EASING NERC TESTING WITH NEW DIGITAL EXCITATION SYSTEMS

David S. Kral, Xcel Energy, and Richard C. Schaefer, Basler Electric

Abstract *- This paper discusses a portion of the NERC Policy involving Generator Excitation Testing. The paper explains the types of tests that are required, operating modes of the excitation system, and includes discussion of how these tests are accomplished using the commissioning tools available in today's digital excitation systems.*

INTRODUCTION

One year after the massive 2003 blackout darkened much of the northeastern United States and eastern Canada, the North American Electric Reliability Council (NERC) prepared a status report that highlights the major actions that NERC and the industry have taken to improve the reliability of the North American bulk electric system.

According to Michael R. Gent, NERC president and CEO, the report showed that NERC and the electric industry took significant and meaningful steps to improve the reliability of the bulk electric system and reduce the risk of another major blackout.

Recently, the United States Congress passed legislation, the 2005 Energy Act, which made compliance with NERC reliability standards mandatory and enforceable. It states, "The Secretary shall establish a comprehensive research, development and demonstration program to ensure the reliability, efficiency, and environmental integrity of electrical transmission and distribution systems ..." The details of who will set and enforce the standards are still to be worked out.

Taken as a whole, these extensive and cooperative efforts will go a long way to reduce the risk of another major outage in North America. To view the NERC status report and other blackout-related documents, go to: <http://www.nerc.com/~filez/blackout.html>.

WHAT IS NERC?

In 1965, major blackouts in the Northeast spurred the need to establish a council to create standards to help ensure the reliability of the bulk power generated in North America. This commission was designated as the North American Electric Reliability Council (NERC) and it represents eight regions in the United States. See Figure 1 from the NERC web site (http://www.nerc.com).

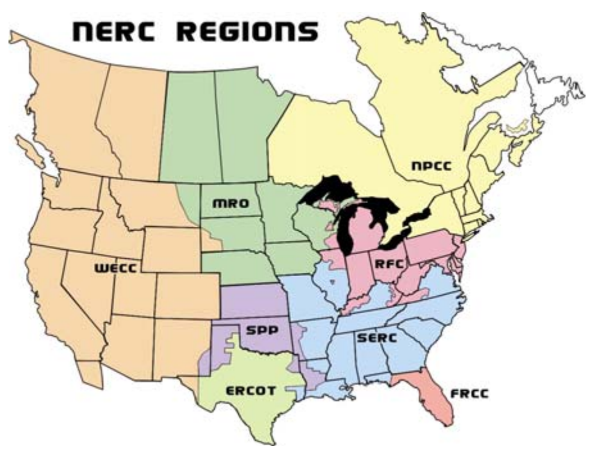

Figure 1: North American Electric Reliability Council's Eight Regions

Standards and policies have been created with additional information forthcoming by the various councils to promote reliability with the interconnected systems. These policies provide guidelines for reporting machine availability due to either scheduled or unscheduled outages, transmission capability concerns, system performance expectations and, among other things, guidelines for generator testing to verify models and performance of synchronous machines.

In its original form, NERC involved a membership program consisting mostly of utilities with volunteer participation. Today, with the many changes due to deregulation, the power industry has changed. Many utilities have divested their generation to holding companies, and an increasingly large number of IPPs (Independent Power Producers) is becoming more responsible for power produced into the transmission system.

In the United States, the Federal Energy Regulatory Commission (FERC) has been authorized to enforce compliance with the NERC standards for all entities using the Bulk Electric System. This mandatory compliance went into effect in June 2007 for 83 of the NERC standards. Similarly, compliance is not mandated in Canada, though it is done by the Provincial governments.

WHO WILL BE REQUIRED TO COMPLY?

The NERC standards apply to all entities connected to the Bulk Electric System. In the past, each Regional Reliability Organization determined the details of compliance and set exemption criteria. The minimum size unit required to be tested, for example, ranged from 10 MVA to 75 MVA in different regions. Currently, a NERC Standards Drafting Team is rewriting the generator verification standards to remove the responsibility for defining the detailed requirements from the RRO's and incorporate them into the standards so that the requirements are applicable continent-wide. But what does this mean to the owners? Since reliability is the primary issue, machine capability and anticipated performance during and after a fault is important to predict system response. To accomplish this requirement, information is required of the machines interconnected to the system. This information includes:

- Reactive capability range of the machine.
- Excitation system models with data validated by test.
- Generator characteristics including synchronous, transient, subsynchronous, and reactance that is verified by test data.
- Excitation Limiters must be modeled and verified.
- Generator Protection Relays must be tested and verified that they coordinate with the excitation limiters, such as the Volts/Hertz limiter versus Volts/Hertz protection.
- The excitation system must be operated in automatic voltage regulation mode to help provide voltage support to the system in the event of a disturbance.
- Excitation and generator systems operating in western United States or areas requiring the power system stabilizer must be enabled and operating and a verified model provided.

This paper discusses what is involved in accomplishing the various tests and the reasons for operating in the suggested characteristic modes. It also discusses the testing tools in new digital excitation systems today that make these tasks less formidable and more time efficient. [10]

Figure 2: Laptop computers are connected into the excitation system serial port to gather information

WHY THE NERC REQUIREMENTS?

In 1996, a major power blackout in the northwestern United States occurred; it resulted in millions of residential homes and businesses suddenly without power. After the blackout, investigations were made to determine the cause of failure. The problem: many generators were operating in manual control in lieu of the automatic voltage regulator, and for those systems that were equipped with power system stabilizers to provide system damping, many of the power system stabilizers were turned off, which created an even larger potential of an eventual system collapse. Since the 1996 Northwest blackout and the large 2003 blackout that hit the Northeast, the Energy Act of 2005 has been passed. It defines the expectations of the generator connected to the transmission system in North America to improve "reliability" of the connected system.

