA and power factor. The authors of this EPRI report have observed this practice carried over to units which have had new digital plant control systems installed, with many alarms set based on prior practice or perceived limits, and not reflecting the actual conditions of the equipment or applicable standards.

In general, the authors' observation was that the concept of reactive power and its relationship to system voltage was not well understood. Historically, the role of power plants in the power system was believed to be limited to real power production, and attention was not given to reactive capability.

The solution to each of these problems was a recalibration of the existing devices. No new equipment was purchased and some transmission reactive resources planned for installation were abandoned. The net gain for the utility was 500 MVAr of reactive capability and an estimated savings of $5-45 million dollars (1994). In addition, throughout the next summer peak load season, the generators tested were running at approximately 35 percent of their recognized reactive capability as opposed to approximately 90 percent during the previous years.

Other papers provide similar highlights. Reference [1-20] notes that while the manufacturer's capability curve reflects the design capability of the turbine-generator set (at rated machine voltage, frequency, and coolant temperature), the actual reactive capability of the unit when interconnected to the transmission system can be lower because of one or more of the following factors [1-20]:

- Generator step-up transformer (GST) tap setting [1-16, 1-17]
- Station service transformer (SST) tap setting [1-16, 1-17]
- Generator or station bus voltage limits
- Excitation system protection limits (minimum excitation limit, etc.) [section 3]
- Operational limits (operation at nominal instead of rated H2 pressure)
- Equipment condition limits (shorted rotor turns, de-rated GST, vibrations, coolers out-of-service)
- Reference [1-20] outlines some of the reasons for incorrect capability curves:
- The model data was based on preliminary design data and the final "as-built" design data was never entered in the model database.
- The generator owner may have re-rated his generator, the GST, the generator bus, or some other component. Or he may have replaced the field or stator winding or the excitation system. These type changes can affect the machine reactive capability but may not have been incorporated into the model.
- The model may not account for the actual set points of excitation system limiters, which are typically computed by the generator manufacturer or engineer. As an example, the under excitation limiter (UEL) is normally set to protect against excitation that is too low, which can result in machine end-iron overheating or exceeding steady state stability limits. Thus, the generator capability to absorb reactive power is limited by the UEL characteristic rather than the generator capability curve. The UEL is plotted on the capability curve as a standard practice (See Figure 2-8 for an illustration of this).

- The model may assume the full capability curve capability is available, when operating experience and/or other studies may have shown that this is not the case. For example, studies for setting the transformer taps on the GST and SSTs may result in tap settings that limit generator reactive production or absorption. This is usually caused by generator voltage limits or station equipment voltage limits that cannot be fully corrected by changing the available transformer tap settings.
- The generator owner or operator may have operational limits that limit reactive production or absorption, but these were never communicated to the modeler. An example would be shorted rotor turns that limit field current and, hence, reactive capability.

Where limitations are found, the goal is to improve the reactive capability where possible.

2

COORDINATION OF PROTECTION, CONTROL AND CAPABILITIES

The following section addresses draft standard PRC-019 "Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection" [1-3]. This standard is presently under development by the NERC Generator Verification Standards Drafting Team. This section is based on the draft standard issued in September 2006. Any significant changes to the final standard will need to be considered when reviewing the material of this section and formulating a compliance plan. Many of the concepts discussed in this Section are based on conventional industry practice and standards and will therefore not be affected by any changes to the final NERC requirements.

The primary technical requirement of the draft standard was stated as follows [1-3]:

Generator Owner shall have study results that show it verified that its generator voltage regulator controls and limit functions are coordinated with the generator's capabilities and protective relays. This study shall include plots or data that could be plotted for the following:

- *Generator capability curve, including specification of nominal voltage, ambient air or cooling temperature, or hydrogen pressure.*
- *Steady state over-excitation limiter and under-excitation limiter control characteristics.*
- *MW limit of the prime mover.*
- *Any other limit that could restrict the megawatt or megavar capability.*
- *Loss of excitation/field protective relay characteristics.*
- *Volts-per-hertz protection settings including volts-per-hertz limiters in the automatic voltage regulator.*

The focus of this technical standard is on coordination of the excitation system limiters. However, the following steps should be taken during this process based on good engineering practice:

- document generator capability for specified service conditions and identify required limits
- ensure that excitation limiters prevent operation outside of the stated capability but without any unnecessary restrictions
- ensure that protective relays operate to trip the unit for specified faults or equipment malfunction after excitation limiters have had an opportunity to restore operation to within limits

The general approach to meeting these requirements is summarized in Figure 2-1. Some of these steps can be performed in parallel or in a different sequence. However the approach identified in this drawing should minimize repetition and ensure that any problems are identified and corrected before the documentation process is complete. This can be modified to allow scheduling of any changes and re-verification to occur in parallel during and immediately following scheduled outages thereby reducing restrictions on unit operation

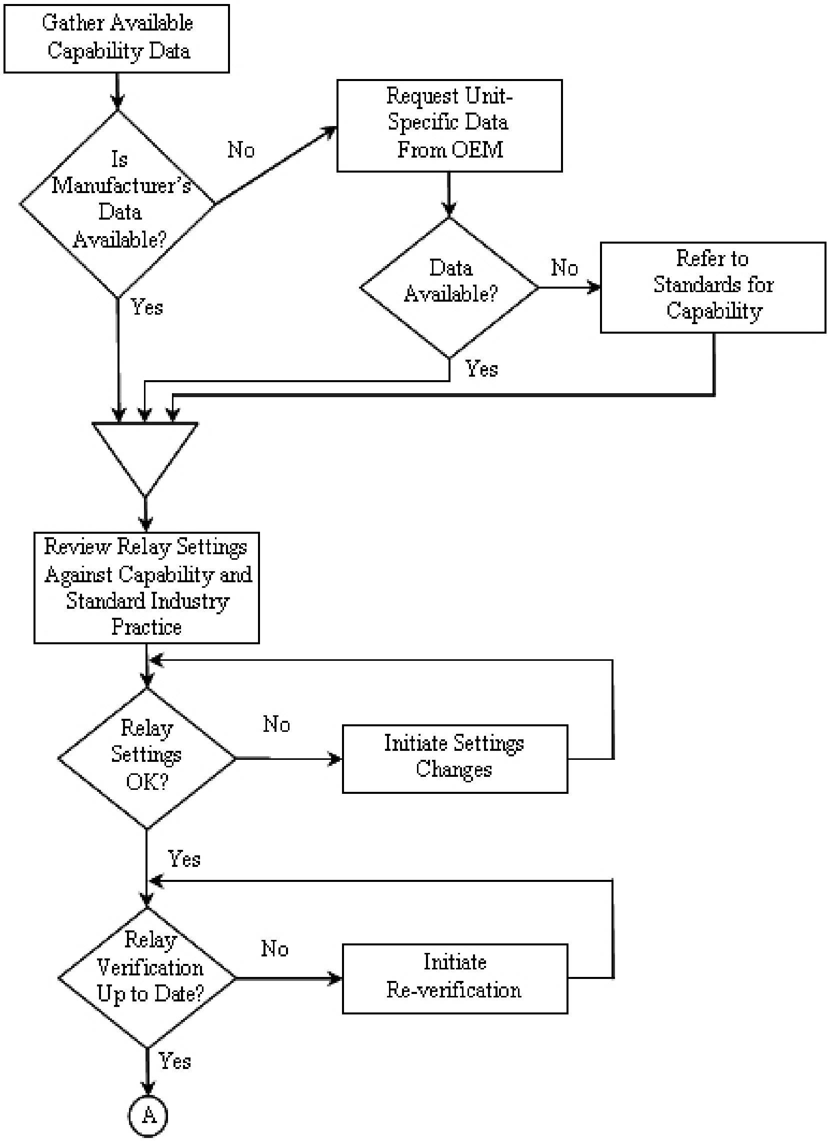

Figure 2-1
Coordination Process

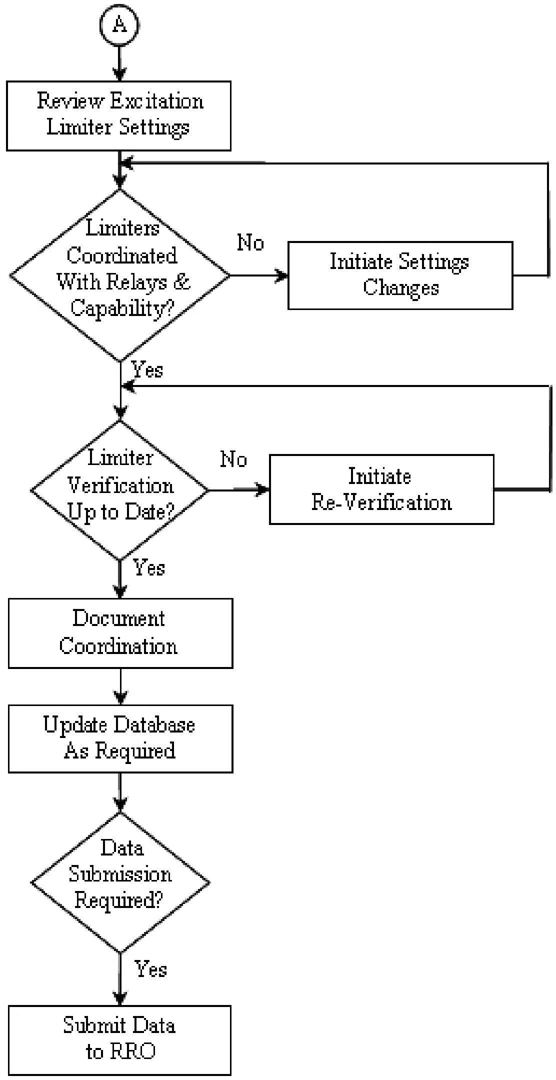

Figure 2-1
Coordination Process (Continued)

Some aspects of coordination overlap with the requirements contained in NERC Standards MOD-024 [1-1] on real power verification and MOD-025 [1-2] on reactive power capability verification. Specifically, there will be instances where it is not possible to directly measure the full active and/or reactive capability of units due to system restrictions (e.g. voltage, dispatching issues) and it will be necessary to supplement measurements with engineering analysis of the generator capability, limits and protective relay settings for other conditions. An effort has been made to avoid duplication between these two sections and references are made to concepts/ calculations introduced in Section 2 rather than repeating them here.

2.1 Coordination Summary

Table 2-1 summarizes the interaction between capability, excitation limiters and protective relays. Each of the limiters and relay elements is discussed in a separate sub-section.

Table 2-1
Summary of Excitation Limiter Coordination

Excitation Limiter	Equipment Capability	Protective Function
• Field Over Current Limiter	• Field winding short-term thermal capability • Excitation system current rating	• O/C (50/51E) on excitation transformers • dc O/C (76) or O/V timed relays (exciter)
• V/Hz Limiter	• Generator flux limit • Transformer flux limits	• V/Hz (24)
• Terminal Voltage Limiter	• Generator continuous voltage limit	• O/V (59)
• Stator Current Limiter	• Stator thermal rating • GST current rating	• Backup voltage-restrained or voltage-controlled O/C (51V) • Backup distance protection (21) • Stator thermal overload relay (49)
• Under-Excitation Limiter	• Core-end overheating • Steady-state stability • Exciter minimum field current limit	• (40) Loss-of-excitation relay • Loss-of-conduction detection (exciter)

The topic of excitation limiter coordination and the impact of limiter operation has been widely researched and discussed by various authors in the literature [2-1] to [2-5]. The importance of coordinating the limiters with the generator's capability and the protective relay settings has been highlighted in numerous reviews of the response of generators during system disturbances [1-13], [2-6]. It is important that the limiters allow the excitation system to exploit the full excitation and generator capability to support power system requirements during disturbances. Overly conservative settings are not beneficial since unnecessary trips stress both the power system and the unit itself.

Ninety percent of the survey respondents indicated that they verify the settings and operation of their protective relays on a routine basis. The majority used internal resources for this purpose with a minority indicating that they also use external consultants. Secondary injection testing was used by 75% of those that confirmed the relay settings with the remainder using a combination of engineering calculations, disturbance monitoring and other methods.

A smaller majority, 67%, reported verifying coordination between excitation limiters, capability and protective relays. There was a relatively even distribution of methods used for this purpose including reviewing manufacturer's data, engineering calculations, off-line secondary injection testing. Only 33% of those that verified coordination did so using staged tests with the unit running. All the respondents used inside resources for this purpose with half reporting the use of external consultants as well. Only 25% obtained training or equipment for this purpose but just under half indicated that there were significant costs associated with the verification.

The focus of the remaining sub-sections is a summary of the coordination issues and the steps required by the generation operator to demonstrate coordination for the purpose of complying with PRC-019.

2.2 Equipment Capability Definitions

PRC-019 refers to the capability of the generator itself, however implicit in this is the assumption that connected equipment (i.e. Generator Step-Up Transformer (GST), station and unit service transformers, auxiliary load equipment, buses, breakers) that must be in-service to support unit operation, must also be operated within limits and that their protection be coordinated. Figure 2-2 displays an overview of the connections for a typical generator-transformer connection to the grid. This is just one of many possible configuration options but serves to illustrate the main components that are discussed in this Section.

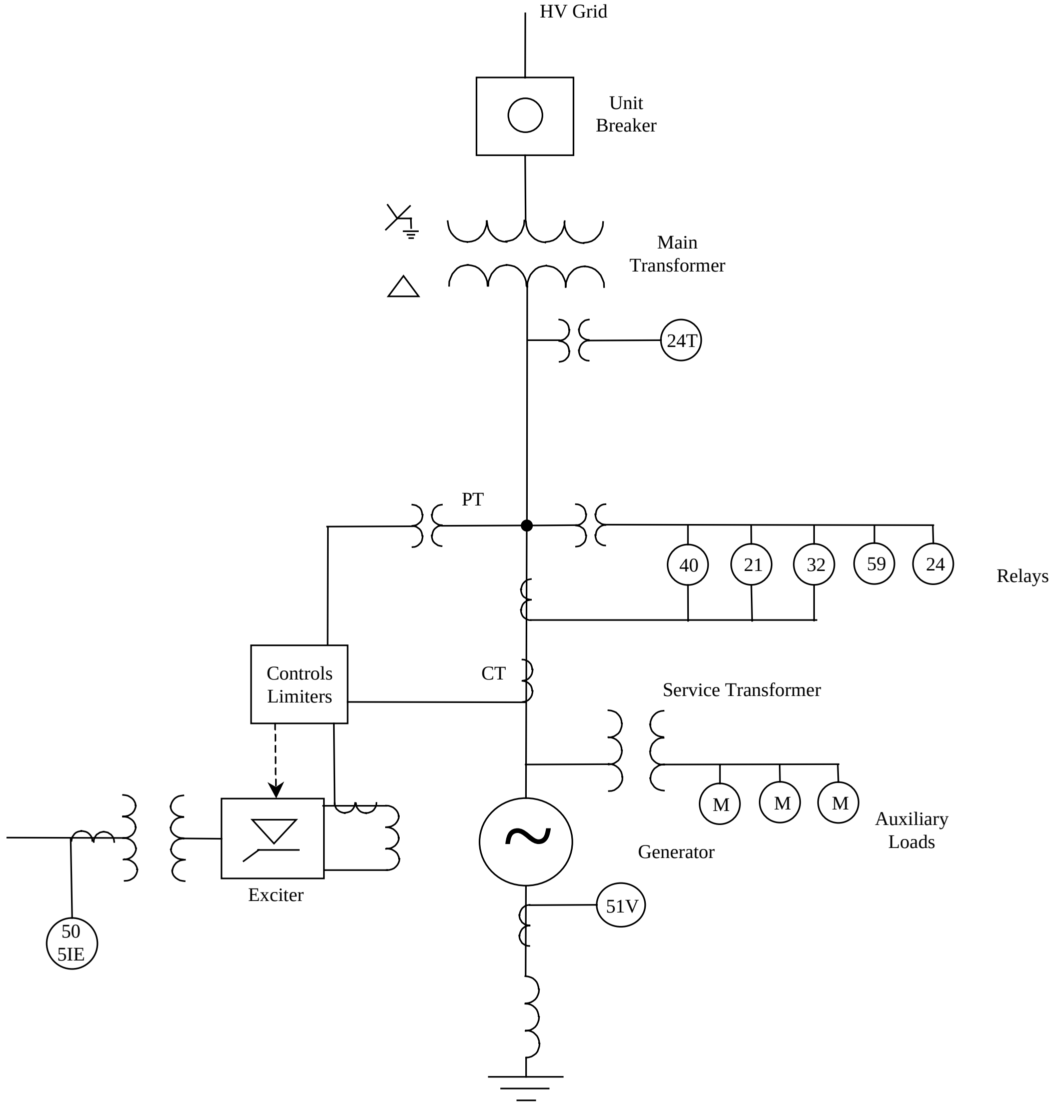

Figure 2-2
Example Generator Equipment Configuration

Central to this standard is the capability of the generator itself. The North American system is composed of generators with ratings from under 1 MVA to well in excess of 1000 MVA built beginning in the early 1900s. RRO requirements vary but it is safe to assume that this compliance standard will be applied to larger units which were designed and built based on the standards applicable when they were ordered. Generation owners are encouraged to search for unit-specific data for their units to establish any special limitations on the operation of their units. In the absence of specific manufacturer's data the industry standards that applied at the time of the construction can be used to establish coordination requirements.

Utility scale synchronous generators are of either salient-pole or cylindrical rotor construction. The latter is often also referred to as round-rotor in the literature. The applicable ANSI/IEEE standards describing the ratings and performance characteristics of these units are C50.12 (salient-pole) [1-4] and C50.13 (cylindrical-rotor) [1-5]. Manufacturers will sometimes quote these standards or their earlier versions in their documentation rather than repeating all of the performance characteristics or allowable service conditions for their generators. Use of these standards to establish capability for the purpose of coordination on older units is subject to the following:

- The standard that was in place at the time of the generator's design, or that is specifically quoted by the Manufacturer, should be used since the revisions may contain differences that are relevant to the continuous or limited-time capability.
- Older generators may have reduced capability due to damage or normal ageing. It is not uncommon for generators to be operated beyond their original stated service life and they may have limitations on operating voltage or reactive capability due to issues such as shorted rotor turns. Supporting documentation may be required if these issues are used to justify reduced capability.
- Modifications to the generator (e.g. rewinds) or re-rating based on new operating practices may not always be documented along with the original design data. The maintenance history of the unit should be reviewed for modifications that affect the unit capability.

In cases where units are operated at power levels significantly below their originally intended ratings, Owners may have some flexibility in establishing lower operating limits as long as they are not unnecessarily restrictive and do not impede the unit's ability to respond to system disturbances.

The following sub-sections review the capability of generators designed in accordance with C50.12 and C50.13, as it pertains to PRC-019.

2.2.1 Voltage Capability

Both salient-pole and round-rotor machines designed in accordance with C50.12 and C50.13 are capable of continuous operation within the confines of their reactive capability curves between 95% and 105% of rated voltage. Sustained operation at higher voltages is to be avoided to prevent premature ageing of insulation. Sustained operation at lower voltages is permissible with appropriate de-rating of the output to keep core and winding temperatures within limits.

Much work has been undertaken, and many papers written on the relationship between operating voltages and reactive capability of generators [1-11], [2-8], [2-9]. Section 1 discussed this in the context of verifying reactive capability. Limits on the continuous operating voltage of the generator, GST and auxiliary equipment all impose practical limitations on unit operation especially when attempting to verify reactive capability through staged testing. A properly designed generating station will exhibit the following characteristics, as long as the generator is operating within its continuous apparent power, power factor and voltage ratings:

- The GST ratings and tap position have been selected such that it remains within its apparent power and voltage ratings [2-10].
- The auxiliary transformer ratings and tap positions have been selected such that they remain within their apparent power and voltage ratings.
- The station and unit service loads connected to the auxiliary buses have been selected such that they remain within their apparent power and voltage ratings.
- Series connected equipment (i.e. equipment connected to the ac terminals of the generator and conducting the output power to the connection point with the grid, such as GST, buses and breakers) have ratings that equal or exceed the net or gross output capability of the generator as appropriate.

It is understood that these conditions are not always met and many authors have reported encountering voltage-related problems during actual operation and testing of units. Nevertheless the focus of the standard is on establishing coordination between generator capability, limits and protection with the understanding that other elements will not be limiting or that this is a deficiency that will be corrected or reported. A qualitative discussion of the capability of connected equipment will be included in this Section especially in areas where experience dictates that operation may be limited by other equipment (e.g. V/Hz capability of GST).

The assumptions on connected equipment capability are necessary when considering that much of the analysis of reactive capability described in the literature has been for units connected to the grid through a dedicated GST, as shown in Figure 2-2, but many other connection configurations are possible. For example, many units at hydroelectric facilities and co-generation sites have connections with multiple units sharing a step-up transformer connection to the grid.

Generator step-up transformers have their apparent power ratings, percent impedance, and sustained overvoltage capability expressed in terms of quantities measured at their secondary (high-voltage) terminals [2-10]. Unless otherwise specified by the manufacturer, the transformer will be rated for up to 110% of rated voltage on any tap when operating on open circuit and 105% of rated voltage for operation at rated apparent power and 0.8 power factor [2-11]. Most generator step-up transformer low-voltage windings have nominal voltages 4% to 5% below that of the generator to which they are connected to compensate for the regulation effect (i.e. leakage reactance voltage drop) on the high-voltage windings at rated load conditions. The difference in nominal voltage must be considered when comparing transformer settings with the generator.

According to the standard [2-11], the transformer is only required to deliver rated apparent power for voltages between 100% and 105% and not at lower voltages. Individual manufacturer specifications or utility requirements may dictate a wider voltage range including the ability to operate at rated power at voltages down to 95% or below.

2.2.2 V/Hz Capability

Flux levels in generator and transformer cores are directly proportion to the ratio of operating ac voltage and frequency, commonly referred to as V/Hz, and expressed in percentage or per-unit on the nameplate voltage and frequency base of the generator. Both salient-pole and round-rotor machines designed in accordance with C50.12 and C50.13 are capable of continuous operation within the confines of their reactive capability curves for V/Hz levels up to 105% of rated. Sustained operation at moderately higher levels (up to 110%) leads to increased core heating. Continuous operation at these higher levels coincident with operation near the limits of the generator's reactive capability curve may cause accelerated insulation ageing. Figure 2-3 is used in both standards [1-4], [1-5] to represent the permissible continuous operating range in terms of voltage and frequency.

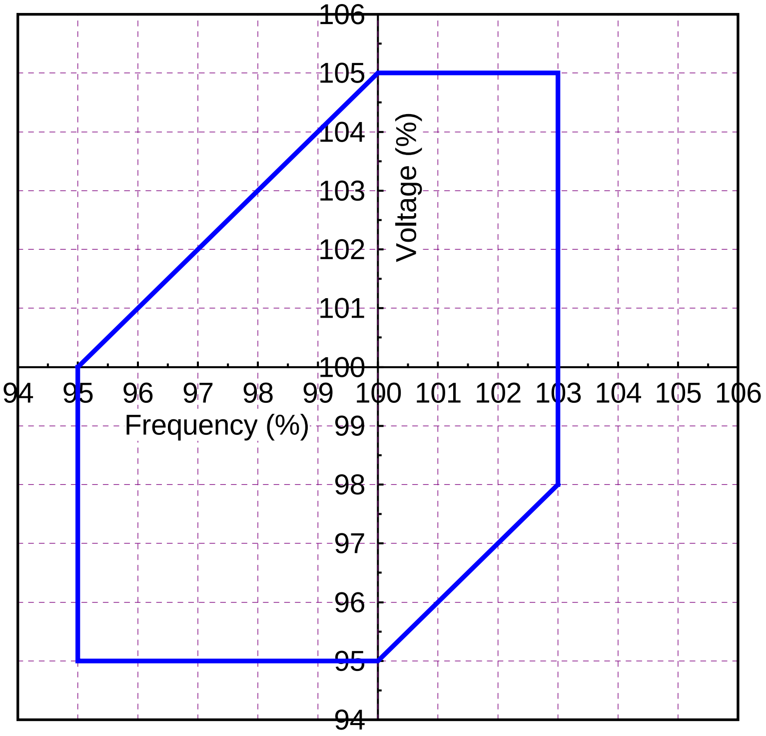

Figure 2-3
Generator Voltage/Frequency Operating Range

For higher levels of V/Hz (> 110%), saturation can lead to high leakage flux levels with consequent high eddy current flows, localized heating and the possibility of damage to inter-laminar insulation. The standards do not supply recommended limited-time ratings for V/Hz capability of either salient pole or round-rotor generators. Instead they recommend that owners request this information from the manufacturer for each generator design.

The GST capability must also be considered when considering coordination since it is possible for it to be a limiting factor for V/Hz levels. Unless otherwise specified by the manufacturer, the voltage ratings discussed earlier (1.10 pu on open-circuit or 1.05 pu at rated load and rated frequency) can be used for coordination purposes.

2.2.3 Continuous Excitation Capability

Most manufacturers provide continuous field current and voltage ratings as part of their nameplate data. As discussed in Section 1, rated continuous generator rotor field current should be specified by the manufacturer as the excitation current required for full load operation at rated voltage and power factor including suitable margin [1-5]. This level of field current should result in observable temperature rises (measured by average field winding resistance method) equal to or below the limits for the insulation system in question.

The continuous field current limit is shown on the example capability curve of Figure 2-4 as the segment AB depicting the locus of constant field current in the power plane. By convention this will intersect the rated apparent power circle at the machine's nameplate power factor, in this example 0.9 pf.

Rated continuous field voltage on the generator is defined based on the rated field current level and field winding resistance at the rated temperature, based on allowable temperature rise and maximum allowable coolant temperature for the unit. The Manufacturer may specify higher values for this quantity on the nameplate of the generator.

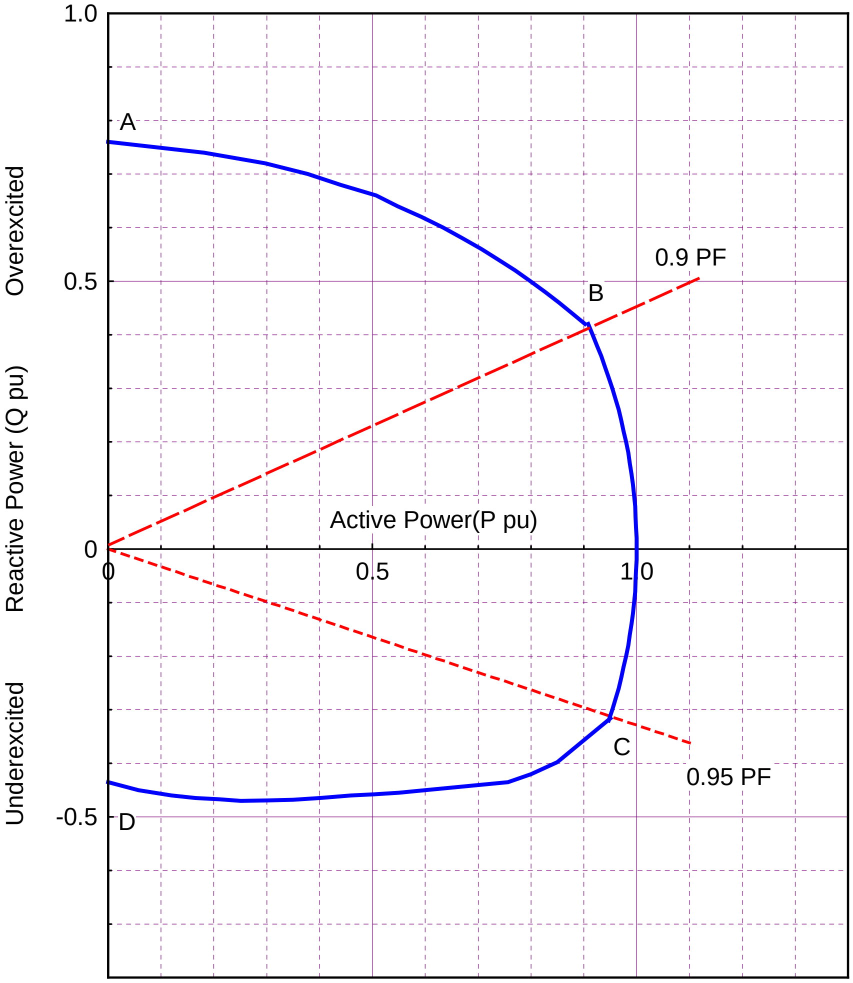

Figure 2-4
Example Cylindrical Rotor Generator Capability Curve

2.2.4 Limited Time Excitation Capability

Limited-time field overcurrent capability is necessary to accommodate field forcing to support system reactive requirements during disturbance conditions on the power system. The forcing capability is based on allowing a fixed level of additional temperature rise (e.g. 5°C) above the rating for selected events (< 2/year) during the life of the generator. On round-rotor generators this capability is expressed in the latest version of standard C50.13 [1-5] as Equation 2-1 with selected values in Table 2-2. Field current is expressed as a percentage of the continuous full-load field current discussed earlier and time is expressed in seconds.

$$I_{fg}(\%) = 100 * \sqrt{\frac{33.75}{t} + 1}$$

Equation 2-1

Table 2-2
Limited-Time Field Current Capability

I_{fg} (%)	209	146	125	113
time (s)	10	30	60	120

Past versions of the standard expressed this relationship in terms of field voltage rather than current. These are equivalent when expressed as a percentage of rated since the assumption for the limit is that the starting point is rated temperature conditions on the field winding.

The standard for salient-pole generators does not provide a comparable set of limited-time ratings. Past experience indicates that the limited-time capability of utility-scale salient pole generators is significantly higher than for comparable round rotor generators. In the absence of unit-specific limits, it is common practice for generation owners to apply the values of C50.13 to these units [2-2]. If the generation owner is intent on maximizing the limited-time capability or is concerned about applying the round-rotor standard to larger salient-pole machines they should request unit-specific data from their manufacturer.

2.2.5 Continuous Stator Current Capability

Rated stator current is defined based on rated apparent power and rated terminal voltage and is usually explicitly listed. Some utility-scale generators are capable of operating at rated MVA and power factor for voltages within the range of 95% to 105% subject to the allowable temperature rise on the stator windings based on the insulation system [1-4], [1-5]. As noted in Section 1, the standards only require rated apparent power capability for rated voltage conditions. If observed temperature rises are higher at the stated current level the manufacturer should be consulted for guidance on whether de-rating is necessary.

The continuous stator current limit is shown on the example capability curve of Figure 2-4 as the segment BC, an arc with radius equal to the rated apparent power. This limitation will dictate the limits of reactive output for lagging power factors below the nameplate power factor and for leading power factors above the intersection with the core-end heating limit, in this example at 0.95 power factor.

2.2.6 Limited-Time Stator Current Capability

Limited-time stator overcurrent capability is available to accommodate the short-term supply of additional reactive power during disturbance conditions. On round-rotor generators this capability is expressed in the latest version of standard C50.13 [1-5] as Equation 2-2 with selected values in Table 2-3. Stator current is expressed as a percentage of the continuous full-load current discussed earlier and time is expressed in seconds.

$$I_s(\%) = 100 * \sqrt{\frac{37.5}{t} + 1}$$ **Equation 2-2**

Table 2-3
Limited-Time Stator Current Capability

I (%)	218	150	127	115
time (s)	10	30	60	120

2.2.7 Under-Excited Operating Capability

Under-excited operation on utility-scale generators can be restricted by a number of factors but the only one solely associated with the generator is core-end overheating. As discussed in Section 1, for extreme underexcited conditions increased armature leakage flux in the end-region can produce large eddy currents since the flux is perpendicular to the stator laminations. This can impose a very significant limitation on under-excited operation on older round-rotor machines where the structural materials used to maintain pressure on the core ends and stator teeth were constructed of magnetic material [2-12]. Even on newer round-rotor machines this phenomenon is normally the limiting factor on operation in the under-excited region depicted by segment CD of Figure 2-4.

Due to their construction, salient-pole generators are normally not constrained by core-end overheating in this region. Other factors, discussed in later sections normally determine the practical limits of operation.

Generators constructed along the guidelines of C50.12 and C50.13 are normally capable of operation to at least 0.95 power factor leading. Salient-pole generators are often capable of operation at lower leading power factors. Their extended under-excited capabilities can be utilized when they are operated as synchronous condensers or lightly loaded during system restoration and line energization.

2.3 Generator Protection Overview

The protective functions that are examined for coordination are those that could potentially operate during power system disturbance conditions (i.e. active and reactive power swings, over/under voltage, over/under frequency). Relays that are designed as primary protections against faults within or near the unit such as primary over-current, differential and ground fault relays are not included in this analysis since they are not the focus of this specific draft standard.

Table 2-4 summarizes the elements that are discussed. The term elements will be used interchangeably with the term relays since many of these functions are now commonly implemented in a single multi-function relay rather than in individual discrete relays.

Table 2-4
Summary of Protective Elements Considered in Coordination Study

Device No.	Function
24	V/Hz over-excitation
27	Under-voltage
40	Loss-of-excitation
50/51E	Excitation transformer over-current
51V	Backup relays that may respond to unit overload conditions or transient swings
59	Over-voltage
76	DC overcurrent relay (field circuit application)

The sub-sections that address coordination introduce the implementation and "typical" settings that are applied to the protective elements listed in Table 2-4. A complete treatment of this topic is clearly outside of the scope of this report. However, in order to provide a meaningful discussion of the topic of coordination it is necessary to identify where there is a potential for coordination issues, and therefore settings must be introduced. For further information and background numerous resources are available including:

- textbooks on protection systems
- industry standards [2-13] to [2-15]
- peer-reviewed papers on the topic of settings and coordination [1-13], [2-6], [2-7], [2-16] to [2-17]
- relay manufacturers' documentation

2.3.1 Coordination Plots and Definitions

When discussing generator terminal quantities, power system engineers typically express values in a per-unit system based on the generator's apparent power and voltage nameplate ratings. Protection engineers on the other hand normally discuss quantities in per-unit on a common apparent power base (e.g. 100 MVA) and a voltage base that matches the nameplate and connection point of the equipment under consideration. Base conversions are straightforward as expressed in Equations 2-3 through 2-6 for voltage, power, current and impedance quantities based on the apparent power base, S_B, and terminal voltage base, V_B.

$$V_2(pu) = V_1(pu) \bullet \frac{V_{B1}}{V_{B2}}$$ **Equation 2-3**

$$P_2(pu) = P_1(pu) \bullet \frac{S_{B1}}{S_{B2}}$$ **Equation 2-4**

$$I_2(pu) = I_1(pu) \bullet \frac{V_{B2}}{V_{B1}} \frac{S_{B1}}{S_{B2}}$$ **Equation 2-5**

$$Z_2(pu) = Z_1(pu) \bullet \frac{\left(V_{B1}\right)^2}{\left(V_{B2}\right)^2} \frac{S_{B2}}{S_{B1}}$$ **Equation 2-6**

Operators and power system engineers are normally familiar with plots of generator capability in the power (PQ) coordinate system introduced in Section 1. Protection engineers are often more comfortable plotting relay characteristics in the impedance (R-X) coordinate system. Impedance-based relay settings (e.g. loss-of-excitation, distance) are usually expressed as impedance values in secondary-ohms at the point of relay connection. The conversion between the two coordinate systems is provided in Equations 2-7 and 2-8. The inverse transformation is obtained by substituting P for R and Q for X in each of the equations where each of the variables is expressed in pu.

$$P = V^2 \frac{R}{R^2 + X^2}$$ **Equation 2-7**

$$Q = V^2 \frac{X}{R^2 + X^2}$$ **Equation 2-8**

An example of the conversion process is displayed in Figure 2-5 where a simple generator capability curve and loss-of-excitation relay characteristic have been displayed in both coordinate systems.

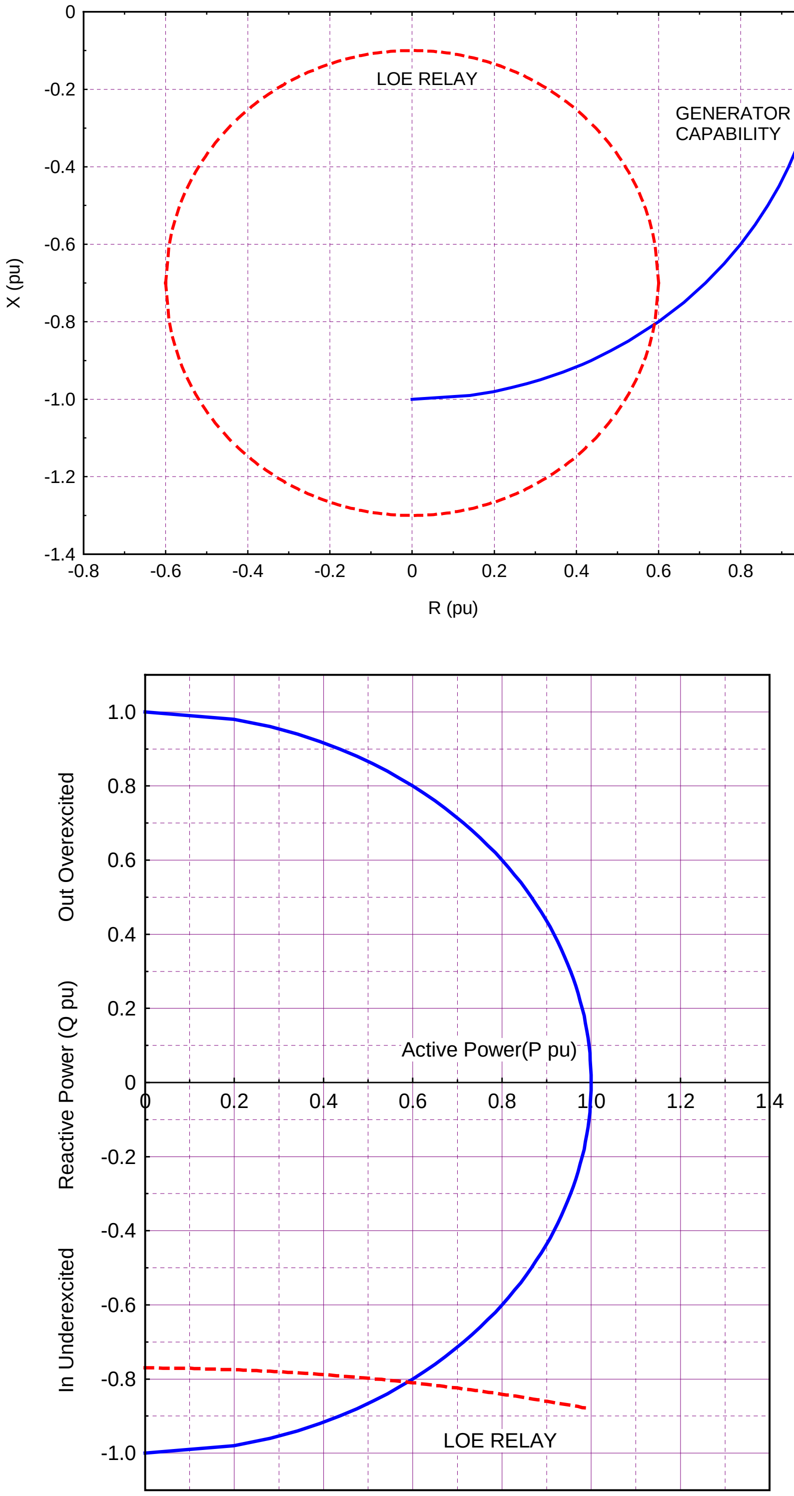

Figure 2-5
Relationship Between RX and PQ Coordinate Systems

2.4 Excitation Limiter Overview

Excitation limiters serve to reduce or increase excitation, as appropriate, to protect equipment and avoid exciter and/or generator trips. In general, excitation limiters can be classified in two categories: over-excitation limiters (OELs), which act to reduce excitation when it is too high, and under-excitation limiters (UELs), which operate in the opposite direction. Two-types of OELs are normally supplied with excitation systems, field current limiters that limit generator field current directly or indirectly and voltage limiters that limit either ac terminal voltage or the ratio of V/Hz.

The terms maximum and minimum excitation limiters are avoided here because the acronym MEL has been used in the literature to describe both and can lead to confusion.

Stator current limiters (SCLs) are a relatively recent addition to the available excitation limiters and may operate for both under-excited and over-excited conditions and will therefore be discussed separately.

Limiters can further be classified according to the method used to control excitation. The two main options are summing and take-over style limiters. Summing limiters operate by adding a signal to the summing point of the controlling regulator. For example with the AVR in control a summing style UEL would add an input to the AVR summing junction where the reference setpoint and compensated voltage feedback are combined in order to determine the field voltage and current. The advantage of this arrangement is that other controls such as the AVR and PSS continue to supply input to the calculation of the firing signal and therefore continue to provide benefits such as improving stability. The disadvantage is that since the limiter does not have complete control over the excitation level it is possible that the operating point will exceed the limit unless the limiter gain is high enough to overcome other inputs.

As their name implies, take-over limiters operate by taking over control of excitation once the limit has been exceeded. The advantage of this design is that coordination does not have to take into account other inputs. The disadvantage is that other regulators, and possibly limiters cannot influence the excitation level. One other option that may be applied to ac voltage or V/Hz limiters are setpoint limiters that operate to prevent the AVR setpoint from being raised above a level that would exceed the selected limit, or actually reduces the setpoint as the limit is exceeded. These limiters operate on the principle that the AVR will regulate the voltage to the setpoint and that a separate control loop is not required.

Recommended models for OELs and UELs are documented in references [2-18] and [2-19] respectively.

Great care must be taken in tuning the control loop settings of limiters and they must be tested or simulated with other control functions in-service in order to confirm that there are no conflicts and numerous utilities and manufacturers have shared their experiences with tuning and testing of excitation limiters [2-1] to [2-5], [2-20].

2.4.1 Field Current Limiters

Almost all modern excitation systems are equipped with some form of field current limiter, set to maintain exciter current within the rating of the excitation system and generator field winding. On the earliest exciters inverse-time dc overcurrent or overvoltage elements were used to switch from AVR control to a fixed field rheostat if the timed setting was exceeded. The settings were selected to emulate the rotor capability but were normally fairly crude in their adjustments. The field rheostat would be positioned to produce a field current level for which no further increases in temperature would take place.

Newer exciters commonly used analog-electronic timers that switched from an instantaneous limit, I_{inst} (e.g. 125% to 160% of rated), to a lower limit, I_{lim} (e.g. 90% to 100% of rated), when the calculated field thermal capability was approached. Un-limited operation was normally permitted for a short fixed or adjustable period to prevent the exciter from responding to induced field currents resulting from faults on the ac system. These limiters used a thermal limit, I_{therm} (e.g. 100% to 105% of rated), above which the timer would begin to operate. The amount of time permitted between the thermal limit and instantaneous limit was determined by the implementation of the timer. In some cases the time to operate, T_{op}, was based on a fixed timer, but more often an inverse-time limit was used based on the simple relationship of Equation 2-9.

$$T_{op} = \frac{K}{I_{fg} - I_{therm}}$$ **Equation 2-9**

where K was selected to coordinate with some parts of the capability. Since temperature rise is directly proportional to the square of the field current, these systems had to be set conservatively at some points to coordinate with actual capability.