VOLTAGE REGULATOR PERFORMANCE EXPECTATIONS

Most excitation systems are equipped with two operating modes: the automatic voltage regulator and manual control. While the automatic voltage regulator helps provide reactive and voltage support for disturbances and relay fault clearing, manual control tends to make the generator a voltage follower, providing no voltage support, and jeopardizes relay tripping coordination. Today, manual control is primarily intended to be a commissioning tool and a fall back mode in case the PT fuse fails at the voltage regulator input. Hence, the concern of any extended operation in manual control and system disturbance occurring may lead to potential loss of field and a machine pole slip, and due to insufficient field excitation.

The need to operate in automatic voltage regulator mode becomes apparent. When a system voltage dip occurs due to a system fault, the generator voltage will decrease by the percentage of the impedance between generator and the fault. The smaller the impedance, the larger the voltage drop. In response, the voltage regulator will sense the lower terminal voltage and increase the voltage into the field of the generator in an attempt to raise the generator terminal voltage and force current into the fault needed for relay tripping.

After the fault clears, a very fast voltage regulator with rapid response will be able to maximize the synchronizing torque of the generator to stabilize the rotor and allow for its recovery back to its steady state position. See Figure 3.

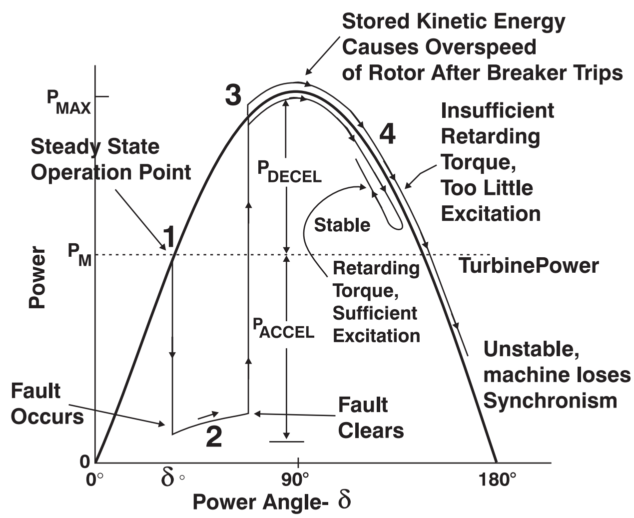

Figure 3: Generalized Diagram of Transient Stability after a Fault, as the Rotor Regains Steady State Operating Point

THE NEED FOR TRANSIENT STABILITY

Transient stability is primarily concerned with the immediate effects of a transmission line disturbance on generator synchronism. Figure 3 illustrates the typical behavior of a generator in response to a fault condition. Starting from the initial operating condition (point 1), a close-in transmission fault causes the generator electrical output power, Pe, to be drastically reduced. The resultant difference between electrical power and the mechanical turbine power causes the generator rotor to accelerate with respect to the system, increasing the power angle (point 2). When the fault is cleared, the electrical power is restored to a level corresponding to the appropriate point on the power angle curve (point 3). Upon clearing the fault, one or more transmission elements may be removed from service and at least temporarily may weaken the transmission system. After clearing the fault, the electrical power out of the generator becomes greater than the turbine power. This causes the unit to decelerate (point 4), reducing the momentum the rotor gained during the fault. If there is enough retarding torque after fault clearing to make up for the acceleration during the fault, the generator will be transiently stable on the first swing and will move back toward its operating point. If the retarding torque is insufficient, the power angle will continue to increase, causing a loss of machine synchronism. Power system stability in the transmission system after a fault depends upon a number of factors including whether the system is in manual control or automatic voltage control, relay tripping time to clear the fault, the power angle of the transmission system at the time of the fault, and the severity of the disturbance.

Another problem known as small signal instability may also exist. It is most often associated with NERC council regions located in the western United States. While fast excitation systems are important to improve transient stability following large impact disturbances to the system, a fast responding excitation system also can contribute a significant amount of negative damping that reduces the natural damping torque of the generator, causing undamped MW oscillations after a disturbance. This can occur if the synchronous machine is interconnected to a weak or high impedance transmission line where the loads are far from the generating plants, typical in areas of the western United States. Thus, an excitation system has the potential to contribute to small signal instability of power systems. Small signal stability is defined as the ability of the power system to remain stable in the presence of small disturbances. These disturbances could be minor variations in load or generation on the system. If sufficient damping torque doesn't exist, the result can be rotor angle oscillations of increasing amplitude. Where these MW oscillations grow, the machine eventually can result in a trip caused by a loss of unit synchronism or damage to the turbine shaft. See Figure 4.

With the very old electromechanical excitation systems, the transient response was relatively slow compared to systems introduced today. This slow response has minimal effect in reducing the damping torque.

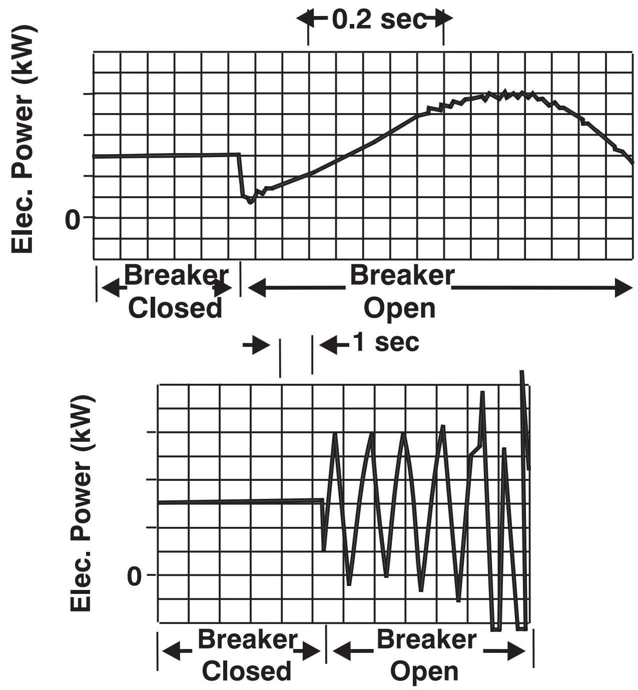

Figure 4: Transient Response. Top Graph Highlights the Initial Swing Damping by the Voltage Regulator. Lower Graph Illustrates MW Oscillation Increases after First Swing

To address the problem of small signal instability, a power system stabilizer is combined with the voltage regulator to provide positive damping to MW oscillations. With the aid of a power system stabilizer, the excitation system will vary the generator flux to apply torque into the rotor coincidental with the rotor MW oscillation. The MW oscillations after the fault may vary in frequency from .1 to .7 Hz, which is known as the interarea mode oscillation, and .7 to 2 Hz for local mode oscillation. In the Western United States and Canada, interarea and local mode oscillations are of primary concern for damping; hence, the need for power system stabilizers.

MODEL VERIFICATION TESTING

One of the important ways that NERC Planning Standards can ensure a more reliable interconnected transmission system is to realistically simulate the electrical behavior of the components in the interconnected networks. In order to predict the behavior of the system during and after a fault, generator and excitation models have become increasingly important tools for system transmission studies. The models provide transmission planners with the ability to analyze generator performance as well as overall response of the interconnected system during disturbances. It is important that the information used in the model be correct. Therefore, it is extremely important to have accurate data that can be used in the models that represent the generator, the excitation equipment, and the system.

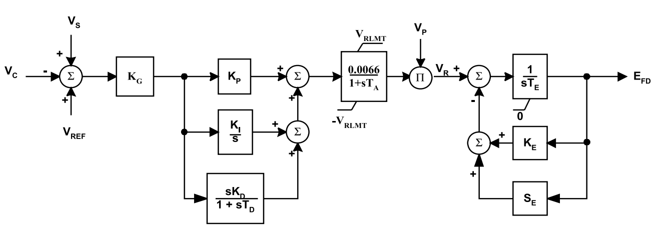

Figure 5: Model Diagram for Digital Excitation System with Rotating Rectifier Excitation System Type AC8B

Figure 5 represents a sample model of a digital excitation system [12][5]. The variables in the model change as a function of the application (for example, whether the generator has a rotating exciter or static exciter working into the main field) and the speed of the voltage regulator response. Collected test data of the generator and excitation system is used to validate the model for various conditions that need to be examined.

Model Gathering Data Includes:

1. Open circuited field voltage, field current generator saturation curve to determine the generator air gap saturation characteristics. Generator voltage is measured every 1000 Volts starting at approximately 50% generator voltage to 110% of the open circuit machine voltage. See Figure 6.

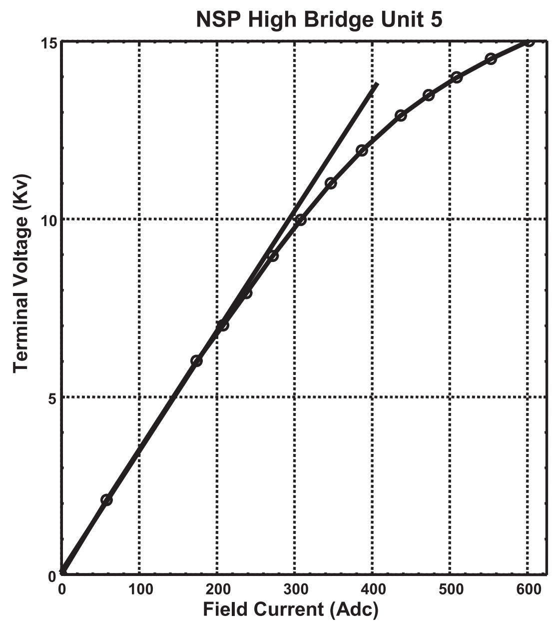

Figure 6: Open Circuit Generator Saturation Curve – Northern States Power High Bridge Unit 5 [9]

2. Unit trip with 0 MW load in manual voltage control, underexcited to estimate internal generator reactances including X"d, X'd, T"d, and T'do.
3. Generator trip at 10% MW, 0 Vars to determine inertia constant and governor's performance.
4. Excitation response in AVR mode and manual mode by performing voltage step changes with the generator open circuit.
5. Generator excitation system frequency response to determine bandwidth of the excitation system with the generator.

Once this information is collected, performance data is compared with the simulated data produced by analytical studies.

Generator voltage response is monitored when performing a 2% voltage step change into the voltage regulator when the generator is open circuited (generator breaker open) to monitor the response of the synchronous machine with the gains established for the excitation system. For a well-tuned excitation system, the generator should never experience more than 10% voltage overshoot during the voltage step change [8][6]. Correlation of the data, actual test data versus the mathematical model simulation should provide close approximation of the information. Figure 7 illustrates generator voltage, exciter field voltage, and current response after a 2% voltage step change has occurred. Studying simulated versus actual measured performance will show close correlation of the data.