Modern digital systems often have very complex field current limiter designs including such features as:

- instantaneous limiting with adjustable delay
- field forcing based on an inverse-square relationship coordinated with generator limited-time capability
- cool-down limits to prevent over-heating during multiple forcing events
- off-line limiter settings to prevent over-excitation un-related to field winding over-heating
- transfers/trips after time delays if expected limiter action does not occur

The timed forcing capability for most of these units is based on an inverse-squared relationship (Equation 2-10) for coordination with the generator capability.

$$T_{op} = \frac{K}{I_{fg}^2 - 1}$$ **Equation 2-10**

The value of K representing generator capability is 33.75, from Equation 2-1. By setting K to lower levels, the limiter can be set to operate with adjustable margin.

The multitude of settings can be somewhat overwhelming on newer digital systems, however coordination with capability and protective relays usually only involves examining the on-line values of I_{inst}, I_{therm} and the timing method.

A well-designed excitation system should not be the limiting factor in establishing the setting of this limiter (i.e. the exciter will be capable of supplying all of the field current that the generator can handle). In the event that this is not the case the field current limiter may be set to respect the output limitations of the exciter.

On some excitation systems with rotating main exciters the OEL uses measured pilot exciter output current (i.e. main exciter field current) as its input and uses the main exciter input-output relationship to coordinate settings with the generator capability. This introduces the generator field resistance into the calculation. Since the field resistance can change by over 20 percent for a normal range of operating temperatures (e.g. 25°C to 75°C), this needs to be accounted for in the calculations. Using the field resistance at the maximum allowable temperature of the winding is normally done to take into account the fact that damage will only occur if the maximum temperature rise is exceeded.

Most field current limiters are structured as takeover-style limiters. Off-line testing of field current limiters of this design may be all that is required, since control dynamics are straightforward and normally will not involve interaction with other controls.

Some designs of digital excitation system allow field current limiter setpoints to be modified based on hydrogen pressure or cooling inlet temperature. The idea is to match the setpoints of the limiter to the different capability characteristics supplied by the manufacturer for different cooling pressures or operating temperatures. The use of these features is not widespread, in part due to concerns about the quality/reliability of transducer signals for pressure and temperature and the potential for unnecessary de-rating.

2.4.2 Voltage and V/Hz Limiters

V/Hz limiters have been included in some models of excitation systems for many years but were normally only applied to large round-rotor machines to protect them against over-fluxing during start-up and shut down. This was particularly appropriate given that excitation was sometimes applied to these units at low speeds as part of the warm-up process during start-up. In some of the older designs detection of high V/Hz levels was used to ramp down the setpoint at a fixed rate. On more modern designs, closed-loop limiters similar to the field current limiter structures are used. Digital systems often implement limits on AVR setpoint since once this is lowered the AVR will control excitation to the required level. Most of the earliest systems and some of the modern systems implement a limit at a single V/Hz level with no time-dependent characteristic. In the newer digital excitation systems the user can select a time-dependent characteristic as well as a fixed upper limit to coordinate with generator capability and common protective relay configurations.

Terminal voltage limiters were not common on early excitation systems since the AVR implements a direct terminal voltage control. If the AVR is unable to fulfill this function then it is unlikely that a limiter will be able to correct the problem. Terminal voltage limiters are most common in conjunction with supplementary controls such as power system stabilizers where the AVR setpoint may be modulated resulting in higher voltages even with the AVR in control. In these cases the terminal voltage limiter can be used to limit the overall setpoint to prevent supplementary controls from increasing voltage beyond reasonable levels. These limiters are almost always implemented with a single fixed setpoint and no time dependency.

2.4.3 Under Excitation Limiters

After the field current limiter, the UEL is the most common form of excitation limiter and implementations were available on even the earliest magnetic amplifier based excitation systems. The term URAL (Underexcited Reactive Ampere Limiter) has also been used by some Manufacturers to describe this function. UELs limit operation in the underexcited region to respect a variety of limits, including core-end overheating, steady-state stability and loss-of-excitation relay characteristics [2-1]. Normally, UELs measure the reactive component of the stator current, or simply the reactive power, and boost excitation when the machine operates too far into the underexcited region. They can readily be set up to act as slow limits, basically performing the function of a set point limiter.

Although UEL designs utilize various types of input sensing and signal processing, their limiting characteristics are usually plotted in terms of active and reactive power on the generator capability curve. The IEEE [2-19] classifies UEL characteristics based on the three most common implementations: circular (Type UEL1), straight-line (Type UEL2), multi-segment straight-line (Type UEL3). Figure 2-6 depicts each of these with settings coordinated with a core-end heating limit of the example capability curve of Figure 2-4. Circular and linear characteristics are most often found in older magnetic or analog electronic excitation systems while piecewise linear characteristics are often available as look-up tables in digital systems. The latter design provides the most flexibility in tailoring the limit to match the machine limitations.

UELs normally operate with no intentional time delay although some newer digital designs allow for entry of fixed delays along with continuous time constants. UELs appear as both summing-style and takeover-style limiters and the IEEE models [2-19] accommodate both designs. With proportional designs (i.e. the output of the limiter is proportional to the difference between setpoint and the measured reactive power) the steady-state limited value may lie outside the selected operating characteristic and this regulation effect must be taken into account in selecting the margin between the limit and the capability.

As was the case with field current limiters, UELs may be equipped with the ability to recalibrate their operating limits based on cooling temperatures or pressure. This allows coordination with the changes to the core-end heating limit for these conditions. These systems and their actual usage are not yet common, but should be documented if present.

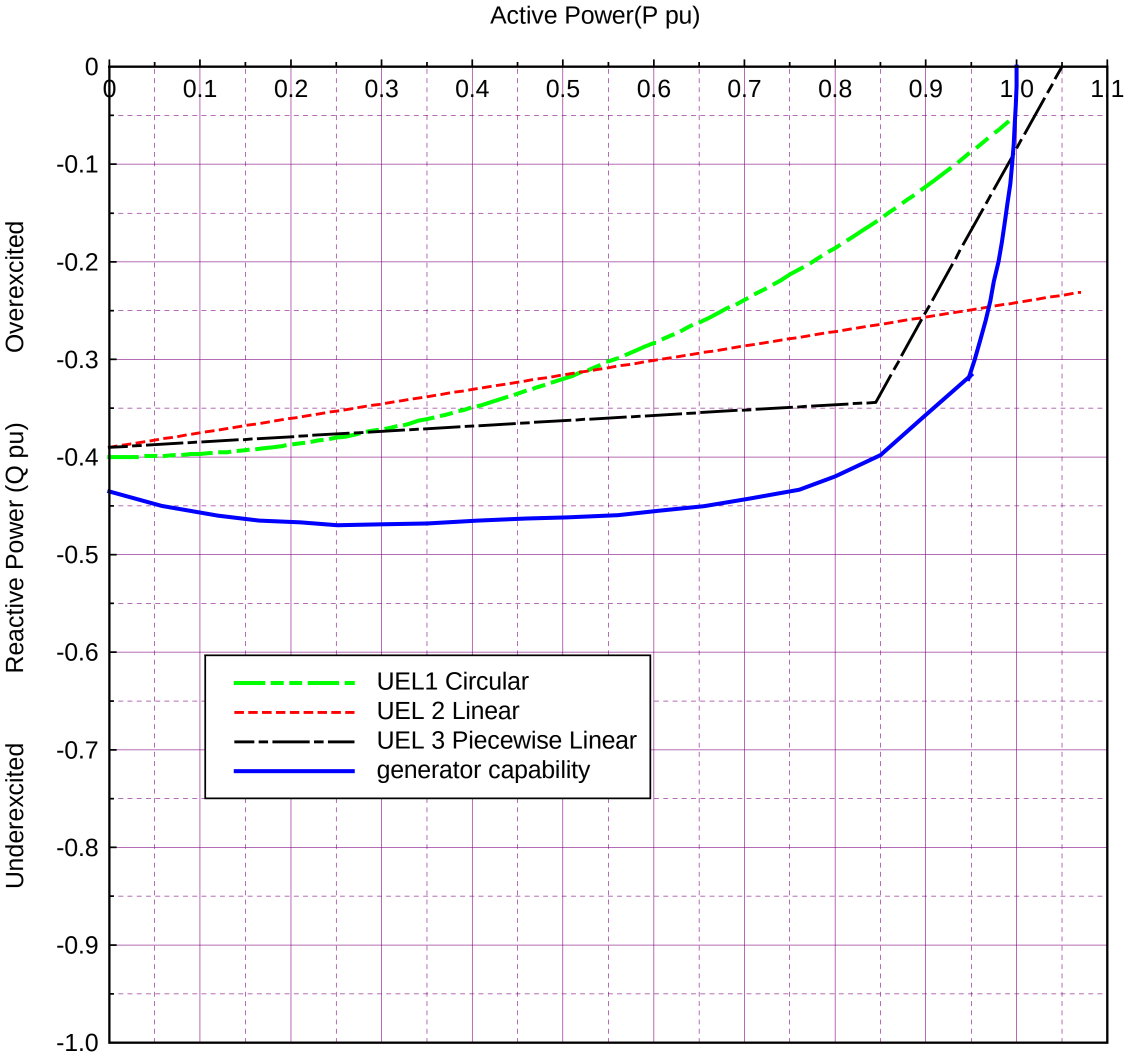

Figure 2-6
Example UEL Characteristics

2.4.4 Stator Current Limiters

Stator current limiters in excitation systems raise or lower excitation in order to reduce the level of stator current. As a result they will either raise or lower excitation depending on whether the unit is initially operating over or under-excited. Although not common on older designs they were sometimes implemented as “VAR-runback” circuits which brought the unit to unity power factor operation based on a command from the Operator or a measured condition such as a stator temperature alarm or loss-of-coolant pressure or high temperature. It is important that these systems have slow dynamics since otherwise they could interact with generator electromechanical oscillations.

One scenario where SCLs could be put to use is for cases where a turbine has been uprated without a matching uprate in the apparent power rating of the generator. This could result in an operating zone where the field current limit is not exceeded but the stator current level is exceeded [2-2]. Although this could create an area where the unit could be operated outside of its rating, stator temperature alarms will warn the Operator before damage is done to the insulation system.

2.5 Field Current Coordination

The field current limiter settings need to be coordinated with the following:

- generator continuous capability (Section 2.2.3) and limited-time capability (Section 2.2.4)
- rotating main exciter and static exciter ratings
- excitation supply overcurrent protection (50/51E)
- excitation output overload protection (76)

The coordination for the case of a potential source static excitation system and a rotating main exciter fed by a pilot excitation system with field current limiter are discussed separately in the following sub-sections.

2.5.1 Accuracy and Measurement Considerations

The field windings of generators and rotating main exciters are un-grounded and subject to potentially high transient voltages and currents due to exciter forcing and induced currents from the generator during fault conditions. As a result the measured generator field current and voltage must be isolated from the exciter controls. The feedback measurement required by field current limiters is derived by one of two methods: non-inductive shunt with voltage isolator or direct current CT (DCCT). Calibrated shunts are available but once installed are rarely removed and re-calibrated. Shunts operated continuously at current close to or above their rating may not provide a reliable calibrated output over time. This Author's recent experience has been that it is possible for shunts that have been damaged by continuous or transient overloads to produce results that are significantly different than their nameplate stampings. The condition of the shunt should be visually examined and any signs of heat damage or deformation should be considered as reasons to replace or verify the calibration of the shunt, especially on units that are operated close to temperature rise limits on the exciter or field winding.

Voltage isolators designed with the high common-mode rejection ratio required in this application are prone to offsets and gain errors. DCCTs, normally based on saturable-reactor or hall-effect principles are not normally intended to provide metering class accuracy.

Based on this discussion it is apparent that the measurement of field current within excitation systems may be prone to offset and gain errors especially if older systems have not been calibrated since installation. Coordination between limiters and capability must take this into account and build in adequate margin between the desired coordination and the practical settings.

The source of measurement for relays associated with excitation supply or output overload have similar issues.

DC overvoltage or overcurrent relays connected directly or indirectly to field circuits are likely to have significant measurement uncertainty. The thermal timers that were sometimes used to implement overload characteristics on older excitation systems can exhibit large variations in their operating characteristics and this should be taken into account when examining coordination.

For potential-source static excitation systems the overcurrent relays installed on the ac supply (Figure 2-7) have to contend with harmonics and the relationship between their operating levels and the dc current fed to the generator needs to be considered in any coordination calculations.

2.5.2 Coordination Calculations

Coordination associated with generator field quantities often requires conversion to represent operating levels on the same base. The generator's continuous field current capability, I_{rated}, will be used as the base value in expressing quantities in percentage or per-unit in this section.

For potential-source systems such as the one shown in Figure 2-7, it is often necessary to compare the PPT supply RMS current, I_{ac}, with the corresponding dc field current, I_{fg}. For conventional three-phase fully controlled rectifier configurations the relationship is given by Equation 2-11.

$$I_{ac} = \frac{\sqrt{2}V_{PPT-S}}{\sqrt{3}V_{PPT-P}} * I_{fg}$$

Equation 2-11

where V_{PPT-P} and V_{PPT-S} are the primary and secondary rated line-to-line voltages of the PPT.

The rating of the PPT can be converted from its nameplate apparent power, S_{PPT} expressed in VA, to an equivalent rectified dc current, I_{PPT-DC}, using Equation 2-12.

$$I_{PPT-DC} = \frac{S_{PPT}}{\sqrt{2} * V_{PPST-S}}$$

Equation 2-12

For units equipped with rotating main exciters, either dc or ac machines, the field current limiter usually utilizes the pilot exciter output current as the input to the limiter. In this case the relationship between the generator field current and main exciter current must be known. Figure 2-9 displays an example open-circuit and loaded main exciter saturation curve for an ac rotating main exciter. The loaded main exciter curve depicts the output voltage when loaded with a resistance equal to the generator field winding when operating at its rated temperature. The rectification voltage drop must be included in any calculation of the main exciter field current, I_{fe}, corresponding to generator field current, I_{fg}, from Equation (2-13).

$$I_{fe} = f\left(\frac{I_{fg} * R_{fg}(\text{at } T_{rated})}{F_{EX}}\right)$$ **Equation 2-13**

The function f() in this equation represent the loaded main exciter characteristic. The variable F_{EX}, is the rectification factor that accounts for commutation voltage drop in the diode bridge. For ac systems this factor is defined in IEEE 421.5 [2-21]. For dc systems this variable is not required and can be set to unity.

It is important to remember that the overall relationship is nonlinear, can be used in converting currents in both directions, and must be evaluated for each field current level to be used in calculating coordination.

2.5.3 Static Exciter Coordination

Full potential source static excitation systems are normally not equipped with excitation output (i.e. dc) protective relays other than those set to operate for dc bus faults. The operating levels of these devices should be set well above normal full load current levels and they will not be considered in this discussion. Static exciters will normally be equipped with supply overcurrent relays (50/51E) to detect excitation transformer and dc bus faults as depicted in Figure 2-7 below.

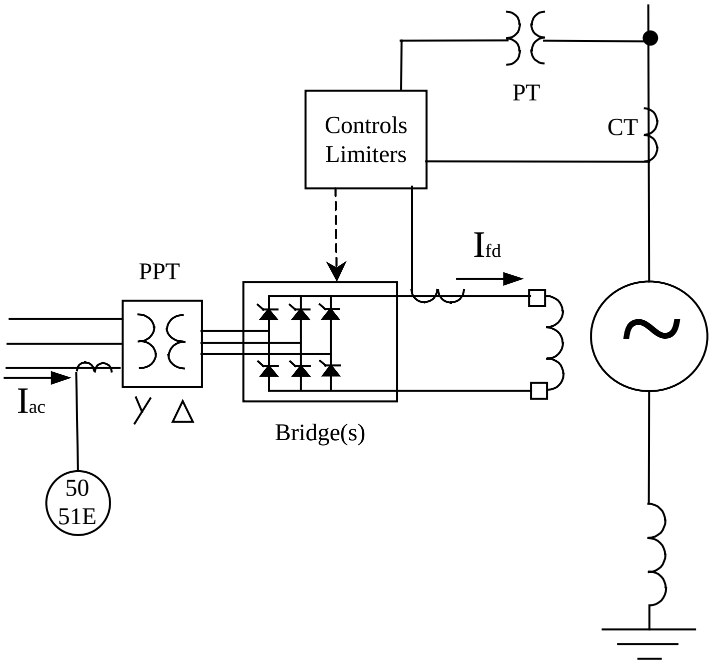

Figure 2-7
Basic Potential Source Excitation System Configuration

The steps for verifying coordination for this configuration are as follows.

Continuous current levels

1. Determine generator field winding continuous capability, I_{rated}, from nameplate or manufacturer's data.
2. Determine exciter continuous rating, I_{exc-c}, from nameplate or manufacturer's documentation.
3. Determine excitation PPT rating from nameplate and convert to equivalent rectifier output dc current, I_{PPT-DC}, using Equation 2-12.
4. Determine and convert (Equation 2-11) minimum pickup for 51ET timed excitation overload relay, $I_{51ET-MIN}$.
5. Determine the minimum pickup of the field current limiter, I_{therm}.

Verify coordination between continuous levels, using the inequalities of Equations 2-14 and 2-15.

$$I_{51ET-MIN} > I_{exc-c}\ I_{PPT-DC} \geq I_{exc-c} \qquad \textbf{Equation 2-14}$$

$$I_{exc-c} > I_{rated} \geq I_{therm} \qquad \textbf{Equation 2-15}$$

The timed relay minimum pickup is sometimes set above the PPT continuous rating to provide some margin but may also be set slightly below this level to prevent long-term overloads. In the former case the manufacturers/utilities are normally relying on the PPT temperature alarms and Operator action to prevent damage from long-term operation slightly above the continuous rating.

If the excitation capability is less than the generator rating, as is sometimes the case when field windings are rewound after an exciter is installed, the lower rating must be used to determine the excitation limiter setting.

The excitation limiter thermal level, used to initiate timing of the field current limiter, may be set equal to or in some cases above (e.g. 105%) rated field current [1-13], [2-5]. The latter approach, which is quite common, is done to reduce the likelihood of unnecessary limiting, especially taking into account the accuracy associated with field current measurement within the excitation system. An alarm is sometimes used to warn Operators when they are operating above rated field current or when the limiter thermal threshold is exceeded and timing has commenced.

The locus of (P,Q) values corresponding to the excitation limiter thermal level are sometimes added to the capability curve along with the generator rating, but this is not necessary to demonstrate coordination.

Limited-time forcing levels

1. Plot the generator field winding limited-time overload capability from the manufacturer's data or based on the continuous rating and the standard capability of Equation 2-1.

2. Plot the excitation transformer limited-time rating from the manufacturer's data. This is normally a standard transformer damage curve and is normally not a limiting factor in examining coordination so it is often left off the curve.
3. Plot the excitation transformer timed overcurrent characteristic (51ET) after converting it to equivalent rectifier dc current levels using Equation 2-11. On smaller systems, fuses are used and the time-current characteristic for the fuse is then used.
4. Plot the excitation limiter characteristic using the formula provided by the Manufacturer (e.g. 2-9, 2-10)

Figure 2-8 displays an example coordination curve. In this case the limiter followed the inverse-squared characteristic of Equation 2-10 and was set to begin limiting at 1.05 pu and operate with a small margin to the generator capability. An internal exciter protection was set to operate in the event that the limiter failed to operate as expected. The 51ET protection is set to protect the transformer and no attempt has been made to fit this to the generator capability.

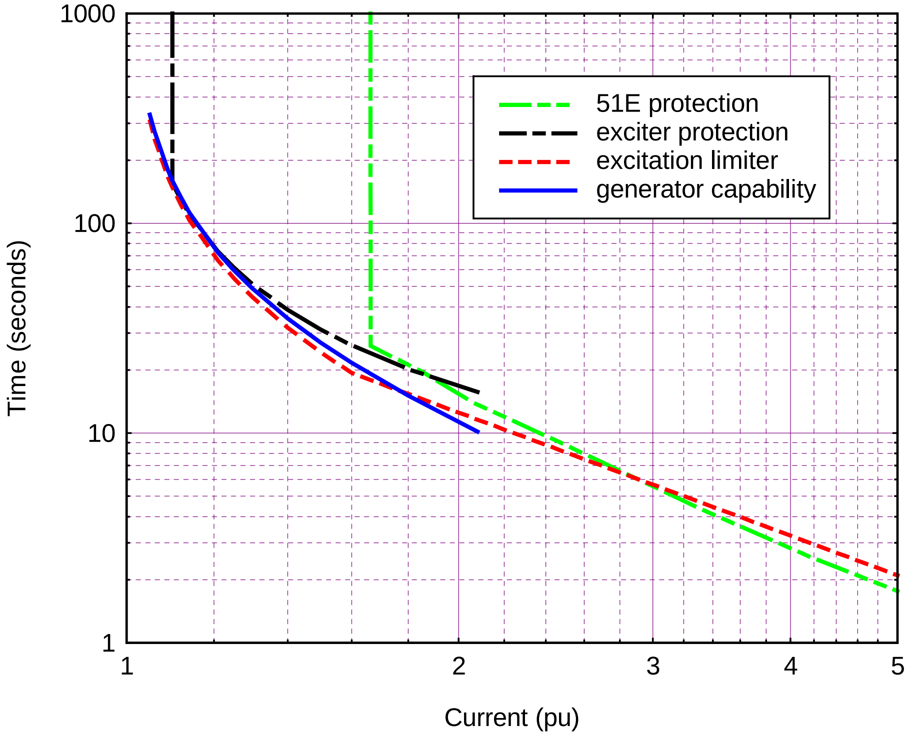

Figure 2-8
Example Field Current Limit Coordination Curves

The crossover between the excitation transformer protection and limiter characteristic for higher current levels illustrates a common problem of coordinating devices with different inverse-time characteristics. In some cases, this protection is set to closely coordinate with the field winding's limited-time capability. This is not recommended since this protection is not designed for this purpose and the potential for incorrect coordination is very large due to the difference in the sources for the field current measurement and the differences between inverse-time characteristics available on many overcurrent relays and the rotor's limited-time characteristic.

Although it will not always be possible to coordinate characteristics over the entire range of possible currents it is important to demonstrate coordination between rated current and the selected ceiling current on the exciter. In the example of Figure 2-8 this was 1.6 pu and the limiter will operate before the capability is reached at all lower field current levels.

The maximum field current forcing level used by different utilities varies within the standard range of Table 2-2, up to levels of 200% [2-20] however the range of 125% to 160% is relatively common.

The amount of margin used by generation owners varies widely with some setting the limiter to closely follow the limited-time capability of the field winding, thereby taking advantage of the full capability for grid support during disturbances. Others apply conservative settings with the maximum forcing set below 150% and the amount of time permitted at this level set to 50% of the available capability. To-date these selections are left up to the individual owners as long as they are documented and coordination has been demonstrated.

2.5.4 Rotating Main Exciter Coordination

For units equipped with rotating main exciters, the loaded main exciter saturation characteristic, such as the one shown in Figure 2-9, must be used to determine the relationship between the two field currents, as identified in Equation 2-13. The generator field winding resistance at rated temperature is used in translating since the concern is heating beyond this level.

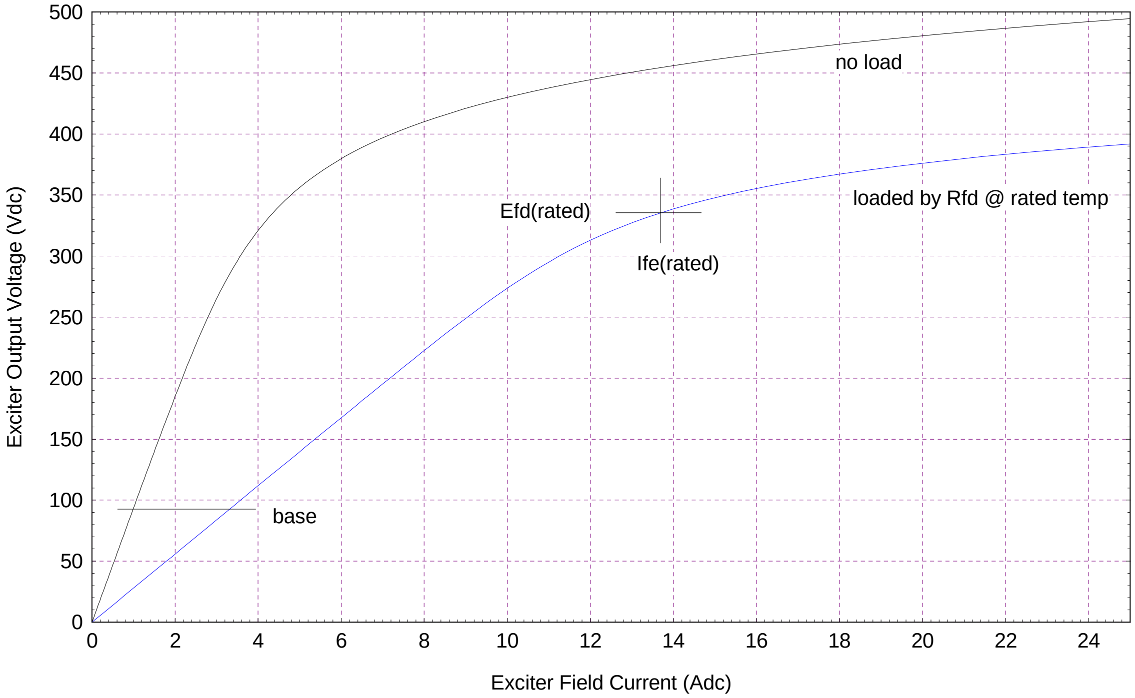

Figure 2-9
Main Exciter Characteristic Curves

The steps for verifying coordination for this configuration are as follows.

Continuous current levels

1. Determine generator field winding continuous capability, I_{rated}, from nameplate or manufacturer's data.
2. Determine main exciter output continuous rating, $I_{exc\text{-}c}$, from nameplate or manufacturer's documentation.
3. Determine the pilot exciter output continuous rating and convert to the equivalent generator field current, I_{PE}, using Equation 2-13.
4. Determine and convert the minimum pickup of any pilot exciter protection $I_{PE\text{-}prot}$ to the corresponding generator field current level.
5. Determine the minimum pickup of the field current limiter, I_{therm}, and convert using Equation 2-13.
6. Verify coordination between continuous levels, normally by satisfying the inequalities of Equations 2-16 and 2-17.

$$I_{PE\text{-}prot} \geq I_{PE} > I_{exc\text{-}c} \qquad \textbf{Equation 2-16}$$

$$I_{exc\text{-}c} > I_{rated} \geq I_{therm} \qquad \textbf{Equation 2-17}$$

Similar comments to the ones for the static excitation case apply here. The extra degree of uncertainty associated with the main exciter characteristic means that additional margin should be used between capability and limiter and protective relay settings. It is important to note that for field winding temperatures below rated, the limiter settings applied to the pilot exciter may allow higher levels of field current on the generator field winding. This is considered to be acceptable since the concern is for heat rise above the rated temperature.

Limited-time Forcing Levels

The same basic technique described for static systems is once again applied however it must be remembered that the relationship of Equation 2-13 must be evaluated for each current level being considered in the coordination. A curve similar to Figure 2-8 can be produced to demonstrate coordination.

2.5.5 Testing to Demonstrate Coordination

Some owners test limiter coordination by operating the unit up to the pickup point [2-20]. For field current limiters this is often not practical due to voltage restrictions and other system restrictions, and it is not necessary to demonstrate compliance with this standard. Even when the continuous limiter level can be reached some method is required to test the limited-time forcing coordination.

The capability levels described in the previous section are determined by examination of manufacturer's literature and test results. The operating points for field current limiters and any relevant protective relays can be confirmed from secondary injection testing during outages, a practice that is commonly used for verifying all protective relays.

As previously discussed the input to most OEL units is field current, although in some cases, field voltage may be used. The following discussion assumes that field current is the input. Testing of systems that employ field voltage will involve simply substituting the correct input signal.

Obviously it is not practical to reproduce the high current levels associated with over-excited conditions during off-line operation. Instead the usual approach is to replace the isolated quantity that is presented to the input of the limiter. In many systems, field current is measured using a standard shunt with a standard output (e.g. 50 mV, 100 mV) for current levels up to or slightly above the exciter rating. If this is the case, the connection to the shunt output can be disconnected and a dc test source inserted to provide an input signal scaled to represent different field current levels (Figure 2-10). If the shunt scaling is not available, either from the manufacturer's literature or on a physical stamping, the ratio can be measured by making a few cross-readings with the unit on-line. If another measurement source is not available, the current can be determined for known conditions (e.g. operation on open-circuit at rated voltage) using manufacturer's data such as the open-circuit saturation curve, and then compared to mV readings.

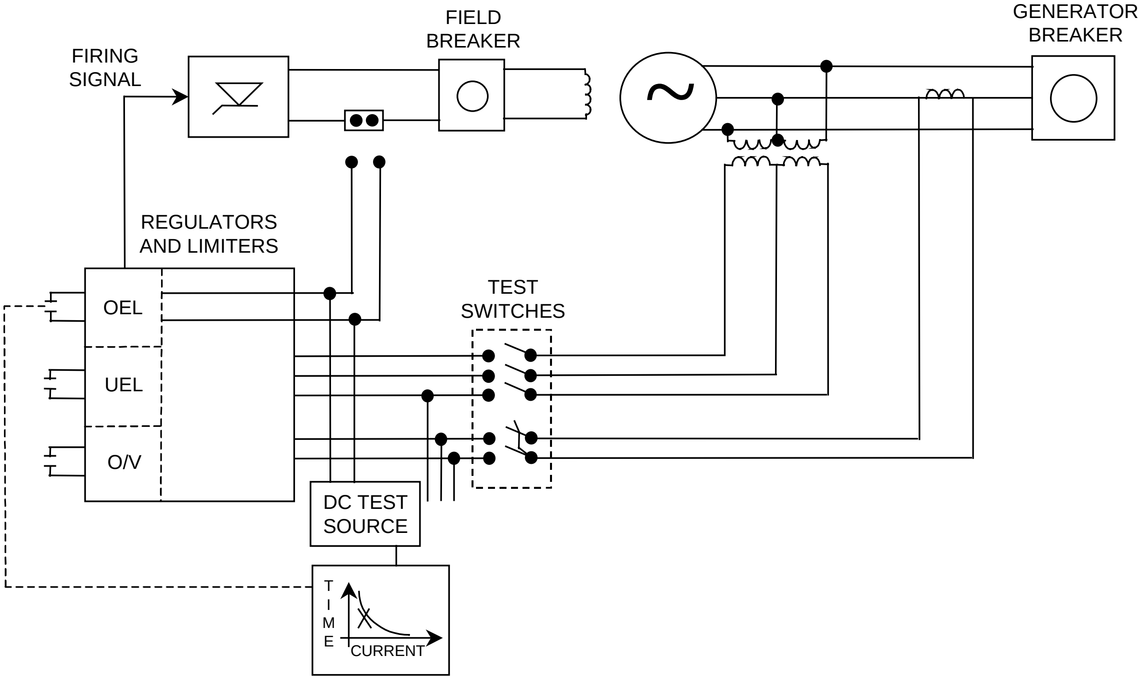

Figure 2-10
Off-Line Testing of Field Current Limiter

On some systems, field current shunts are not used and the measurement is obtained from the secondaries of ac CTs on the supply side of rectifier supplies or using DCCTs designed for direct measurement of high-level direct currents. Regardless, at some point, these signals will be isolated and conditioned to produce a low-voltage signal, suitable for connection to the regulator circuitry.

Once the signal substitution has been performed, the output of the limiter must be located so that it can be monitored during testing. Some OELs have output contacts or lamps that indicate when the unit is in limit or even when the current has exceeded the maximum continuous level at which the timer will start. If the manufacturer has not provided this type of function, then the design should be inspected to determine which signal could be monitored to provide an indication of limiter operation.

The minimum pickup of the OEL, the point at which the timed limit is initiated, must be measured and compared with the rated field current on the unit. Once the minimum pickup has been established the input signal should be reset and then applied at higher simulated current levels to measure the timing characteristic of Figure 2-8.

Some generation owners also perform on-line tests of the limiter to confirm its dynamic response. Although helpful this is not always required since the closed-loop field current limiter dynamics are normally stable. On digital systems this test may be relatively straightforward to perform and may also be the best method of verifying that the selected setpoints are followed.

The protective relays must be tested in the same manner. This is relatively straightforward for the ac supply over-current relays (50/51ET) however it may require some additional effort for dc overvoltage or overcurrent relays where direct connections to primary quantities are used.

2.6 Voltage and Over-Excitation (V/Hz) Coordination

The voltage and V/Hz limiter settings need to be coordinated with the following:

- generator continuous voltage capability (Section 2.2.1) and limited-time V/Hz capability (Section 2.2.2)
- overexcitation protection (24)
- undervoltage (27) and overvoltage (59) relay settings

Unlike the field current limiter the type of excitation power source need not be considered for voltage coordination. The only complicating issue is the capability and protection of transformers connected directly to the terminals of the generator, in particular the GST must be considered.

2.6.1 Accuracy and Measurement Considerations

The measurement of voltage and V/Hz via potential transformers is straightforward and has been implemented in many different ways based on the available technology in each era. The following factors must be remembered when examining coordination:

- The excitation system and generator protective relays will almost always be supplied by different sets of PTs, possibly with different accuracy classes. Some allowance must be made for differences in source voltages to the two schemes. A reasonable margin for this purpose would be 1% to 2%.

- The measurement of V/Hz and even voltage may be realized with two very different methods within the exciter and relays. Older excitation systems cannot be expected to implement this measurement with metering class accuracy and they need to be calibrated through off-line tests. On older systems, implemented with magnetic components and analog electronics some allowance must be made for drifting settings over time.

In some cases it will be necessary to compare voltage settings on the generator and GST. As discussed earlier GST ratings are applied at their high-voltage windings. Translation of these settings for relays fed from PTs measuring the high-side voltage must take into account any differences in the rated voltage of the GST low-voltage winding and the voltage drop associated with the transformer leakage reactance, X_T. Equation 2-18, can be used to convert high-side voltage settings and operating levels to the low voltage generator base for loaded conditions, neglecting winding resistance.

$$V_{gen}(pu) = \frac{V_{GST-LV}}{V_B} * \sqrt{\left(V_{HV} + \frac{Q_{HV} * X_T}{V_{HV}}\right)^2 + \left(\frac{P_{HV} * X_T}{V_{HV}}\right)^2}$$

Equation 2-18

where

V_B	generator voltage base
V_{GST-LV}	GST low voltage base
V_{HV}	GST high-voltage operating level in per-unit at the selected tap
P_{HV}, Q_{HV}	active and reactive power measured at the high-voltage secondary

2.6.2 Calculation of Coordination

Under-Voltage

Generator under-voltage (27) protection is not common however it has been finding its way onto more units as multifunction relays are used to replace old discrete relays. When applied a typical setting is 70% of rated terminal voltage for instantaneous operation and a timed delay setting starting at 90% with a significant delay to coordinate with fault clearing times on the grid [2-13]. In most cases these devices are used for alarm purposes only.

Even when generator under-voltage relays are not applied, auxiliary bus under-voltage relaying is used to prevent damage to motors and other loads [2-6]. A typical setting would be 90% of the auxiliary bus voltage and this needs to be converted to the corresponding generator voltage for full load operating conditions to confirm that the generator will not be prevented from operating down to 95% of its rated terminal voltage.

The AVR lower reference adjustment limit must permit operation down to 95% of rated voltage for all operating conditions, including the influence of any reactive current compensation. Typical values used for AVR lower limits are between 85%-90%.

Over-Voltage

As noted earlier, many exciters are not equipped with over-voltage limiters since a properly functioning AVR will not allow voltage to exceed the AVR reference by a significant amount. The exception is units equipped with summing-style UELs and PSS that add to the normal AVR reference and can lead to a setpoint above the continuous voltage rating of 105%. In these cases limiters may be applied, sometimes integral to the PSS function, preventing its contribution from increasing terminal voltage above a limit. In other cases the limiters are simply open-loop limits on the total setpoint with no time delay.

The AVR upper reference adjustment limit must permit operation up to 105% of rated voltage for all operating conditions, including the influence of any reactive current compensation. Typical values used for AVR upper limits are between 105% and 110%.

The application practices for over-voltage protection (59) vary, with some older schemes set to alarm only and others set for tripping. The lowest setting for a timed O/V element is between 110% of rated [2-13] and 115% [2-20]. The only coordination requirement is that any O/V limiter setting be selected to coordinate with the minimum pickup of the O/V protection and that there be adequate margin (e.g. 2%) between the limiter and protection setpoints. Adequate time must be provided for the AVR to respond. For systems with HIR this will be less than one second while for older systems a few seconds may be required. If there is any doubt about the time response of the system, the excitation system model can be used to perform a simulation and confirm coordination between the exciter response and O/V protection delay.

V/Hz

V/Hz protection (24) has historically been applied on large cylindrical rotor generators and less frequently on salient pole generators. As noted earlier and in Section 2.2.2, the limiting factor may be the GST rather than the generator itself. When applied, the V/Hz protection on older systems normally took the form of one or more definite-time relays. On newer systems inverse-time characteristics are now available and are beginning to be used.

The steps to verify coordination are as follows:

1. Obtain the generator's limited-time V/Hz capability from manufacturer's data. In the absence of unit-specific data, "typical" data for similar units may have to be used since the standards do not supply recommended levels. Plot this characteristic.
2. Plot the generator V/Hz protection characteristic(s).
3. Obtain the transformer's voltage ratings, impedance data and limited-time V/Hz capability. Transform the high-side characteristic to the low-voltage winding on the same base as the generator using Equation 2-18 and plot against the generator characteristic.
4. Plot the excitation limiter characteristic.

Figure 2-11 is an example plot to demonstrate coordination of these characteristics. The generator capability was more restrictive than the transformer in this case and the V/Hz relay protection was implemented with two definite-time relays set at 1.18 pu (6 second delay) and 1.1 pu (60 second delay). In this case the exciter is also equipped with a protective feature that operates if the limiter action does not act properly. The limiter is coordinated properly and allows operation up to 105% of rated voltage at rated frequency.

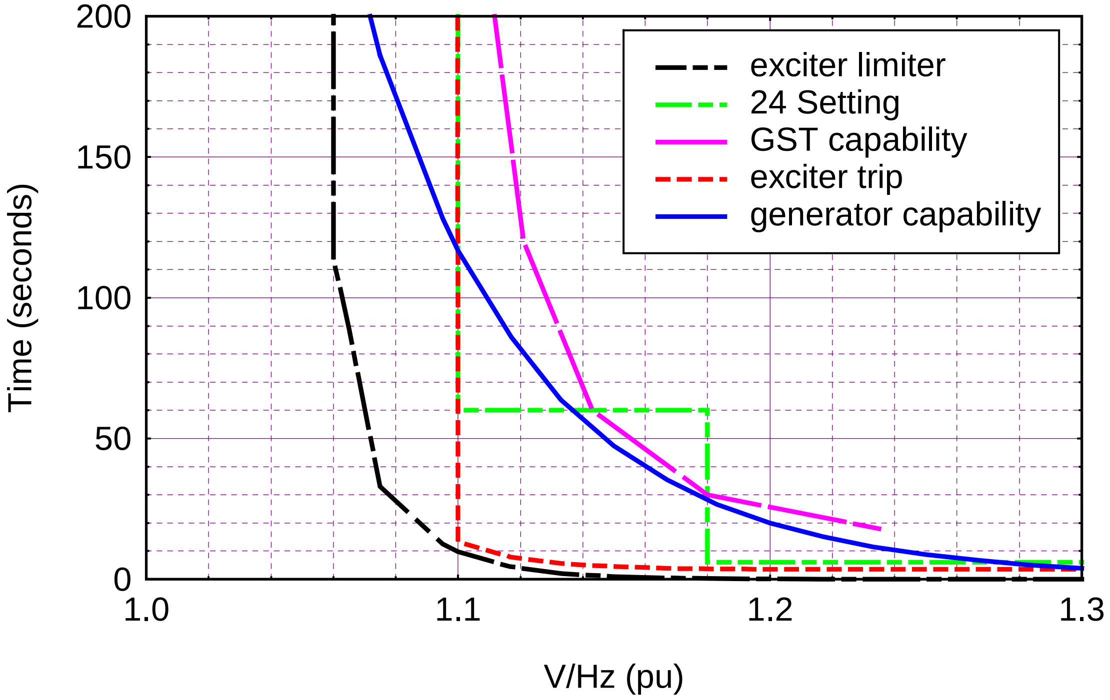

Figure 2-11
Example V/Hz Limit Coordination Curves

A review of common utility practice reveals that the limiters are frequently set to operate at 1.1 pu [2-5], [2-18], [2-20], although lower settings such as 1.08 pu [2-8] are reported.

2.6.3 Measurements to Confirm Coordination

These are normally the simplest of the limiters to verify through off-line injection testing. A three-phase test voltage source is substituted for the generator PT connections to the AVR that typically also feed any over-voltage or over-flux limiting functions. Figure 2-12 depicts the test connections for this type of test. The test set voltage and frequency are then adjusted to represent the required conditions and the minimum pickup of the limiter is measured. Like the OEL, some O/V limiters have an alarm contact to indicate when the unit has entered a limit or timing has begun. The discussion on the OEL monitoring also applies to the O/V limiter, if an operation indication does not already exist.

On O/V or V/Hz limiters with timed characteristics, different levels can be applied to allow measurement and confirmation of the timed characteristic. If the test set permits operation at different frequencies the V/Hz limiting relationship can be confirmed at different frequency and voltage combinations that provide the same ratio.