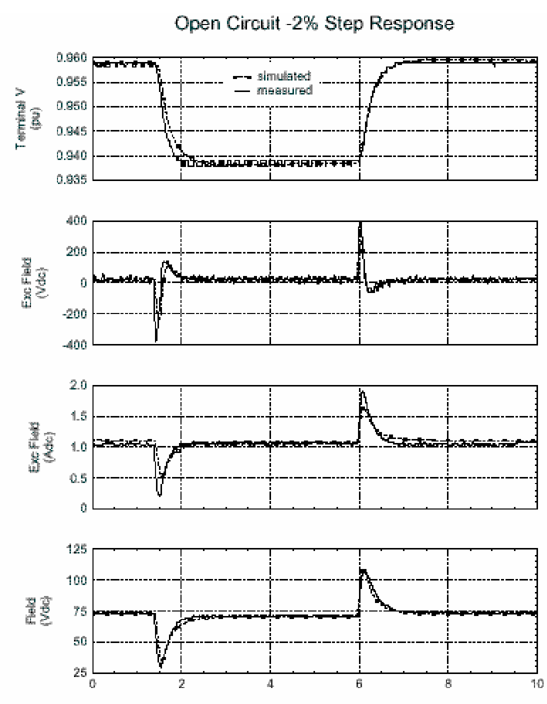

Figure 7: Measured 2% Open Circuit Voltage Step Response Versus Simulation Study Minnesota Power & Light, Boswell Unit 1 [8]

In the past, actual test data (as shown above) would have been collected by a chart recorder connected externally to the excitation system. Today, the digital excitation system comes with accessory features to reduce or eliminate external test equipment by having built-in software tools that accomplish the same, such as a real time chart recorder and oscillography. Effective performance gains for the excitation system are quickly derived with the ability to execute test and evaluate performance using the built-in testing tools. See Figure 8. A laptop computer is used, connected to the serial port of the excitation system that provides convenient means to determine system response.

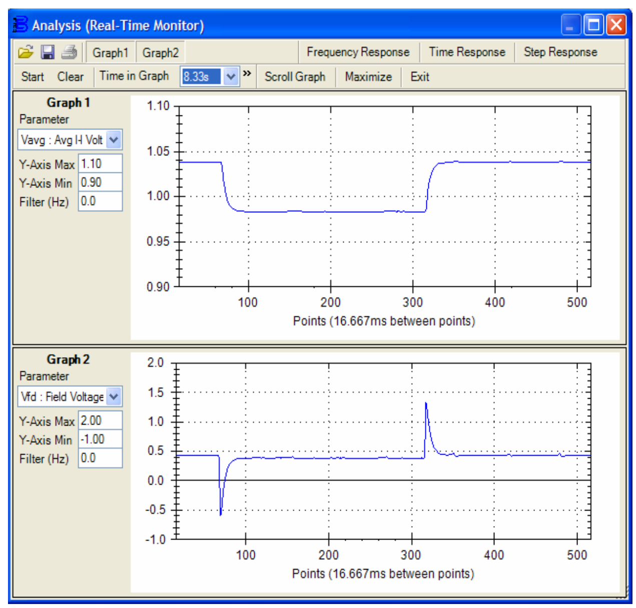

Figure 8: 5% Generator Voltage Step Change using Built-in Chart Recorder Software Function to evaluate voltage response gain

REACTIVE POWER TRANSFER REQUIREMENT, VOLTAGE SUPPORT

The ability to maintain system voltage support can require the full utilization of the generator reactive capability limit of the synchronous machine to establish limits under both pre- and post-contingency conditions to avoid voltage instability or system collapse. When the system is lightly loaded or a line fault has open-circuited a portion of the transmission line, the result can be an increase in system voltage. In order to lower the system voltage, reactive power needs to be absorbed into the machine in the under excited region of the generator. The voltage regulator provides corrective action by acknowledging the high terminal voltage and causes a reduction in field excitation. Too much corrective action by the voltage regulator can result in an insufficient excitation to maintain synchronizing torque for the generator power output, which may cause a trip by loss of field relaying. To prevent this from occurring, the voltage regulator is equipped with an underexcitation limiter (UEL) that limits the maximum reactive power that can be absorbed into the generator based upon the MW load of the machine [11]. The greater the MW loading, the fewer the vars that can be absorbed into the machine. Hence, coordination of the limiter versus the maximum reactive capability limit, loss of field relay, and steady state stability limit is critical for machine stability.

Tests are conducted to determine the maximum reactive power that a generator can absorb under normal conditions. Since the underexcited region represents the least stable operating point of the machine, both steady state and dynamic tests are performed to verify system stability when the underexcitation limiter is active and the machine is absorbing reactive power with the generator producing maximum MW.

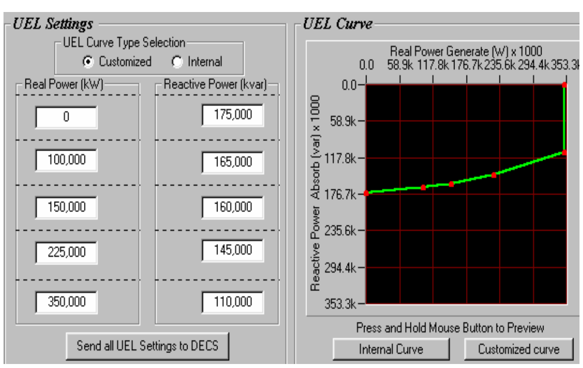

Figure 9: UEL Testing Verifies Generator Capability Curve against UEL Limiter Action

Figure 9 represents the capability curve of the generator whose capability curve is programmed into the voltage regulator underexcitation limiter. Testing verifies that the dynamics stability of the machine is maintained with a –2% step change of the voltage regulator set point. See Figure 10.