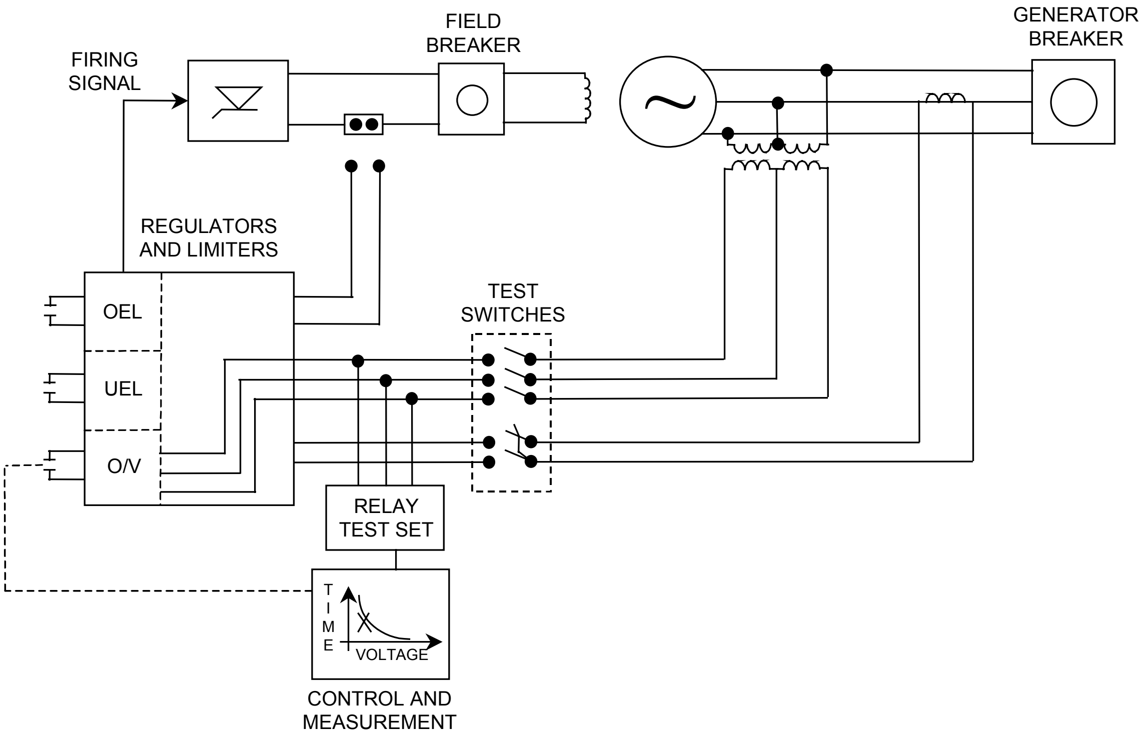

Figure 2-12
Off-Line Testing of Voltage and V/Hz Limiters

Tests of dynamic performance with the unit running at lower setpoints are relatively easy to perform on units equipped with digital exciters and are often used as the primary test method as opposed to performing off-line injection testing. These can also be done on older designs but this normally requires on-line settings changes that introduce uncertainty as to the final setting.

The corresponding relays can be verified using the same configuration or the results of routine relay calibrations collected to demonstrate coordination.

2.7 Under-Excitation Coordination

Conservatively set Loss of Excitation (LOE) relays account for a significant portion of unnecessary trips of generators during system events [2-6]. Although there have been many discussions of the topic of under-excited operation in the literature there still remain some significant misconceptions that come into play when coordination is performed in the leading power factor region [1-13], [2-3] to [2-5], [2-19], [2-20]. The selection of Under-Excitation Limiter (UEL) settings should take into account the following factors:

- generator continuous leading power factor capability (Section 2.2.7)
- loss-of-excitation relay (40) settings
- self-excitation and minimum exciter current limits
- stability issues
- restoration issues (e.g. line charging)

There is little disagreement that the UEL must be configured to operate before the generator's core-end heating limit is exceeded and before any protective relay characteristics are entered. Where there has been some significant variation in application is in the selection of LOE (40) relay settings. Originally the intent of this protection element was to identify true loss of excitation and trip the unit relatively quickly to prevent the resulting changes in generator terminal and field quantities from disturbing the network or neighboring units or from causing damage to the unit.

The LOE function is normally implemented with a combination of one or more impedance relays, directional units and under voltage elements. Reference [2-13] discusses the various choices for selecting settings for 40 elements. The most common approach for cylindrical rotor machines is with a pair of circular impedance characteristics offset below the origin by half of the generator's transient impedance ($X'_d/2$). The first relay is set with a diameter equal to the d-axis synchronous reactance X_d, and a minimum delay of 0.5 seconds. The second relay is set with a diameter of 1.0 pu and a short time delay (e.g. 0.1 s). These settings produce characteristics in the impedance and power planes similar to those shown in Figure 2-5.

On salient pole generators the direct axis reactance is often close to 1 pu, and the same approach cannot be used. In this case a single mho relay may be applied with diameter X_d and offset $X'_d/2$ and a longer time delay. Other utilities have used smaller diameters to move this characteristic further away in recognition of the fact that saliency allows these units to operate down to the self-excited limit and that core-end overheating does not normally occur on these units.

In other cases relay engineers have advocated using a positive offset for the relay characteristic, producing a curve that encircles the origin in the PQ plane and can therefore be tailored to follow the steady-state stability limit or core-end heating curve [1-13], [2-13]. In this application the LOE is no longer being used to detect loss of excitation but rather operation below a heating or calculated stability limit. These settings increase the likelihood of false trips on recoverable swings. To coordinate the UEL with this characteristic often requires very conservative settings imposing a significant limitation on under-excited operation. Some have argued that setting the UEL anywhere below the thermal limit based on stability constraints is an unwarranted waste of reactive capability [2-3]. It has also been pointed out that the calculated steady-state stability limits are based on the assumption of constant field voltage and current, a condition for which the UEL is not in service on most excitation systems [2-1]. Overly conservative UEL settings can lead to unacceptably high voltages during system disturbance conditions and interactions between V/Hz limiters and UELs can even occur.

Ultimately it is the generation owner that must decide the criteria to be used in establishing the LOE relay settings and the limits to be included in selecting the UEL settings for their units. The following sub-sections briefly discuss the required calculations and measurements for demonstrating coordination.

2.7.1 Accuracy and Measurement Considerations

As was the case with the voltage measurements of the previous section the accuracy of different PT sources must be considered in establishing an appropriate margin for settings. This is also the case with the CT supplies used for calculation of power levels in the limiters and apparent impedance in the relays. Older electromechanical relays are more likely to exhibit errors between their calculated settings and actual operating points.

Coordination plots can be produced in either the impedance (RX) or power (PQ) coordinate systems. LOE plots are most often available in the former while UEL plots are normally produced in power coordinates. Conversion between the two systems is accomplished using Equations 2-7 and 2-8 or their inverse relationships. Coordination plots are normally produced in the power plane since the resulting plots are a useful guide for operations and planning staff.

Voltage dependence of limits can be discussed based on the voltage exponent, N_V, that applies to the limits as follows:

$$\begin{aligned} P &= P_{LIM} * V^{N_V} \\ Q &= Q_{LIM} * V^{N_V} \end{aligned}$$

Equation 2-19

where the actual limit point (P,Q) at an off-nominal voltage is determined from the operating point at nominal voltage (P_{LIM},Q_{LIM}).

2.7.2 Calculation of Coordination

The steps to verify coordination are as follows:

1. Obtain the generator manufacturer's capability curves for selected cooling conditions and rated terminal voltage conditions.
2. Obtain all 40 relay settings and recent calibration sheets.
3. Convert secondary ohms to the generator per-unit base (Equation 2-6).
4. Convert from impedance coordinates to power coordinates (Equations 2-7 and 2-8).
5. Add the calculated steady-state stability limit curve to under-excited portion of curve if used in coordination.
6. Add any exciter low-current or self-excited curves as appropriate.

Figure 2-13 is an example plot to demonstrate coordination of these characteristics. In this example the LOE was set with a positive offset to coordinate with the generator's core-end heating characteristic. A simple piecewise UEL curve was selected to provide a relatively constant margin. The practical steady-state limit is assumed to not be restrictive in this case.

The decision on how much margin is required between the UEL characteristic and the most restrictive of the protection and generator capability characteristics is not always a simple decision. If the core-end heating limit is the most restrictive curve then the UEL may be set to follow this characteristic with minimal margin (e.g. 5% to 10% of rated MVA) since a short duration excursion beyond the limit may be tolerated. In the unlikely event that the calculated steady-state stability limit is used as the basis for the UEL setting, margin may not be required since this limit is already conservative based on its method of calculation.

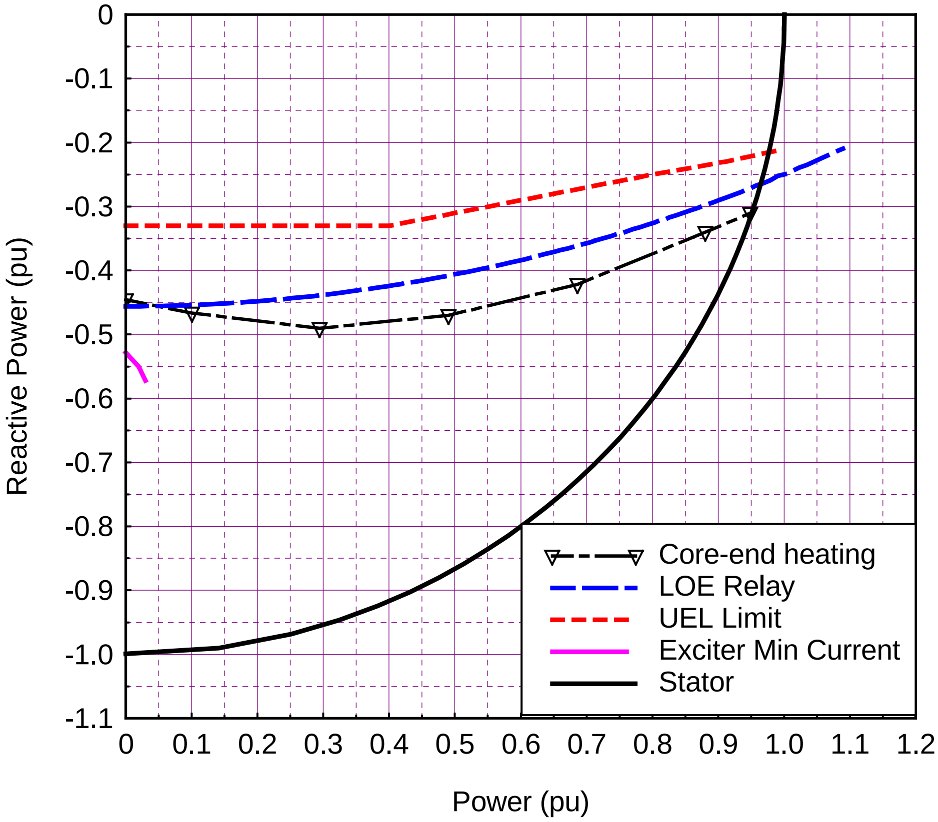

Figure 2-13
Example Under-Excitation Coordination Curve

If the most restrictive limit is the LOE then the closed-loop exciter response while under UEL control must be considered along with the LOE time delay to determine the required margin. In some cases transient simulations are run to determine whether the trajectory of apparent impedance will remain within the LOE relay characteristic long enough to result in a trip [1-13]. Running such detailed simulations for each unit is not very common especially since detailed UEL models have only recently been standardized [2-19] and are not yet available in most simulation programs. In order for these results to be realistic, detailed models of all neighboring units may be required including their controls. When detailed simulations are not performed, results of dynamic response tests of the UEL can be examined to determine the amount of overshoot and settling time that can be expected and the margin can then be set on this basis.

References [1-13] and [2-5] advocate a margin of 10% of rated MVA, while reference [2-3] uses 15% and other owners have reported using a margin of 10% of the limit value, which is normally half of the margin based on rated apparent power.

2.7.3 Variation in Limits With Cooling Conditions

A common feature of newer excitation systems is recalibration of limiters based on an external measurement of cooling pressure or temperature. The temperature or hydrogen pressure measurements are interfaced to standard station transducers used for Operator alarms or indication. The signal is introduced to the exciter as an analog value or discrete contact that operates when a certain threshold is crossed. The exciter logic can then switch between different limiter characteristics, each one tailored to the prevailing cooling conditions. Based on experience with new systems and discussions with owners it appears that this new feature is rarely used.

For excitation systems that allow only a single limit, owners must select the conditions and corresponding capability curve that will be used in selecting the UEL settings. Some report using rated operating pressure while some advocate using the lowest [1-13] pressure that can be used in operating the unit. Although the latter approach is conservative, it may not be practical, since when combined with some setting margin it may lead to very restrictive limits in the underexcited region.

2.7.4 Variation in Limits With Operating Voltage

The effect of operating voltage on the various capability curves and limits must be included in any analysis of coordination. If the voltage-dependence of the excitation limiter is the same as the most restrictive curve then coordination for rated voltage conditions will apply at other operating voltages as well. If however the voltage-dependence is different then additional margin may be required to account for this effect.

The possible dependencies are listed below along with their applicability.

- No voltage dependence ($N_v = 0$). This applies to excitation limiters where active and reactive power are measured and used to calculate the limiter output with no intentional voltage scaling introduced.
- Proportional to voltage ($N_v = 1$). This applies to excitation limiters that use active and reactive current as their inputs. This also normally applies to core-end heating limits since the heating effect is proportional to under-excited current. The manufacturer should be consulted to confirm this.
- Proportional to square of voltage ($N_v = 2$). This applies to impedance-based relays, most calculated steady-state stability limits and excitation limiters that operate based on an impedance characteristic.

On newer excitation systems the user can often select the voltage-dependence of the limits and the following rules can be used:

- LOE relay or steady-state stability most restrictive - use $N_v = 2$
- Core-end heating limit most restrictive - use $N_v = 1$

In cases where the dependence cannot be programmed, coordination should be verified for voltages between 95% and 105% to confirm that settings selected at rated voltage do not overlap. The effect is illustrated in Figure 2-14 for the case where the voltage has been increased to 105%. The limits at rated voltage have been retained on the curve and the corresponding limit at the higher voltage are shown with bold lines. In extreme cases, the limit curve may no longer be properly coordinated with the limiting factor and additional margin will need to be used.

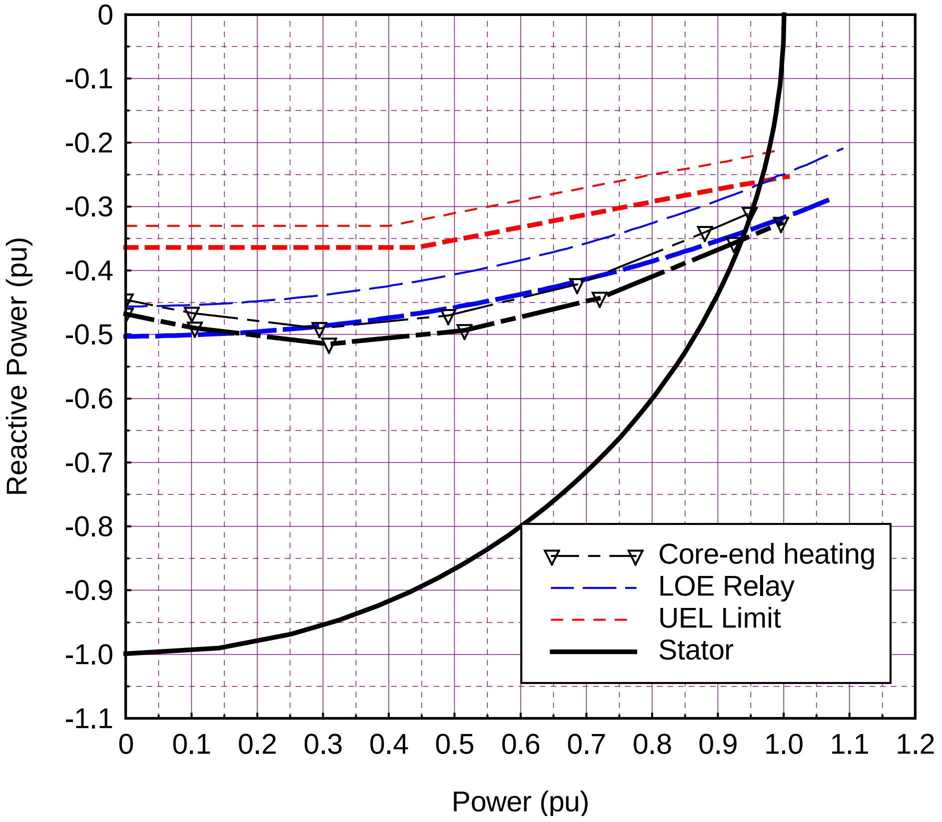

Figure 2-14
Voltage Effects on Limits in Under-Excited Region

2.7.5 Measurements to Confirm Coordination

Once again secondary injection testing is normally used to confirm the limiter operating points. This is critical on older units where impedance or analog-electronic elements are used to implement the limiter but is even recommended for digital units, especially during commissioning to confirm correct scaling of secondary PT and CT inputs. The voltage dependence of the limits can be confirmed by verifying calibration for three voltage levels: 95%, 100% and 105%. Figure 2-15 depicts the test connections for this type of test. It is often convenient and economical to schedule this testing at the same time as LOE relay tests are performed since the same equipment and settings are used.

Unlike other limiters that normally provide stable closed-loop response, UELs may be dynamically unstable unless tuned correctly [2-1], [2-4]. This is particularly important to verify when used in conjunction with a power system stabilizer. If it is not possible to test the response at the normal limit due to voltage restrictions, then the limit may have to be temporarily increased. On digital systems this is straightforward, however on analog-electronic systems this can be problematic since the final setting cannot be re-verified. Another alternative is to use a digital simulator that allows both static limit verification and closed-loop dynamic response measurement.

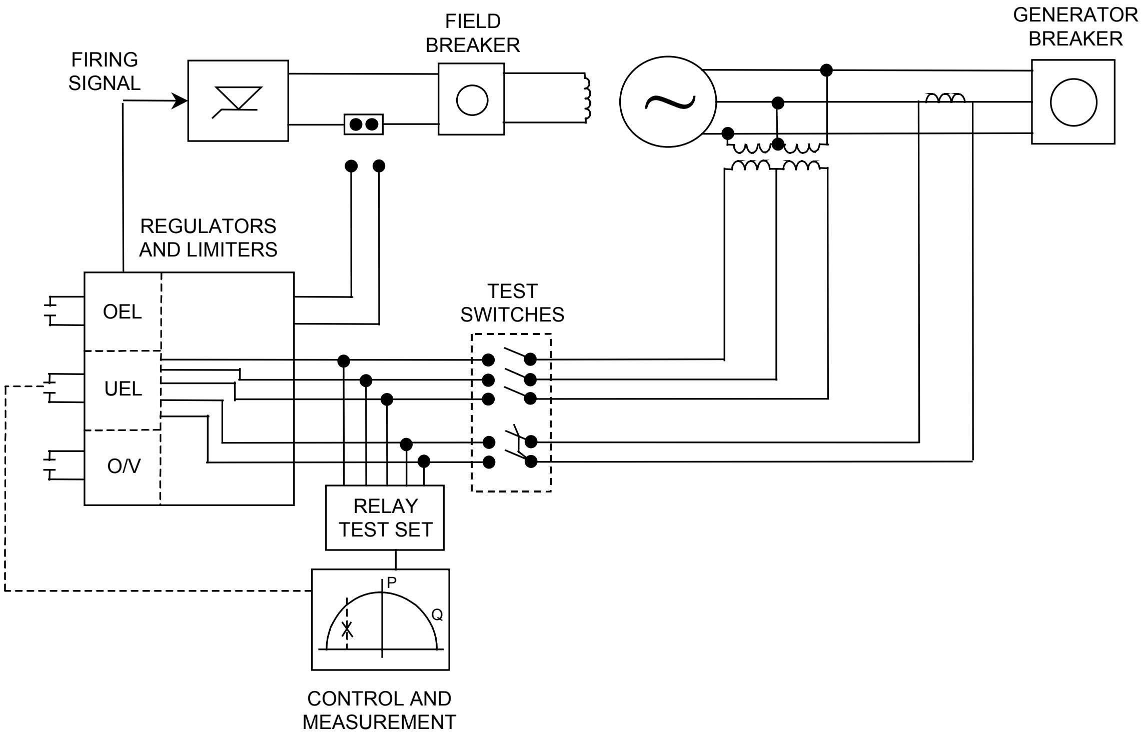

Figure 2-15
Off-Line Testing of UEL Limiters

2.8 Stator Current Coordination

As noted in the previous section, conservatively set backup voltage-restrained overcurrent relays account for a significant portion of unnecessary trips of generators during system events [2-6]. Stator current limiters (SCLs) have begun to appear in newer digital excitation systems. Discussions with generation owners suggest that they are not normally used even when available and the total percentage of units with this feature in North America is believed to be quite small. Nevertheless if SCLs are used their settings should take into account the following factors:

- generator continuous and limited-time capability (Section 2.2.6)
- backup protection (51V, 21) relays
- stator thermal overload (49) relays

The accuracy and measurement issues for this limiter are similar to the UEL and are not repeated in this section.

The recommended settings for voltage-restrained (51-VR) or voltage-controlled (51-VC) overcurrent relays are somewhat different [2-7], [2-13]. For voltage controlled relays, current settings below rated may be used but this element should not operate for non-fault conditions and is therefore not considered for coordination purposes. Voltage-restrained relays will normally have current settings well above rated current.

Distance relays used as backup protection (21) are normally set to operate for levels of between 150% and 200% of rated apparent power. The previous discussion of voltage exponents for impedance characteristics applies here [2-7], [2-13].

If typical settings are applied then the backup relays will not need to be analyzed in any further detail to confirm coordination. If other settings have been used these should be reviewed and converted to the power coordinate system for comparison with the expected loading of the generator.

Some owners make use of thermal overload elements (49) monitoring the stator winding RTDs to produce an alarm and in some cases trip the unit if the winding's insulation system temperature limits are approached or exceeded. If trip functions are enabled then the manufacturer's documentation should be reviewed to convert the temperatures into current levels for worst-case cooling conditions for comparison with the reported capability curve and any limiter settings.

2.8.1 Confirmation of Coordination

The steps to verify coordination are as follows:

1. Obtain the generator manufacturer's apparent power capability and calculate the corresponding stator current at rated voltage. Confirm whether this limit corresponds to rated temperature rise for the insulation system or if the unit can be operated at rated apparent power down to 95% terminal voltage. Select generator stator limit, I_{stator}.
2. Convert the backup relay (51V, 21) characteristics into the equivalent current values for the lowest emergency voltage operating level permissible on the system, I_{backup}.
3. Convert any thermal relay (49) settings into equivalent stator current levels for the maximum coolant temperature, $I_{thermal}$.
4. Determine the minimum pickup for the excitation system's SCL, I_{SCL}.
5. Verify coordination between stator current levels, normally by satisfying the inequalities of Equation 2-20.

$$I_{backup} > I_{thermal} > I_{SCL} > I_{stator}$$ **Equation 2-20**

No plots are required to demonstrate coordination although any factors that limit the generator's apparent power output below the generator manufacturer's capability curves should be identified on those curves until the limit can be corrected.

SCL static limits can be tested using the secondary injection testing described for UELs and the dynamics tested by lowering the setpoint to within normal operating levels.

3

VERIFICATION OF MODELS AND DATA FOR EXCITATION SYSTEM FUNCTIONS

The following section addresses draft standard MOD-026 “Verifications of Models and Data for Generator Excitation System Functions” [3-1]. This standard is presently under development by the NERC Generator Verification Standards Drafting Team. This section is based on the draft standard issued in January 2007. Any significant changes to the final standard will need to be considered when reviewing the material of this section and formulating a compliance plan. Many of the concepts discussed in this Section are based on conventional industry practice and standards and will therefore not be affected by any changes to the final NERC requirements.

This standard requires the generator operator to ensure accurate information on generator excitation system functions (including voltage regulator controls, limiters, compensators, and power system stabilizers, if applicable) is available for models used to assess Bulk Electric System reliability. Each Region is responsible for dictating methods for obtaining the information, and the documentation allows the use of engineering analysis, manufacturer’s data, comparison with test results and disturbance data. Items to be reported are:

- Verified manufacturer and type of excitation system/voltage regulator control system (i.e. static, brushless, rotating, etc.).
- Verified model for each excitation system/voltage regulator control system with associated gains, time constants, and limits.
- Verified static set points for under and over excitation limiters.
- Verified line drop compensator settings.
- Open circuit test response data showing generator field voltage and generator terminal voltage (exciter field voltage and current data for brushless units).
- Verified model for each power system stabilizer with associated gains, time constants, and limits.

Different jurisdictions presently specify various alternatives for verification of this data including use of manufacturer data, commissioning data, performance tracking, engineering analysis, field verification of equipment settings, testing, simulation and comparison with test results or disturbance monitoring data. The method of verification should be reported including any applicable conditions under which the data was verified.

Prior to discussing validation procedures and options, this section provides some background material on excitation systems and important definitions. For those unfamiliar with excitation systems, references are provided to widely available industry references on the topic.

3.1 Excitation System Design

The generator excitation system is designed to meet a variety of requirements which may be summarized briefly as:

- Supply generator field current to magnetize generator and enable conversion of power
- Meet the power system's short-term reactive power support requirements
- Limit excitation to prevent damage to generator

In some locations the exciter is also called upon to respond to voltage changes with sufficient forcing capability to improve system stability.

As a result, the excitation system has a number of components working together in a closed-loop system. The main elements of an excitation control system are shown in Figure 3-1 [2-21]. In this document, the term excitation system is used to describe all of the components that control and supply dc current to the generator field winding. This includes the regulators and limiters which determine what the field voltage and current should be at any given point in time, and the power stage(s) which provide the required amplification to boost low-level electrical control signals into the large currents necessary to meet the generator's excitation requirements. The automatic voltage regulator (AVR), which adjusts excitation to maintain a desired ac terminal voltage, is just one of the regulators commonly supplied with excitation systems.

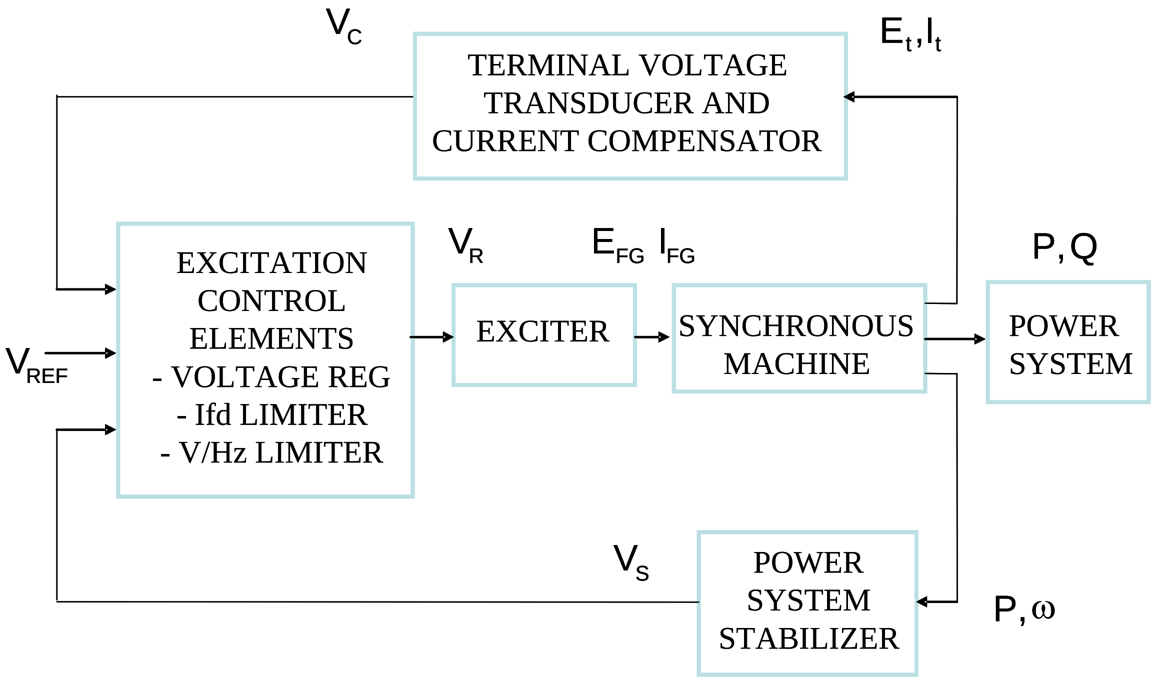

Figure 3-1
Excitation Control System [2-21]

The term excitation system will be used to refer to the entire closed-loop system including controls and power sources to the field winding of the generator. The term exciter will be used to refer to the portion of the system that supplies voltage and current to the field winding of the generator (i.e. the power source). Presently installed excitation systems encompass a variety of different designs and technologies. In order to organize the discussions in this document the material will be arranged based on the type of power source and the type of technology used to implement the controls according to the following categories:

Exciters

- **DC** rotating exciters feeding the generator field through brushes and slip-rings
- **AC** rotating exciters feeding either rotating rectifiers directly connected to the generator field (brushless) or stationary rectifiers feeding the generator field through brushes and slip-rings
- **ST** static exciters consisting of a power electronic controlled rectifier (usually thyristor bridge) fed from a transformer and connected to the generator field through brushes and slip-rings

Controls

- magnetic (e.g. magnetic amplifiers)
- electronic (e.g. transistors)
- digital

A detailed review of these excitation system configurations is encouraged; some basic definitions are included in the glossary section of this report, while detailed information can be found in the reference materials [2-21].

3.1.1 Exciter

As discussed in the introduction, the Exciter comprises the power supply which is connected to the synchronous generator field terminals.

The exciter technology impacts on modeling and testing in several ways.

- Saturation (differences between dc and ac)
- available signals to measure
- transducer requirements
- response (time constant)

The following sub-sections provide a brief review of each of these technologies.

3.1.1.1 DC Main Exciters

DC Excitation Systems (type DC) are characterized by the use of a rotating dc machine, either separately- or self-excited, as the final stage of the power supply providing current to the rotor of the synchronous machine through slip rings. The voltage regulating systems for these exciters range all the way from non-continuously-acting rheostatic systems, through systems that use many stages of magnetic amplifier and rotating amplifier amplification. The older style of DC excitation system is gradually disappearing, as few new dc systems are being built.

The main exciter is a dc generator, and like the synchronous generator, has a nonlinear input-output relationship based on its saturation characteristic.

The exciter field current and voltage may be supplied by a variety of low-power amplifier technologies including:

- Self-excitation and manual or discontinuous rheostatic control
- Magnetic amplifier sometimes in conjunction with amplidyne automatic voltage regulators
- Analog or digital electronic voltage regulators controlling a power electronic bridge that supply the main exciter field

The significance of these different control technologies will be discussed further in the sections below.

3.1.1.2 AC Main Exciters

AC Excitation Systems (type AC) are characterized by the use of a rotating ac machine as the final stage of the power supply, providing current to the rotor of the synchronous machine through either uncontrolled or controlled rectifiers. This category includes systems where the rectifiers are stationary and the field current is fed to the generator field through slip rings and systems where the rectifiers are rotating and slip rings are not employed. Rotating rectifier systems were developed as a result of difficulties with commutators at the time and perceived difficulty in going to higher commutator ratings.

The main exciter is an ac generator, and like the synchronous generator, has a nonlinear input-output relationship based on its saturation characteristic.

In early AC excitation systems the voltage error signal was amplified through a combination of magnetic and rotating amplifiers to modulate the excitation. On new systems, the exciter field current and voltage are typically supplied by analog or digital electronic voltage regulators controlling a power electronic bridge with separate excitation of the main exciter field. Details of closed loop voltage controls are discussed separately below.

3.1.1.3 Static Exciters

Static Excitation Systems (type ST) are characterized by controlled-rectifier bridges supplying current directly to the field of the synchronous machine through slip rings. Supply to the thyristor bridge(s) is most commonly provided by a three-phase potential transformer fed from the generator terminals or a unit supply bus. The majority of new excitation systems being supplied today fall into this category. In some cases, the bridge supply is provided by potential and current windings that are built into the generator.

The exciter output current (either feeding the generator field or main exciter field in pilot exciter applications) is a dc value because of the filtering effect of the generator field time constant. Field current may be measured via a resistive shunt; however some static systems employ dc Hall Effect devices or indirect measurement of field current from CTs at the excitation transformer. If internal recording of the exciter output quantities is not available a temporary calibrated shunt may have to be installed to provide the required measurements of generator field current.

The exciter output voltage will typically be from a 6-pulse thyristor bridge or sometimes for pilot exciter applications from a PWM controlled transistor amplifier. In this case, a special transducer is required to provide both the necessary isolation and attenuation for safety and signal conditioning to produce an average value without introducing objectionable levels of phase shift. Transducers are discussed further in sections 3.3 and 3.4.

3.1.2 Excitation Controls

As discussed in the introduction, the excitation controls may be implemented via magnetics, analog electronics or digital electronics. Manual rheostatic control and discontinuous style regulators will not be discussed here, since detailed models are not required and these units can be represented as having fixed excitation.

The excitation control technology determines the nature of the simulation model, the available vendor data, and the method of testing.

3.1.2.1 Magnetic Amplifiers

Magnetic amplifier and mag-amp/amplydine systems are common 1950’s vintage designs providing closed-loop controls including automatic voltage regulation, reactive current compensation and under excitation limiting. Although old, many of these systems are still in service. They do provide continuous small and large-signal response and may, in some cases, have sufficient bandwidth to meet modern small-signal and transient performance requirements. Due to their design and age, settings may change and regular testing is recommended confirm closed-loop performance.

Testing is complicated by the nature of the magnetic amplifier design. In these systems, saturable control windings are used to combine feedback signals from the generator PTs and CTs as well as exciter field or generator field voltage to provide voltage regulation and stabilization. If extra windings are available, test signals may be injected to perform dynamic tests. Often, these windings are all in use, or it is not practical to connect external sources to introduce test signals. In this case, other means must be used to initiate a controlled disturbance to test the closed-loop performance. Modulation of the PT feedback through a variac transformer has been successfully used for this purpose.

3.1.2.2 Analog Electronic Controls

Analog electronic controls are common in systems built from the 1960’s through 1990’s. These designs typically have a complete array of closed-loop controls including automatic voltage regulation, reactive current compensation, over and under and volts-per-hertz excitation limiting. They provide continuous small and large-signal response and typically have sufficient bandwidth to meet modern small-signal and transient performance requirements. Due to their design and age, settings may change and regular testing is recommended to confirm closed-loop performance.

3.1.2.3 Digital Electronic Controls

Digital electronic controls are supplied for virtually all new and retrofit control applications. These designs typically have a complete array of closed-loop controls including automatic voltage regulation, reactive current compensation, over and under and volts-per-hertz excitation limiting, and a host of other controls and displays for operator convenience.

Unlike their mag-amp and analog electronic predecessors, digital controls are not continuously acting either in time or magnitude. As a result, small and large-signal responses may not meet the expected levels of performance, and there are typically limitations to the ranges of gains and time constants which may be applied. The quality of the digital controls in resolution and emulation of the transfer functions shown in the documentation varies widely. Once configured and modelled, settings should not drift and less frequent testing may be appropriate. Configuration management is essential to ensure that settings are not changed without corresponding changes to models for the system.

3.2 Response and Modelling

Simulation models and test procedures are thoroughly documented in the IEEE standards [1-14], [1-15], [3-2]. The major simulation software vendors provide models corresponding to these standards.

The correct setting and operation of the generator excitation system and supplementary controls such as the power system stabilizer (PSS) are fundamental to the proper response of a generator during a large system disturbance. As a result NERC requires testing of most of the major regulators and limiters within the excitation system.

3.2.1 Excitation Definitions

The following generator base quantities are used when discussing excitation systems [2-21], [1-15] with reference to the generator open circuit saturation curve of Figure 1-1:

Base terminal voltage – The per-unit base is the manufacturer's nameplate rating for line-to-line RMS voltage. Typical values for large thermal and nuclear units are 22 and 24 kV. Hydraulic units are usually in the range of 12 kV to 15 kV.

Base Field Current – The per-unit base is the field current required to produce rated terminal voltage, assuming no saturation (i.e. rated terminal voltage on the Air Gap Line).

Base Field voltage – The per-unit base is the field voltage required to produce one per unit field current at a stated rotor temperature. For thermal units the rotor temperature is taken at 100°C. For hydraulic units, a temperature of 75°C is used. Temperature is specified since it affects the rotor resistance, which in turns affects the voltage necessary to drive the field current through the circuit.

Rated Field Current – The rated field current is the generator's nameplate value of field current. By convention it is the value of field current which results in operation at the nameplate lagging power factor (overexcited) rated apparent power and rated terminal voltage. This value may be equal to the maximum continuous temperature rise for the insulation system of the field winding.

Rated Field Voltage – This value is calculated from the rated field current and rotor resistance at the stated temperature used to determine the base field voltage.

3.2.2 Dynamics and Closed-Loop Voltage Control

MOD-026 does not specify levels of closed-loop response for the excitation system or related controls (e.g. PSS). Individual RROs or ISOs may specify performance requirements for their jurisdictions. This sub-section provides summarizes terminology related to dynamics and closed-loop response.

The excitation system response to disturbances forms the basis for most of the performance requirements evaluated by ISOs and the NERC regions. The various performance measures and definitions are documented in IEEE 421.2 Guide for Identification, Testing, and Evaluation of the Dynamic Performance of Excitation Control Systems [3-2]. The following measures are used when discussing excitation system performance.

Voltage Response Time – The excitation system voltage response time measurement begins at the time a disturbance is initiated and ends when the field voltage reaches 95% of the difference between ceiling voltage and rated field voltage for a specified disturbance. Various ISOs define the disturbance in different ways, with the most common disturbance being a specified drop in generator terminal voltage or corresponding increase in voltage regulator reference. Depending on the ISO, the terminal voltage/reference change is either 5% or 10% of generator rated terminal voltage. Systems with a voltage response time less than 100 ms are considered to be “High Initial Response” (HIR) [3-2]. Some ISOs will require even faster response (33 ms and 50 ms are figures in present use).

Practically speaking, there is no way to operate a unit at rated field voltage and then to cause a system disturbance such that the generator voltage drops by the specified amount. As a result, the standard practice is to validate the closed-loop excitation system response to a controlled disturbance, e.g. 2% terminal voltage reference step change, and validate the simulation model used to represent the system. The simulation model is then used to simulate the conditions of the voltage response time test.

Steady-state regulation – Typically specified in exciter bid documents to meet a certain maximum generator terminal voltage regulation error. The error may be related to the AVR dc gain, K_A, for proportional control. Voltage regulators which include an integral component, the error between the set point and output will become zero, and there is no corresponding requirement for proportional gain.

Large-signal performance – Evaluated based on the excitation system time response. The performance requirements are typically specified in two parts: the ceiling voltage level and the response time. The ceiling voltage level is typically specified as a percentage of rated requirements, e.g. 200% of rated field voltage. Since some static excitation systems are fed from a transformer connected to the generator terminals, rather than from a fixed auxiliary bus voltage or other relatively constant voltage source, some ISOs specify the ceiling requirement in terms of both the field voltage and the generator terminal voltage, e.g. 150% of rated field voltage at a generator terminal voltage of 75%.

Ceiling Voltage – The maximum dc voltage that the exciter is designed to provide as determined by the construction of its power source. Many jurisdictions have requirements for excitation system transient performance which are specified in terms of the ceiling voltage and response time to a transient generator terminal voltage change. For rotating exciters, the ceiling is specified at rated speed. For potential source exciters whose supply is derived from the generator terminals, both the exciter ceiling voltage and generator operating voltage are specified. A ceiling voltage of twice rated voltage at rated generator terminal voltage and rated speed is typical for static exciters.

Ceiling Current – The ceiling current of the excitation system should have a transient time capability equal to or greater than the short-time overload capability of the synchronous generator to which it is connected [1-4], [1-5]. Whichever rating is lower becomes the limiting rating.

There is much confusion about excitation transient ratings for rotating exciters. The reader is referred to IEEE standards 421.1 and 421.4 for a discussion of appropriate ratings and terminology. Briefly, ceiling voltage and current ratings are meant to be used to characterize high initial response excitation systems, e.g. those which have been specified to meet transient response requirements. Static excitation systems can meet these requirements, with appropriate selection of limits and gains. Most rotating exciters cannot meet these transient performance requirements. In this case, another, older rating system referred to as the excitation system nominal response is used to characterize their transient characteristics. The nominal response should not be used in specifications of new equipment or existing equipment when assessing its performance against NERC, regional or ISO requirements which specify transient performance characteristics.

To satisfy the excitation system time response, the ceiling voltage must be reached for sustained drop in terminal voltage of a specified level (typically 5% or 10%). This will imply a minimum value of AVR "transient" gain. Depending on the type of control, this will translate into a proportional gain, or combination of proportional gain and time constants and/or feedback gain.

These criteria may be evaluated by a combination of off line and on line AVR reference step response tests.

Small-signal performance – Evaluated based on the closed-loop response of terminal voltage when the unit is on line and the de-stabilizing effect of angular variations fed through the AVR control loop. Jurisdictions which specify small signal performance requirements typically require application of power system stabilizers (PSS). In this case, the performance requirements are typically specified in terms of the phase compensation requirements of the PSS as measured or calculated from the frequency response of the unit without and/or with the PSS.

These performance measures are specified in different ways by various ISOs, however the methods of evaluation are per the standard [3-2].

Evaluation of the small signal performance and use of power system stabilizers typically involves testing and/or system simulations which require specialized equipment and simulation capabilities beyond what can be reasonably expected for on-going compliance testing and is not discussed here.

3.2.3 Modeling Data Sources

A recommended approach to equipment modeling is to begin the process with a review of all available data. The primary sources of these data are:

- factory test results
- manufacturer's manuals
- commissioning reports
- in-service settings
- utility databank models

The following sub-sections provide details on specific information for each type of exciter and control technology.

3.2.3.1 DC Main Exciters

Manufacturer's data which is required for modeling includes the saturation curves, electrical ratings, and dynamic data. For a dc exciter, the electrical ratings include: speed, rated output voltage, rated output current, rated power. Additionally, the exciter field requirements (rated load voltage and current) and resistance, at a stated temperature, are required for modeling.

For dc exciters, the constant resistance load saturation characteristic of exciter voltage output versus exciter field current input is used in simulation models [2-21]. This characteristic may be measured directly because of the connection of the exciter output to the generator field through brushes and slip rings. Manufacturers should be requested to provide calculations or factory measurements of the complete constant resistance saturation characteristic. If data is unavailable or verification is required, measurements of the main exciter field voltage and current and generator field voltage and current may be made with the unit on open circuit, during measurement of the generator open circuit saturation characteristic, and on line during reactive capability measurements to verify the characteristic at higher exciter output voltages than are achievable off line.

The exciter output voltage and current are both dc values, and typically a shunt is available for direct measurement of field current.

Dynamic data is limited to the exciter time constant. For manual or discontinuous voltage control, the rheostat time constant(s) are required for large and small signal voltage errors.

3.2.3.2 AC Main Exciters

Manufacturer's data which is required for modeling includes the saturation curves, electrical ratings, and dynamic data. For an ac exciter, the electrical ratings include: speed, rated output voltage, rated output current and rated apparent power. Additionally, the exciter field requirements (rated load voltage and current) and resistance, at a stated temperature, are required for modeling.

The no-load saturation curve for alternator-rectifier exciters is used because exciter regulation effects are accounted for by inclusion of a demagnetizing factor, which represents the armature reaction of the ac exciter synchronous impedance, and commutating reactance voltage drops in the model [2-21]. This characteristic cannot be verified in-situ with the main exciter connected to the generator field. For units with brushes and slip-rings, the vendor's no-load exciter saturation curve is required. For brushless units, the no-load exciter saturation curve is required together with either the constant resistance load main exciter saturation curve and complete ac main exciter impedance data. The manufacturer's generator open circuit saturation curve will also be required in this case as no measurements are possible.

On systems with brushes, shunts are often available for direct measurement of main exciter and generator field current. On brushless systems the main exciter output is not accessible and the main exciter field quantities (voltage and current) are the only available measurements.