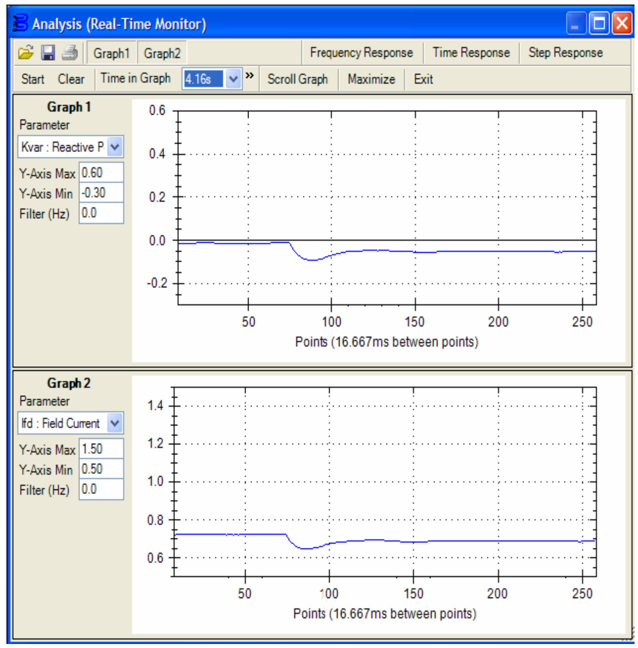

Figure 10: Under Excitation Response using Built-in Chart Recorder Function

Reactive Power. Top: Field Current, Below: Trace

The maximum vars available from a generator is of concern to ensure short time boost as well as extended var capability of a machine at rated MVA. During a fault, the generator excitation system will be required to provide field forcing to help support the depressed system voltage and maximize voltage support. During this period, the generator will be expected to extend its var capability for a short period of time to restore the depressed voltage back to normal. As the field is heating, maximum excitation limiters need to limit the heating effects to a safe value to prevent damage to the field. Again, testing is required to verify parameters. When performing step tests to verify the machine at its maximum capability, machine safety will be a concern. *To verify unit stability, verification is often performed* *at lower levels of excitation and machine output to ensure safety of the system.* Testing requires evaluation of generator protective relays, such as generator overvoltage and field overvoltage/ overcurrent versus limiter operation to verify coordination.

Figure 11 uses oscillography to highlight step test of an overexcitation limiter (OEL) as the generator is forced into the overexcited region of the machine. The overexcitation limiter illustrates three decreasing limit levels of field current.

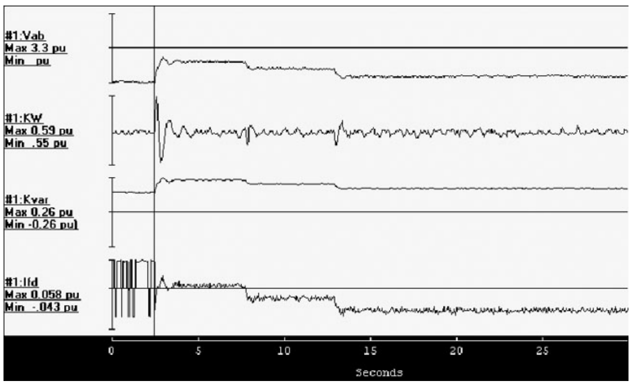

Figure 11: 2% Step Change with Over Excitation Limiter Response using oscillography record

The maximum vars the generator is capable of delivering is important to verify the system contingency needs during stressed transmission voltage levels.

Limiters, such as Volts/Hertz, are tested for functionality and performance verification. Here, terminal frequency is varied or terminal voltage is raised below the level of the volts per hertz relay to verify proper coordination of the two devices. See Fig 12.

Programmed Ratio 1.99 **Check at 1.05 Nominal Vac**	*Frequency*	*PT Instrument System Voltage*	*System Voltage* **Kvac**
1.98	60	119.25	14.31
1.997	59.1	118.18	14.18
2.0	58.5	117	14.04
1.993	58.4	116.4	13.96
2.02	58.3	118.74	14.24
2.0	58.2	116.4	13.96
1.996	58	115.8	13.89
1.994	57.8	115.3	13.83
1.997	57.3	114.43	13.73
2.0	57.2	114.6	13.75
1.987	57	113.3	13.59
1.992	56.7	112.96	13.55
Final Setting of V/Hz Ratio Limiter=2.05 108% Nominal Vac			

Figure 12: Volts/Hertz Ratio Limiter Must Be Coordinated with Volts/Hertz Protection

Where stator current limiters are utilized, step tests are performed that ensure machine stability is not comprised while limiting in both the under and overexcited region of the generator. The importance of the limiter test is to verify that no instability develops with the limiters active due to excessive gains.

VAR/POWER FACTOR CONTROLLER APPLICATION CONSIDERATIONS

Over the years, Var or power factor control became popular alternative controls used in lieu of the automatic voltage regulator for small machines. Small machines tend to be classified as voltage followers that have little to minimum effect on the system voltage stability [4]. The var controller provides a supplementary control into the automatic voltage regulator loop to cause the system to regulate constant vars in lieu of the terminal voltage regulator mode. See Figure 13. Operation at unity power factor will extend life of the machine, because the machine will run cooler.