Dynamic data includes the exciter time constant, as well as the exciter synchronous impedance and demagnetization factors. Again, modeling is complicated by the absence of brushes and slip-rings, so that manufacturer's data is essential for these units.

3.2.3.3 Static Exciters

Manufacturer's data requirements are modest for these systems. Because the power stage is electronic, it has a very small intentional time constant. The electrical rating data may be read from the exciter transformer nameplate: rated apparent power, high and low side line-to-line voltage and impedance. The exciter maximum and minimum voltages are determined from these ratings and the minimum and maximum firing angles for a thyristor bridge.

3.2.3.4 Magnetic Amplifiers

Manufacturer's data is typically in the form of bulletins and schematics showing the functionality of the various feedback and control stages. Because these systems are based on magnetic components, they typically do not have gains and time constants which may be directly read from calibrated dial settings. Even where calibrated dials or switches are provided these should not be relied upon for direct translation to model parameters. As a result, testing is required both for tuning these controls and for validating their mathematical models.

3.2.3.5 Analog Electronic Controls

Manufacturer's data is typically in the form of bulletins and schematics showing the functionality and calibration of the various feedback and control stages. They often have gains and time constants which may be directly read from calibrated dial settings. They typically also have readily-available inputs and output to various electronic test points for signal injection and monitoring, simplifying testing and tuning these controls and for validating their mathematical models. Models may often be derived directly from these settings, although, because of the precision of the components and drift due to age, heat and humidity, the actual gains and time constants may vary considerably from the calculated values.

3.2.3.6 Digital Electronic Controls

Manufacturer's data is typically in the form of block diagrams showing a continuous-time representation of the functionality of the various feedback and control stages. The most modern systems will provide these models in the standard format desired by system planners for integration into their system studies [2-21].

These systems typically have gains and time constants which may be directly read from their digital settings or printed out to ASCII format files. Because the implementation of most of the features is in software, the settings once entered do not drift over time and do not need to be calibrated. At the inputs and outputs of the digital control, there are still analog electronic components which may have to be calibrated or checked on a routine basis.

Test features and data recording may be provided in the vendor's software; however the availability of these features varies between vendors. All of these systems should have readily-available analog inputs and outputs for signal injection and monitoring, to allow independent verification of calibrations and tuning. Again, this varies among vendors.

3.2.4 Conversion of Settings to Simulation Models

The simulation model structure should be confirmed to match the equipment in service. Reference [2-21] includes a cross-reference of various vendor equipment to IEEE standard model structures.

As discussed above, vendors of modern digital controls may provide their in-service settings in the desired simulation model format. The final as-commissioned data should be obtained as the initial vendor models are typically provided in advance based on default values, which are adjusted during the commissioning process.

For analog controls, there may not be a one-to-one correspondence between equipment settings and the desired simulation model. The vendor should provide a commissioning report for the equipment which may include this model, but as a minimum should include as-built settings. For equipment which is calibrated during major outages, the latest calibration report should be obtained.

Initially, more complex models are developed and they allow for direct correspondence between the model parameters and the settings of the physical system. Figure 3-2 provides a portion of an overview block diagram of an excitation system in which external components are identified for each module. One of the blocks, the damping feedback circuit shows the relationship between the external settings and transfer function constants. The transfer functions and defining equations for each of the blocks is developed in a similar manner to include gains, time constants and limits in terms of the physical components and available settings (e.g. potentiometer settings, resistor values, jumper positions).

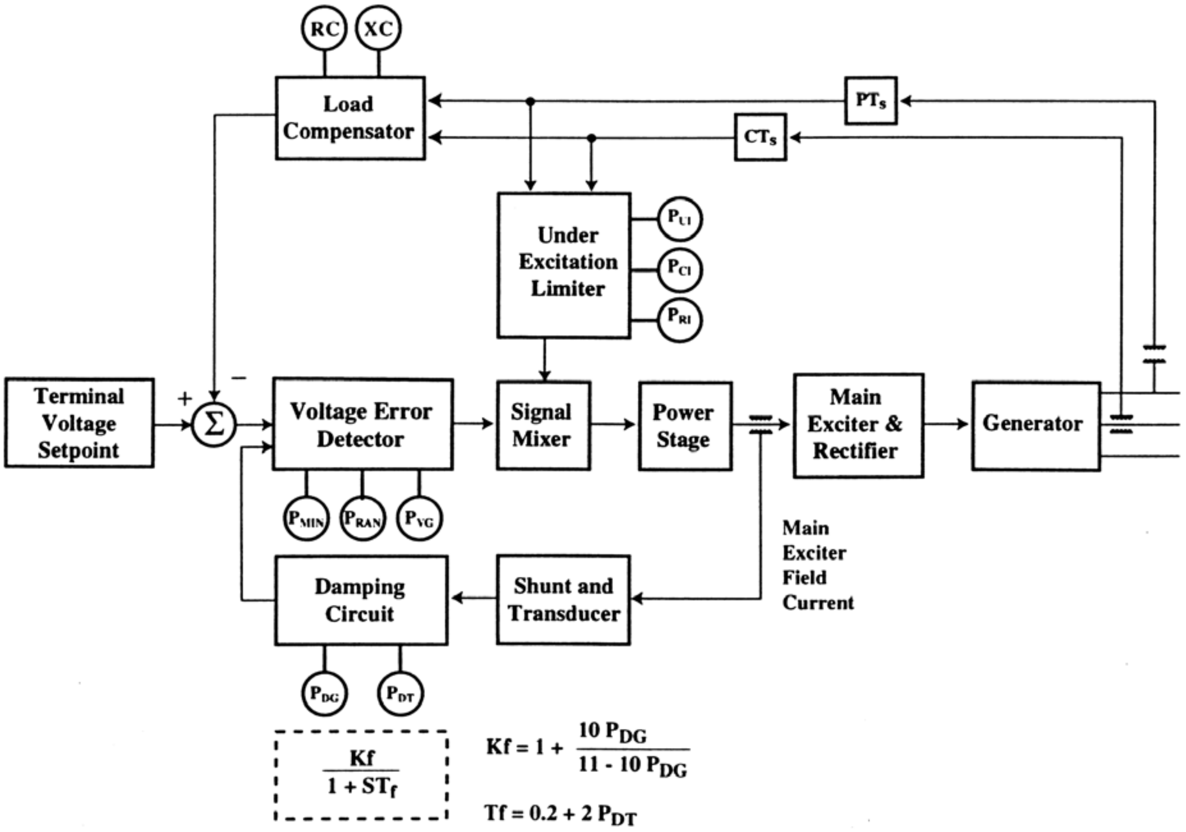

Figure 3-2
Overview Block Diagram of Exciter Including External Settings

The advantage of this type of model is that it allows the results of studies to be translated into recommended changes which can be implemented in the field to obtain performance improvements, and the variables are represented in engineering units (e.g. V, A,…) which can be compared directly with measured results [3-3].

The disadvantage of this structure is that the models are complex, manufacturer-specific and are not in a standard format that can be used in commercial simulation software. Therefore, the detailed models are often used as a starting point for developing standard non-linear or linear models. Figure 3-3 is an example of one such model, IEEE Standard Type AC1A [2-21], representing an alternator-rectifier excitation system with non-controlled rectifiers. Translation between the equipment settings and model parameters must be made by someone familiar with both the equipment and simulation models.

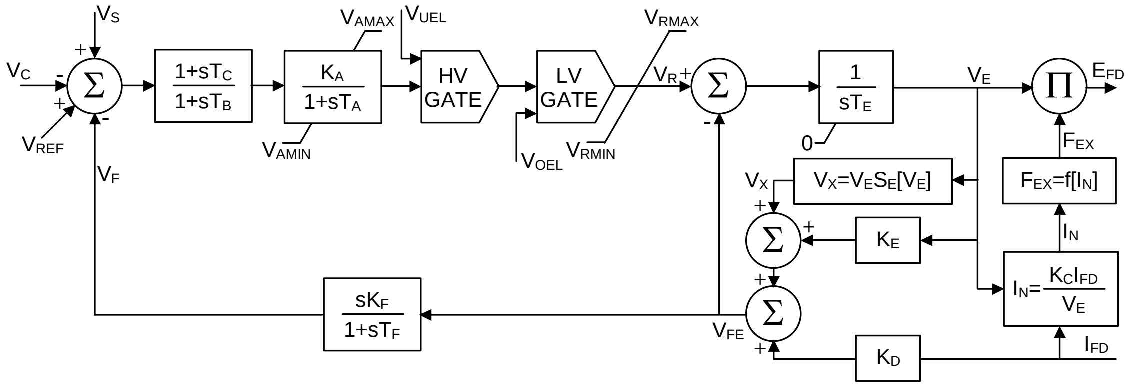

Figure 3-3
Excitation System Model Type ACIA

For most system studies, a block diagram representation of the exciter power stage and AVR control will be adequate, while for other studies the excitation limiters or supplementary controls must be added to reproduce the unit's behavior [2-4]. While industry standards also provide guidance for modeling these features, there tends to be a higher level of customization, often requiring user-defined representations.

3.3 Testing Methodology

For new units or those for which a validated model is unavailable some form of testing is normally required. Validation for first-time modelling requires the model development described in the previous section followed by staged tests. Re-verification of models can normally be performed with simpler tests or recording of the response to actual system events, often referred to as ambient recording. Figure 3-4 depicts the different events leading up to staged testing. The left-hand side represents the path that would be followed in developing a new model for the system, while the right-hand side could be used to validate models from disturbance recordings or identify units that require re-testing based on their response to these events.

Staged testing is often also required as part of commissioning of major equipment to confirm that the equipment provides the necessary performance. At this time manufacturers' data are normally available, and a manufacturer's representative is normally on site. Tests should be prioritized as discussed in Section 6, with priority being given to testing new equipment during commissioning, system critical equipment, and equipment where the manufacturer's data or models clearly do not match that found in the databank.

Once this baseline model has been obtained, typically simpler methods are allowed to confirm that the equipment continues to perform as it was originally modeled. This may be as simple as configuration control techniques, such as ensuring control settings have not been changed or gathering calibration records from maintenance outages.

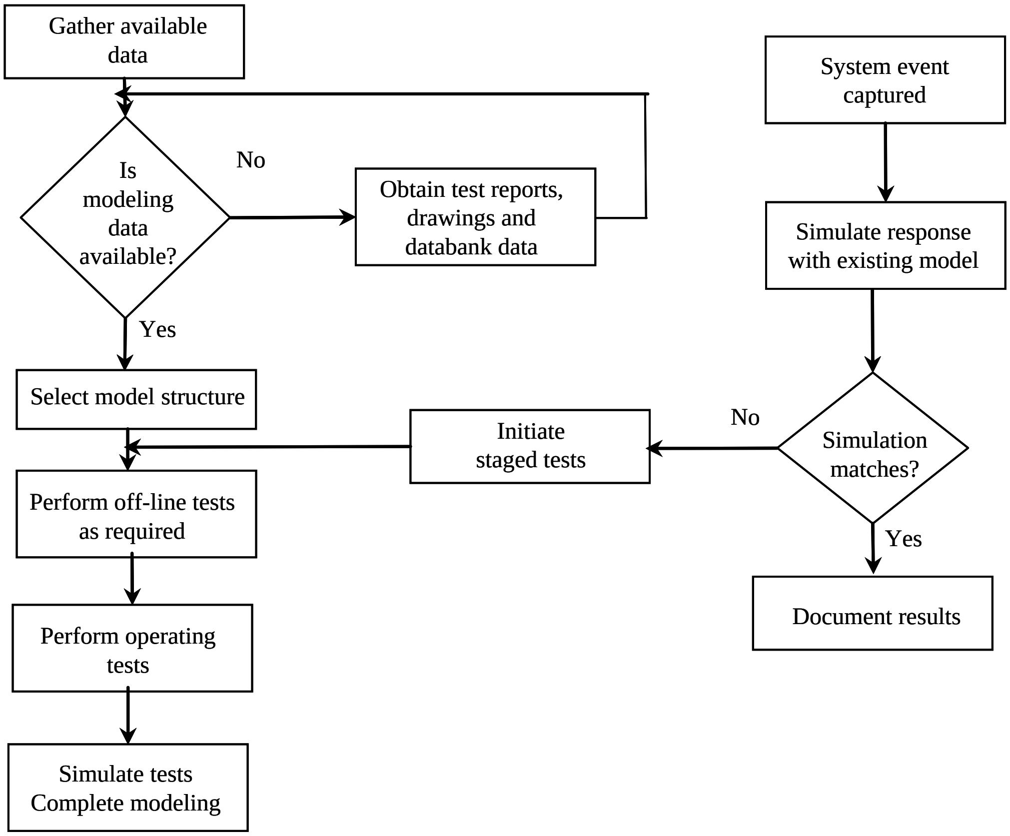

Figure 3-4
Sequence for Data Collection and Testing

The following is a brief description of the steps summarized in Figure 3-4 and described in further detail in reference [3-4]. Not all of these steps are required for each location and each piece of equipment.

Step 1-Review available data: Collect data from the station and from the manufacturer of the equipment. This includes the existing utility databank models, equipment operating manuals, diagrams, capability and rating data, previous test results, and, where available, block diagrams.

Step 2-Select model structures: Based on the available data, develop a block diagram of the equipment to be modeled. This often involves selecting the standard model that is the best fit to the equipment.

Step 3-Develop test plan: The test plan should include measurements to identify all of the key parameters, and provide additional data for validating the final product - the completed model. The selected tests should determine the relationship between the settings (e.g. potentiometer setting, jumper position, fixed component selection) and the model parameters. The test plan should clearly identify any special equipment requirements, the station/unit operating state during each phase, and the safety/reliability issues.

The test plans should be in the form of a detailed checklist and include a comprehensive review of the personnel and equipment safety issues. The expected outcome of each test is described along with a "back-out" procedure. These descriptions must be reviewed with Operations and Station technical staff prior to each test to ensure that everyone is clear on their role.

Step 4-Perform site tests: Included in the actual testing should be a review of nameplate data and any equipment modifications and a comparison to the manufacturer's data gathered earlier. It is not uncommon to find differences between field wiring, installed component values, equipment settings and documentation. The functional and dynamic tests also frequently identify latent deficiencies, such as defective components or incorrect settings. These may not be apparent during typical day-to-day operation.

Step 5-Validate data: Compare measured and modeled responses for modules and/or complete system. In order to expedite this stage, digital data acquisition systems are used which format the data for use with simulation and analysis software. Whenever possible, parameters are calculated on-site and compared with test results. This provides an opportunity to identify inconsistencies or missing data, which can then be rectified prior to removing the test equipment.

Step 6-Produce reduced-order model: Eliminate feedback loops, time constants and limits not relevant to the target model. Convert all parameters to per-unit values for use within simulation software.

3.3.1 Staged Tests

For model validation purposes, normally two distinct types of tests are required: off-line tests used to measure detailed transfer functions or measure limiter operating characteristics and open-circuit or on-line dynamic response tests that allow confirmation of the closed-loop response of the Automatic Voltage Regulator (AVR), Power System Stabilizer (PSS) and selected limiters. These tests are defined later in this subsection.

Survey response indicates that a large portion of companies (~ 90%) that are validating excitation system models use a combination of off-line tests combined with testing while the unit is running.

An example plan used for testing a unit equipped with a dc rotating main exciter, using minimal equipment, has been attached in Appendix C. Equipment-specific plans can be developed for each location to be tested using this approach.

Ambient monitoring (disturbance recording) has recently been accepted as a means of verification of exiting simulation models. This method is discussed in Section 4.

The following is a brief overview of the types of tests performed, based on the unit operating condition. Each of these tests is described in more detail in the following sub-sections, along with specific examples of equipment connections and results. Excitation system testing techniques are discussed in detail in [3-2].

- **Off-line tests** are performed on individual modules within the excitation system while it is energized from test supplies and isolated from the field winding. Tests performed in this manner are used to verify static operating points of limiters, calibrate transducer inputs and outputs. They can also be used to verify gains and time constants for modelling purposes, especially for complex controls such as power system stabilizers. Closed-loop performance of part or all of the system can be tested using advanced test sets. These tests pose the lowest risk to the unit.
- **Open Circuit tests** are performed with the generator on open circuit running at rated speed. The MOD specifically requires a test of the closed-loop voltage regulator with the unit in this condition. These tests pose little risk to the unit but are often in the critical path of start-ups.
- **On-Line tests** are performed with the generator synchronized to the grid and operating at a variety of active and reactive power levels. These tests may be required to confirm correct performance of the excitation system's reactive compensation, PSS or excitation limiters.

3.3.1.1 Off-Line Tests

During the off-line tests, the exciter is energized using a test supply, and test signal generator outputs are substituted for the normal input signals (e.g. three-phase ac voltage input to the voltage regulator, dc millivolt source in place of field current shunt feedback). Individual modules or sub-modules are isolated and tested separately to validate the derived transfer functions. Step response and frequency response techniques are normally used to measure the small signal performance. Non-linearities in the electronic controls, such as limits, can be measured at this stage by inputting large signal changes at selected inputs.

These tests have the advantages that they are performed during outages of other equipment in the plant and do not pose any risk to the generator or power system and minimal risks to the equipment under test. If off-line tests are planned, preparation is required to safely energize the various equipment test supplies. The ease with which voltage regulator functions may be enabled in this state varies from machine to machine.

Testing of limiter and protective relay operating settings, associated with the excitation system, can also be performed at this stage using test sources as inputs. This is important since it is not practical to operate the unit on-line at the high excitation levels necessary to reach the typical limiter settings. Testing is complicated with excitation limiters since it involves verifying that once engaged, the limiter is capable of controlling the excitation level in a stable fashion. For summing limiters, this involves the complex interaction with other control loops such as the AVR and PSS. For this reason, excitation limiter testing is normally performed in two stages. First the operating limit characteristic (e.g. field current or reactive output points at which the limiters take over control) is measured during off-line tests through secondary signal injection. Once the limit characteristic is known, the limit is temporarily adjusted to lower limit settings that permit the limiter to be engaged during open-circuit operation or on-line operation at low active and reactive power load levels. Under these controlled conditions, the control-loop dynamics can be measured with minimal risk to the unit or power system.

A new class of test sets that combine static and dynamic closed-loop simulating capability may allow both types of tests to be performed during outages reducing the need for some or all of the on-line tests. See Figure 3-5. These test sets simulate the dynamic response of the generator and power system. Prior measurements or a detailed representation of the generator is necessary for this approach to be used with confidence to verify dynamic regulator and limiter response.

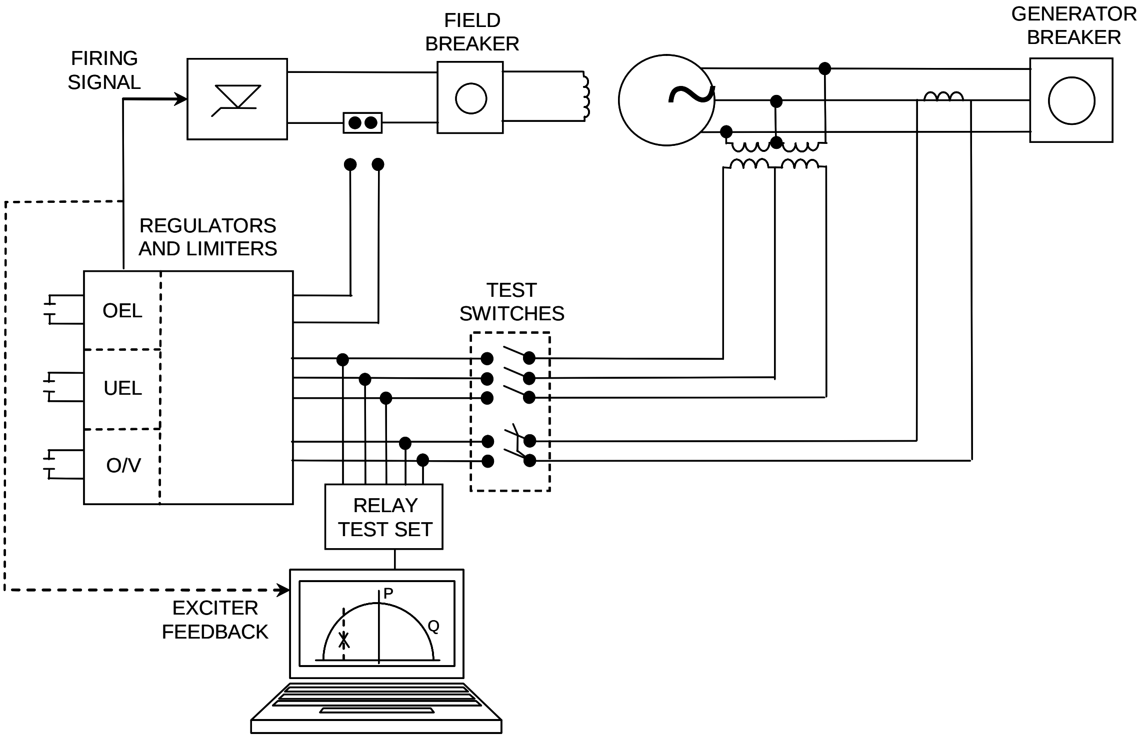

Figure 3-5
Closed-Loop Simulation Diagram

Off line limiter tests are discussed in detail in Section 2.

3.3.1.2 Open–Circuit Tests

Open circuit tests are performed at rated speed and rated voltage with the generator not synchronized. The open circuit tests normally consist of the following stages:

- Steady-state measurements of the exciter and generator quantities. This is often performed concurrent with the main exciter and/or generator saturation characteristic measurements. Steady-state measurements of intermediate signals are used to confirm the validity of the detailed model in representing the normal operating levels of key quantities. At this point, the scaling of the field current measurement can be checked. This allows confirmation of the scaling used in the off-line limiter tests.
- Dynamic tests (time-response or frequency-response) of the closed-loop AVR. The measured data can be compared with simulations performed using the block diagram model.
- Dynamic tests of the excitation limiters. The over-excitation limiters, which normally operate to limit terminal voltage, generator field current and/or exciter output current, can be tested on open-circuit, by lowering the limit set points to the open-circuit operating levels. The unit's operation is then forced into the limit set point, by injection of a test signal into the AVR or firing circuit or by simply increasing the AVR setpoint until the limit is reached.

In addition to verifying that the AVR and limiters have a suitable dynamic response, these tests also provide data for confirmation or derivation of parameters such as the main exciter time constant.

One of the most common of the open circuit tests is the AVR step response test. This test is specifically identified in MOD-026 for confirmation of excitation system response. As a minimum, generator terminal voltage, generator field voltage, or pilot exciter field voltage for brushless systems, should be measured during the application of a step change signal that will produce a 1% to 2% change in the terminal voltage reference. This test is performed by injecting a small, short duration change in the AVR reference level. This causes the generator terminal voltage level to change suddenly and provides a controlled measure of the overall response of the excitation system.

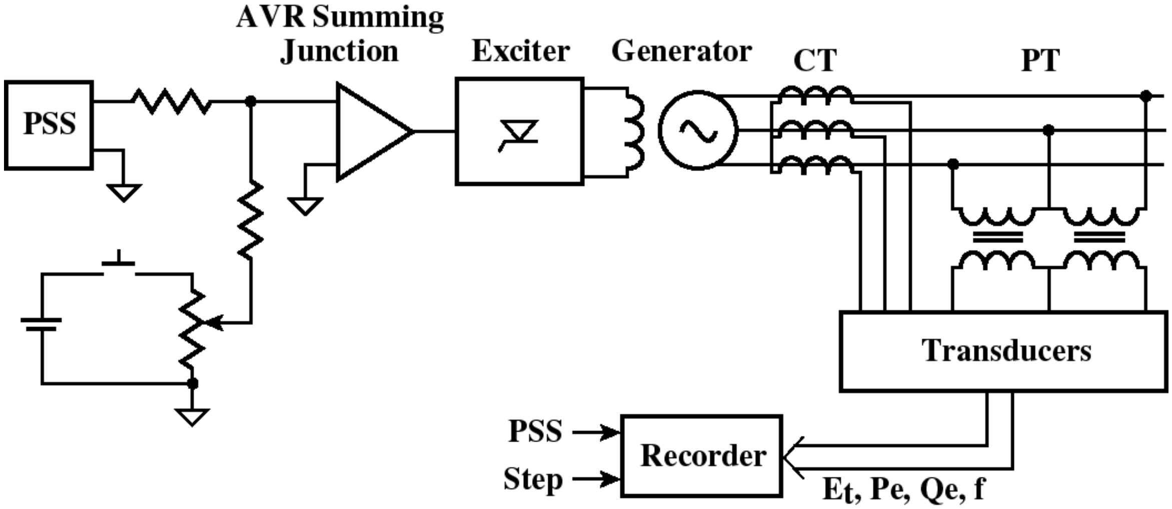

Figure 3-6
Simplified Setup for Both Open-Circuit and On-Line Step Response Test [3-5]

The type of exciter will dictate the method used to inject the AVR reference step change. On analog-electronic systems, the signal is normally a low-voltage (e.g. 0-12 Vdc) applied to the input of an operational-amplifier summing-junction. On modern digital systems, the exciter is normally equipped with a built-in facility for introducing controlled step changes to the voltage reference signal. On a system equipped with a magnetic amplifier, the signal may be applied as a current injection into a spare control winding. On older systems such as those equipped with discontinuous regulators, the signal may be introduced by altering the three-phase PT feedback signals at the AVR input. This approach can also be used on more modern systems if detailed design information or interfacing software is unavailable. This technique has the added advantage of explicitly including the terminal voltage transducer in the forward path of the disturbance.

Another step response test can also be accomplished by transferring from constant field (manual) control mode to the AVR mode with a small unbalance between the set points. This method has the advantage of not requiring equipment to inject a change in AVR reference.

Simulation of this test is the most widely recognized means of excitation system model validation. Figure 3-7 presents responses typical of the changes in terminal voltage that are obtained in the excitation system tests and the corresponding simulation result [3-5]. This type of record would be adequate to meet the compliance requirements associated with verifying the model associated with the AVR and excitation system.

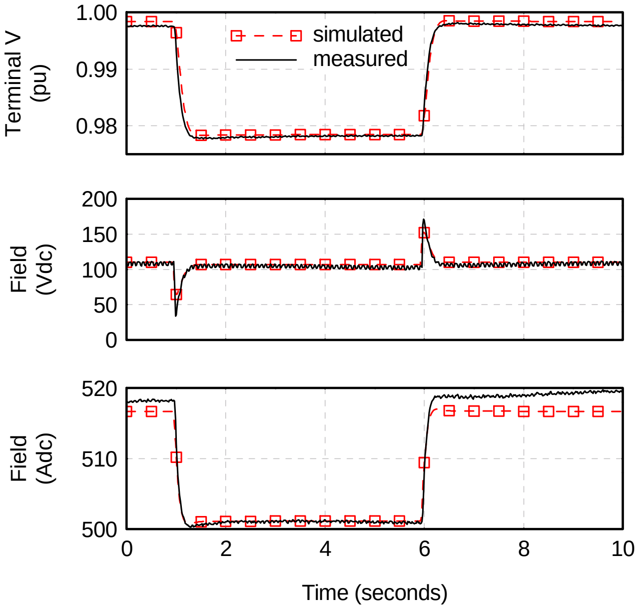

Figure 3-7
Typical Step Response of Static Excitation System [1-21]

An alternative to AVR step response tests are load rejection tests with the unit absorbing reactive power [3-6]. Upon opening of the generator circuit breaker, the excitation system will respond to the step change in reactive current in a manner similar to that seen for a step test. The AVR response in the opposite direction can be tested with the unit producing reactive power. The amount of reactive power produced or absorbed prior to opening the circuit breaker will determine the magnitude of the AVR response. This method also has the advantage of not requiring any equipment to inject a change in AVR reference, but requires the coordination involved in a load rejection. On some digital systems care must be exercised in interpreting results since AVR or limiter dynamic settings or set points may be switched when the ac breaker is opened [1-21].

3.3.1.3 On–Line Tests

On-line tests are performed with the generator synchronized to the grid and operating at different active and reactive power levels. Among the tests performed with the unit on-line, are the following:

- Steady-state measurements of exciter and generator quantities. These measurements supplement the open-circuit measurements, and can be performed over a wide range of generator field current levels and are normally performed at the same time as reactive capability testing
- Dynamic tests (time-response and frequency-response) of the closed-loop AVR. Many of these tests would only be required during commissioning or on units equipped with power system stabilizers.
- Dynamic tests of the excitation limiters and other features. All of the limiters and other features that are not operational on open circuit (e.g. UEL, RCC) are tested at this stage.

Dynamic measurement of the field current limiter operation is typically performed with reduced limit settings as described in the earlier off-line testing section. Figure 3-8 shows an example from such a test [3-5]. Settings are reduced to avoid excessive bus voltage and stator current during the performance of the test. Limit levels are reduced, and a terminal voltage step is applied to force the field current into the new limit.

Care must be taken when tuning the UEL dynamic performance under all circumstances, but particularly when it is used in conjunction with a power system stabilizer. When testing and calibrating UELs, several factors must be considered, all of which suggest performing dynamic tests with reduced settings (e.g. with reactive power settings closer to zero). Low bus voltage will result from operation at extreme under excited levels and should be avoided. In some cases, where there is limited margin between the UEL and loss-of-excitation relay or generator core-end overheating characteristic, there is the possibility of entering one of these regions if the limiter does not function as expected. Figure 3-9 [3-5] shows an example of a stable UEL response, tested with the limit level temporarily adjusted to near unity power factor. At these modest under-excited levels, tuning and testing could be performed with little risk of unit trips.

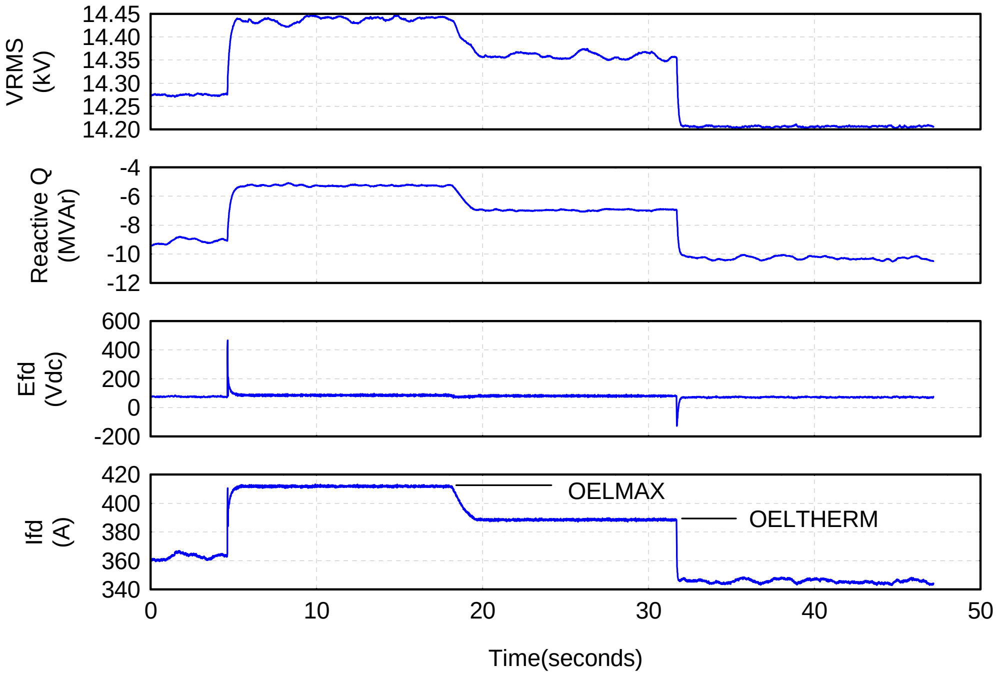

Figure 3-8
Over Excitation Limiter Test

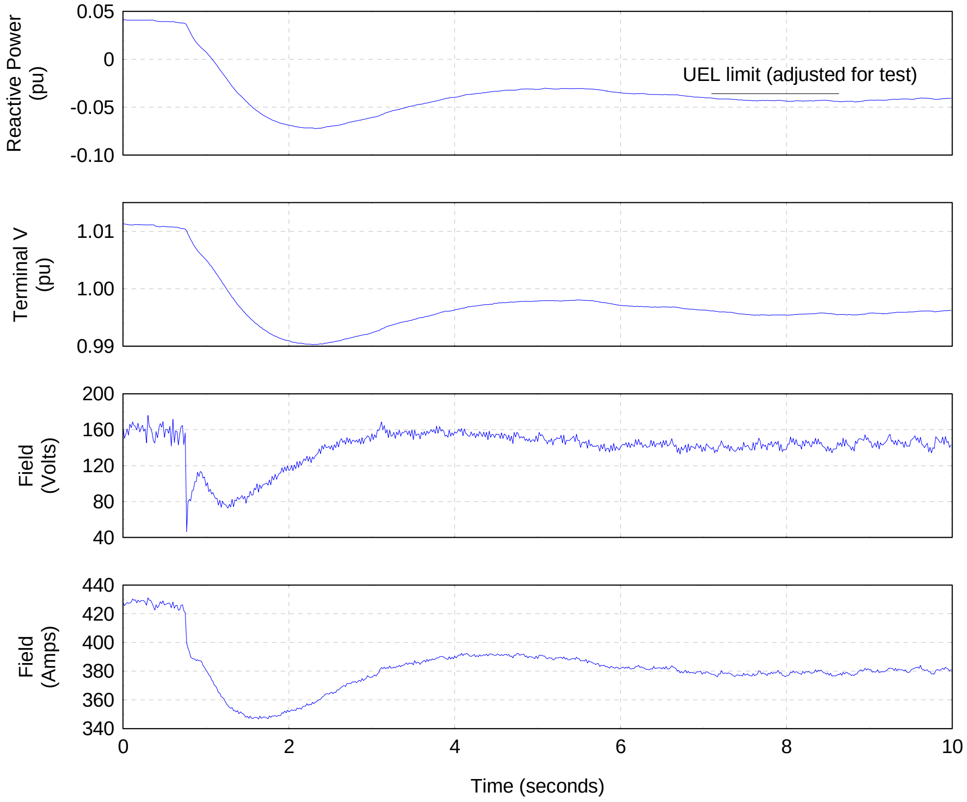

Figure 3-9
Under Excited Limiter Test

Power System Stabilizers

The techniques used to test the AVR and power system stabilizer (PSS) mirror the techniques that are used in their simulation and tuning. That is, one should seek to measure the required compensation characteristics, measure the effect of the settings on the closed-loop response and finally perform special measurements which could alert us to possible side-effects of the AVR and PSS settings during both normal and disturbance operating conditions. References [3-7] to [3-8] describe various aspects of testing of these controls.

The selection of phase compensation is critical to the proper functioning of the stabilizer. As a result it is important to have accurate measurements of the phase relationship between the generator terminal quantities and the stabilizer signals. Any transducers or amplifiers used for this process must be scrutinized to ensure that they do not introduce unnecessary filtering and associated phase lag in the frequency range of interest, 0.1 Hz to 10 Hz. Analog electronic hardware is being superseded by digital measurement systems, which incorporate the transducer functions with the data storage and analysis software. In many cases, some or all of the required signals are directly available from the stabilizer itself, as these quantities are used in the stabilizing signal generation.

Two types of tests are normally performed: time-domain and frequency-domain. For the time-domain tests, the quantities should be recorded with a bandwidth sufficient to ensure that higher-frequency components in some of the signals (e.g. turbine shaft torsional components in the speed signal) are captured. If frequency response tests are done with the generator synchronized, care must be taken to avoid shaft torsional frequencies. The generator manufacturer should be consulted prior to on-line frequency response testing.

Regardless of the techniques that are used, the test must validate the following model parameters: gains, time constants, limits and calibration of measurement transducers.

If detailed models exist from commissioning tests or studies, simple step response tests, such as the one shown in Figure 3-10 may suffice to confirm continued validity of an existing model [3-5]. For equipment where no model exists, bench tests to confirm transducer calibrations and output limits may be required, as the required operating ranges of inputs and outputs may be impossible to test with the equipment in service on line. Transfer function tests will likely also be necessary for various stages of the stabilizer characteristic, requiring access to internal stabilizer signals and appropriate isolation transducers, with suitable bandwidth as discussed above. As with excitation systems, the techniques and details are discussed in the reference [3-2], [3-7] to [3-8].

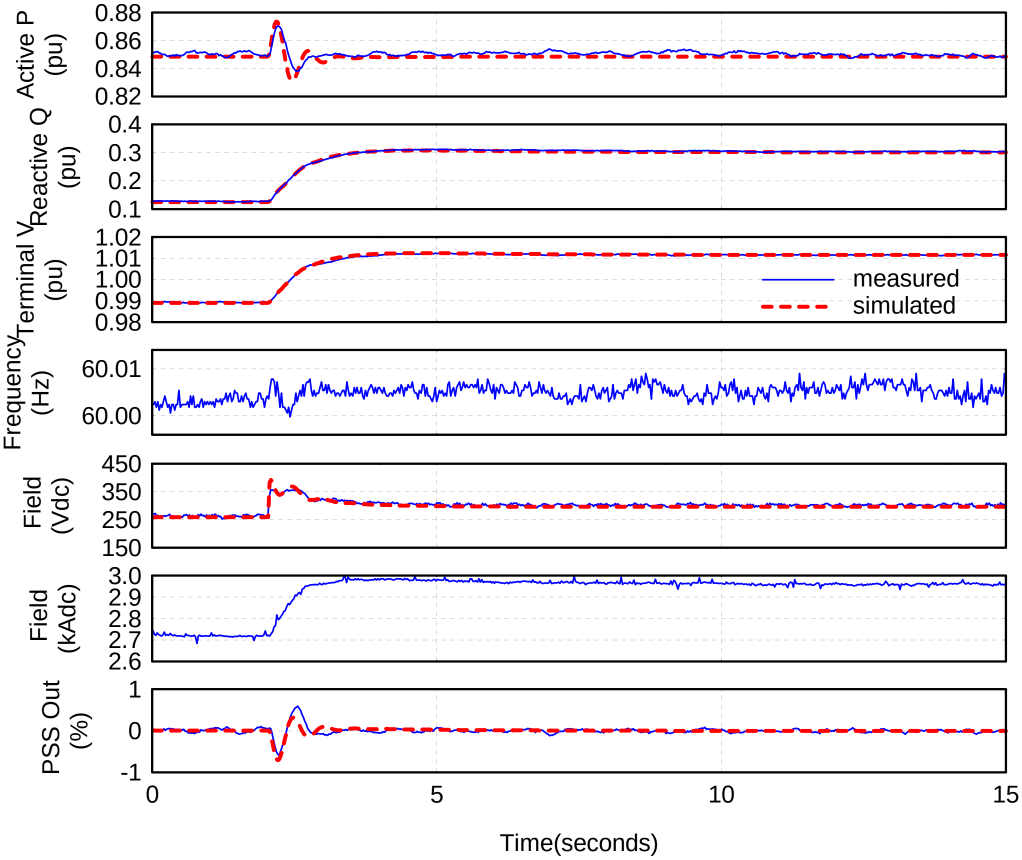

Figure 3-10
On-Line Step Response of Static Excitation System Including Power System Stabilizer

3.4 Test Equipment

Performing measurements on generator control systems requires extreme care. Generator excitation controls use high-power high-voltage components and low-power logic circuits. It is often important to make simultaneous measurements at these levels, requiring the use of proper techniques and equipment. The selection of equipment and the use of proper measurement techniques are critical for the following reasons:

- **safety** – The safety of personnel is of paramount importance and dictates that all test instrumentation meet strict isolation requirements to avoid injuries. Although many of the signals to be measured are below 120 volts ac, the generator field voltage can be much higher. Also all of the signals associated with the generator are subject to sudden changes in amplitude due to the possibility of system or unit faults. It is not enough to examine the steady-state rating of equipment to establish the appropriate level of isolation.
- **avoidance of severe system disturbances and equipment damage** – The instrumentation used must be reliable and prevent inadvertent short circuits on PT secondaries, open circuits on CT secondaries, grounding of generator field circuits or the introduction of noise into sensitive circuits.

- **elimination of undesirable noise components** – Generating stations are electrically noisy environments due to the presence of high magnetic and electric fields. Certain signals will contain very large magnitudes of noise which must be filtered in order to resolve relatively small (but nonetheless important) changes. This is particularly important for the field voltage, field current, and shaft speed signals.
- **accuracy** – Different equipment is required for measurements of absolute signal levels versus deviations about the steady-state. Consideration must be given to the requirements for obtaining both magnitude and phase information for some signals.

Several different types of instruments are used for the recording and display of generator quantities, including, multi-meters, oscilloscopes, direct-writing recorders, tape recorders and transfer function analyzers. The cost of highly functional instruments has decreased recently and many different manufacturers now supply equipment that is suitable for this environment.

Grounding

A common problem in generator control measurements is that different quantities may be ungrounded or grounded at different points, and as a result floating measurements (i.e. not referenced to ground) are usually required. For almost all testing applications, floating or isolated instruments or isolating transducers are required.

Transducers

In the testing of exciters and stabilizers it is necessary to observe several key system quantities. These signals may include:

- generator terminal voltage
- generator field voltage (systems with brushes)
- generator field current
- generator electrical power (active and reactive)
- main exciter output voltage and current
- shaft speed
- frequency
- AVR, limiter, and PSS electronic signals

Though test facilities are now included in modern exciters, stabilizers, and governors, there are still situations where the parameters to be monitored during field-testing are not available in a form suitable for direct recording. Transducers must therefore be selected and connected to the equipment under test. Even for situations where some of the signals are already in a suitable form, it is useful to review how these built-in monitoring circuits are designed to understand the limitations of the transducers, in particular their inherent filtering and accuracy.

Test Sources

Typically, some means of injecting controlled step or sinusoidal signals into the AVR reference or other circuits is required to perform modeling tests. The discussion above on grounding and isolation apply equally to any test signal sources.

3.4.1 Recommended Built-In Test Facilities in New Equipment [1-21]

With most generator control systems now being implemented using digital technology, opportunities exist to design equipment with useful features to aid the model validation process.

With such systems the control system settings are typically displayed on either a built-in display or on a laptop computer. However, simply examining settings in this way can only be considered as a quick and easy check to ensure that the system has correctly retained programmed settings.

Built in test features should normally include the ability to assign analog input and output signals to the inputs and outputs of the various internal stages of the control system. This allows separate verification of the operation of each stage and facilitates confirmation of the time constants and gains.

Internal test signal generators should be incorporated into the equipment. The internal test signal may then be used as an alternative to an external test signal generator and associated isolation. It should be possible to easily adjust the frequency, amplitude and wave shape of the internally generated signal.

Digital data recording facilities are a tremendous aid to model validation. The digital data logging should enable sampled waveforms to be viewed on laptop computers, and saved for later reference. This facility should be provided with flexibility to allow signals to be recorded from various stages in the control system, with various sampling periods and with various archiving and triggering options.

While it is recommended that the internal recording and signal generation features should be incorporated into equipment, on occasion it may be necessary to use separate signal injection and data recording equipment to provide independent verification of the operation of excitation control equipment.

4

VERIFICATION OF GENERATOR FREQUENCY RESPONSE

The following section addresses draft standard MOD-027 “Verification of Generator Unit Frequency Response” [4-1]. This standard is presently under development by the NERC Generator Verification Standards Drafting Team. This section is based on the draft standard issued in January 2007. Any significant changes to the final standard will need to be considered when reviewing the material of this section and formulating a compliance plan. Many of the concepts discussed in this Section are based on conventional industry practice and standards and will therefore not be affected by any changes to the final NERC requirements.

The term “Frequency Response” is defined in [4-2] as “an automatic and sustained change in the power consumption or output of a device that occurs within 5-30 seconds of and is in a direction to oppose a change in the Interconnection frequency.” The requirements for a minimum response for each event (rate, amount, duration) are described in the paper. Its use and calculation are described in [4-3].

References [4-2], [4-3], [4-4], [4-5] and [4-6] document declining frequency response within the Eastern and Western Interconnections when it should be increasing because of increasing load and the associated increase in generation. Frequency Response within the Texas Interconnection has been statistically constant.

MOD-027 requires the generator operator to verify the generator unit frequency response (other than Automatic Generation Control) for use in models for reliability studies. Each region must maintain procedures for the verification of frequency response including:

- the response time to be modeled, e.g. up to 30 seconds for steam units, up to 45 seconds for hydro units
- Verified manufacturer and type of speed governor controls.
- Verified model for each speed governor control with any associated dead band, gains, time constants, and limits (e.g., maximum valve opening velocity, maximum capability of the turbine, etc.).
- Verified frequency response data of the unit, considering additional plant controls that affect the response of the unit (blocked or nonfunctioning governors or modes of operation that limit frequency response).

NERC MOD-027 requires that the regions specify detailed governor and turbine modeling requirements, however few have done so. For many jurisdictions the only data presently required is the governor droop and speed measurement dead band. Depending on the design of the governor, droop is normally determined by monitoring valve positions and speed reference as the unit load is changed. Dead band is measured through high-resolution measurements of governor reference, system frequency, control valve position and/or power output.

The WECC region has modified their requirements to classify governor response based on broad requirements that do not necessarily require staged testing but can be identified through monitoring of unit response to system frequency variations [4-4]. The technique requires a high-resolution frequency measurement system that can be installed in a plant environment and set to trigger for ambient frequency variations while recording the unit's output response (e.g. active power, valve position, demand). Multiple generator operators have implemented an ambient monitoring program. The authors of this report have developed hardware and analysis techniques that are successfully being implemented as part of ambient monitoring governor validation programs for NERC compliance. Detailed information on ambient monitoring can be found in section 4.3.3 of this report.

Reference [4-7] summarizes the present state of industry practices and cites the disparity between simulations and actual observed response to system frequency disturbances. It concludes that the simulation models used need to be proven, and more attention is required to limiting criteria which compromise governing ability. This task force paper also recommends future work in reliability, use of models in simulations, and recommends on-line monitoring to estimate the governor steady state droop and response of turbine-generator action. This is discussed further in the ambient monitoring section below.

4.1 Prime Mover Design

Synchronous generators may be powered by turbines with different sources. The type of controls and expected frequency response vary based on the source. Steam, gas and hydraulic turbines will be considered here.

4.1.1 Steam Turbines

A significant portion of North America's electricity is generated through thermal-mechanical generation systems. A vast percentage of these plants burn fossil fuel or employ nuclear reactors to generate heat with which they produce steam. In these systems, super-heated steam is fed into multi-stage turbines to produce mechanical energy that drives the generator. In a typical steam turbine, the steam first enters the high pressure stage where it expands as it flows through the stationary blades (or nozzles) and is then directed at the rotating blades where it is converted to mechanical energy. It then moves on to subsequent stages, each of which is optimized to work with the lower pressures and higher volumes of steam exiting the previous stage. A speed governor controls the amount of steam entering the turbine as a means of regulating the units speed.

4.1.1.1 Boiler Control Modes

MOD 027 also requests data on “additional plant controls that affect the response of the unit (blocked or nonfunctioning governors or modes of operation that limit frequency response)”. These controls are prevalent in steam turbine units. Plant controls are usually hierarchical, with boiler controls (or reactor controls for nuclear units), being used to set the unit operating load point. Typical control modes are [4-8], [4-9]:

Boiler Following

- governor responds to speed changes and re-positions valves
- boiler responds to steam flow and pressure changes

Turbine Following (valves control boiler pressure)

- valves control boiler pressure
- power changes initiated through changes to boiler set points
- governor responds to speed changes and re-positions valves

Coordinated Control

- feed-forward of power mismatch to boiler controls
- governor responds to speed changes and re-positions valves

Sliding Pressure Control

- valves wide open
- power changes initiated through changes to throttle pressure
- no speed governing

These control loops are typically only modeled for long-term dynamics studies.

4.1.2 Gas Turbines

The advent of gas turbines and co-generation has created a new class of facility, which is becoming widespread as the choice for new construction. In newer gas-fired plants, the combustion by-products are circulated directly through the turbine. A compressor mounted on the same shaft as the turbine section compresses air prior to mixing with the natural gas for combustion. The heated exhaust gas is passed directly through the turbine.

In combined-cycle operations, the exhaust gases from the turbine are used as a source of heat for a heat-recovery steam boiler. The resulting steam is then used to drive a conventional steam turbine, and its low-pressure, low-temperature exhaust may be utilized as steam source for industrial processes. Models of these units are available in the literature, but are not yet in commercial simulation programs [4-10].

The fuel controls have several different modes: speed droop control (the normal operating mode for off-line or partial load conditions), acceleration control (for startup and maneuvering), and temperature control. For economic reasons, many of these units are loaded to near full output, and are controlled to respect temperature, pressure and emission constraints. In this mode, the speed/load droop control is not active unless frequency rises and lowers demand. As these facilities may represent a significant portion of the total generation in an area, new control guidelines and models are being developed to correctly model their overall load and frequency control performance. The primary valve demand control signal is selected by a low-value gate from the outputs of the three control loops.

4.1.2.1 Temperature Limits

The temperature control is a hard limit at the temperature set-point. It should be noted that this is the normal mode of operation for most gas turbines, for peak efficiency. In this mode, speed droop control is not active for system frequency decreases; when frequency increases (or set-point decreases), droop control is restored.

In some Regions, measurement and documentation of this limit is required. It may be confirmed by raising load until the unit is operating in temperature control mode and then continuing to increase the speed reference, which will have no further effect on unit output once the limit is reached.

The maximum power output of a gas turbine, whether in combined-cycle power plants or operated as simple-cycle units, is dependant on the ambient air conditions [4-10]. The manufacturer should provide data, typically as a curve showing the turbine active power output under various ambient conditions for system studies. This relationship cannot be entered directly into the available system models. Rather, it should be used to adjust the temperature limit parameter used in simulation studies to reflect the expected conditions during the study under test (e.g. summer peak or winter peak conditions).

One survey respondent also noted that in severe under frequency (i.e. under speed) conditions, gas turbine compressors lose significant output, thus restricting the ability of these units to help restore frequency.

4.1.3 Hydraulic Turbines

Hydraulic turbines fall into two basic categories: impulse and reaction [4-9], [4-11]. In an impulse turbine all the available head is converted to kinetic energy at the nozzles, which direct the high velocity water to the buckets on the runner. Control of power is through adjustment of nozzle discharge by means of a servomotor-controlled needle valve. This design of turbine is normally used with relatively high head applications. In a reaction turbine (mainly Francis or propeller), the runner is completely submerged, and both the pressure and velocity decrease from the inlet to the outlet. A Francis turbine has wicket gates, which are controlled by the speed governor to regulate unit speed. A propeller turbine may have fixed-pitch or variable pitch blades. Coordinated control of both pitch and wicket gates are used to regulate the speed of variable pitch propeller (Kaplan) turbines. Typically, the wicket gates provide the primary response to speed demand changes, and the blade angle is then controlled to provide optimum efficiency.

The steady-state characteristics of a hydraulic turbine-generator connected to a load can be described in terms of its gate-power curve. Whereas steam turbines normally have built-in valve linearization characteristics, the nonlinear relationship between gate or nozzle position and output must be modeled explicitly. A small gate opening is required to maintain zero output power at rated speed, normally between 10% and 20% of full gate opening. The governor must be designed for stability under these conditions since speed control is required at this point to allow synchronization with the grid.

4.1.3.1 Hydraulic Turbine Dynamics

Unlike steam or gas units, modeling of turbine dynamics is necessary for hydro units in order to correctly represent closed-loop speed control. The representation for the turbine is completed by adding a dynamic equation representing the water column within the penstock. Assuming a lossless water passage and ignoring any traveling wave dynamics associated with the penstock, the dynamics of the water column is typically modeled by a single parameter denoted as the water starting time, T_W [4-9]. Various simulation models incorporate more or less complexity into the representation of non-linearities at partial loads.

Most often the non-linear power-gate relationship is included as a look-up table at the output of the model.

4.2 Response and Modeling

Governors respond to changes in unit speed (and therefore system frequency when on line) and open or close the controlling elements (e.g. gates, nozzles) to restore the system's load-generation balance. The main elements of any hydraulic governor are: speed sensing, amplification and compensating controls.

Early speed governing systems were completely mechanical-hydraulic with fly ball heads being driven directly by the turbine shaft, or indirectly by a belt connection or in modern systems by a shaft-coupled permanent-magnet generator connected to a fly ball head motor. For all of the above systems, the complete control system was mechanical-hydraulic. For most new systems, most of the governor including the speed sensing is electronic, with only the final amplification stages being hydraulic.

Speed droop is the mechanism used to control the contribution of individual units to power imbalances on the system. The droop determines how much the unit will re-position its gates (nozzles, steam valves...) in response to a given change in system frequency. The term permanent droop, R_P, is used to describe the component of droop that determines the steady-state response of the unit to system frequency changes.

For units which utilize electrical power rather than control valve position as their feedback signal, speed regulation is defined in [4-12] as the speed reference adjustment required to achieve 100% generator power. This standard also specifies that the regulation be linear from zero to full power.

NERC Policy says all generators over 10 MW will have governors and that these governors should be set to have 5% droop.

NERC Operating Policy 1.C, Guide 3 recommends that the intentional dead band of the speed measurement at rated speed shall not exceed +/- 36 mHz. That is, the governor should fully respond to frequency deviations greater than +/- 0.036 Hz. They can (and should) respond to smaller deviations. Some ISOs have specific dead band requirements which are lower than this. Vendors of electronic governors typically include an adjustable intentional dead band as a means to reject input signal noise. This can be used to reduce governor response to low-amplitude noise or run-out components. This is especially important if derivative gain is to be used with a PID control function. In this case, the upper limits must be set to respect the ISO or NERC requirements.

Often, the governor settings switch automatically between modes for different unit or system conditions (such as on-line/open-circuit or large system/small system) and the operating mode must be taken into account during testing and modeling.

Reference [4-13] provides a tutorial on Speed Governors.

4.2.1 Mechanical Hydraulic Governors

Speed is sensed by a fly-ball head which is coupled through a series of linkages to the speed reference mechanism. The resulting speed error is amplified by a series of hydraulic servomotors, finally resulting in a control valve change.

Speed sensing dead band is not shown in most simulation models, but it may be important to represent it in studies of overall area response. At one time excessive dead band was a concern to system frequency regulation, and most models included this effect. With the advent of more modern (relatively-speaking) fly ball head arrangements, these concerns decreased and dead band was often omitted in modeling.

The load/speed set point is often controlled by a motor-operated device, and it is through this mechanism that load is adjusted remotely. If the unit is operated on Automatic Generation Control, then the AGC signals would drive this setting mechanism.

The method used to implement speed droop varies with the governor design as discussed below. In most mechanical-hydraulic governors, a speed error will result in the flow of oil to the main servomotor changing its operating point until equilibrium is restored via a position change that corresponds to the governor's droop setting. The servomotor essentially acts as an integrator; its position will continue to change linearly as long as oil is flowing. This representation is depicted in the block diagram models. In these models, the pilot valve plunger center position is zero.

Both hydraulic turbines and steam turbines may be equipped with mechanical hydraulic governors and these will be discussed below.

4.2.1.1 Hydraulic Turbine Governors

Reference [4-12] provides an overall guide of the design, commissioning and modeling of speed governors to achieve a minimum speed control performance of hydraulic turbines. It specifies that permanent speed droop (or speed regulation) should be adjustable between 0 and 5%. Some ISOs specify adjustable droop, but with other ranges (e.g. 3-7% in the Province of Ontario). The speed (or frequency) measurement dead band is specified not to exceed 0.02% (12 mHz) [4-12]. A third performance measurement, the "dead time", is specified as: for a step load change of more than 10% of the capacity of the turbine, the dead time of the governor shall not be more than 0.2 seconds.

In most hydraulic turbine governors, when the gate servomotors begin to move to a new position, this change is transmitted back to the governor cabinet via a restoring cable which, through the speed droop connections, restores equilibrium, producing a new steady-state operating point of speed and gate position that corresponds to the governor's droop setting. Because of this feedback of gate position, there is a need to represent the gate-power relationship in order to combine the governor model with the generator model.

The simple block diagram of Figure 4-1 represents a fairly large variety of mechanical governors for hydraulic turbines [4-14]. Some systems are configured with droop feedback brought back from an intermediate point, and in these cases a slightly different structure may be required depending on the settings. As is the case with excitation systems, the full functional block diagram of the system should first be developed, and then reduced to an appropriate model, which may or may not fit a standard configuration.

The direct linkage that implements the permanent droop feedback is modeled as the proportional feedback, R_P, in the block diagram.

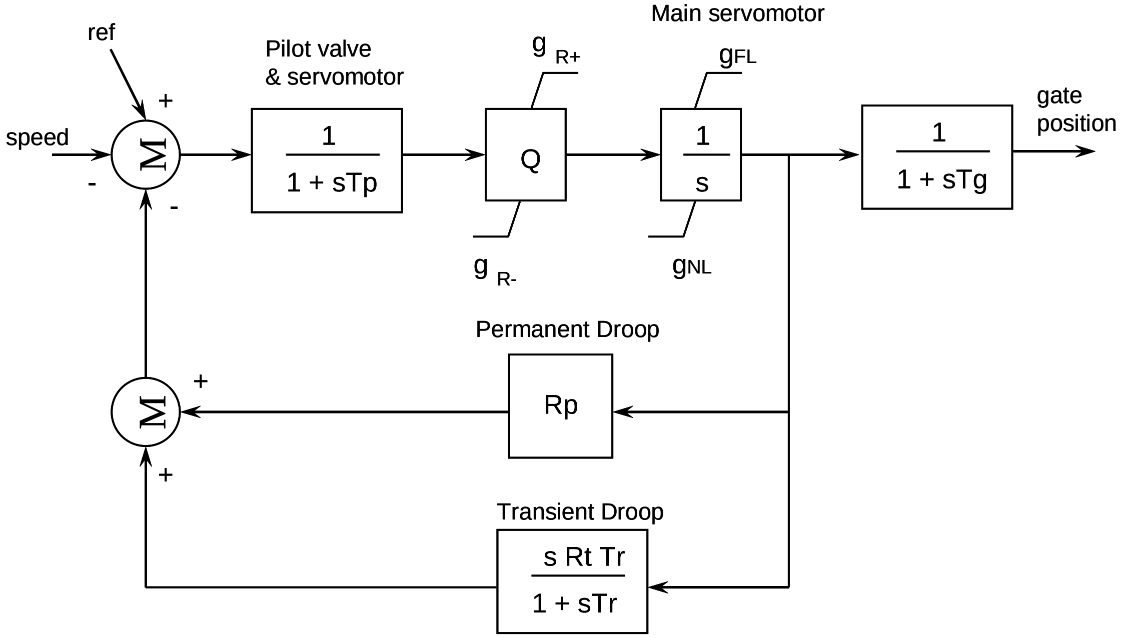

Figure 4-1
Mechanical Hydraulic Governor Model for Hydraulic Turbine

The turbine gain, Q, shown in this figure represents the gain of the hydraulic amplification stages and is controlled by the connections between the small pilot valve which implements the speed sensing feedback and the first stage servo (relay) valve. In some models, this gain is represented as the reciprocal of a time constant T_G.

The rate limits (G_R+ and G_R-) are normally set using mechanical limits such as stop nuts and as a result the rate limit must be measured. These limits are often asymmetrical, with the closing rate higher to help control speed increase following load rejections.

The combined action of the pilot valve and feedback from the control plunger is represented by the time constant T_P, in the block diagram model. The time constant, T_P, is determined primarily by the physical design of the pilot valve.

The additional time constant, T_G, modeled outside of the main feedback loop is sometimes included to represent an equivalent time constant associated with various other effects such as flyball head spring constants.

Transient droop is required to maintain stability of hydraulic turbines for open circuit or isolated (small system) conditions. Transient droop, as its name suggests increases the droop temporarily to a level that limits initial gate position changes in response to sudden speed changes. On mechanical-hydraulic governors, this is accomplished using a compensating dashpot. Temporary droop is set based on stability considerations. These settings are not selected to meet NERC or Regional requirements, but are required to tune hydro governors to meet isolated-system stability requirements. Often, the governor settings switch automatically between modes and the operating mode must be taken into account during testing and modeling. References to these detailed measurements and standards are provided in many references and textbooks, such as [4-9].

4.2.1.2 Steam Turbine Governors

Reference [4-15] provides an overall guide of the design, commissioning and modeling of speed governors to achieve a minimum speed control performance of steam turbines of different types. It specifies that permanent speed droop (or speed regulation) should be adjustable between 2.5 and 5%, with a maximum allowable level of 10%. The speed (or frequency) measurement dead band is specified not to exceed 0.06% (36 mHz) for most steam turbine types and 0.1% (60 mHz) for others.

Steam turbines do not require compensation, and therefore most operate in an open loop configuration with unit speed compared with a speed set point and the resulting error signal amplified for control with a gain term, K, which is inversely proportional to the speed droop.

Speed/Load control on steam turbines is controlled by the Control Valves (CV) that throttle steam flow to the HP section. Intercept Valves (IV) to the IP/LP sections are typically held wide open when the unit is loaded. Stop Valves are used to interrupt the steam flow to the main inlet and Reheater during load rejections. In some stations Operators also use the Stop valves to throttle steam flow during start-up and at low load. Typically, only the control valves are modeled in system simulations. The standard steam turbine governor model IEEEG1 is shown in Figure 4-2 [4-16].

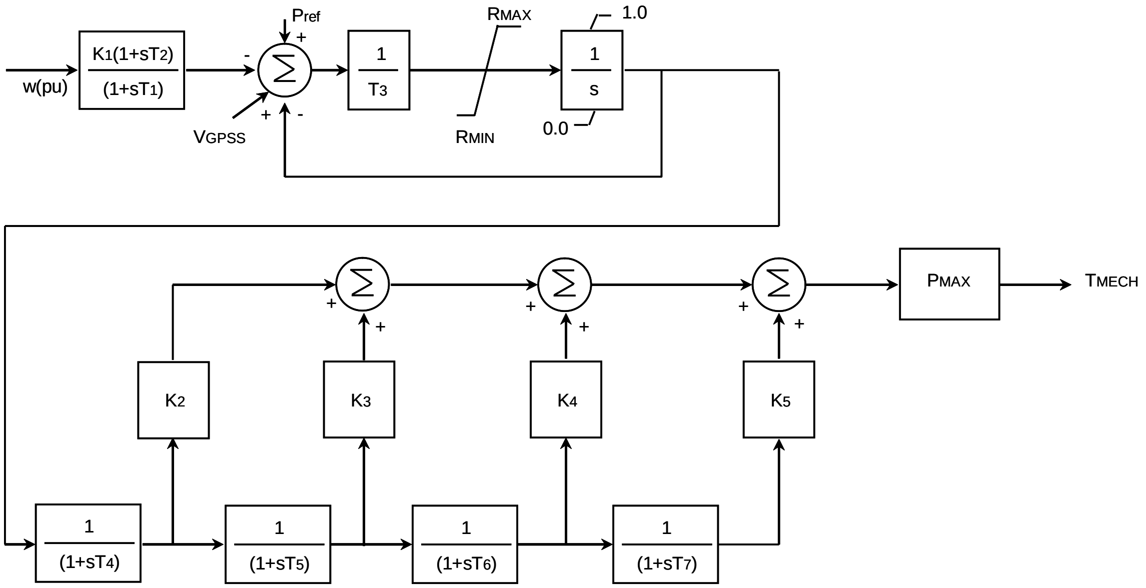

Figure 4-2
IEEE G1 Steam Turbine/Governor Model

The droop (regulation) is represented by the K1 coefficient, and any governor compensation is modeled using time constants, T1 and T2 (compensation is not normally present in the mechanical governors being discussed in this section). The control valve time constant (T3) and rate limits are represented in the next stage. Each turbine section is then modeled sequentially in the model with a combination of a time constant and coefficient to represent the fraction of output power contributed by each stage. The sum of K2 through K5 must total one in this model since each of these is a fraction of the power supplied.

Model values K2-K5 and T4-T7 must typically be provided by the turbine vendor, as there are no electrical signals available to independently monitor these variables.

4.2.2 Electro–Hydraulic Governors

New governing systems are almost exclusively of the electro-hydraulic design. The speed feedback signal to the governor can be a pulse train supplied by magnetic speed sensors mounted in proximity to a toothed wheel on the turbine shaft, or may be an ac voltage from the generator PTs. In some implementations, test signals can be introduced on a spare analog input of the speed sensor module, or via access to the digital speed reference setting. An intentional dead band is often used on the speed signal, to prevent constant motion of the fuel valve resulting from noise in the input signals and controller. This dead band must be kept within the allowed guidelines as discussed above.

Due to the ease of electronic control design, there is more variety of control configurations than in their mechanical counterparts. This is becoming even more prevalent as more of the systems are digitally implemented permitting a higher degree of customization based on end-user requirements. As a result, the actual control structure may not be available in a format compatible with the available simulation models.

4.2.2.1 Analog Electronic Controls

Manufacturer's data is typically in the form of bulletins and schematics showing the functionality and calibration of the various feedback and control stages. They often have gains and time constants which may be directly read from calibrated dial settings. They typically also have readily-available inputs and outputs to various electronic test points for signal injection and monitoring, thus simplifying testing and tuning and validation of their mathematical models. Models may often be derived directly from these settings, although, because of the precision of the components and drift due to age, heat and humidity, the actual gains and time constants may vary considerably from the calculated values.

4.2.2.2 Digital Electronic Controls

Manufacturer's data is typically in the form of block diagrams showing a continuous-time representation of the functionality of the various feedback and control stages. The most modern systems will provide these models in a standard simulation format.

The interface to the settings of digital governors is either via a control-panel interface or via connection to an external personal computer running an interface client program. The advantages of digital control include: stability of settings, direct implementation of settings in engineering units and the ability to switch between settings based on the system operating conditions.

Instrumenting and performing dynamic tests on digital versions has proven to be very challenging due to the absence of built-in test facilities and the difficulty of injecting signals for this purpose. However, even if the manufacturer has not provided built-in test facilities, dynamic response tests can usually be performed with some guidance from the manufacturer.

4.2.2.3 Hydraulic Turbine Governors

Feedback of gate/valve position is obtained from a rotational or linear displacement transducer. In some cases electrical power is used in place of gate or fuel valve position for the governor feedback signal. The speed reference, measured speed and droop (or regulation) feedbacks are combined electronically, either with analog circuitry or using a digital implementation. Once the controlling output signal is determined it is amplified to drive an electro-hydraulic transducer, which positions a pilot valve. The stages of hydraulic amplification are similar, if not identical, to those used with equivalent mechanical governors although new systems often use commercial proportional valves provided by other manufacturers.

Three-term PID (proportional, integral and derivative) control is typically employed. Feed forward elements allow differing responses to operator-initiated changes and system frequency changes. Figure 4-3 is an example block diagram for one implementation of an electronic governor [4-11].

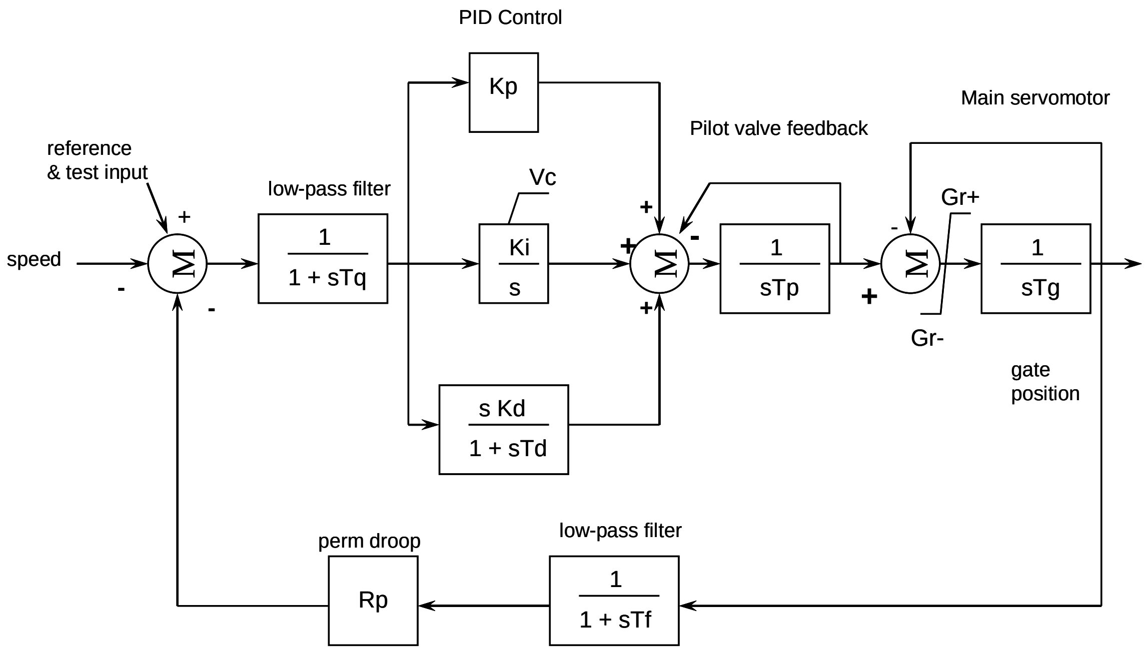

Figure 4-3
Electro-Hydraulic PID Governor Model

4.2.2.4 Steam Turbine Governors

Electro-hydraulic steam turbine governors may typically be modeled with the open-loop control model of Figure 4-2. The droop (regulation) is represented by the K1 coefficient, and any governor compensation is modeled using time constants, T1 and T2. These are typically the only model settings implemented in the governor electronics; the rest of the system being mechanical hydraulic components, with the same design and modeling issues as discussed above.

4.2.2.5 Gas Turbine Governors

The present recommended simulation model of a multi-shaft gas turbine is shown in Figure 4-4 [4-4].

The governor control is typically implemented in analog or digital electronics. In these systems, governor droop is often implemented as a constant relationship between turbine speed and generator electrical power (speed regulation, as opposed to droop). Some implementations do use fuel valve position or compressor discharge pressure, which is proportional to mechanical torque as a droop feedback signal, and the standard simulation model allows for either. The vendor's on-line speed droop control block diagram and settings will be required for modeling.

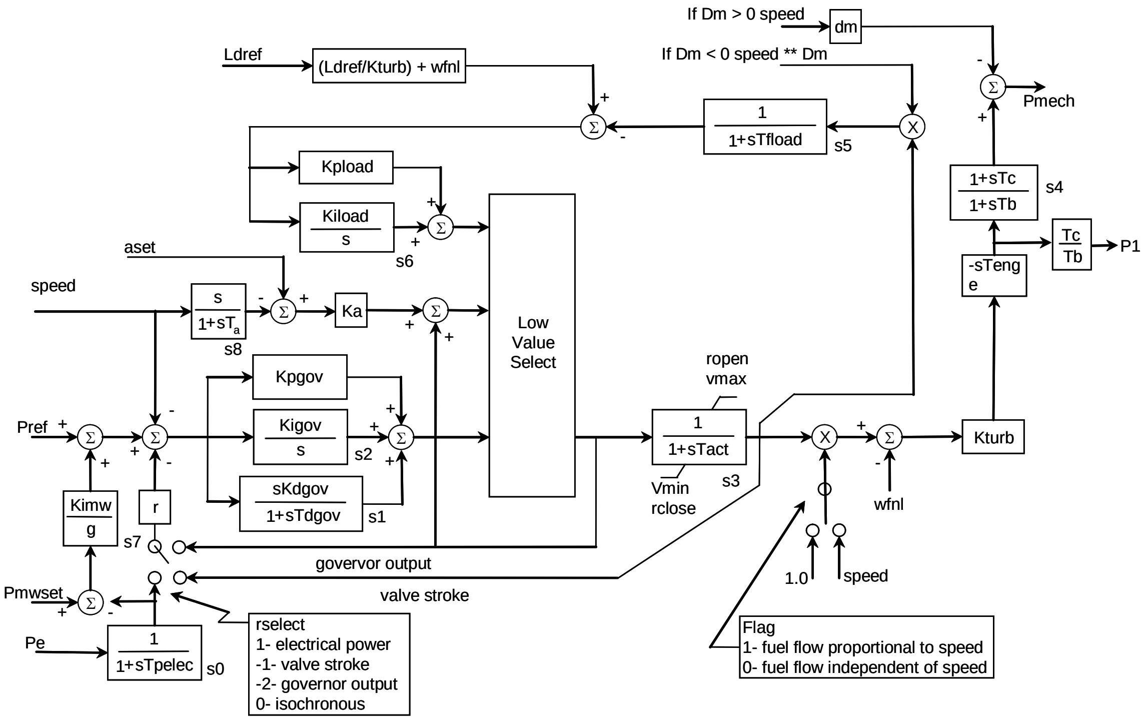

Figure 4-4
Gas Turbine Governor Model GGOV1

For combined-cycle units the droop setting is implemented in the governor controls of the individual gas turbines. The effective droop of the entire plant is a combination of the gas turbine response and the subsequent dependence of steam turbine power on gas turbine output. The steam turbine output follows the gas turbine, with a large time constant associated with the heat-recovery steam-generator. The steam turbine is typically operated with valves wide open [4-10]. Regional rules and simulation models of combined-cycle plants are only recently becoming available, and most jurisdictions will only be able to model individual units.

4.2.3 Outer Loop Controls

In addition to model data derived from tests performed on the turbine-governors, NERC MOD 027 requires additional model data for plant controls that affect the unit load set point, as separate from speed-droop governor control. Such controls may be MW set point controls or gas turbine temperature limit controls. Plant load controls are also becoming common in conventional steam and multi-unit hydro plants, and models and tests are presently under development.

Outer-loop controls act to maintain a pre-selected set-point, typically active power output level, on the unit as specified by the operator. This control loop will effectively override the initial response of the turbine droop-governor in the event of a system disturbance bringing the unit's output back to the pre-selected level [4-5]. Ideally, this loop should be disabled on units participating in primary frequency regulation.

Studies conducted during 2002 demonstrated that representing base loading of generators and generator load controllers has a dramatic effect on simulation results, not only in frequency deviation studies (reserve, under frequency load shedding, etc.), but will impact the results of many system stability studies, such as those used to set transfer limits, remedial action, etc [4-4]. The results of these studies and the new recommended models for thermal turbine-governors were distributed to WECC members in a report by a task force of the Modeling and Validation Work Group titled "New Thermal Turbine Governor Modeling for the WECC" [4-5]. The report clearly indicates the significant improvement in system simulations as a result of the new thermal modeling and the corresponding inadequacies of the existing thermal governor models.

This reference and follow-up papers recommended that all gas turbine units should be modeled using the GGOV1 model in Figure 4-4, which includes modeling of an outer-loop MW set point as typically used in these installations [4-4], as well as identifying a base-load temperature limit. A load control model which is now available in commercial simulation programs was recommended for modeling of hydro or steam units that operate under load control in addition to the appropriate governor model. Some jurisdictions accept presentation of the model structure and allow use of typical parameters, either presented by the generator owner, or based on a survey type questionnaire developed to group units into one of several typical classifications.

4.3 Model Validation

As with excitation systems, model verification is easiest on new equipment and most easily done during the commissioning process. For electro–hydraulic governors, most of the model parameters can be calculated with field testing used simply to verify the data. Gate travel rates and times are relatively easy to measure and water starting time for hydraulic turbines is normally available or can be estimated from drawings. Methods for model parameter determination and verification are the topic of numerous publications [4-17], and standards are available which describe the methods that can be applied [4-18].

There are two main methods of gathering the data necessary for simulation model validation: staged testing and ambient monitoring. Each of these will be discussed below.

When a unit is modeled for the first time, or has a major equipment change, such as a new governor, detailed staged testing may be necessary to confirm that the equipment meets the necessary performance or model verification requirements.

Once this baseline model has been obtained, typically simpler methods are allowed to confirm that the equipment continues to perform as it was originally modeled. This may be as simple as configuration control techniques, such as ensuring control settings have not been changed or gathering calibration records from maintenance outages. Ambient monitoring may also be used to satisfy on-going verification requirements as discussed in section 4.3.3 below.

4.3.1 Instrumentation

The following quantities may be instrumented during governor model validation:

- frequency (based on generator three-phase voltage or governor PMG signal)
- shaft speed (tachometer measurement from optical or magnetic pickups)
- gate or valve position (slide-wire potentiometer)
- pilot valve and servomotor position (Linear Voltage Displacement Transducer “LVDT” or Rotational Voltage Displacement Transducer “RVDT”)
- Electrical power (Watt transducer)
- Fuel flow (water, steam or gas)

Not all of these signals are required depending on the equipment or model complexity, and in many cases suitable transducers are already available as part of the governing and metering controls. This is especially true for modern installations where many of the quantities are converted to calibrated electrical quantities (voltages or currents). In this case, suitable high-impedance isolation amplifiers can be used to measure the required quantities. Data can be collected digitally or using direct-writing recorders.

4.3.2 Validation Tests

The first stage in developing a model validation plan is to examine the governor and determine a suitable model structure. A common pitfall is to attempt to fit measured results to the wrong structure. Once a structure has been selected, a list of the required model parameters should be compiled. Using the block diagram of Figure 4-1 as an example, the required parameters are: Rp, Rt, Tr, Tp, Tg, and Q.

Two different approaches can be taken to determining these parameters. One method, which is commonly used, is to perform an overall response test (e.g. load rejection or reference step change) and measure as many variables as possible (e.g. gate position, frequency, initial power, pilot valve position, dashpot plunger position). The test is then simulated to select parameter values which provide a good match to the measured results. This may not provide the most accurate results for all parameters, and can be a time–consuming, iterative process if some of the values are not known in advance. It is normally better to use the overall test to confirm the results of modeling performed through other tests.

The other approach is to design individual tests to measure the required parameters. The general approach is to use tests that isolate specific variables. Appendix D provides an example test plan. The following sub-sections describe some of these tests, highlighting the differences between different prime movers and different governor technologies.

4.3.2.1 Permanent Droop

Permanent droop is often set through a calibrated adjustment with an indication of the actual value. While this calibration is often reasonably accurate, permanent droop should be measured directly as a confirmation, especially on older mechanical units where changes may have been made to governor components.

This measurement may be performed without the benefit of any special equipment. The simplest approach is described below.

With the unit operating off-line, apply excitation such that the unit is operating close to rated terminal voltage. Adjust the speed reference to different settings above speed no-load (e.g. +/-4 % in 1% increments) and tabulate the unit's frequency versus reference setting. In cases where the speed reference does not have marked settings this will sometimes involve adding temporary markings to dials or gear wheels.

Synchronize the unit and adjust the speed reference to the values above speed-no-load that were tabulated in the previous step. Tabulate the final gate or fuel valve position and active power versus speed reference setting.

Table 4-1
Example Speed Droop Measurement for Mechanical Governor/Hydraulic Turbine

Speed Dial	Open Circuit Frequency	On Line Gate
(Turns)	(Hz)	(%)
0	60	10
1	60.6	30
2	61.2	50
3	61.8	70
4	62.4	90
5	63	100
average (%)	1	20
droop (%)	5	

Plot the measured off line speed and on line feedback signal used for permanent droop for corresponding speed reference settings. The slope of this curve at any point is the permanent droop. The average slope over the entire operating range is usually quoted as the droop value.

This test is equally applicable to hydraulic and thermal turbine governors. The monitored on line quantity should be that used for implementation of droop (e.g. gate position, active power, compressor discharge pressure...). When this procedure is applied to steam turbines the overspeed trip settings need to be confirmed prior to performing the off-line measurements.

Table 4-2
Example Speed Droop Measurement for Digital Governor/Gas Turbine

Speed Reference	Open Circuit Frequency	On Line Power
(rpm)	(Hz)	(MW)
3600	60	0
3636	60.6	10
3672	61.2	20
3708		30
3744		40
3780		50
average (%)	1	20
droop (%)	5	

Additional information should be gathered during these measurements to establish the turbine steady-state relationships (e.g. gate or gas valve or steam valve position versus power curve; static gains of the turbine or governor model,...). Quantities to be monitored for gas and steam turbines are listed below. These measurements are typically performed at the same time as generator reactive capability measurements, so that the unit loading is not changed from its normal schedule for longer than absolutely required.

For governor designs which do not have a calibrated speed reference available when the unit is on-line, validating the droop becomes a challenge. For all governor types, the manufacturer's block diagrams and technical bulletins should be obtained prior to testing in order to confirm the model structure and to determine the applicable test method. Many new digital units utilize an operator active power or gate position set-point, and speed droop is implemented in the controller by a comparison of actual speed or frequency to a signal generated internally which is a function of the operator set-point, converted to an equivalent speed reference.

If the governor has a built-in speed reference or speed error test facility, it may be used both off line and on line to introduce a small (e.g. 0.5% to 1%) speed reference change. The droop may then be evaluated by comparing the off line speed change with the on line gate (or valve, power etc) change to this test signal. The test signal may have to be applied for a period of minutes in order to achieve steady state for on line conditions.

If the governor control includes neither an on-line speed reference indication nor on line step test facility, then the manufacturer's control block diagram and settings may only be confirmed by ambient monitoring of system frequency changes, as described below.

4.3.2.2 Deadband

Although in theory it is possible to introduce very small reference changes in modern electronic or digital governors this is rarely an effective method of assessing the overall dead band. This is an ideal application of ambient monitoring as discussed in Section 4.3.3.

4.3.2.3 Hydraulic Turbine Governor Dynamic Tests

The following is a simplified test description suitable for use with most mechanical-hydraulic governors for hydraulic turbines. The test equipment requirements may be quite modest: gate position transducer, hand tools, stop watch, multimeter capable of measuring frequency.

The signals below are typically monitored or recorded:

- Speed Reference
- Turbine Speed
- Gate Position Demand
- Gate Position or Needle and Deflector Positions

Prior to testing, tabulate as-found settings and adjust, if necessary, to match any recommended settings.

Operate the unit on line with the speed reference at a calibrated setting (e.g. 2% above speed-no-load).

Tabulate or record the initial gate position and rapidly change the speed reference to a new (calibrated) position (i.e. one full turn clockwise on the speed reference dial). Allow the gates to settle to a new steady-state position and tabulate the final gate opening.

To obtain a record of the transient response of the governor, connect slide wire or other transducer to produce a voltage signal proportional to servomotor position. Follow the steps outlined above and record the gate position response as shown in Figure 4-5.

On units with small versus large system settings, repeat the test with the small system (damped) settings as well as the large system (fast) settings. Note the normal on-line mode of operation.

New governing systems are almost exclusively of the electro-hydraulic design. In this case speed reference step response tests may be initiated and recorded in the same way as they are performed for analog electronic or digital voltage regulators, and the same precautions, recording, and analysis techniques apply. See section 4.2.2 on the speed reference test options.

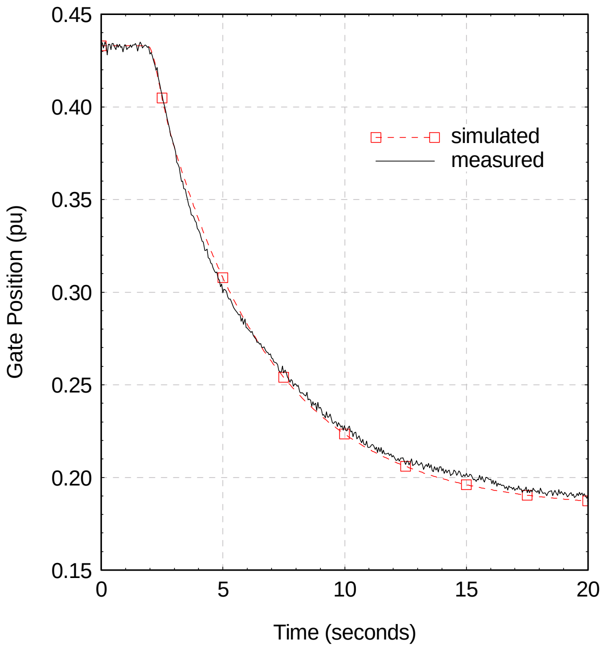

Figure 4-5
Mechanical Governor Damped Response

Once individual parameters have been identified, to the extent possible, an overall test can be performed to verify the correct performance of the model. Load rejection tests are one method used for this purpose [1-21]. It should be noted that many governors of all technologies switch modes or set-points when the unit synchronizing breaker opens. As a result, on many units neither on-line dynamics nor droop can be validated from a load rejection test. In this case, some means of disturbing the speed reference or one of the feedback signals must be employed with the unit operating on-line as described above.

4.3.2.4 Thermal Unit Testing

The manufacturer's bulletins as well as the on-line speed droop control block diagram and settings and any limiter settings will be required to select the model structures as well as settings.

Static measurements described in 4.3.2.1 may be used to establish the permanent droop and turbine operating curve (gate or fuel flow versus power output) and associated intermediate controller gains.

The following signals are typically monitored or recorded:

Gas Turbine Monitored Signals

- Speed Reference
- Power Turbine Speed
- Fuel Flow

- Valve Position Demand
- Valve Position
- Turbine Inlet and Exhaust Temperature
- Compressor Discharge Pressure

Steam Turbine Monitored Signals

- Speed Reference
- Turbine Speed
- Steam Flow
- Valve Position Demand
- Control Valve Positions
- Steam Temperature
- Steam Pressure

These units typically have slow ramp rates, so validation of governor dynamics by speed reference or feedback modulation or step changes is not generally possible. In addition, most governors employ reference changes and/or changing governor dynamic settings when switching from on-line to off-line modes, so that load rejection testing does not provide a method of validating on-line parameter values. In this case, the model must be computed from the manufacturer's settings and the only option for validation may be ambient monitoring as discussed below.

Reference [4-5] notes that the use of detailed thermal governor models has not produced load and frequency response simulations which match measured system events. This reference presents a new turbine-governor modeling approach that correctly represents thermal units that have demonstrated unresponsive characteristics such as "base loaded" units, or as units with load-controllers. This approach focuses on the use of data collected from station recorders during actual events rather than staged tests.