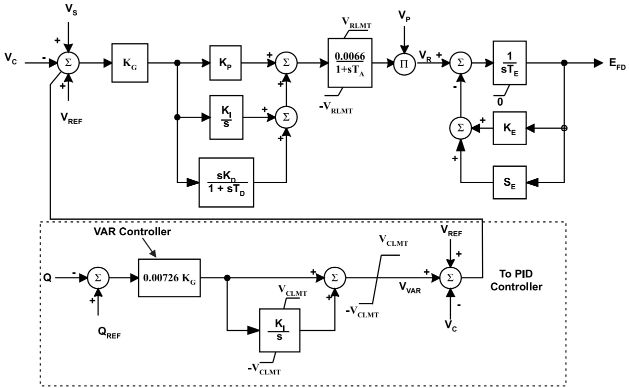

Figure 13: Model for Var Control Supplementary Control Loop into the PID Controller Input

Unfortunately, during a fault the var controller has been known to counteract the voltage support action of the regulator depending upon the gain setting of the device. Instead, the var controller maintains constant vars and a voltage collapse may occur, jeopardizing relay coordination. For large machines that are critical to system stability, var control is not an acceptable mode of operation. NERC Standard VAR-002 prohibits operation of a generating unit connected to the Bulk Electric System from operating in var-control or power factor-control modes unless permission is specifically granted by the Transmission Operator.

Another problem that can occur where var controllers are used is incompatibility with a power system stabilizer operation. In that case, action tends to be opposite in correction. Power system stabilizers want to push vars to stabilize MW swings, while the var controller wants to maintain constant vars. This opposing action can lead to undamped system instability. Hence, var control always should be disabled when a power system stabilizer is required.

Although still not advocated, new digital systems can provide the solution for fast excitation voltage response and still provide var control by careful tuning of the excitation system. In this case, the voltage regulator PID gains are tuned to be very aggressive during a system disturbance. Slower var control gains are tuned for slower response, so voltage control is always within the first couple of seconds; then var control response follows after disturbance recovery has occurred.

POWER SYSTEM STABILIZER REQUIREMENTS

In the Western United States, machines are required to have power system stabilizers to improve the dynamic stability of the system. Over the years, the size of the machines where the power system stabilizer is utilized has dropped progressively. With the limited transmission capability and high loading expectations of the system, the transmission lines are stressed, which makes them particularly vulnerable to high loading margins and the likelihood of a sustained or growing oscillation after a fault. See Figure 4. Power system stabilizers (PSS) have proven to provide necessary damping for these voltage- weak transmission systems. Current NERC/ WECC policies dictate that machines that exceed 30 MVA or a group of machines that exceed 75MVA with excitation systems installed after November 18, 1993, require power system stabilizers to be added if the excitation meets the performance criteria (specifically, if the excitation system has a bandwidth of not more than 135 degrees phase lag at 1 Hertz). For these systems, a PSS is a candidate for the application [3]. When a power system stabilizer is utilized, the excitation system response is tuned to be very aggressive to terminal voltage deviation to improve the transient stability of the system for the first rotor swing. As the transient stability is enhanced, the natural damping in the system is restored by the PSS.

To determine the proper selection of the time constant and parameters required in the power system stabilizer, a frequency response is performed. A small signal frequency ranging from .1 to 3 Hertz is applied into the summing point of the voltage regulator, and compared with the generator output signal frequency for phase shift. See Figure 15. Once this information is obtained, the time constants can be defined for the Lead and Lag networks of the power system stabilizer. See Figure 16.

Historically, accomplishing the Frequency Response has been tedious from the moment of interconnection, collecting the data, and removing the hardware from the machine that would take a minimum of three days to accomplish. With digital excitation systems, a built-in "Dynamic System Analyzer" reduces the time considerably. In Figure 14, a selection of the chosen frequency range is identified, and the mode selection is set for "Auto". Hours of setup and data gathering are reduced to 10 minutes, with phase lag and gain all calculated and provided into a Bode Plot that characterizes the generator and excitation system using operating software in the excitation system. See Figure 15.