4.3.3 Ambient Monitoring

In the application of governor model verification, ambient monitoring involves the passive measurement of governor and/or generator output quantities with the intent of capturing the response of the machine to system disturbances. This technique involves recording the response to abnormal system or plant disturbances, but in some cases capturing the response to normal disturbances provides sufficient data for model validation.

This technique is used in place of or in addition to staged governor testing and is considered to be a less intrusive form of validation testing with lower risks to the unit and power system. It is also used to overcome some of the inherent features found in certain governor control system types that prevent model validation using staged techniques. Additional benefits of ambient monitoring include: a detailed knowledge of the manufacturer's design is not required and it may be possible to use existing transducers and recorders to collect the data.

Ambient monitoring equipment should be designed for permanent or semi-permanent installation. The equipment should continuously buffer the measured quantities or capture and store data based on predefined triggering events with ability for post-event retrieval. It should have adequate speed and resolution such that dynamic performance can be measured and evaluated.

Many, including the authors of this paper, have used ambient monitoring techniques in the verification of governor control models. It has proven to be particularly useful in confirming that a unit meets droop, dead band and frequency response requirements. Figure 4-6 illustrates a technique for confirming dead band. In this example, simulated governor response is subtracted from measure ambient data with the resultant graphed in equivalent frequency. The graphed analysis demonstrates the dead band tolerance of the governor control system. The dead band shown is an estimate based on the gate position variation calculated from the governor model response to the measured frequency deviation. This technique requires that there is sufficient ambient frequency variation to make a reasonable assessment, and that a suitable signal is available for comparison to the target simulation model response.

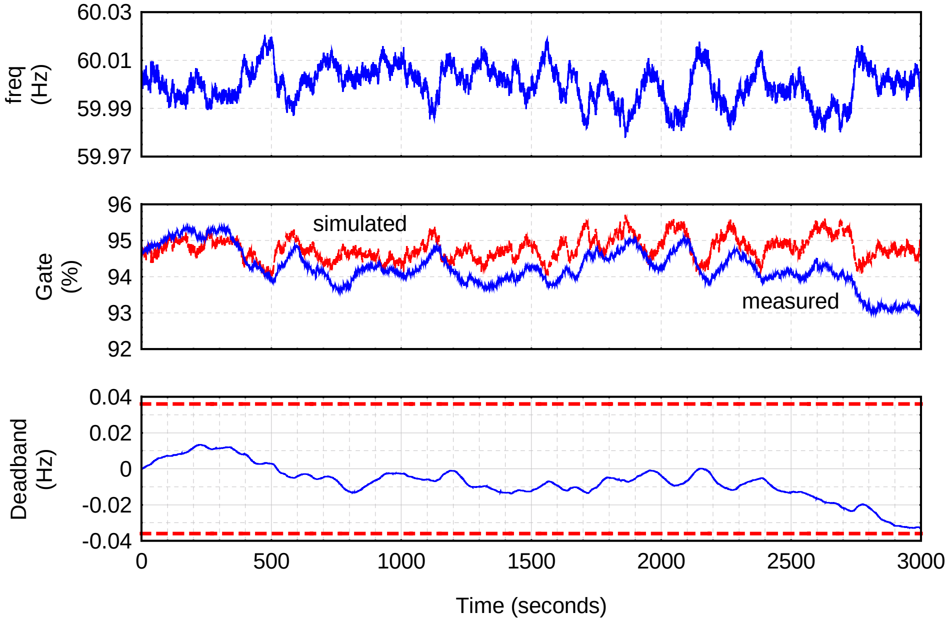

Figure 4-6
Governor Dead Band

5

COMPLIANCE PROGRAM

This document has dealt with the details of complying with the NERC technical generator regulatory requirements. For Generation Owners with limited experience in this area it will appear that they are being subjected to a large number of new technical requirements and that significant investment in new technology or training will be required. Many organizations will find that they already have in place technical and asset management practices that will provide much of the resources and information that is required to meet the new requirements.

When setting up a Compliance Program, organizations can achieve significant secondary benefits while minimizing disruption and costs if they follow these basic principles:

- treat regulatory compliance as an ongoing activity that is part of year-round engineering and operations rather than a series of discrete events
- integrate regulatory compliance with their existing business practices rather than centralizing all of these activities in a separate entity

Clearly each organization will need a group or individual with responsibility for tracking the evolving requirements and coordinating the organization's response. However by training staff to understand the new requirements and their role in meeting them, many of the regulatory requirements can be met as a by-product of normal operations.

This Section describes some of the steps that can be taken by organizations in developing their Compliance Program and integrating it into their business practices. A Compliance Life-Cycle model is introduced for validation and documentation. With this approach, regulatory reporting requirements are met as a byproduct of the process, rather than being the main focus. The goal is to achieve compliance with regulatory requirements at a reasonable cost with minimal disruption to normal operation.

5.1 Compliance Programs and the Compliance Life Cycle

Many of the Generation Owners that have undertaken wide-scale validation programs to meet regional regulatory requirements have done so based on a series of "snapshots" of their equipment. The data collected represented the status of the system at a particular instant in time. The validity of this snapshot was always questionable because there was often no change control process in place to ensure that settings and configurations were maintained. Operators could change the operating status of the unit (e.g. transferring from AVR to Manual control of excitation) or maintenance staff could change control settings without identifying these changes to the parties responsible for reporting. In many cases this was due to a lack of understanding of the effect of these actions on a generator's interaction with the power system. In extreme cases, wholesale equipment changes were made without communication of the changes to the personnel responsible for maintaining the data and performing system studies. NERC rules on the operating status of excitation equipment (i.e. AVR and PSS) have clarified the reporting requirements for Operations and should reduce instances of un-reported operation in Manual control and with the PSS turned off.

What is lacking for many Generation Owners is an effective change control process coupled with training for staff at all levels. The goal is to ensure that all parties are aware of the following:

- Location of the official settings for the unit. On digital systems this will normally consist of one or more files that are downloaded directly from the controller and document its complete state at the time of verification.
- Procedures that document the steps to be taken for any changes (e.g. for changes to AVR settings such as gain, repeat baseline tests and/or report modified model).
- Reporting hierarchy to ensure that any relevant changes are reported to the part of the organization that will initiate the appropriate action (e.g. initiate follow-up tests, report revised settings, etc.).

The importance of this process will increase with the proliferation of digital control and protection equipment since the re-verification requirements may be much simpler on these units. If an appropriate change control process is in place the act of re-verifying the performance of an excitation system might be as simple as the following steps:

- Verify that critical hardware has not been replaced since the last verification.
- Verify that the software settings have not changed from the official settings for the unit.
- Verify input and outputs of device. For example for a power system stabilizer this would involve verifying that the input quantities (e.g. power and speed or compensated frequency) are still being measured correctly and the that the output continues to function normally.

Depending on how the final rules are implemented this kind of verification might be adequate to meet compliance requirements.

The remainder of this Section describes one possible framework for a Compliance Program and the “Life Cycle” of the data derived from the validation process.

5.1.1 Overview of Compliance Life Cycle

Compliance requirements can be met most effectively by moving away from static snapshots of equipment condition toward a living database of equipment status and performance information. The database is constantly in a state of transition reacting to changes in the system as they happen. In this model, re-verification is triggered by events such as equipment changes or maintenance cycles but can also be tied to periodic scheduled re-verification mandated by NERC or the RROs. By constantly tracking changes and executing appropriate procedures the period between routine scheduled tests may be increased. This model may have to be adjusted depending on the final design of the NERC compliance requirements. Engineering judgment and cooperation between all levels of an organization is used to reduce unnecessary testing or duplication of effort. Improved communications and staff training are the cornerstones of this process.

Figure 5-1 is a simplified flow chart that summarizes the main process from initial data gathering to data submission. The following sub-sections describe each of the stages in detail. Subsequent sections discuss the triggers and requirement for re-verification (Figures 5-2 and 5-3).

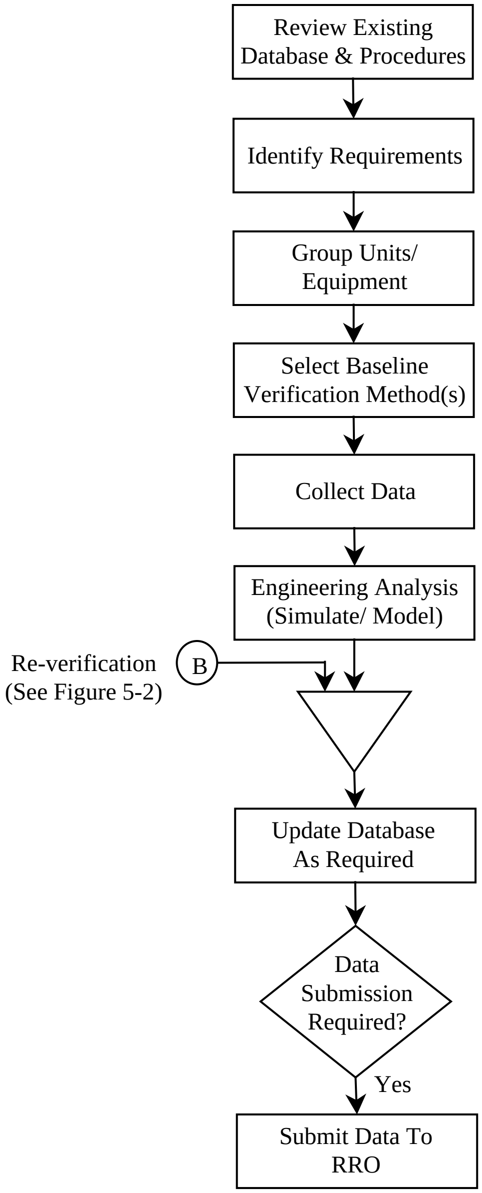

Figure 5-1
Compliance Process Flowchart

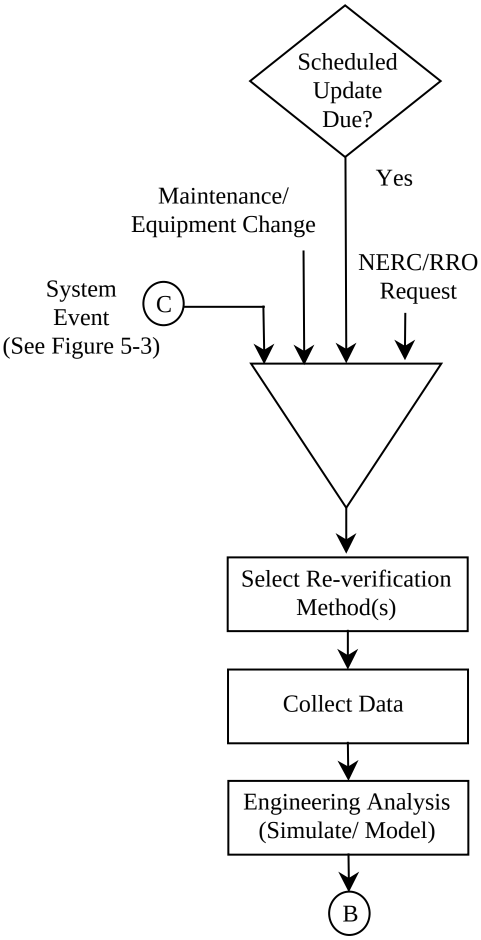

Figure 5-2
Re-Verification Flowchart

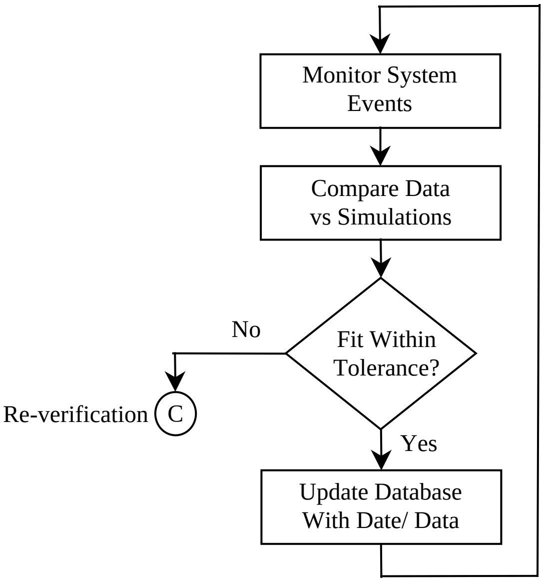

Figure 5-3
Monitoring of System Events

5.1.2 Initial Review/Definition of Requirements

Prior to embarking on a Compliance Program the Generation Owner should review the existing state of preparedness of their organization as depicted in the entry point to the flowchart of Figure 5-1. It is difficult for the organizer of any compliance program to be in regular contact with all of the technical staff involved in procurement, maintenance, simulation, data collection or testing. As a result, valuable information may be overlooked. By identifying all of the stakeholders at the beginning of the process the owner can avoid the risk of "re-inventing the wheel".

At this stage the following questions should be answered:

- Do the equipment specifications used to procure new equipment require Vendors to supply all of the required data for meeting compliance requirements?

Sixty-seven percent of the survey respondents replied that their purchasing specifications include a requirement for manufacturers to provide capability information and simulation model data for new generation equipment. Based on this there should be useful data available as a starting point for the majority of organizations.

- What kinds of type tests and commissioning tests do the vendors perform on the generators and associated equipment?
- Does the organization have centralized engineering and testing expertise, does it rely on expertise in each plant or does it rely on manufacturers and consultants?

Of the survey respondents that reported performing reactive capability verification on their units, all of them indicated that internal engineering resources were used for this purpose and 36% indicated that they supplemented internal resources with external consultants. This percentage increased to 50% for protection testing and 70% for exciter and governor testing. Based on these results it appears that most organizations will have engineering resources to coordinate or lead the required verification and data collection and that the requirement to bring in outside resources increases with the specialization of the testing and complexity of the equipment.

- Does the organization have documented change control processes? In other words, if generator equipment or settings are changed, are the changes reviewed and approved in a consistent manner?
- What internal documentation is available and who are the custodians?

Eighty-nine percent of the survey respondents reported maintaining some form of database of model and capability data for their generators and associated control equipment. This database is the obvious starting point for any effort to develop a compliance program. With some modifications it may meet all of the organization's compliance reporting requirements or it may need to be supplemented by a database or tool designed specifically for this purpose.

- What kinds of simulation studies are performed and what tools are available?

In obtaining answers to these questions the organizations strengths and weaknesses in this area will be documented. This will also generate the list of stakeholders that will be involved in the process. This is critical to the eventual success, because this process is multi-disciplinary, requiring cooperation between many different levels within the Organization.

Once the organizational issues have been reviewed and documented the next step depicted in Figure 5-1 is creating an inventory of the individual stations and units, identifying similar/identical equipment so that Main and Sister units can be selected. For example, in a multi-unit station if all of the generators are identical but different control equipment is used (e.g. excitation systems) the validation requirements can be reduced on some units since generator model parameters will not have to be validated in detail. Similar equipment may be used at different stations within a Generator Owner's system and significant savings can be achieved by identifying common equipment at the outset. This is particularly true where units are equipped with modern digital controls since performance will be dictated primarily by the settings that are applied and not the condition of the individual units.

Once units have been grouped according to their equipment and similarity to other units within the organization the list of unique Main units and Sister units can be used to prioritize and schedule verification. Depending on the RRO, baseline verification may only be required on Main units allowing Sister units to undergo a simpler series of tests. If adequate manufacturer or test data is already available for Main units the baseline tests may be reduced or bypassed completely allowing simpler re-verification to be applied to all similar units. Large stations with little or no available data are obvious candidates for early testing. This process should also allow station staff to identify maintenance or equipment replacement schedules. Nobody benefits from tests performed on obsolete equipment that is scheduled for replacement. There can be a significant economic benefit to harmonizing compliance testing with plant outage schedules. In some cases, the costs of adding these tests to an existing outage or equipment replacement plan will be almost negligible.

5.1.3 Baseline Verification

Once the organization's state of readiness and requirements has been identified, and the generating units grouped, the method of baseline verification needs to be selected for the Main units (Figure 5-1). Baseline verification refers to the initial data collection or testing that is used to produce a baseline response that can be used to model the equipment or characterize its response to meet compliance requirements. The available methods to perform this verification depend on the equipment and will be dictated by the final NERC and RRO regulations. WECC and other RROs that were early adopters of the NERC standards require staged testing to verify performance or produce a simulation model. Other RROs have allowed the use of Manufacturer's data or engineering analysis to establish capabilities and models.

Depending on the available resources at a given plant site, it may be possible to obtain some of the required results using the station's operating and maintenance staff by integrating the tests into the normal dispatching of the units. For example, reactive capability tests can be performed at a variety of different active power levels during a normal run-up or following an outage. The existing station transducers can be used to provide the measurements as long as they have been calibrated against known references prior to the test. The advantage of using operating staff to perform these tests includes:

- Familiarizes staff with the actual capabilities of the unit in a controlled fashion
- Minimizes disruption to normal unit operating schedule

- Allows tests to be performed during appropriate system conditions. For example under-excited capability tests can be run during light-load conditions (e.g. at night) when system voltages are normally high, allowing the unit(s) to absorb reactive power without reducing voltages below acceptable levels

Regardless of the method used, the outcome is a baseline model for the generator and control equipment that can be used to establish both steady-state and dynamic performance.

Once the engineering analysis is complete the models and performance data that are created need to be stored in some form of database for future access and for compliance reporting purposes. In the past era of vertically integrated utilities the dynamic model data was often stored in one or more data files in the format of the simulation program(s) used to perform Operating Security Limit or Planning studies for the utility. Most survey respondents indicated that they store the data in some form of database. Organizations need to review these databases to ensure that they meet the new Regulatory reporting requirements and include some form of notification, data tracking and change control process. Depending on the ISO or RRO requirements any new or modified data may have to be submitted to be included in upcoming studies or analysis.

In order for the compliance process to be truly useful it is critical that the baseline data not be treated as a static snapshot. At this point several triggers should be used to initiate the re-verification portion of the process.

5.1.4 Re-Verification

Re-verification refers to the process of verifying performance or model data on units that have already been subjected to baseline measurements or are Sister units to Main units that have undergone detailed analysis and/or testing. The types of analysis or testing required at this point is intended to be significantly simpler that the baseline since the intent is only to ensure that there have been no changes to registered data and that the generating unit's performance has not been diminished in some manner.

As depicted in Figure 5-2, re-verification may be initiated by a variety of triggers. The most familiar trigger is the scheduled one based on the NERC requirements. For example, many of the NERC Standards call for units to be verified on a five-year rotating schedule with the Generation Owner responsible for scheduling and selecting the order of re-verification.

Re-verification may also be required for other reasons such as:

- On demand by NERC/RRO or even the ISO. Normally the regulators will only ask for an un-scheduled update if there is uncertainty regarding the validity of the data provided previously or if a generating unit or station is believed to have not performed correctly during some form of system disturbance. In some cases, simulation studies performed following large system disturbances may not reproduce the actual event properly and one or more stations may be called on to verify their data or performance.
- Following equipment maintenance or modifications. Station maintenance staff must be trained to identify the kinds of changes to station equipment that are significant to the reported data so that they can trigger this re-verification. For example, replacement of a

faulty fan on an excitation system will not trigger this requirement but changes to settings or replacement of modules that affect the closed-loop dynamics of the terminal voltage regulator require further investigation. Engineering review of the change may confirm that no further action is required but even this information should be stored in the compliance database to demonstrate due diligence.

- Following analysis of a system disturbance or event. Where appropriate, organizations may decide to meet their regulatory data requirements through un-attended recording or monitoring of the response of their generators to minor and major system events. In this case these recordings should be reviewed periodically or after any major event and the response of the unit compared against expected performance. This review could be as simple as viewing by an experienced engineer or as complicated as detailed simulation of the event and comparison with the measured response. In either case any significant deviation from the expected outcome should be used to trigger re-verification. This process is depicted in the flowchart of Figure 5-3. An important feature of this process is that any data and analysis should be tracked in the database even if it does not result in a change to the reported data. The reason for this is that successful re-verification of the model or performance can “reset the clock” on the scheduled re-verification process. Ideally this form of monitoring and re-verification could almost eliminate the need for some or all of the scheduled re-verification requirements.

Once the need for re-verification has been established then the method(s) need to be selected. The focus of re-verification testing is to confirm that past models and performance continue to apply. Therefore any analysis and testing can be simplified to focus on confirming similarity to past performance. Some of the options presently available for this purpose include:

- Simulation of the response of the unit to ambient small and large system disturbances and comparisons with recorded data. This approach requires that a recording device, which is capable of continuous recording or triggering on events, be available and that simulations be performed. This approach is un-scheduled and relies on the occurrence of suitable external events.
- Limited staged tests intended to replicate past measurements. The new data is compared to previous ones by a trained engineer to check if they match each other sufficiently. If the exact test conditions can be reproduced then the comparison task is greatly simplified and the level of experience required is greatly reduced. An example of this would be the simple step response test on an excitation system performed with the generator running but not synchronized to the grid. The conditions for this test are completely under the control of the Generator Operator and therefore can be matched to past ones. If the same quantities are measured with equivalent transducers and recorder then a direct comparison can be performed. The advantage of this approach is that no simulations are required. These tests would normally be scheduled to coordinate with outage or operating schedules to reduce any disruptions to the normal operation of the unit.
- Engineering review of settings and condition coupled with selected off-line tests. This approach is normally used for protection and control equipment such as relays and some elements of excitation systems. An example is secondary injection testing of generator protection relays. The generation (electro-mechanical or first generation digital equipment, etc.) of the equipment involved determines the extent of required testing. For example, for a modern digital excitation system it may be acceptable to confirm that settings have not

changed and that the input measurements continue to function normally. Relay test sets equipped with generator simulation capability can be used to provide realistic closed-loop testing and may provide an adequate substitute for on-line testing of units if allowed by NERC and the RROs.

Once data is collected the engineering analysis may be greatly simplified and may not involve any requirement to simulate performance using the models (Figure 5-2). At this point the original process of Figure 5-1 is re-entered and any new or changed data is stored in the database and reported to regulatory authorities as required.

The key to the entire process is that all maintenance, analysis, review, simulation or other activity that demonstrates attempts to comply with the requirements be documented and stored along with any data that is reported directly to the regulators. If this process is continuously applied then compliance reports can be generated on-demand with little or no additional effort. Tracking of this information may also allow Generator Owners to postpone or eliminate disruptions to their operation.

Controlled copies of any test plans or calculations should be stored in the database for each location to act as a resource for future testing and troubleshooting. Updating and correcting this material based on test experience, and whenever required based on changes to plant equipment or settings, will ensure that staff have access to a valuable resource.

5.1.5 Timing of Validation Testing

Timely validation of computer models is necessary to ensure their continued validity. Equipment wear, upgrading and refurbishment, component drift, adjustments to settings and configuration management all contribute to possible changes in the dynamic response of the unit. Guidelines for frequency of model validation testing are summarized below.

Model validation testing should be part of equipment commissioning. If model validation was not performed during commissioning then it should be done as soon as practical.

The measured responses to actual power system disturbances should be compared with simulations performed using the models, and differences used to prioritize testing. If no modifications have been made to the equipment since the last model validation test, then repeat model validation testing need only be performed if measured responses to system disturbances disagree with model predictions.

Validation of tunable settings should be performed periodically (e.g. following a major unit outage) as determined by experience with the particular equipment in use and every time a change or upgrade is made. The history of the equipment, such as component failures and the need for adjustments should be used to determine when re-testing of a model may be warranted.

Validation of equipment characteristics set by design is typically only performed during commissioning or at the start of a test program. Simple re-verification tests may be performed occasionally or when evidence of changes to unit behavior occurs.

Rotating Equipment – Most generator and rotating exciter model data is fixed by design. Generator inertia will not change unless generator or turbine modifications are made, and thus repeated testing is not a necessity. Generator rewinding is not expected to introduce changes to the generator impedances although the values expressed in per-unit on the new base will change. Periodic reactive capability tests and confirmation of the open circuit saturation characteristic will reveal unexpected reductions in unit capability, for instance, shorted rotor turns, or control system automation enforcement of operational limits. Reactive capability verification is mandatory in many jurisdictions.

Closed-Loop Controls – Whenever the controls are modified or upgraded a new model may be needed and model validation testing will need to be performed. Equipment technology plays a large role in determining the necessity and frequency of testing.

Older mechanical or magnetic amplifier equipment is more likely to be refurbished, has fewer calibrated settings and is more susceptible to drift than more modern equipment, and hence should be tested following major outages.

Both analog electronic and digital electronic equipment rely on input and output electronics which require calibration and may exhibit drift. In these cases, equipment history may provide the best guide for frequency of testing.

Digital electronic equipment may have drift-free settings, but may be subject to change control issues (modification of settings), which should be periodically checked. This equipment typically has both data logging and testing facilities built-in, which remove two of the barriers to re-verification tests.

5.2 Tools and Procedures

This section describes some of the tools and procedures necessary for implementing an effective compliance program.

5.2.1 Compliance Database

One of the key tools required to execute the compliance program is a database designed to not only store the compliance data that is reported to regulators but also provide a resource to staff tasked with meeting the emerging requirements. The need for such a database increases directly with the amount of equipment being managed. Most of the survey respondents reported storing their data in some form of database. In many cases these databases were designed for other purposes, often to provide a source of dynamic model data for simulation tools. Although this is one component of the required data, a modern compliance database requires many other features and even organizations with established testing and modelling programs would be well advised to re-visit their requirements in light of the changing regulations.

Some recommended features to consider when selecting a database are the following:

- Stores all of the data associated with compliance in a single location, accessible on-line by all of the organization's staff that may be involved in the compliance activity.
- Provides security, data backup and change control appropriate for the type of data being stored, some of which may be commercially sensitive.
- Generates reports in a format that can be submitted directly to regulators.
- Generates dynamic data in a format that can be directly used in simulation studies.
- Links reported data to their sources (e.g. digital copies of test records, simulations, drawings, reports, memos)
- Provides notification of scheduled re-verification requirements.
- Notifies stakeholders throughout the organization of changes to data or regulations that may affect their work.
- Provides access to up-to-date copies of applicable NERC, RRO and ISO regulations.
- Provides access to training material, glossaries and other resources that will help staff from various disciplines interact with the information.

This is especially important for organizations with facilities distributed over a large geographical area since their staff has little opportunity for direct interaction, but experience gained in one plant may be applicable to many other parts of the organization. These organizations may also face different detailed requirements from different RROs and must be aware of all of the latest requirements.

5.2.2 Procedures, Documentation and Quality Assurance

Most generation owners implement some form of internal quality assurance (QA) program for many of their activities. For nuclear operating companies this has become a strong focus of the organization and many utilities now require that their suppliers implement some form of recognized QA program (e.g. ISO 9000 series). These companies are already familiar with the process of documenting their activities in the form of technical and administrative work instructions and of preparing for audits by external organizations to confirm compliance.

A cornerstone of the present NERC rules and regulations is their reliance on self-reporting by the member entities. Generation owners and other market participants are expected to continually monitor their own compliance, detect and correct deficiencies and report any non-compliance events. NERC and the RROs will have the power to audit generation owners to verify that they are monitoring their own compliance periodically, but given the large number of participants and generators and the number of available auditors this is unlikely to change in the foreseeable future. As a result the focus will be on the processes used by generation owners to monitor their own compliance rather than on the underlying data. Owners whose compliance strategy is part of an industry-recognized QA program, including a documented internal audit procedure, will be in the best position to successfully handle external audits.

The following is a partial list of procedures and documentation and their relevance to this process:

- Overall compliance program procedures outlining the responsibilities and authority of all staff. Responsibility for maintaining the integrity of the data should be delegated to stakeholders throughout the business. At the stations, maintenance staff can be assigned the responsibility to automatically identify equipment problems that could potentially affect overall performance and data validity. Staff responsible for scheduling equipment outages and modification/replacement of equipment should ensure that the required tests and updates are triggered.
- Procurement procedures must require that specifications for new equipment include requirements for vendors to supply as much data as possible on their equipment in a format that can be reported directly. As noted earlier well over half of the survey respondents indicated that their specifications already included some of these requirements. A governor or exciter with a built-in step-test facility and data recording feature can be tested in a fraction of the time required for a unit without these options. Digital controls should be designed to include communications and human interface software to allow data to be readily accessed following system events.
- Maintenance procedures for equipment should clearly identify any activities that could potentially impact regulatory compliance and provide steps to be taken following equipment modifications or adjustments. Written procedures should be used for all work, completed with the work and then archived for future review. Relating the physical equipment settings (e.g. AVR potentiometers) to the corresponding model parameters in a transparent fashion will allow station staff to understand the implications of their actions when they need to make changes. Critical settings or components should be labeled throughout the station as part of this documentation.
- Commissioning and acceptance test procedures should be clearly documented and list all of the measurements and records that must be retained to meet compliance requirements. Past utility practice was for much of this information to be passed on from senior technical staff to apprentices or other staff (e.g. governor setup and tuning, relay secondary injection testing). This approach is no longer adequate.
- Simulation and engineering calculation procedures should also be clearly documented so that results can be accurately reproduced as required to support data submissions.

Plant operation/maintenance procedure should require that the equipment used for critical measurements be calibrated routinely with an automatic call-up based on outage periods or other scheduled events. The equipment that should be included in this procedure is centralized test equipment (e.g. relay test sets, meters, oscilloscopes, etc.), station metering, fault and disturbance recorders.

5.2.3 Training Requirements

A critical stage of the overall process that is frequently overlooked, is training of staff. Regardless of whether analysis and testing is performed by in-house specialists or outside consultants, this provides an excellent opportunity for training of operations and maintenance personnel. Even experienced station staff can benefit from sessions dealing with the design and operation of generator controls, power system operation and synchronous generator reactive capability. Less than one third of survey respondents reported that training was provided in any of the areas being discussed. Given the changing demographic of the utility industry as a whole this identifies an important need since new staff may have limited opportunities to learn from the large number of retiring staff over the next decade.

This training can take the form of classroom sessions, practical training during testing, computer-based training (CBT) or combinations of these three. A combination of these three approaches is usually used due to the advantages and disadvantages listed in Table 5-1.

Table 5-1
Compliance Training Approaches

Type of Training	Advantages	Disadvantages
Classroom	• opportunity for in-depth training • allows for detailed questions/answers • allows interaction with other staff with different expertise and experience	• limited practical learning opportunity • training is only as good as the instructor
Test Sessions	• best practical experience opportunity • information is directly applicable to operation	• limited opportunities for questions • limits number of staff that can participate • scheduling can be difficult or impractical
Computer-Based	• allows all staff to participate, regardless of shift schedule • self-paced • low-cost refresher training	• trainee's computer skills may limit their ability to participate • Limited direct feedback and opportunity to get answers to questions

Combining these three different training techniques can provide all of the advantages and reduce or eliminate the disadvantages.

A

SUMMARY OF SURVEY RESULTS

A survey of generator owners was conducted as a means of establishing baseline statistics on the current status of generator owner compliance programs. The survey was primarily comprised of objective questions, but it also allowed individuals to comment on practical experiences, lessons learned and best practices associated with compliance testing. The survey questions focused on obtaining feedback on the NERC generator owner standards that are covered by this report. The questions were divided into 5 categories:

- General/Organizational
- Active Power Capability
- Reactive Power Capability
- Protection and Coordination
- Excitation System Models and Voltage Control
- Unit Frequency (Governor) Response

Survey results for each category are summarized in the corresponding section of this appendix. At the end of each section is a summary of the comments submitted in association with the project; this includes a comment section that is specific to nuclear units. Survey questions can be found in Section A.7.

The survey was distributed to 44 individuals that have significant responsibility in their respective company's generator compliance program. The 44 individuals represented 32 generator owning organizations dispersed throughout all 8 of the NERC regions. Of the 44 surveys distributed 18 were completed and returned, the returned surveys represent 17 organizations with generation sites in all of the NERC regions except SPP.

A.1 General and Organizational Related Survey Results

This section covered general corporate compliance programs and some questions related to NERC Standard PRC-002-1.

- Figure A-1 shows the distribution of generator fuel source type of those that responded to the survey.
- Some general compliance program statistics are presented in Figure A-2.
- Survey results indicated that most organizations have not equipped a majority of their units with digital recording systems; Figure A-3 illustrates the results.

- Based on survey results the most common digital recording systems are:
  1. Operator's SCADA system
  2. Data logging built-in to protection or control equipment
  3. Digital fault recorder
- Of those organizations that don't have digital recording systems installed on all units, 62% intend to install new equipment or monitor existing data sources in order to meet compliance requirements.
- Figure A-4 shows a distribution of the survey respondents based on the percentage of units in their organization that have undergone some form of model or capability testing validation during the past year.

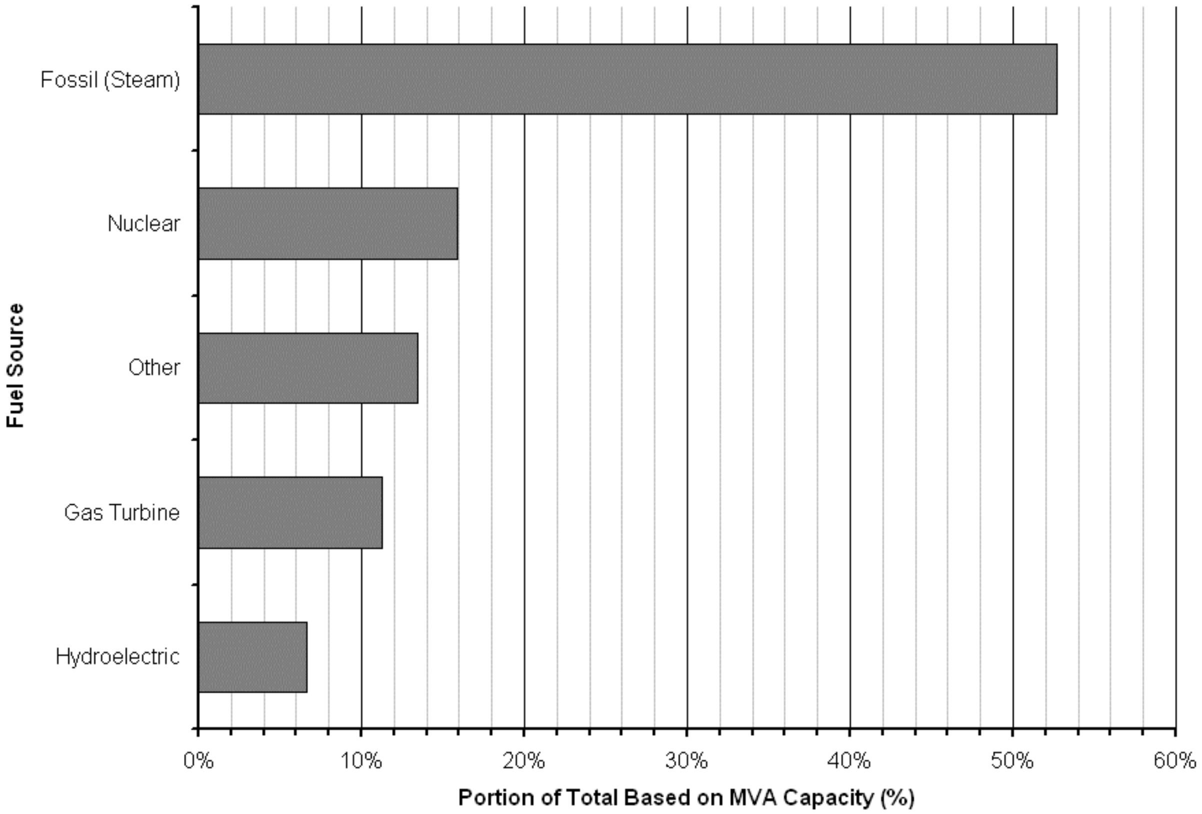

Figure A-1
Unit Fuel Type

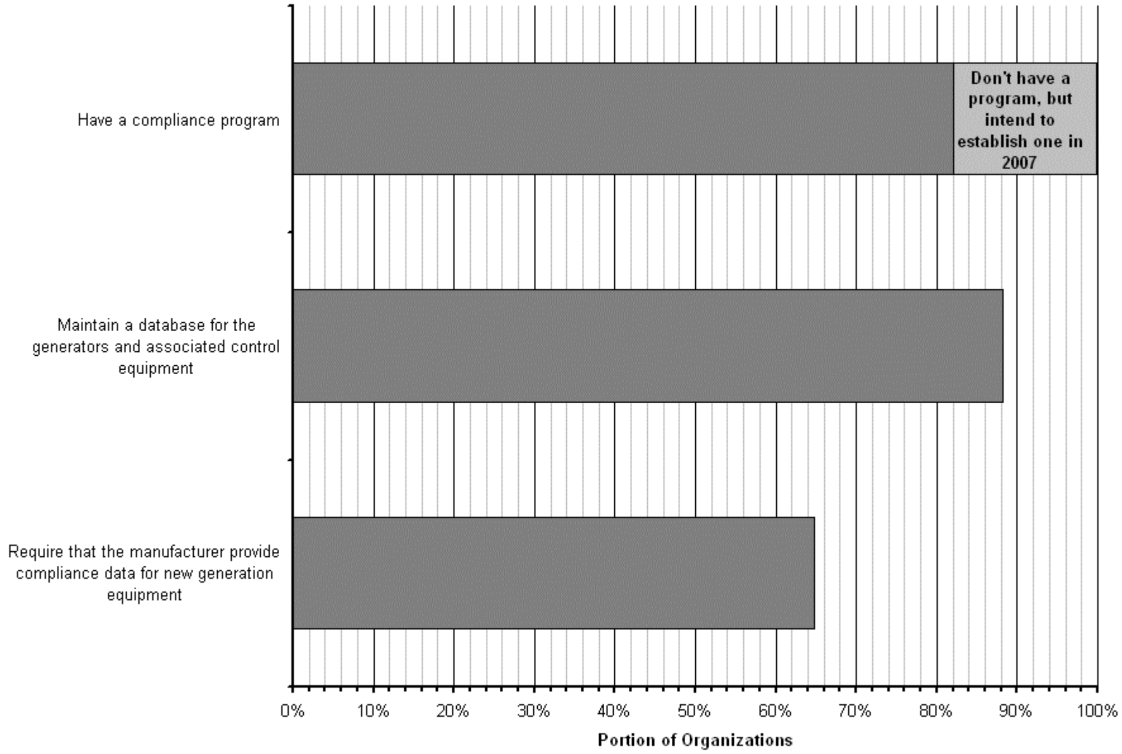

Figure A-2
NERC/RRO Compliance Statistics

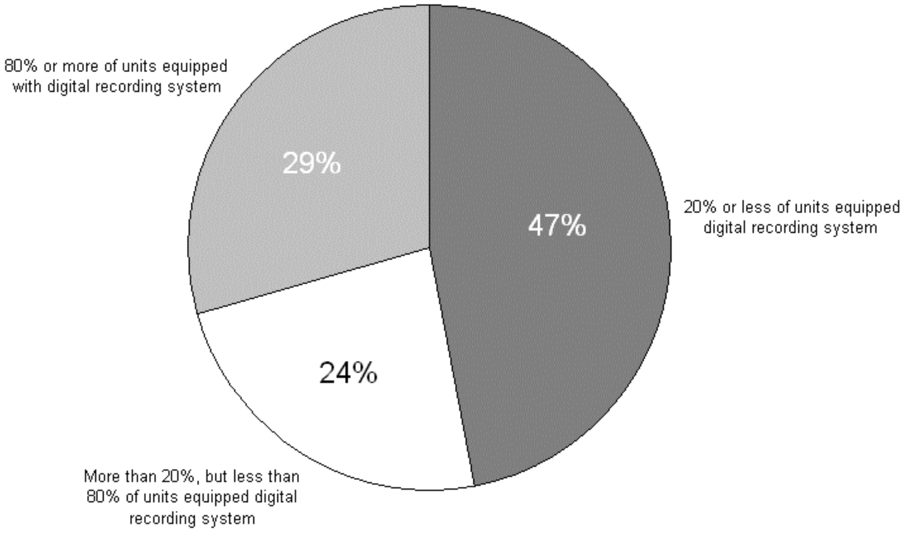

Figure A-3
Organizations With Digital Recording Systems

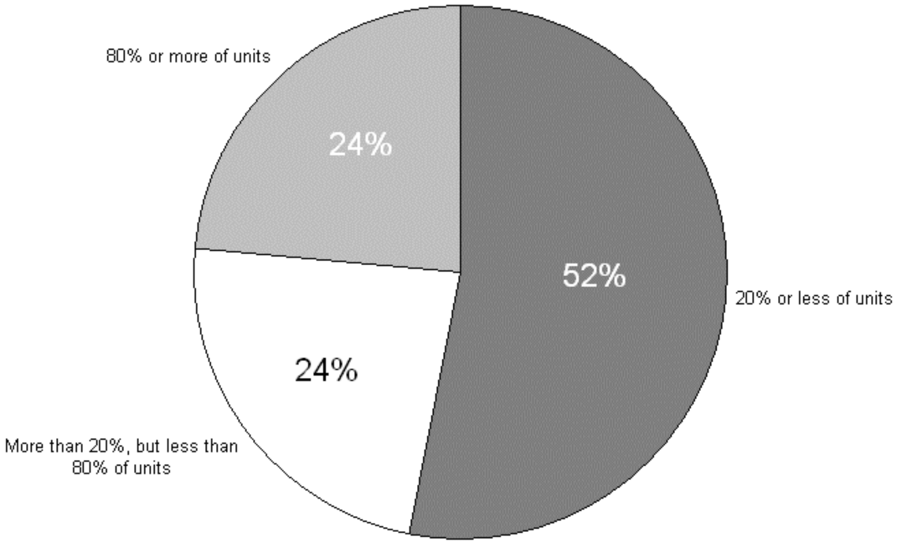

Figure A-4
Organizations that Preformed Unit Validation in the Past Year

General Comment Summary

- Many of the comments in this section pointed out that most modern digital excitation systems and protection devices have data logging capabilities. Upgrading these systems results in the collateral benefit of expanding the organizations event recording capabilities.

Nuclear Unit Comments

- There were no comments that pertain specifically to nuclear units in this section.

A.2 Real Power Capability (MOD-024) Survey Results

Of the 17 organizations that are represented by the survey results, 14 of them verify the maximum gross and net real power capabilities of their units on a regular basis. The following items summarize the survey results of those 14 organizations:

- Staged testing was by far the most common method used for verifying real power capability – it was used by 12 of the 14. Less than 1/2 of the organizations used past data records, while less than 1/3 relied on manufacture's data, estimates or engineering calculations.
- More than 80% indicated that the manufacturer's estimates for real power capability have matched performance when verified by other methods.
- Almost all of the organizations utilized engineering or other support staff within the organization combined with operators to perform the real power verification; while only 2 of 14 contracted outside consultants.
- Table A-1 shows the percentage of organizations that responded yes to the commercial related questions in this section of the survey.

- Most of the responders indicated that existing station meters are used for validating the real power requirements of auxiliary loads, Figure A-5 breaks down the various methods used.
- Only 1 respondent indicated that their organization has discovered other information that was of technical or commercial use as part of real power capability verification.

Table A-1
Commercial Related Results for Real Power Capability

Question	Yes
Was any training required prior to performing this verification?	29%
Were any significant costs incurred to perform this work?	29%
Was any equipment purchased or rented in order to perform this verification?	7%

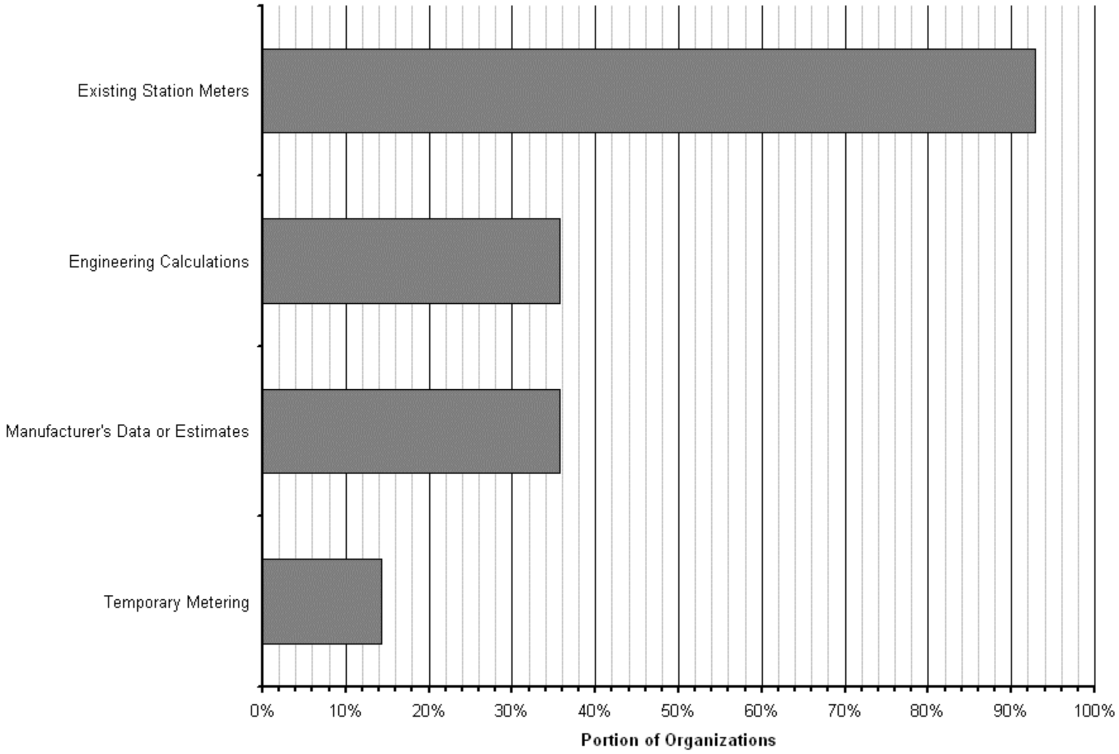

Figure A-5
Methods Used for Validating Real Power for Auxiliary Loads

General Comment Summary

- Many indicated that staged real power verification is performed following generator rewinds or turbine upgrades, while a smaller number of organizations perform this testing on a cyclical basis (some yearly, some every 5 years).
- Fuel cost and initial engineering time were cited as the most significant costs associated with staged real power testing.

Nuclear Unit Comments

- Those that responded or were interviewed indicated that they are not presently conducting staged testing to verify real power capability of the unit. Since nuclear units are base loaded the most common approach is to use historical data to verify real power capability.

A.3 Reactive Power Capability (MOD-025) Survey Results

Of the 17 organizations that are represented by the survey results, 12 of them verify the maximum gross and net reactive power capabilities of their units on a regular basis. The following items summarize the survey results of those 12 organizations:

- Again, staged testing was by far the most common method used for verifying reactive power capability – it was used by more than 90% of the respondents. Nearly 1/2 of the organizations used manufacturer's data and/or engineering calculations, while only 25% relied on past data records.
- Only 50% indicated that manufacturer's estimates for maximum under-excited (leading) reactive power capability matched the performance verified by other methods. While over 70% indicated that manufacturer's estimates matched for maximum over-exciter (lagging) reactive power capability.
- Most of the respondents indicated that existing station meters are used for validating the reactive power requirements of auxiliary loads, Figure A-6 shows a break down of the various methods used.
- During the process of measuring the under-excited (leading) reactive capability the most common limiting factors were:
  - The under-excited limiter in the excitation system – 39%
  - Generator terminal voltage low limit – 24%
  - Total of all others – 37%
- Figure A-7 shows the most common limiting factors during the process of measuring the over-excited (lagging) reactive capability.
- Again, nearly all of the organizations utilized engineering or other support staff within the organization combined with operators to perform the reactive power verification. While 42% worked with outside consultants and other resources to perform the verification.
- Table A-2 shows the percentage of organizations that responded yes to the commercial related questions in this section of the survey.
- 42% indicated that their organization has discovered other information that was of technical or commercial use as part of reactive power capability verification.

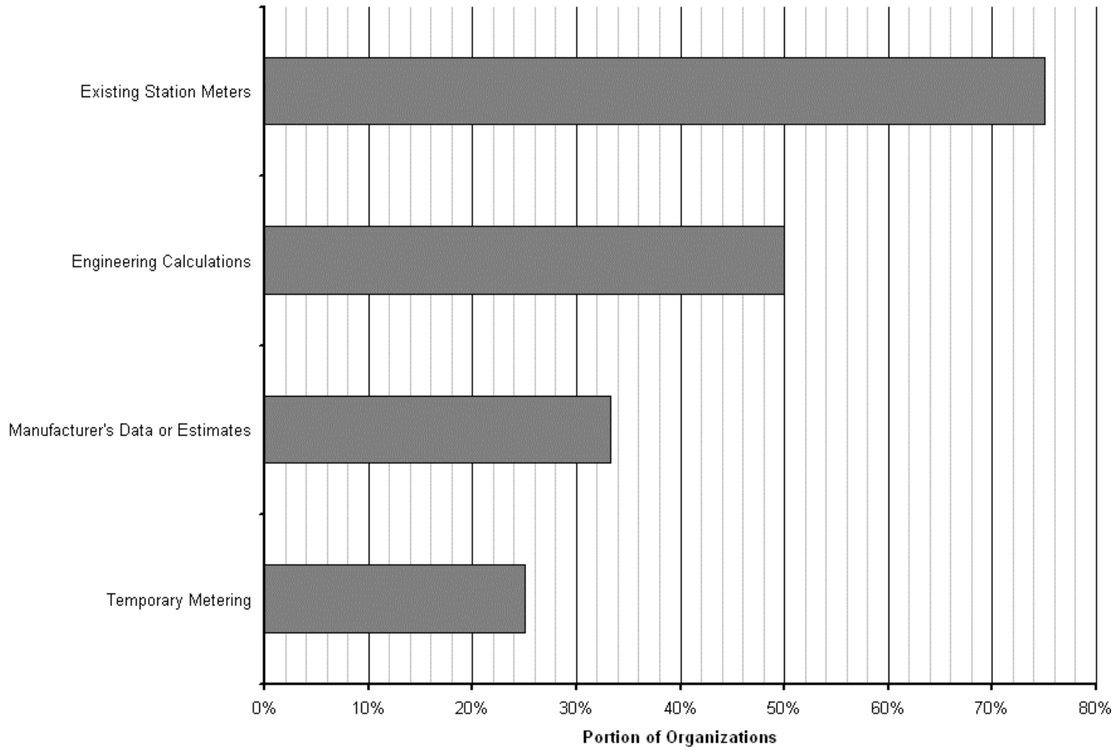

Figure A-6
Methods Used for Validating Reactive Power for Auxiliary Loads

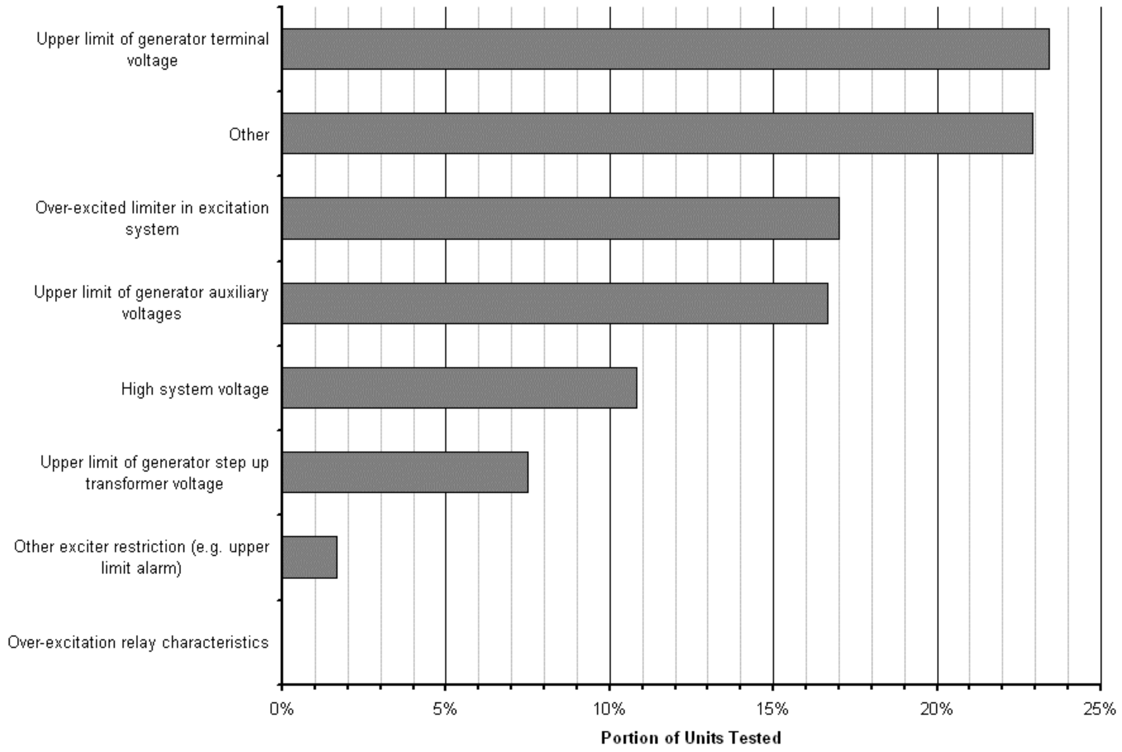

Figure A-7
Limiting Factors for Over-Excited Reactive Capability

Table A-2
Commercial Related Results for Reactive Power Capability

Question	Yes
Was any training required prior to performing this verification?	50%
Were any significant costs incurred to perform this work?	33%
Was any equipment purchased or rented in order to perform this verification?	17%

General Comment Summary

- Grid conditions have a significant effect on staged testing used to verify reactive capability.
- Many indicated that staged reactive power verification is performed following generator rewinds or control system upgrades, while a fair number of organizations perform this testing on a cyclical basis (some yearly, some every 5 years).
- A ‘lessons learned’ comment indicated that during staged testing generator capability was the limiting factor at high real power load levels, while other factors (i.e. auxiliary bus voltage) were limiting at lower real power levels.
- The following additional reactive power limitations were listed: generator stator or rotor temperatures, GSU transformer temperature, manufacturer D-curve and auxiliary bus voltage levels.

Nuclear Unit Comments

- Several commented that they do conduct staged reactive capability testing of their nuclear units. Most have conducted this testing with no problems or unit trips.
- Several currently use calculations and analysis of historical data to establish reactive capability.
- Several commented that based on the size of nuclear units, additional coordination with the system operator and other units is required in order to perform the reactive capability testing.
- Specialized procedures and formal review processes may be required to operate nuclear units in the sometimes abnormal conditions required to conduct the reactive capability testing. This may include a 10CFR50.59 evaluation.
- One commented that staged testing was conducted following a transmission event; the generator and reactor tripped during the test. They indicated that better generator control system preliminary testing and calibration would have prevented the trip.

A.4 Coordination of Limiters, Protection and Control (PRC-019, PRC-005) Survey Results

Of the 17 organizations that responded to the survey, 15 of them verify the operation of generator protective relays on a routine schedule. The following items summarize the survey results of those 15 organizations:

- Almost all of the organizations, 93%, use technicians or other support staff within the organization to perform some or all of the protective relay testing and 46% use outside consultants for some of this testing.
- Methods used for verifying generator protective relays are shown in Figure A-8.
- Only 2 respondents indicated that significant differences have been found between the original settings and the verified characteristics of the relay.
- All of the organizations maintain a database of calibration and settings for each protective device on each generator.
- Out of the 17 organizations that responded, 11 verify the coordination between generator capability, excitation limiters and protective relays. Figure A-9 illustrates the methods used by these organizations.
- Essentially no significant differences between manufacturer's models and settings and data verified by other methods were reported in the survey.
- All of the organizations utilized engineering or other support staff within the organization to perform the coordination verification and 45% utilized outside consultants.
- Table A-3 shows the percentage of organizations that responded yes to the commercial related questions in this section of the survey.

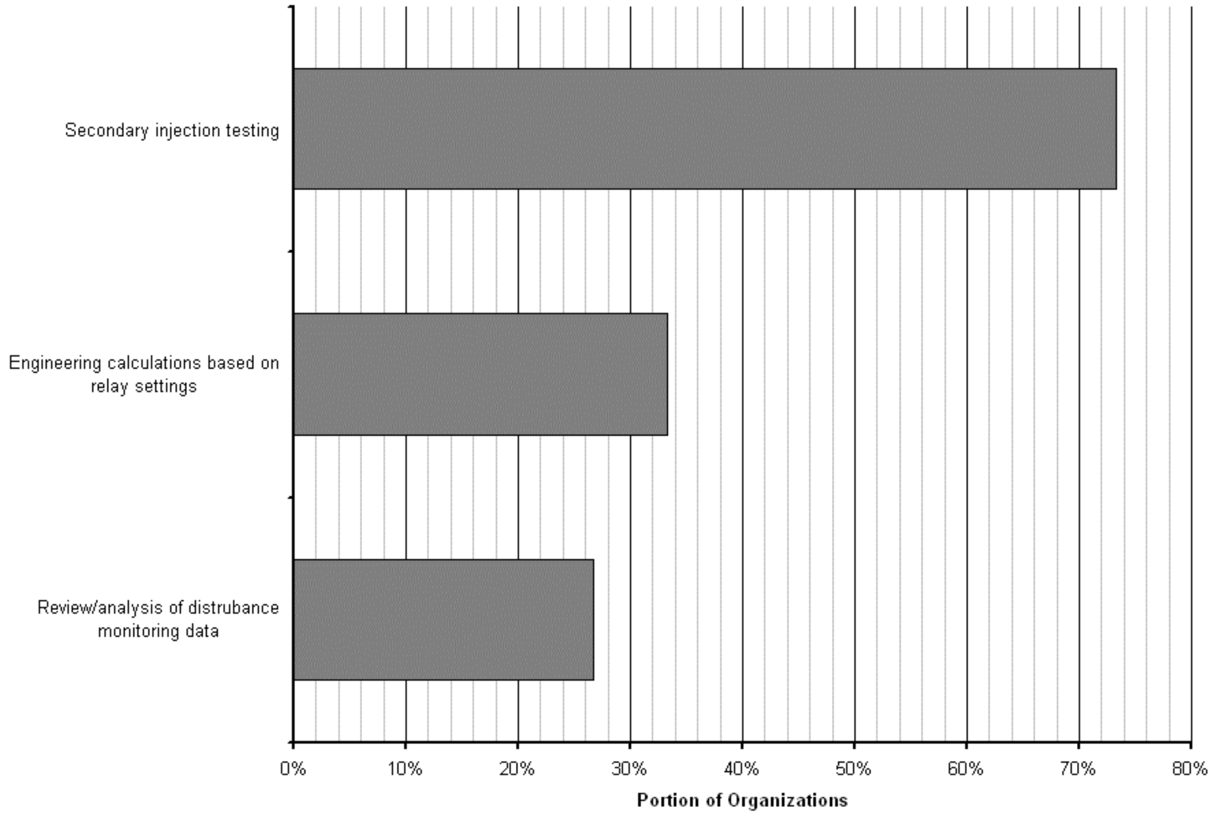

Figure A-8
Methods Used for Verifying Generator Protective Relays

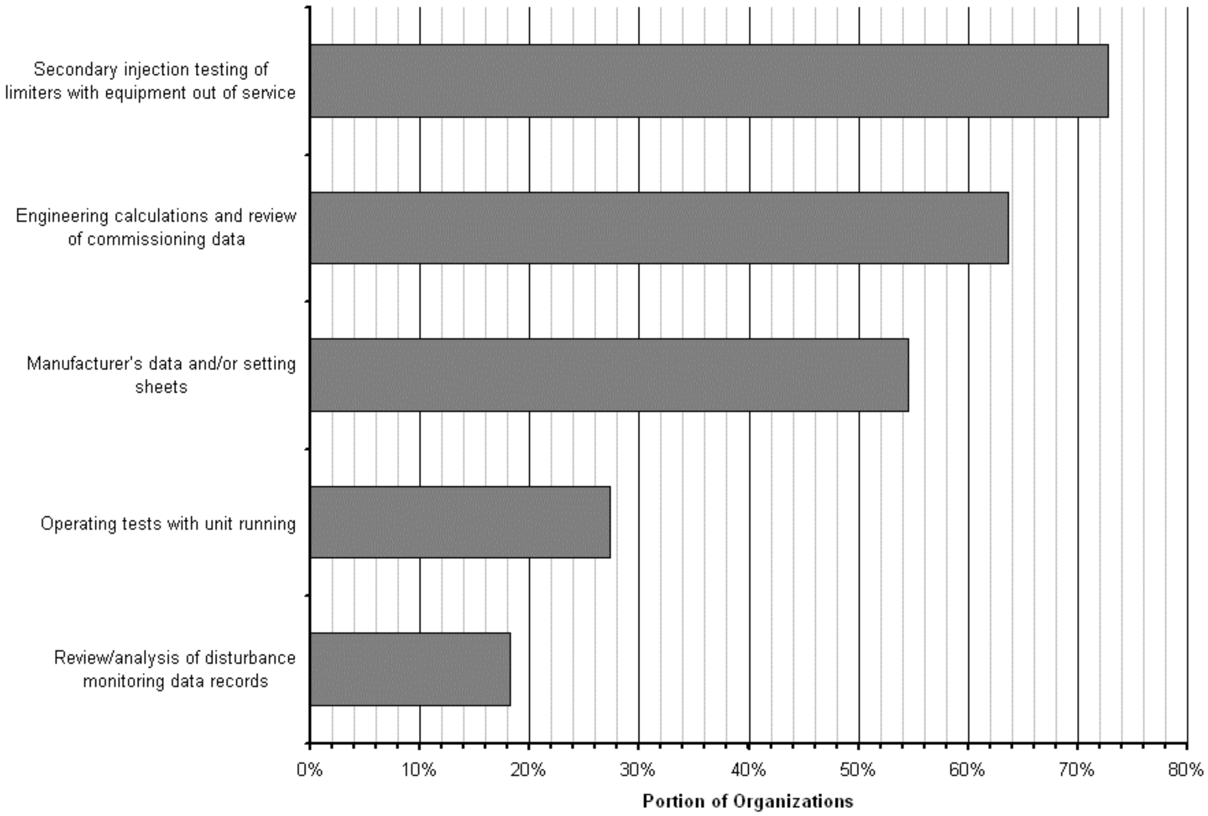

Figure A-9
Methods Used for Verifying Generator Protection Coordination

Table A-3
Commercial Related Results for Protection Coordination

Question	Yes
Was any training required prior to performing this verification?	27%
Were any significant costs incurred to perform this work?	45%
Was any equipment purchased or rented in order to perform this verification?	36%

General Comment Summary

- Most calibrate relays on a cyclical basis, while a smaller percentage calibrate the excitation system on a regular basis.
- Many indicated that they do not verify the coordination between protective devices. Some indicated that coordination studies/verification have led to setting changes.
- Several companies that were interviewed are in the process of developing and auditing their coordination study program.

Nuclear Unit Comments

- There were no comments that pertain specifically to nuclear units in this section.

A.5 Excitation System Models (MOD-026) and Voltage Control (VAR-002) Survey Results

- Fourteen respondents indicated that their organization reports AVR status to the Independent System Operator or Regional Entity, reporting methods are shown in Figure A-10.
- All of the respondents indicated that 90% or more of their units were operating on AVR control at the time the survey was completed; 68% had all units operating on AVR.
- Of the 17 organizations represented, 9 have verified the model and data for at least a portion of their generator excitation systems. Statistical data for various verification methods are shown in Figure A-11.
- Nearly 40% of the exciter verifications included testing while the generator was off-line with the excitation system connected to a test supply, while less than 1/3 were tested with the generator at-speed and not synchronized to the grid or synchronized and at low load. Roughly 10% of the units were tested with the generator at full load.
- Essentially no significant differences between manufacturer's models and settings data verified by other methods were reported in the survey, with the exception of 1 respondent reporting that 1/3 of the units tested had significant differences.
- All of the organizations utilized engineering or other support staff within the organization to perform the excitation model verification and 66% utilized outside consultants.
- Table A-3 shows the percentage of organizations that responded yes to the commercial related questions in this section of the survey.

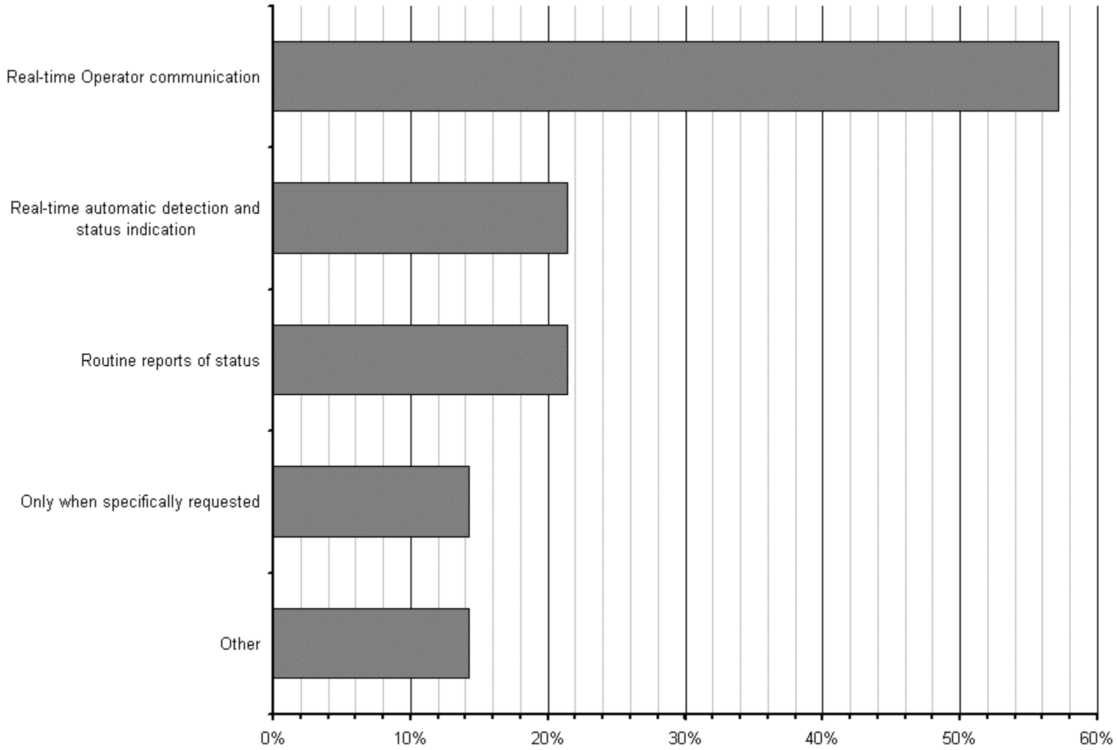

Figure A-10
Methods for Reporting AVR Status

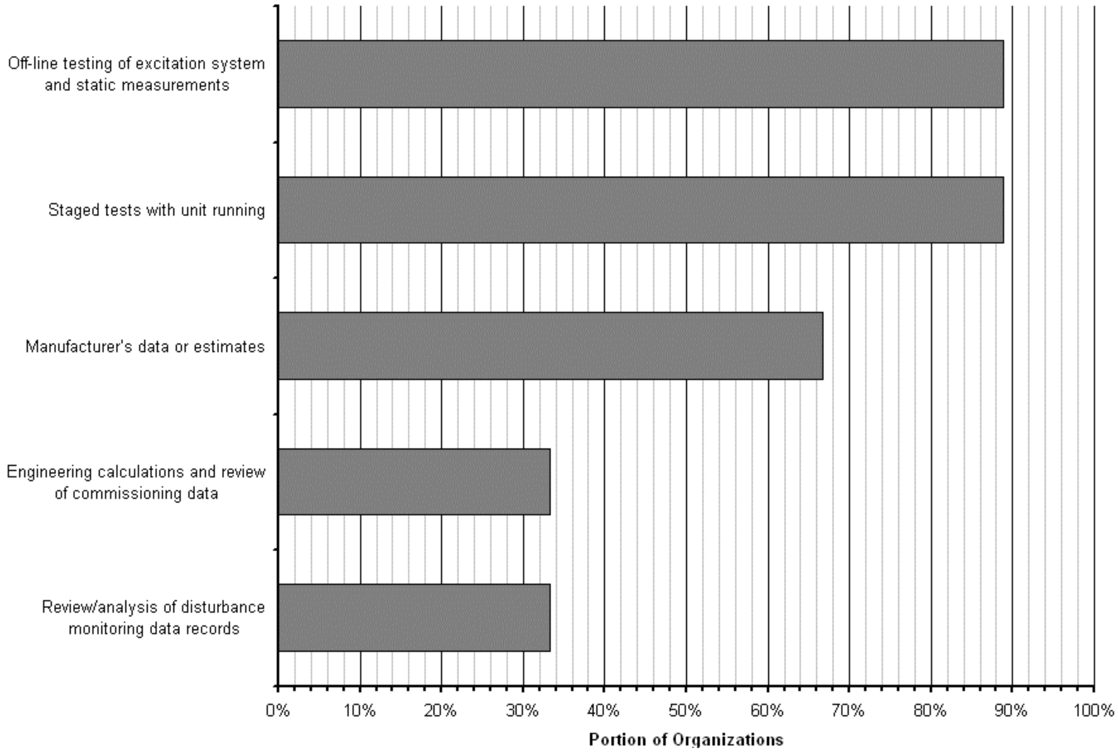

Figure A-11
Methods for Verifying Excitation System Model and Data

Table A-4
Commercial Related Results for Excitation System Models

Question	Yes
Was any training required prior to performing this verification?	56%
Were any significant costs incurred to perform this work?	78%
Was any equipment purchased or rented in order to perform this verification?	67%

General Comment Summary

- Many indicated that AVR step response testing has been conducted to confirm response and/or verify the excitation system model.
- One indicated that excitation system verification testing has identified numerous defects and inappropriate settings.

Nuclear Unit Comments

- Many nuclear plants indicated that they have conducted AVR step response testing. Some plants have reduced the size of the step to add a ‘comfort’ margin.
- Several plants have also conducted swept frequency response testing as part of power system stabilizer tuning.
- At-speed no-load testing would be outage critical path, as a result it would require special management approval.
- On-line testing should be acceptable but has to be evaluated to determine operational risks.

A.6 Verification of Generator Unit Frequency (Governor) Response (MOD-027) Survey Results

Less than half, 47%, of organizations that responded to the survey indicated that they verify governor frequency response. The following items summarize the survey results of the organizations that do verify governor frequency response:

- Figure A-12 illustrates the various methods used to verify governor frequency response.
- The most common reported method used for governor staged testing was generator on-line at low load, followed by on-line at full-load.
- Only 2 respondents indicated that there were significant differences between manufacturer’s information and data verified by other methods.
- Almost all of the organizations utilized engineering or other support staff within the organization to perform the governor verification and more than 1/2 utilized outside consultants.
- Table A-4 shows the percentage of organizations that responded yes to the commercial related questions in this section of the survey.

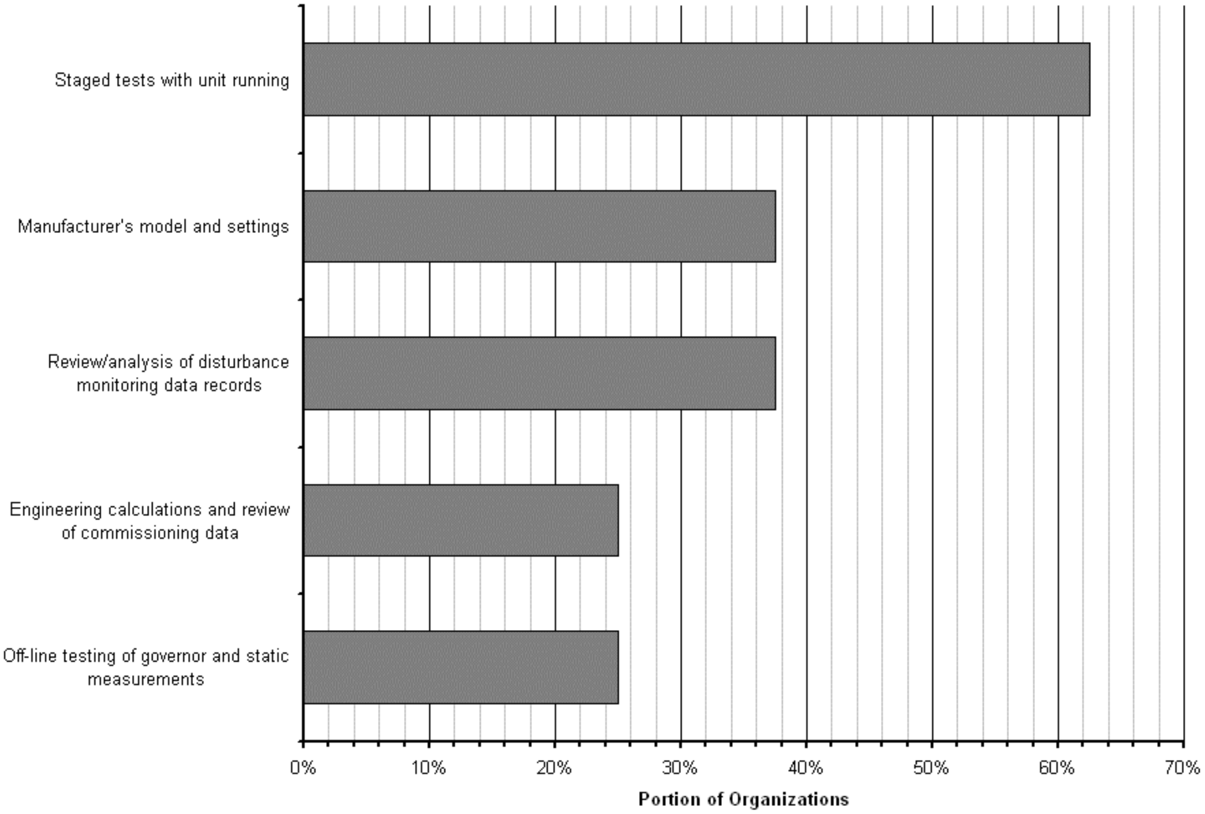

Figure A-12
Methods for Verifying Governor Frequency Response

Table A-5
Commercial Related Results for Governor Verification

Question	Yes
Was any training required prior to performing this verification?	43%
Were any significant costs incurred to perform this work?	14%
Was any equipment purchased or rented in order to perform this verification?	29%

General Comment Summary

- A small number of respondents indicated that they conduct some form of governor staged testing on a cyclical basis.
- Several of the NERC regions require frequency response verification.

Nuclear Unit Comments

- At-speed no-load testing adds to outage critical path time and on-line testing has to be evaluated to assess the operating risk.

- Although load reject tests have been performed on numerous nuclear units, most indicated that they would be reluctant to perform the test. The primary concern cited was that the test would challenge plant systems and the risk of a reactor trip.

A.7 Survey Questions

This section contains the questions as they were presented in the survey.

A.7.1 General/Organizational Section Questions

1.1 Does your Organization have an established program for dealing with NERC/Regional Technical Compliance requirements?

1.2 Is your Organization planning to establish a program for dealing with NERC Technical Compliance requirements in 2007 and beyond?

1.3 Does your Organization maintain a database of model and capability data for your Generators and associated control equipment?

1.4 Do your purchasing specifications include a requirement for Manufacturers to provide capability information and simulation model data for new generation equipment?

1.5 Indicate the percentage of units on your system that are equipped with some form of digital recording system capable of gathering data for meeting Compliance requirements.

1.6 List the approximate percentage of recording device by type from the following list.

- Operator's SCADA system
- dedicated power system disturbance recorder
- phase angle measurement unit (PMU)
- digital fault recorder
- data logging built-in to protection or control equipment
- other

1.7 Is your Organization planning to install new equipment or monitor existing data sources in order to meet Compliance requirements?

1.8 List the approximate percentage of generation capacity (i.e. MVA rating) by type in your Organization.

- nuclear
- steam-turbine fossil-fired (e.g. coal, oil, gas)
- gas-turbine

- hydroelectric
- other

1.9 Provide an approximate percentage for the number of generators on your system that have undergone some form of model or capability validation during the past year.

1.10 Provide any comments or other information on your Organization that you feel is pertinent to this topic in the space provided below.

A.7.2 Real Power Capability (MOD-024) Section Questions

2.1 Does your Organization verify the maximum gross and net real power capability of your units on a regular basis?

2.2 Select the methods that describe the verification of maximum real power capability of your generators (more than one answer allowed):

- manufacturer's data or estimates
- engineering calculations
- review of past data records from station recording devices or Operator's logs
- staged tests or monitored operation at maximum levels
- other

2.3 Have Manufacturer's estimates for maximum real power capability matched performance verified by other methods?

2.4 Who performed the verification? (more than one answer allowed):

- operators
- engineering or other support staff within Organization
- outside consultants
- other

2.5 Was any training required prior to performing this verification?

2.6 Were any significant costs incurred to perform this work?

2.7 Was any equipment purchased or rented in order to perform this verification?

2.8 Select the method(s) that describe the validation of the real power requirement of auxiliary loads (more than one answer allowed):

- manufacturer's data or estimates

- engineering calculations
- existing station meters
- temporary metering added specifically for this purpose
- other

2.9 During the process of verifying the real power capability of your units did you discover any other information that was of technical or commercial use to your Organization?

2.10 Provide any comments or other information (e.g. experiences, best practices) on the verification of the maximum real power capability of generators within your Organization.

A.7.3 Reactive Power Capability (MOD-025) Section Questions

3.1 Does your Organization verify the maximum gross and net reactive power capability of your units on a regular basis?

3.2 Select the methods that describe the verification of reactive power capability of your generators (more than one answer allowed):

- manufacturer’s data or estimates
- engineering calculations
- review of past data records from station recording devices or Operator’s logs
- staged tests or monitored operation at maximum levels
- other

3.3 Have Manufacturer’s estimates for maximum under-excited (leading) reactive power capability matched performance verified by other methods?

3.4 Have Manufacturer’s estimates for maximum over-excited (lagging) reactive power capability matched performance verified by other methods?

3.5 Select the method(s) that best describes the validation of the reactive power requirement of auxiliary loads (more than one answer allowed):

- manufacturer’s data or estimates
- engineering calculations
- existing station meters
- temporary metering added specifically for this purpose
- other

3.6 During the process of measuring the under-excited (leading) reactive capability the following was the limiting factor that was encountered. Assign an approximate percentage for each.

- lower limit of generator terminal voltage
- lower limit of generator auxiliary bus voltages
- low system voltage
- under-excited limiter in excitation system
- other exciter restriction (e.g. lower limit alarm)
- loss-of-excitation relay characteristics
- core-end overheating limit characteristic (cylindrical rotor machines)
- steady-state stability limit
- other

3.7 During the process of measuring the over-excited (lagging) reactive capability the following was the limiting factor that was encountered. Assign an approximate percentage for each.

- upper limit of generator terminal voltage
- upper limit of generator auxiliary voltages
- upper limit of generator step up transformer voltage
- high system voltage
- over-excited limiter in excitation system
- other exciter restriction (e.g. upper limit alarm)
- over-excitation relay characteristics
- other

3.8 Who performed the verification? (more than one answer allowed)

- operators
- engineering or other support staff within Organization
- outside consultants
- other

3.9 Was any training required prior to performing this verification?

3.10 Were any significant costs incurred to perform this work?

3.11 Was any equipment purchased or rented in order to perform this verification?

3.12 During the process of verifying the reactive power capability of your units did you discover any other information that was of technical or commercial use to your Organization?

3.13 Provide any comments or other information (e.g. experiences, best practices) on the verification of the reactive power capability of generators within your Organization.

A.7.4 Coordination of Limiters, Protection and Control (PRC-019, PRC-005) Section Questions

4.1 Does your Organization test or otherwise verify the operation of generator protective relays on a routine schedule?

4.2 Who performs the tests for your Organization? (more than one answer allowed)

- technical or other support staff within Organization
- outside consultants
- manufacturers
- other

4.3 Select the methods that are used to verify the operation of generator protective relays within your Organization.

- engineering calculations based on relay settings
- secondary injection testing
- review/analysis of disturbance monitoring data records
- other

4.4 Have significant differences been found between the original settings and verified characteristics of the relays?

4.5 Does your Organization maintain a database of calibration and settings for each protective device on each generating unit?

4.6 Does your Organization verify the coordination between generator capability, excitation limiters and protective relays?

4.7 Select the methods that describe the verification of coordination on your units (more than one answer allowed)

- manufacturer’s data and/or setting sheets
- engineering calculations and review of commissioning data
- secondary injection testing of limiters with equipment out of service
- operating tests with unit running

- review/analysis of disturbance monitoring data records
- other

4.8 What percentage of units were found with significant differences between Manufacturer's models and settings and data verified by other methods?

4.9 Who performed the verification? (more than one answer allowed)

- engineering or other support staff within Organization
- outside consultants
- other
- other

4.10 Was any training required prior to performing this verification?

4.11 Were any significant costs incurred to perform this work?

4.12 Was any equipment purchased or rented in order to perform this verification?

4.13 Provide any comments or other information (e.g. experiences, best practices) on the verification of generator protective relays and their coordination with generator capability and limiter settings within your Organization.

A.7.5 Excitation System Models (MOD-026) and Voltage Control (VAR-002) Section Questions

5.1 Does your Organization report AVR status to your Independent System Operator (ISO) or Reliability Council?

5.2 Select the method(s) that describe how the information is reported (more than one answer allowed):

- real-time automatic detection and status indication
- real-time Operator communication
- routine reports of status (e.g. monthly)
- only when specifically requested
- other

5.3 Roughly what percentage of generating units on your system are operating under AVR control at this time?

5.4 Does your Organization verify the model and data for some of your generator's excitation systems?

5.5 Select the methods that describe the verification of reactive power capability of your generators (more than one answer allowed):

- manufacturer's data or estimates
- engineering calculations and review of commissioning data
- off-line testing of excitation system and static measurements
- staged tests with unit running
- review/analysis of disturbance monitoring data records
- other

5.6 Indicate the percentage of tests performed for the following conditions

- generator off-line, excitation system connected to test supplies
- generator at rated speed, excitation on, not synchronized to grid
- generator synchronized to grid (low load)
- generator synchronized to grid (full load)
- other

5.7 What percentage of units were found with significant differences between Manufacturer's models and settings and data verified by other methods?

5.8 Who performed the verification? (more than one answer allowed)

- engineering or other support staff within Organization
- outside consultants
- other

5.9 Was any training required prior to performing this verification?

5.10 Were any significant costs incurred to perform this work?

5.11 Was any equipment purchased or rented in order to perform this verification?

5.12 Provide any comments or other information (e.g. experiences, best practices) on the verification of the excitation system models within your Organization.

A.7.6 Verification of Generator Unit Frequency (Governor) Response (MOD-027) Section Questions

6.1 Does your Organization verify the governor frequency response of your units?

6.2 Select the method(s) that are used to verify the frequency response of your units (more than one answer allowed):

- manufacturer's model and settings
- engineering calculations and review of commissioning data
- off-line testing of governor and static measurements
- staged tests with unit running
- review/analysis of disturbance monitoring data records
- other

6.3 Indicate the percentage of tests performed for the following conditions

- generator off-line, governor connected to test supplies
- generator at rated speed, excitation on, not synchronized to grid
- generator synchronized to grid (low load)
- generator synchronized to grid (full load)
- other

6.4 What percentage of units were found with significant differences between Manufacturer's information and data verified by other methods?

6.5 Who performed the verification? (more than one answer allowed)

- engineering or other support staff within Organization
- outside consultants
- other

6.6 Was any training required prior to performing this verification?

6.7 Were any significant costs incurred to perform this work?

6.8 Was any equipment purchased or rented in order to perform this verification?

6.9 Provide any comments or other information (e.g. experiences, best practices) on the verification of governor frequency response within your Organization.

B

GUIDELINES FOR PERFORMANCE OF REACTIVE CAPABILITY TESTS

This section provides details for the performance of a reactive and voltage capability test on a cylindrical rotor generator connected to a steam turbine. Hydroelectric units typically do not have the same restrictions on auxiliary bus voltages, so may be tested in the same way, but with fewer operational or data recording requirements.

It is recognized that Operators may not be called upon to operate units at the limits of their reactive capability on a routine basis. As a result, it is important that they carefully monitor all operating quantities to ensure that the unit and its auxiliary equipment are operating within their continuous limits. The test coordinator should be aware of the latest documented capabilities of the unit under test. The accuracy of all station metering and relay calibration data is critical to obtaining correct results.

Station personnel are responsible for the following preparation:

- Each generator’s reactive capability is depicted in a capability curve. This curve plots physical limitations, such as stator and rotor heating limits, in the power (MW, MVAr) plane. By maintaining operation within the limits depicted on the capability curve, the unit’s continuous ratings will be respected. Participants in reactive capability tests should obtain a copy of the latest reactive capability curve for the unit under test and become familiar with the meaning each of the limitations.
- The station service load fed from the unit under test should match normal operating conditions for the maximum continuous load level. Most jurisdictions require that all generators be capable of operation within the range of 95% to 105% of rated terminal voltage. Station service loads should be capable of continuous operation at voltage levels corresponding to this range of generator terminal voltage. If a test has to be stopped due to station service limitations it is important that the limitation be documented, since this will have to be investigated in detail. Staff must review the metering that will be used to monitor the auxiliary bus voltages along with the limits to be respected throughout the tests.
- During over-excited tests, the generator reactive output is increased by raising the voltage reference of the unit under test. Depending on system voltage conditions, the generator or auxiliary bus voltage limits may be reached before the maximum reactive output is achieved. Every effort should be made to achieve the required reactive output by sufficiently reducing the generator terminal voltage through other means. This can be accomplished by performing the tests during low system voltage conditions (high system load conditions), requesting assistance from the transmission operator, or manipulating the reactive output of adjacent generators. The opposite condition exists for under-excited tests. Over-excited and under-excited tests can be performed at different times to take advantage of prevailing system

voltage conditions. Station staff should be in contact with transmission operators and generation dispatch authorities to review the steps that can be used during the course of these tests to increase the reactive operating range.