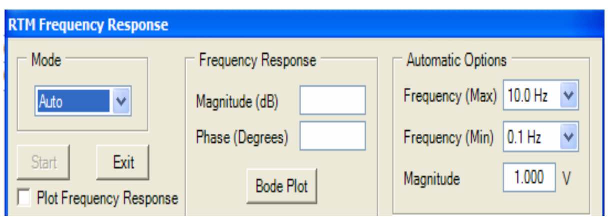

Figure 14: Selection of Parameters for Frequency Response Test

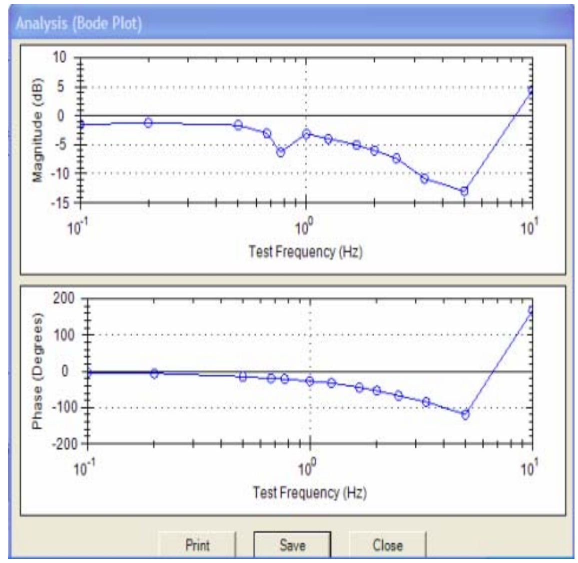

Figure 15: Frequency Response using Built-in Dynamic Analyzer

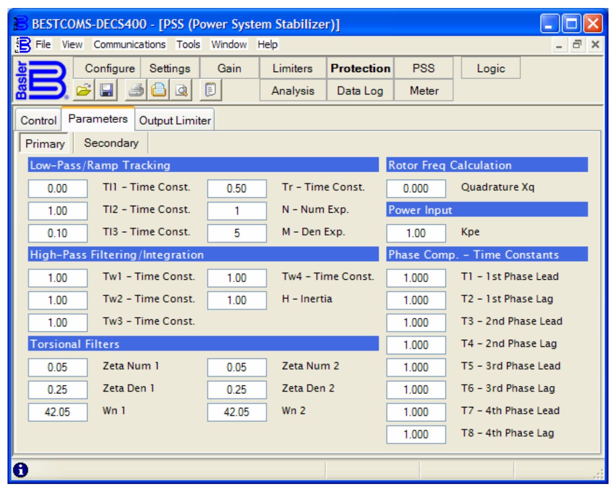

Figure 16: PSS Time Constants are Derived after Performing the Frequency Response

The combined benefit of a frequency response software program and built-in chart recorder allows one to see MWs change as the frequency response is being performed for a visual examination of machine performance during the frequency response test.

Other required data for PSS tuning is the unit inertia that is confirmed by a partial load rejection test as shown in Figure 17. From the figure, the calculated unit inertia value of

2.8 MW-s/MVA is determined that matches the manufacturer data. The inertia is used to scale the active power input to the stabilizer to produce the correct mixing of the stabilizer power and compensated-frequency inputs.

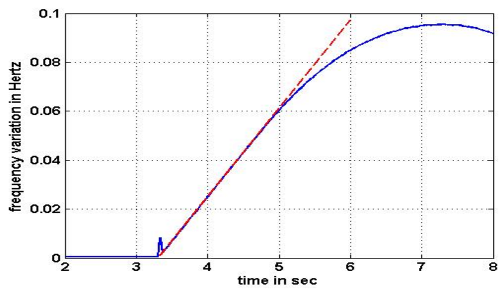

Figure 17: Trip from Load for Inertia Calculation

The last data collection involved is an underexcited trip in manual control to determine the reactances and time constant of the machine. Once these tests are accomplished, values can be applied into the power system stabilizer.

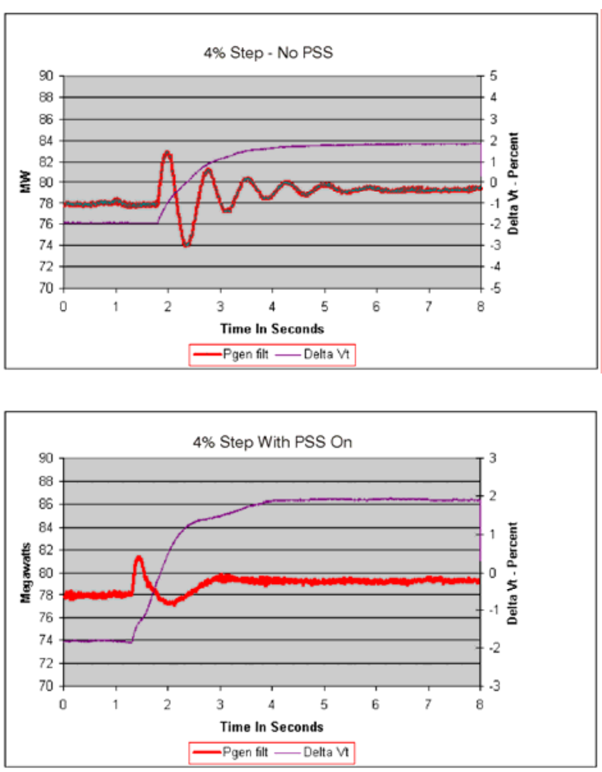

Figure 18: Step tests are performed with Power System Stabilizer
(Courtesy of Arizona Public Service)

When power system stabilizers are utilized, voltage step responses need to be performed to verify satisfactory performance and effectiveness after tuning. The "top" recording in Figure 18 illustrates a 4% voltage step change with the PSS "Off". Notice the underdamp oscillation after the initial swing. The "lower" recording in Figure 18 illustrates the PSS "On" with excellent damping after the initial power swing during the 4% voltage step change.

Limiters also are verified to ensure a stable system. Figure 19 demonstrates the underexcitation limiter performance prior to enabling the power system stabilizer. Note the MW swing that grows in magnitude after the introduction of a -2% voltage step change with the generator connected to the transmission system. The test demonstrates that, without the PSS, the excitation gains have introduced power system instability. Note how the power swings grow in magnitude.

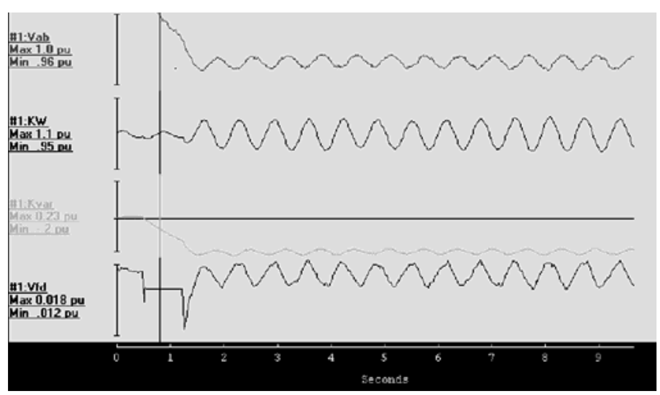

Figure 19: UEL Step Test demonstrates Excessive Gain, Note MW Increasing Oscillation without a Power System Stabilizer

In Figure 20, the PSS is enabled during the underexcitation limiter step test. Here, the MW swings are stable with the aid of the power system stabilizer to dampen unit oscillations to achieve good unit performance.