- During reactive tests the goal is to maintain the reactive power at a constant level, however most ISO rules require that units be operated under AVR control, except under exceptional circumstances. Reactive capability tests can be performed under AVR control as long as Operators maintain a relatively constant reactive output through adjustment of the AVR set point, as required. MVAr control loops can also be enabled for this period, as long as they are voltage-supervised, to prevent voltage from moving outside of the required limits. Operation in Manual is not recommended, especially when operating at the extremes of reactive capability.
- Compile a list of the measurement points that will be checked during the course of the tests and prepare data entry forms or spreadsheets.
- Note all capability limits and assign responsibility for monitoring (e.g. list rated, 95%, 105% generator voltage, generator stator rated current, generator rotor rated current, auxiliary bus voltage or load current limitations, protective relay settings). Assign responsibility for monitoring of capability limits and measured quantities.
- Calibrate field current and field voltage indications (note: these signals are not typically included in regular calibration procedures and are usually fed from 4-20 mA transducers provided for operator convenience in the control room. For detailed tests, raw signals e.g. mV signal from generator field current shunt, should be used for these measurements or at least to check the calibration of station metering).

Risk Awareness

Most of the measurements involve use of existing station transducers and therefore do not introduce any risks other than those normally associated with working in a generating station environment. During the course of these tests the unit will be run at the extremes of its normal continuous capability and all participating staff should be vigilant for any sign of potential problems such as overheating. It is recognized that Operators may not be called upon to operate units at the limits of their reactive capability on a routine basis and may require the support of Engineering Staff to properly prepare for these tests. Support of an extra Operator or other qualified staff should be considered to coordinate Control Room activities for the test and monitor Control Room meters.

Unit Condition

The on-line measurements are performed with the unit synchronized to the electrical network and operating at a specified active power load. In some jurisdictions the number of measurement points are minimal. Standards MOD 024 and MOD 025 require measurement at the seasonally-adjusted rated active power. At each required active power level, the generator field excitation is varied to change the reactive power output until the limits of leading and lagging operation are reached.

In some cases, the ISO or Reliability Organization may require that measurements be performed at several different active power levels. A typical reactive capability test would include up to five different reactive load levels to allow for extrapolation of results to limiting output conditions.

- unity power factor
- over-excited (reactive power = 50% of maximum over-excited requirement)
- over-excited (reactive power = up to100% of maximum over-excited requirement)
- under-excited (reactive power = 50% of maximum under-excited requirement)
- under-excited (reactive power = up to 100% of maximum under-excited requirement)

The generator terminal voltage must be maintained between 95% and 105% of the rated level throughout the tests. It is anticipated that in many cases the full leading and lagging reactive output of the unit will not be achieved before the voltage limits are reached. This is normal, and at no time should the unit be operated outside of this voltage range in order to achieve the higher reactive output level. The unit should be operated on AVR excitation control throughout the test. An Operator should monitor the unit to maintain relatively constant reactive output in the event that system conditions change during the course of the test.

Contingency Planning

In general, if any tests reveal problems with over or under-excited operation, the excitation should be adjusted to restore unity power factor operation, or operation at rated terminal voltage. The choice of operating level will depend on the nature of the problem (i.e. voltage or reactive current).

Tests at Different Reactive Load Levels

- Note the unit operating history (e.g. full-load for six hours) immediately prior to the commencement of the tests.
- Examine the excitation system to ensure that it is operating normally prior to commencing any tests.
- Contact the local Operating Authority to receive permission to proceed with the test. Ask for and record the system voltage level at the point of connection for the unit under test.
- Adjust unit loading to its maximum continuous rating. The load should be within 10% of this level. If this cannot be achieved the engineer responsible for analyzing the results should be contacted to determine whether the tests should proceed.
- Configure the auxiliary loads to match normal operating conditions.
- Record the start-time for the tests and all available operating temperatures
- Adjust excitation on the unit until operation at unity power factor (Zero MVArs, tolerance +/-2% of rated MVA) is achieved. Record all quantities. Cross check critical readings (e.g. excitation current, MW, MVAr, auxiliary bus voltages) appearing on the HMI against other metering or primary measurements where available.

- Gradually decrease excitation on the unit while monitoring all critical quantities against their operating limitations, until the first reactive load level is reached (50% of maximum under excited reactive power). Record all parameters. For under-excited conditions the critical parameters to monitor include the following: generator ac terminal voltage, reactive power, stator core temperature, excitation current, auxiliary bus voltages, currents on critical motor loads (e.g. Boiler Feed Pump [BFP]). If any limits are reached before the target reactive power is reached, stop the test, and assess whether corrective steps can be taken (e.g. adjusting reactive output of adjacent units, transferring loads on buses, requesting that the Transmission Operator dispatch additional reactive resources to increase system voltage levels).
- Gradually decrease excitation on the unit while monitoring all critical quantities against their operating limitations, until the second reactive load level or lower terminal voltage limit is reached (100% of maximum under excited reactive power). Record all parameters.
- Gradually increase excitation on the unit while monitoring all critical quantities against their operating limitations, until the third reactive load level is achieved (50% of maximum overexcited reactive power). For over-excited conditions the critical parameters to monitor include the following: generator ac terminal voltage, reactive power, excitation current, auxiliary bus voltages. If any of the limits are reached before the target reactive power is reached, stop the test and assess whether corrective steps can be taken (e.g. adjusting reactive output of adjacent units, transferring loads on buses, requesting that the Transmission Operator reduce system voltage levels). Record all parameters, including the time that the level is reached.
- Gradually increase excitation on the unit while monitoring all critical quantities against their operating limitations, until the final reactive load level or upper terminal voltage limit is achieved (100% of maximum overexcited reactive power). Record all parameters, including the time that the level is reached.

Maintain this level for a period of time, tabulating temperatures and operating levels at half-hour intervals until temperatures stabilize. (some jurisdictions specify the duration of tests required at full load under- and over-excited conditions).

C

EXAMPLE TEST PLAN FOR EXCITATION SYSTEM FUNCTION DYNAMIC TESTING

The following is an example plan for the testing of a DC rotating excitation system. The tests can be used to verify the overall performance of the unit, or to obtain critical model parameters. In order for these tests to be used for the latter purpose, dynamic records will have to be captured on a media suitable for comparison with simulated data. Simulations using the unit data and correct excitation block diagram can be performed by system performance personnel.

C.1 Test Equipment Set-Up

In preparation for the excitation system tests, several connections should be made to the unit. When possible, these connections should be made with the unit shut down and the exciter de-energized. The test equipment used should be designed to have the required level of isolation. Local safety practices will dictate the appropriate personal protective equipment and use of barriers and work protection.

- Connect a voltage transducer capable of producing a dc voltage proportional to ac RMS terminal voltage across the generator PT secondaries which feed the voltage regulator.
- Connect a current transducer to the generator CT secondaries or to available watt and var transducer outputs for active and reactive power measurements.
- Connect an isolator across the exciter output to permit a reduced voltage measurement of generator field voltage.
- Connect an isolator across the field current shunt.
- Connect an isolator to permit a reduced voltage measurement of the main exciter field voltage.
- Connect an isolator to permit a reduced voltage measurement of the main exciter field current.
- Connect additional isolators as required to supplementary signals such as the power system stabilizer output, damping feedback signal, or any limiter modules.
- (optional) Connect a transducer capable of producing a dc voltage proportional to frequency or speed to the generator PT secondaries or speed signal.

The outputs of the isolators are connected to a recorder for dynamic measurements. A direct-writing recorder (or equivalent) that is capable of measuring a minimum of three channels of data at a moderate rate (e.g. 5-50 samples/second) is required.

C.2 Automatic Voltage Regulator and Associated Function Settings

Purpose: Verify that the voltage regulator gain and time constants are set to the recommended levels and document along with results.

Equipment: True RMS multimeter.

Unit Condition: Unit off line, exciter de-energized.

Procedure: Check selectable resistances, potentiometers and configuration jumpers on individual modules and verify if they match commissioning report or recommended settings. Document as-found settings.

C.3 Closed Loop Voltage Regulator Response

Purpose: Measure the overall performance of the closed-loop regulator using a step-response test. Differences between the measured response and those documented in the commissioning/modeling report should be corrected or documented.

Unit Condition: Unit on open circuit at rated speed.

Procedure: Start the generator on Automatic (AVR) control. Operate the unit on open circuit (do not synchronize). Reduce terminal voltage to approximately 95% using Manual rheostat. Transfer to Manual control. Adjust Manual rheostat for 97% terminal voltage (e.g. operate out of balance with AVR).

Set up recorder to measure available quantities. Transfer to Automatic (AVR) while recording all signals for at least 20 s, including at least 1 s pre-transfer.

Compare with target response from commissioning/modeling report and adjust damping feedback or forward gain as appropriate and repeat. Document as found and as-left settings.

Notes: If analog electronic test input is available at AVR summing junction, then this test is performed by injection of a calibrated voltage step from an isolated dc source. The source level should be gradually increased while monitoring terminal voltage and calibrated to provide a 1-2% terminal voltage reference change.

C.4 Reactive Current Compensation Tests

Purpose:	Verify that the reactive current compensation is set correctly.
Unit Condition:	Unit on line.
Procedure:	Tabulate existing Reactive Compensation card settings. Adjust to match recommended settings if necessary or document any differences found.

Use the test arrangement of the previous test. With the unit synchronized at low, stable load and rated terminal voltage, tabulate terminal voltage and reactive power. Measure the step change of terminal voltage. Calculate the reactive compensation from formula below:

$\Delta Et = \Delta Etref - (X_C \times \Delta Q/Et)$

$X_C = (\Delta Etref - \Delta Et)/(\Delta Q/Et)$

Where:

ΔET = per-unit change in RMS terminal voltage

= (ETfinal-Etinitial)/Etbase (rated kV)

$\Delta Etref$ = per-unit change in terminal voltage reference (equals terminal voltage change on open-circuit or when reactive compensation set to zero>

= (ETfinal - ETinitial)/Etbase with (X_C dial setting at 0 or on open circuit)

ΔQ = per-unit change in reactive power

= (Qfinal - Qinitial)/Sbase (rated MVA)

X_C reactive compensation expressed in pu E_{TREF}/pu MVA (note: X_C is positive for reactive droop and negative for transformer or line-drop compensation)

C.5 Under Excitation Limiter Tests

Purpose: Verify that the under-excitation limiter response is stable. Modify the setting to the recommended level if necessary.

Unit Condition: Unit on line.

Procedure: Tabulate existing Under Excited Limiter settings. Adjust to match recommended settings if necessary.

With the unit on-line at rated terminal voltage, measure the dc voltage at the UEL output or indication test point. Reduce the voltage regulator set-point until the UEL operates. Tabulate MVArs for generator MW loading below, for which the UEL is active.

Note: The generator voltage must be maintained at all times at or above 95% of rated voltage. If the UEL does not operate for the system voltage conditions at the time of the test, it may be necessary to decrease its set point (e.g. less negative reactive power operating level) during this test. Care must be taken with older magnetic or analog-electronic devices when changing set-points which may involve changing the positions of potentiometers or rheostats which have not been recently adjusted. In this case, alternative off line tests may be preferable to on line testing.

Once the UEL operating point has been reached, increase the voltage set-point by 1-2% and verify that the UEL is no longer limiting. Using the step response test method of previous tests, introduce a negative voltage reference step change of sufficient magnitude to enter the UEL limit. Record all available signals for at least 20 s (depending on the response speed of the limiter, 30-50 s may be necessary). Include pre-disturbance conditions in the recording.

A slow, stable response is desired, without oscillations in field voltage or reactive power. Adjust the UEL stabilizing controls as desired to achieve the desired response. Restore the UEL limit level if it was adjusted during the tests. Document the as-found and as-left settings.

D

EXAMPLE GOVERNOR TEST PLAN

Test Plan for Performance Verification of Mechanical-Hydraulic Governors

The following material should be used by qualified staff to measure the performance of mechanical-hydraulic governors on a periodic basis. These tests are not intended to replace any of the manufacturer's recommended maintenance or test procedures. Instead, these tests should be performed after all other work is complete to verify that the governor performance meets the power systems requirements.

D.1 Settings

Plant: ________________________________, Unit # ______, Date: _______________

MVA ________ power factor ____

Turbine rating ___ (MW or HP – note) rpm _____

Record the headwater and tail water elevations to determine gross head.

Head _______ Tail _________ Rated head _______ units (ft/m) ________

Tabulate as-found settings and adjust, if necessary, to match the recommended settings.

Governor Settings

	Recommended	**As found**	**As left**
Droop dial (0-5)			
Compensating Crank (1-10)			
Floating lever connection (inner/outer)			
Restoring ratio			
Dashpot opening (nearest 1/16 turn)			

D.2 Governor Droop

Purpose: Measure the unit's permanent droop.

Equipment: Multimeter capable of reading frequency

Procedure: Operate the unit on open circuit. Apply excitation such that the unit is operating close to rated terminal voltage. Connect the multimeter to measure the PMG secondary voltages or PT secondary voltages, and set for frequency measurement.

Move the speed adjustment dial to different positions above speed no-load and tabulate the unit's average frequency versus dial position in spreadsheet provided. If the governor does not have a calibrated reference dial position, apply temporary markings for reference during on-line tests.

Speed Dial (Turns) Target	Speed Dial (Turns) Actual	Frequency (Hz)
0		
1		
2		
3		
4		
5		

The desired relationship is 1% change in unit frequency for a 1 turn change in the speeder position (if calibrated). At 0/0, the unit frequency should be 60 Hz.

Synchronize the unit and place the speed adjust dial in the positions above speed-no-load which were tabulated in the previous step. Verify calibration of Watts. Tabulate the final gate positions and MW and other turbine parameters (if available) versus speed dial position.

Speed Dial (Turns) Target	Speed Dial (Turns) Actual	Gate /Valve (%)	Active Power (MW)
0			
1			
2			
3			
4			

Combine the measurements from these two steps and calculate permanent droop:

R_P = $100 * \Delta f / \Delta G$

Δf = change in percentage frequency for two different positions of the speed adjust

= $100 * (f_2 - f_1) / 60$

ΔG = change in percentage the variable that is being used to report droop/regulation (either gate position, valve position, power,…) for the speed adjust positions used in the frequency calculation.

= $G_2 - G_1$

R_P = permanent droop = ____ %

Confirm measured value matches the setting recorded above within +/-0.5%.

D.3 Dynamic Response Measurement

Purpose: Determine dashpot reset time. This test should be performed on a routine basis as well as following any outage.

Equipment: Stopwatch. (If dynamic tests are to be recorded, see equipment and recording method in sections D5 and D6).

Procedure: Operate the unit with the speed adjust dial at an initial position corresponding to an integral number of turns (e.g. 1% above speed-no-load).

Tabulate gate (valve...) position and manually adjust the speed reference dial to a new (calibrated) position as quickly as possible (e.g. from 1 turn to 2 turns above speed no load). Allow the gates to settle to a new steady-state position and tabulate the final gate opening (this may take 1-2 minutes). Return the speed adjustment dial to its original position.

Calculate the gate position that will be used to determine the gate time constant:

$G_{TARGET} = (0.63)*(G_{FINAL} - G_{INITIAL}) + G_{INITIAL} =$ __________

Starting at $G_{INITIAL}$, start the recorder. Quickly turn the speed adjust to the final position and start the stopwatch. Record the time required to reach G_{TARGET}.

T_{GATE} = the gate time constant measured in the previous step = __________

Compare with target value from simulation or commissioning report. Document any differences.

Document the normal operating mode (e.g. dashpot in-service or bypassed) and any outer loop controls which act to defeat the governor response to system frequency variations (e.g. MW set point).

D.4 Rate Limits

Purpose: Determine gate rate limits. The rate limits should be measured following major maintenance outages.

Equipment: Maintenance records

Procedure: Obtain the gate timing measurements and convert them to the rate limits as follows:

Topen = gate opening time (s) = _____ s

Tclose = gate closing time (s) = _____ s

Range = range over which timing is performed (typically 50%) = _____ %

Gr + (gate opening rate) = Range/Topen = _____ %/s

Gr - (gate closing rate) = Range/Tclose = _____ %/s

D.5 Ambient Monitoring (Deadband)

Purpose: Confirm governor response to system frequency variations.

Equipment: Transducer for measuring gate position. Transducer for measuring frequency or speed. (Optional) transducer for measuring electrical power.

Procedure: Record Gate position, Frequency (speed), (Active Power) at constant load conditions, preferably during morning or evening active load period, with the unit operating at a constant load dispatch less than full load. Capture several records with 1 Hz sampling rate over a period of 5-30 minutes.

Analyze the recorded gate position and frequency to confirm droop and deadband.

Deadband is the largest change in frequency for which there is no corresponding change in gate position.

Dead band = _________ Hz (nominal acceptable value is < 0.036 Hz)

D.6 Load Rejection Tests

Purpose: Confirm governor response to load rejection. This test is normally performed following a major turbine or governor overhaul.

Equipment: Transducer for measuring gate position. Transducer for measuring frequency or speed. (Optional) transducer for measuring electrical power.

Procedure: Synchronize unit to grid. Operate slightly under-excited on automatic voltage regulator control. Raise gate position to approximately 10-15% above the speed no-load position.

Record Gate position, Frequency (speed), (Active Power) at 60 Hz rate for 60 seconds including one second pre trigger. Set recorder trigger on breaker opening or active power decrease or manually trigger on a countdown.

On a countdown, open the ac breaker but not unit field breaker and record the transient in gate position and frequency.

Confirm stability of off line frequency control (damped governor settings), and adjust as appropriate. Confirm gate closing rate and cushioning rate.

E
GLOSSARY

E.1 Terminology and Definitions

AC Excitation Systems: AC Excitation Systems (type AC) are characterized by the use of a rotating ac machine as the final stage of the power supply, providing current to the rotor of the synchronous machine through either uncontrolled or controlled rectifiers.

Amortisseur (damper): Conductors that are embedded in the pole face and short circuited by means of end rings to help damp out speed oscillations of synchronous generators [1-8].

Area Control Error (ACE): The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias and correction for meter error.

Automatic Generation Control (AGC): Equipment that automatically adjusts generation in a Balancing Authority Area from a central location to maintain the Balancing Authority's interchange schedule plus Frequency Bias. AGC may also accommodate automatic inadvertent payback and time error correction.

Bandwidth: The maximum frequency at which the output of a dynamic system will track an input sinusoid in a satisfactory manner [E-1].

Baseline: Initial simulation model verification from testing.

Base Field Current: (1 per unit) Field current required to produce rated terminal voltage, assuming no saturation (i.e. rated terminal voltage on the Air Gap Line).

Base Field Voltage: (1 per unit) Field voltage required to produce one per unit field current at a stated rotor temperature. For thermal units the rotor temperature is taken at 100°C. For hydraulic units, a temperature of 75°C is used.

Base Line Testing: This is a term used by ERCOT as well as WECC. According to ERCOT definition, Generating Unit Base Line Testing comprises testing, measuring, and calculating of generating unit characteristics and control parameters used to model the synchronous generator, the governor-turbine and the excitation system. The results of the Generating Unit Base Line test will be compared against manufacturer data, commissioning data, disturbance data, etc. to improve the accuracy of the parameters used by the dynamic models in the system dynamic simulation program. Industry accepted testing techniques will be used for testing, measuring and calculating the generating unit modeling parameters, and the Generating Unit Base Line test report should state the type of test conducted for the synchronous generator and for each respective control system and supplementary control. Whenever possible, generator modeling parameters are calculated on-site and compared to test results.

Base Terminal Voltage: (1 per unit) Manufacturer's nameplate rating for line-to-line RMS voltage on generator terminals.

Bulk Electric System (BES): A term commonly applied to the portion of an electric utility system that encompasses the electrical generation resources and bulk transmission system [E-2].

Ceiling Current: The maximum current that an excitation system can source.

Contingency: The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element.

DC Excitation Systems: DC Excitation Systems (type DC) are characterized by the use of a rotating dc machine, either separately- or self-excited, as the final stage of the power supply providing current to the rotor of the synchronous machine through slip rings.

Disturbance: It is defined as one of the following:

- An unplanned event that produces an abnormal system condition.
- Any perturbation to the electric system.
- The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load.

Disturbance Monitoring Equipment (DME): Devices capable of monitoring and recording system data pertaining to a Disturbance. Such devices include the following categories of recorders:

- Sequence of event recorders which record equipment response to the event.
- Fault recorders, which record actual waveform data replicating the system primary voltages and currents. This may include protective relays.
- Dynamic Disturbance Recorders (DDRs), which record incidents that portray power system behavior during dynamic events such as low-frequency (0.1 Hz – 3 Hz) oscillations and abnormal frequency or voltage excursions.

Facility Rating: The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.

Fault: An event occurring on an electric system such as a short circuit, a broken wire, or an intermittent connection.

Frequency Regulation: The ability of a Balancing Authority to help the Interconnection maintain Scheduled Frequency. This assistance can include both turbine governor response and Automatic Generation Control.

Frequency Response (Equipment): The ability of a system or elements of the system to react or respond to a change in system frequency.

Frequency Response (System): The sum of the change in demand, plus the change in generation, divided by the change in frequency, expressed in megawatts per 0.1 Hertz (MW/0.1 Hz).

High Initial Response (HIR): An excitation system capable of attaining 95% of the difference between ceiling voltage and rated-load field voltage in 0.1 s or less under specific conditions.

Independent Power Producer (IPP): Any entity that owns or operates an electricity generating facility that is not included in an electric utility's rate base. This term includes, but is not limited to, cogenerators and small power producers.

Main Unit: One of a group of identical or similar units that is subjected to comprehensive validation through testing or other means. It is sometimes referred to as Unique unit.

Misoperation: It is defined as one of the following:

- Any failure of a Protection System element to operate within the specified time when a fault or abnormal condition occurs within a zone of protection.
- Any operation for a fault not within a zone of protection (other than operation as backup protection for a fault in an adjacent zone that is not cleared within a specified time for the protection for that zone).
- Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity.

Maximum continuous rating (rotating machinery): The maximum values of electric and mechanical loads at which a machine will operate successfully and continuously. Note: An overload may be implied, along with temperature rises higher than normal standards for the machine.

Negative Forcing: An excitation system feature that results in inverting the field voltage.

Off-line system/unit: A unit that is not connected to the power system and is not running. A system that is dormant until it is called upon to operate (IA/PSE) 493-1997.

Off-line test: Off-line tests are performed on individual modules within the excitation system while it is energized from test supplies and isolated from the field winding.

Online/Synchronized: Condition in which a generator is running and connected to the power system.

Online test (test, measurement, and diagnostic equipment): Testing of a generator while it is synchronized to the grid and operating at a variety of active and reactive power load levels.

Open-circuit: Condition in which a generator is running at its rated speed and producing rated voltage at its terminals but not connected to the power system.

Open-circuit test (synchronous machines): A test that is performed with the generator on open-circuit.

Protection System: Protective relays, associated communication systems, voltage and current sensing devices, station batteries and DC control circuitry.

Rated Field Current: The direct current in the field winding of the synchronous machine when operating at rated voltage, current, power factor and speed.

Rated Field Voltage: Field voltage required to produce rated field current at a stated rotor temperature. For thermal units the rotor temperature is taken at 100°C. For hydraulic units, a temperature of 75°C is used

Reactive Power (Q): The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. It is expressed in units of kilovars (kVAr) or megavars (MVAr).

Real Power (P): The portion of electricity that supplies energy to the load. It is more properly termed Active Power.

Regional Reliability Organization (RRO): It is defined as follows:

- An entity that ensures that a defined area of the Bulk Electric System is reliable, adequate and secure.
- A member of the North American Electric Reliability Council. The Regional Reliability Organization can serve as the Compliance Monitor.

Re-verification: Tests or other methods used to verify that models and rating submitted during the baseline validation continues to apply to the units.

Rotor (rotating machinery): The rotating member of a machine, with shaft.

Round-rotor (rotating machinery) (cylindrical rotor): A rotor of cylindrical shape in which the coil sides of the windings are contained in axial slots.

Salient-pole (rotating machinery): A field pole that projects from the yoke or hub towards the primary winding core.

Salient-pole machine: An alternating-current machine in which the field poles project from the yoke toward the armature and/or the armature winding self-inductance undergoes a significant single cyclic variation for a rotor displacement through one pole pitch.

Sister Unit: Units can be considered sisters in regard to that equipment or system if it can be demonstrated that the units, equipment, or systems have identical designs, identical major components, identical significant control system settings and similar verified capabilities. For some ISOs, a reduced set of tests is adequate for sister units of a main unit, which has undergone detailed model validation through baseline testing. However, other ISOs may require that a complete set of model validation test be conducted on every single unit in a power plant in its jurisdiction. A power plant owner/operator should check with the ISO in his/her area for testing requirements.

Special Protection System: An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and MVAr), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.

Stability: The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances.

Stability Limit: The maximum power flow possible through some particular point in the system while maintaining stability in the entire system or the part of the system to which the stability limit refers.

Staged Test: A test conducted under controlled conditions, usually before or after a planned outage of the facility. This is as opposed to online tests which can be carried out during normal operations.

Standard: An agreement among any number of organizations that defines certain characteristics, specification, or parameters related to a particular aspect of technology. For example, ANSI, ISO, and IEEE are standards-making bodies. [610.10-1994w].

Static Excitation Systems: Static Excitation systems (type ST) are characterized by controlled-rectifier bridges supplying current directly to the field of the synchronous machine through slip rings.

System Operating Limit: The value (such as MW, MVAr, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:

- Facility Ratings (Applicable pre- and post-Contingency equipment or facility ratings)
- Transient Stability Ratings (Applicable pre- and post-Contingency Stability Limits)
- Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability)
- System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)

System Operator: An individual at a control center (Balancing Authority, Transmission Operator, Generator Operator, Reliability Coordinator) whose responsibility it is to monitor and control that electric system in real time.

Type Tests: A test made by the manufacturer on a machine that is identical in all essential respects with those supplied onan order, to demonstrate it complies with this standard. (PE/EM) 11-1980r.

Validation: This is a term used by ERCOT as well as WECC. "Generating Unit Model Performance Validation" insures the response of the PSS/E dynamic models accurately represents the actual response characteristics of the synchronous generators and the generating unit control systems, including supplementary controls. The essential principle of dynamic response validation is that the chosen model of the generating facility in the dynamic simulation program must reproduce the results of tests or reproduce recorded disturbances within normal acceptable levels of accuracy. The measure of success of Generating Unit Model Performance Validation is the quality of the agreement between the recorded and the simulated results.

Verification: Methods to confirm simulation model data which can include use of manufacturer data, commissioning data, performance tracking, engineering analysis, field verification of equipment settings, testing, simulation and comparison with test results or disturbance monitoring data, etc. including any applicable conditions under which the data should be verified [3-1], [E-3].

E.2 Acronyms

AVR	Automatic Voltage Regulator
CT	Current Transformer
FCR	Field Current Regulator
HIR	High Initial Response
MEL	Minimum Excitation Limiter
MOT	Main Output Transformer
OEL	Over Excitation Limiter
PID	Proportional Integral Derivative
PPT	Power Potential Transformer
PSS	Power System Stabilizer
PT	Potential Transformer
RCC	Reactive Current Compensation
SCL	Stator Current Limiter
UEL	Under Excitation Limiter
V/Hz	Volts-Per-Hertz Limiter

E.3 Symbols and Variables

The following is a list of common symbols and variables appearing in generator test reports. Where appropriate, the normal units of measure have been included in parentheses. If duplicate definitions exist for a symbol, they are listed with an indication of the context.

E_{fg}	generator field voltage (Vdc)
E_{fe}	main exciter field voltage (Vdc)
E_t	generator ac three-phase terminal voltage (kV)
E_{tref}	terminal voltage reference (kV)
F	generator terminal frequency or compensated frequency (Hz)
I_{fg}	generator field current (Adc)
I_{fe}	main exciter field current (Adc)
I_t	generator ac terminal current (kA)
K_a	AVR gain (pu E_{fd} / pu E_{tref})
K_c	rectifier loading factor (pu)
K_P	proportional gain
K_I	integral gain
K_D	derivative gain
P	generator active power (MW)
Q	reactive power (MVAr)
R_c	resistive load compensation component
R_{fg}	generator field winding resistance (Ω)
R_{fe}	main exciter field winding resistance (Ω)
R_P	governor permanent droop
R_t	governor temporary droop
S	apparent power (MVA)
T_r	exciter terminal voltage feedback time constant (s)
	governor dashpot reset time (s)
V_c	compensated terminal voltage feedback signal (pu E_{tref})
VRMS	generator ac three-phase terminal voltage (kV)
Ω	speed (Greek symbol omega) (pu)
X_c	reactive load compensation component
V, E	voltage
I	current
P	active power (in some documents referred to as real power)
Q	reactive power (in some documents referred to as imaginary power)
X	impedance, per unit

F
REFERENCES

[1-1] Verification of Generator Gross and Net Real Power Capability, NERC Standard MOD-024-1, February 2006.

[1-2] Verification of Generator Gross and Net Reactive Power Capability, NERC Standard MOD-025-1, February 2006.

[1-3] Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection, Draft Standard PRC-019-1, NERC Phase III-IV Draft Standards for Field Tests, September 2006.

[1-4] Requirements for Salient-Pole 50 and 60 Hz Synchronous Generators and Generator/Motors for Hydraulic Turbine Applications Rated 5000 kVA and Above, ANSI/ IEEE Std. C50.12, 2006.

[1-5] Requirements for Cylindrical-Rotor 50 and 60 Hz Synchronous Generators Rated 10 MVA and Above, ANSI/IEEE Std. C50.13, 2006.

[1-6] Guide for Test Procedures for Synchronous Machines, IEEE Std. 115, December 1995.

[1-7] Guide for Synchronous Generator Modelling Practices for Stability Analysis, IEEE Std. 1110, 2003.

[1-8] P. Kundur, Power System Stability and Control, McGraw Hill, 1993.

[1-9] J. Grainger and W. Stevenson, Power System Analysis, McGraw Hill, 1994.

[1-10] Hunt, J.P. “Capability Curves and Excitation Requirements of Saturated Cylindrical Rotor Synchronous Machines,” IEEE Transactions on Power Apparatus and Systems, Vol. PAS-86, No. 7, July 1967, pp 855-859.

[1-11] N. E. Nilsson and J. Mercurio, “Synchronous generator capability curve testing and evaluation,” IEEE Trans. on Power Delivery, Vol. 9, no. 1, pp. 414–424, Jan. 1994.

[1-12] J. H. Carter, “Operation of Turbine Generators with Low Field Currents,” AIEE Conference Proceedings, 1950.

[1-13] Coordination of Generator Protection with Generator AVR Control and Generator Capability, Report of IEEE Working Group J-5 of the Rotating Machinery Subcommittee, Power System Relay Committee, 2007.

[1-14] Guide for the Preparation of Excitation System Specifications, IEEE Std. 421.4, 2004.

[1-15] Definitions for Excitation Systems for Synchronous Machines, IEEE Std. 421.1, 2007.

[1-16] "Reactive Capability Limits," IEEE Trans. on Industry Applications, Vol. 33 Nov 1997.

[1-17] M. M. Adibi et. al., "Optimizing Generator Reactive Power Resources," IEEE Trans. Power Systems, Vol. 14, No 1, Feb 1999.

[1-18] G. J. Nolan et. al., "Estimation of Reactive Power Export and Import Capability for Non-Utility Generators," IEEE Trans. on Industry Applications, Vol. 33, Nov 1997.

[1-19] Guide for Transformers Directly Connected to Generators, IEEE Standard C57.116, 1989.

[1-20] Terry Crawley, "Validation of Generator Reactive Capability," IEEE PES GM1055, Vol. 3 Jul 2003,

[1-21] IEEE Task Force on Generator Model Validation Testing of the Power System Stability Subcommittee, "Guidelines for Generator Stability Model Validation Testing," IEEE PES General Meeting 2007, paper 07GM1307.

[1-22] "Field Assessment of Reactive Capability," IEEE Trans. on Power Systems Vol. 10, No 1, Feb 1994.

[2-1] Berube, G.R.; Hajagos, L.M.; Beaulieu, "A Utility Perspective on Under-excitation Limiters", IEEE Trans. on Energy Conversion, Volume 10, Issue 3, Sept. 1995, Page(s):532 – 537.

[2-2] Murdoch, A.; Boukarim, Gott; B.E.; D'Antonio, M.J.; Lawson, R.A., "Generator Over Excitation Capability and Excitation System Limiters," Power Engineering Society Winter Meeting, 2001. IEEE Volume 1, Feb 2001, Pages: 215 – 220.

[2-3] Ribeiro, J.R., "Minimum excitation limiter effects on generator response to system disturbances," IEEE Trans. on Energy Conversion, Volume 6, Issue 1, Mar 1991, Pages: 29 – 38.

[2-4] Ramos, A.J.P.; Lins, L.R.; Fittipaldi, E.H.D.; Monteath, L., "Performance of under excitation limiter of synchronous machines for system critical disturbances," IEEE Trans. on Power Systems, Volume 12, Issue 4, Nov 1997, Pages: 1702 – 1707.

[2-5] A. Murdoch, R.W. Delmerico, S. Venkataraman, R.A. Lawson, J.E, Curran, W.R. Pearson, "Excitation System Protective Limiters and Their Effect on Volt/var Control – Design, Computer Modeling, and Field Testing," IEEE Trans. on Energy Conversion, Volume: 15, Issue: 4, Dec. 2000 Pages: 440 – 450.

[2-6] Working Group J6 of the Rotating Machinery Protection Subcommittee, “Performance of Generator Protection During Major System Disturbances,” IEEE Trans. on Power Delivery, Vol. 19, No. 4, October 2004.

[2-7] “A Survey of Generator Back-Up Protection Practices, IEEE Committee Report,” IEEE Trans. on Power Delivery, Vol. 5, April 1990.

[2-8] Panvini, A. and Yohn, T. J., “Field Assessment of Generators Reactive Capability,” IEEE Trans. on Power Systems, Vol. 10, No. 1, February 1994.

[2-9] M.M. Adibi, D.P. Milanicz, “Reactive Capability Limitation of Synchronous Machines,” IEEE Trans. on Power Systems Vol. 9, No. 1, Feb 1994.

[2-10] A. W. Goldman, “Selection of Generator Step-up Transformer Ratings”, IEEE Tran. on Power Apparatus and Systems, Vol. 100, p. 3425, July, 1981.

[2-11] IEEE Standard, Test Code for Distribution, Power and Regulating Transformers, ANSI/IEEE C57.12.

[2-12] J. H. Carter, “Operation of Turbine Generators with Low Field Currents,” AIEE Conference Proceedings, 1950.

[2-13] IEEE Guide for AC Generator Protection, IEEE Standard C37.102, 2004.

[2-14] IEEE Guide for Abnormal Frequency Protection for Power Generating Plants, ANSI/IEEE Standard C37.106, 2004.

[2-15] IEEE Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems, IEEE Std 242, 2001.

[2-16] IEEE Tutorial on the Protection of Synchronous Generators, IEEE Power Engineering Society, 95-TP-102, 1995.

[2-17] J. S. Dudor, L. K. Padden, “Protective Relay Applications for Generators and Transformers,” IEEE Industry Applications magazine, July/August 1997.

[2-18] IEEE Task Force on Excitation Limiters, “Recommended Models for Overexcitation Limiting Devices,” IEEE Trans. on Energy Conversion, Vol. 10, No 4, December 1995

[2-19] IEEE Task Force on Excitation Limiters, “Underexcitation Limiter Models for Power System Stability Studies,” IEEE Trans. on Energy Conversion, Vol. 10. No. 3, September 1995.

[2-20] G. K. Girgis and H. D. Vu, “Verification of limiter performance in modern excitation control systems,” IEEE Trans. on Energy Conversion, Vol. 10, no. 3, pp. 538–542, Sept. 1995.

[2-21] IEEE Recommended Practice for Excitation System Models for Power System Stability Studies, IEEE Standard 421.5-2005, April 2006.

[3-1] Verifications of Models and Data for Generator Excitation System Functions, MOD-026-1, Sept. 2006.

[3-2] Guide for Identification, Testing and Evaluation of the Dynamic Performance of Excitation Control Systems, IEEE Standard 421.2, Sept. 1990.

[3-3] K. Shah, G.R. Bérubé, R.E. Beaulieu, “Testing and Modelling of the Union Electric Generator Excitation Systems”, Missouri Valley Electrical Association Meeting, Kansas City, MO, April, 1995.

[3-4] G. R. Bérubé and L. M. Hajagos, “Testing and Modeling of Generator Controls,” SERC Generator Testing Workshop, Atlanta, GA, December 2000 (http://www.kestrelpower.com/Articles.php).

[3-5] “Regulatory Compliance and Generator Controls Training Course”, Course Notes, Kestrel Power Engineering Ltd. 2000-2007.

[3-6] L. N. Hannett and J. W. Feltes, “Derivation of Generator, Excitation System and Turbine Governor Parameters from Tests,” CIGRÉ Colloquium on Power System Dynamic Performance, Florianópolis, Brazil, 1993.

[3-7] P. Kundur, M. Klein, et al, “Application of Power System Stabilizers for Enhancement of Overall System Stability,” IEEE Trans. on Power Systems, Vol. 4, May 1989, pp 614-626.

[3-8] IEEE Tutorial Course: Power System Stabilization Via Excitation Control, Sponsored by the IEEE Power Engineering Education Committee, Center, Piscataway, NJ, June 2007.

[4-1] Verification of Generator Unit Frequency Response, NERC Standard MOD-024-1, February 2006.

[4-2] “Frequency Response Standard Whitepaper”, Prepared by the Frequency Task Force of the NERC Resources Subcommittee, April 6, 2004.

[4-3] “Understand and Calculate Frequency Response”, NERC Training Document, NERC Training Resources Working Group, February 20, 2003.

[4-4] “Guidelines for Thermal Governor Model Data Selection, Validation, and Submittal to WECC”, Prepared by the Governor Modeling Task Force, WECC Modeling & Validation Work Group, Revised November 4, 2002.

[4-5] L. Pereira, J. Undrill, D. Kosterev, D. Davies, and S. Patterson, “A New Thermal Governor Modeling Approach in the WECC”, IEEE Trans. on Power Systems, May 2003, pp 819-829.

[4-6] James W. Ingleson, Dean M. Ellis, "Tracking the Eastern Interconnection Frequency Governing Characteristic", Proceedings of IEEE PES GM 2005, Page(s):1461 - 1466 Vol. 2, 12-16 June 2005.

[4-7] "Interconnected Power System Response to Generation Governing: Present Practice and Outstanding Concerns", IEEE Special Publication 07TP180, Final Report, May 2007.

[4-8] J. Weisman, L.E. Eckart, Modern Power Plant Engineering, Prentice Hall, 1985.

[4-9] P. Kundur, Power System Stability and Control, McGraw Hill, 1993.

[4-10] CIGRE Technical Brochure 238, Modeling of Gas Turbines and Steam Turbines in Combined-Cycle Power Plants, December 2003.

[4-11] IEEE PES Working Group on Prime Mover & Energy Supply Models for System Dynamic Performance Studies, "Hydraulic Turbine and Turbine Control Models for System Dynamic Studies", IEEE Trans. on Power Systems, Vol. 7, No 1, Feb. 1992, pp.167-79.

[4-12] IEEE Recommended Practice for Preparation of Equipment Specifications for Speed-Governing of Hydraulic Turbines Intended to Drive Electric Generators, ANSI/IEEE Std 125, 31 Oct 1988.

[4-13] Hoa D. Vu & J. C. Agee, "WSCC Tutorial on Speed Governors", WSCC Control Work Group, February 1998.

[4-14] D.G. Ramey, J.W. Skooglund, "Detailed Hydrogovernor Representation for System Stability Studies", IEEE Trans., Vol. PAS-89, pp 106-112, January, 1970.

[4-15] IEEE Recommended Practice For Functional and Performance Characteristics of Control Systems for Steam Turbine-Generator Units, IEEE Std 122-1991, 10 Feb 1992.

[4-16] Working Group on Prime Mover and Energy Supply Models for System Dynamic Performance Studies, "Dynamic Models for Fossil Fueled Steam Units in Power System Studies,", IEEE Trans. on Power Systems, Vol. 6, No 2, May 1991.

[4-17] J. M. Undrill and J.L. Woodward, "Nonlinear Hydro Governing Model and Improved Calculation for Determining Temporary Droop", IEEE Trans., Vol. PAS-85, pp. 750-756, July 1966.

[4-18] "International Code for Testing of Speed Governing Systems for Hydraulic Turbines", IEC Publication 308, 1970.

[E-1] G. Franklin, Feedback Control of Dynamic Systems, Prentice Hall, 2002.

[E-2] Glossary of Terms Used in Reliability Standards, NERC, May 2, 2007.

[E-3] Verifications of Generator Unit Frequency Response, NERC MOD-027-1.

[E-4] "IEEE 100 The Authoritative Dictionary of IEEE Standards Terms Seventh Edition," IEEE Std 100-2000, 2000.

[E-5] NERC HR6 RELIABILITY LEGISLATION Section 1211 of H.R. 6, the "Energy Policy Act of 2005," August 8, 2005.

[E-6] Regional reliability organization documents.

Export Control Restrictions

Access to and use of EPRI Intellectual Property is granted with the specific understanding and requirement that responsibility for ensuring full compliance with all applicable U.S. and foreign export laws and regulations is being undertaken by you and your company. This includes an obligation to ensure that any individual receiving access hereunder who is not a U.S. citizen or permanent U.S. resident is permitted access under applicable U.S. and foreign export laws and regulations. In the event you are uncertain whether you or your company may lawfully obtain access to this EPRI Intellectual Property, you acknowledge that it is your obligation to consult with your company's legal counsel to determine whether this access is lawful. Although EPRI may make available on a case-by-case basis an informal assessment of the applicable U.S. export classification for specific EPRI Intellectual Property, you and your company acknowledge that this assessment is solely for informational purposes and not for reliance purposes. You and your company acknowledge that it is still the obligation of you and your company to make your own assessment of the applicable U.S. export classification and ensure compliance accordingly. You and your company understand and acknowledge your obligations to make a prompt report to EPRI and the appropriate authorities regarding any access to or use of EPRI Intellectual Property hereunder that may be in violation of applicable U.S. or foreign export laws or regulations.

The Electric Power Research Institute (EPRI), with major locations in Palo Alto, California; Charlotte, North Carolina; and Knoxville, Tennessee, was established in 1973 as an independent, nonprofit center for public interest energy and environmental research. EPRI brings together members, participants, the Institute's scientists and engineers, and other leading experts to work collaboratively on solutions to the challenges of electric power. These solutions span nearly every area of electricity generation, delivery, and use, including health, safety, and environment. EPRI's members represent over 90% of the electricity generated in the United States. International participation represents nearly 15% of EPRI's total research, development, and demonstration program.

Together...Shaping the Future of Electricity

Program:

Steam Turbines, Generators, and Balance-of-Plant

♻ *Printed on recycled paper in the United States of America*

1014911

Electric Power Research Institute
3420 Hillview Avenue, Palo Alto, California 94304-1338 • PO Box 10412, Palo Alto, California 94303-0813 USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com