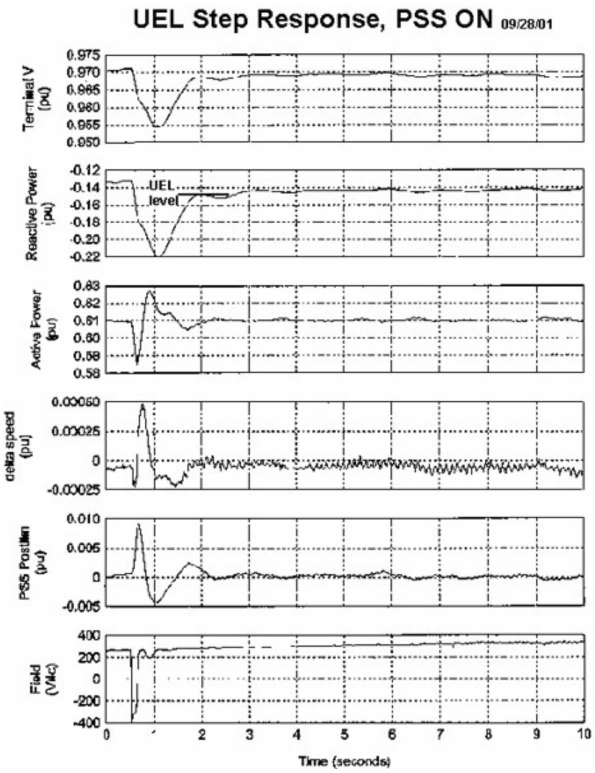

Figure 20: -2% Step Change Demonstrates UEL Limiter Stability

According to NERC/WECC requirements, where PSS are utilized, their activities are to be reported every three hours without exception, and the PSS should never be turned off except below the power threshold that is deemed appropriate for the system.

VALIDATING EVERY FIVE YEARS

NERC requires the revalidation of all tests described above every five years. Oscillography internal to the excitation system provides a means to store files after performance testing has been accomplished and to compare old performance to new test data when needs dictate. Many of the new digital systems offer built-in features to perform step tests and automatically log the data into COMTRADE or log files to speed testing and commissioning requirements.

Knowing what happens during and after a disturbance is equally important for analyzing unit trips. Oscillography triggers can be set to monitor MW, line current, generator voltage, vars, field voltage, and field current in order to analyze the behavior of the system during the event and to understand the cause and reaction of the generator/excitation system.

CONCLUSION

With the passage of the 2005 Energy Act, performance testing of the generator excitation system has become mandatory for an increasing number of power producers who sell power into the grid, regardless of region, depending upon size of machine. It may be mandatory for machines as small as 10 MVA or power plants with collective power rating of 10 MVA. Current testing requirements or specific features requirements (such as a power system stabilizer) may vary depending upon region of the country, but testing and verification of system models will be important tools to ensure future reliability of the transmission system. This paper describes many of the requirements for generator testing as stated in NERC Standards MOD-025, MOD-026, and PRC-019. Currently, auditing programs exist in all regions to verify compliance. In the new electrical legislation, the congressional body has mandated auditing to ensure machines meet the suggested policy standards. The need for these policies is based upon the ability to provide uninterrupted and reliable power for homes and businesses now and for years to come.

REFERENCES

[1] Rasheek M. Rifaat, “Independent Power Producers (IPP) Perspectives and Experiences with WSCC Requirements for Generator Model Validation”. IEEE Transactions on Industry Applications, Vol. 37 No.4, pp.1210-1215 July/August 2001.

[2] NERC Standards web site - http://www.nerc.com NERC/WECC Publication doc. http://www.wecc.biz

[3] WSCC Modeling Working Group, "Criteria to Determine Excitation System Suitability for PSS in WSCC

System", presented in San Diego, CA, January 20, 1993.

[4] Thomas W. Eberly, Richard C. Schaefer, "Voltage Versus VAR/Power Factor Regulation on Synchronous Generators", IEEE Transactions 2002, IEEE Pulp and Paper Conference, June 2002.

[5] IEEE Std. 421.5-1992, IEEE Recommended Practice for Excitation System Models for Power System Stability Studies.

[6] IEEE Std. 421.2-1992, IEEE Guide for Identification, Testing, and Evaluation of the Dynamic Performance of Excitation Control Systems

[7] IEEE Std. 421.4-1990, IEEE Guide for the Preparation of Excitation System Specifications

[8] Les Hajagos, Kestrel Engineering, “Power System Tuning and Modeling Minnesota Power & Light, Boswell Unit 1, Report Number K2002_07, Dated August 21, 2002”.

[9] Les Hajagos, Senior Research Engineer, “Power System Tuning and Modeling Northern States Power, High Bridge Unit 5, Report Number Wo 8329-020, Dated 31 May - 1 June, 2000”.

[10] Michael Brimseck, Kiyong Kim, Pranesh Rao, and Richard C. Schaefer, “Featured Enhancements in New Digital Excitation Systems Speeds Performance Testing”, Doble Client Conference, Boston, April 2006.

[11] Michael J. Basler, Richard C. Schaefer, Kiyong Kim, Russell Glenn, “Voltage Regulator with Dual PID Controllers Enhance Power System Stability“, Hydrovision Conference, Portland, OR, 2002.

[12] IEEE Task Force on Digital Excitation Systems, “Computer Models for Representation of Digital-Based Excitation Systems”, IEEE Transactions On Energy Conversion, Vol. 11, No. 3, September 1996, pp. 607-615.