Tools to Optimize Maintenance of Generator Excitation System, Voltage Regulator and Field Ground Detection

Technical Report

Tools To Optimize Maintenance of Generator Excitation System, Voltage Regulator and Field Ground Detection

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REPORT SUMMARY

This report contains information to optimize maintenance of generator-excitation systems, voltage regulators, and field ground protection.

Background

Main generator excitation system failure, though not occurring frequently, can cause a high value of loss. The cost of lost generation can greatly exceed the cost to repair the excitation system. The advent of new maintenance and diagnostic technologies and techniques has greatly reduced the cost of maintaining the excitation system in a high state of reliability. With the fiscal restraints many power plants now have on their operating and maintenance budgets, a program of a low cost-benefit ratio is needed to maintain and improve reliability and availability.

Objectives

To determine commonly performed excitation system maintenance tasks used by generation plants, to identify excitation system failures occurring in generation plants, to identify component failure rates per make and model of excitation system, and to determine the most effective maintenance tasks and programs for excitation systems.

Approach

The project team surveyed generation plants for excitation system maintenance and failure data. The team also reviewed industry databases for excitation system failure data. Team members compiled and analyzed data for common failure and maintenance practices. They researched industry literature, including IEEE standards, and manufacturer documents. From the data analysis and literature review, the team developed an effective maintenance program.

Results

Excitation systems vary greatly in the type of equipment and the method of producing generator excitation. The maintenance performed by power plants on the excitation also varies greatly, even when plants have the same type of excitation system. However, there is some commonality among the diverse systems. For example, almost all types of excitation systems use brushes to apply excitation current to the generator’s rotating field. Brushes are one of the components requiring the most labor to ensure reliable performance. Furthermore, brushes and associated components are involved in a disproportionate number of personnel safety issues due to the electrical shock hazard they present.

Predictive maintenance (PdM) technologies and techniques provide opportunity for enhancing reliability while reducing the need for certain preventive maintenance (PM) tasks. Although many PM tasks remain necessary for reliable system operation, reducing the number and possibly the frequency of PM tasks with PdM technologies increases the availability of the

system and decreases maintenance costs. Maintenance tasks, including both PdM and PM tasks, are described in this report. A typical routine maintenance plan also is given.

Cost-benefit analysis provides a tool to determine the appropriate tasks and frequencies of maintenance. Using cost-benefit analysis, a plant can develop a maintenance plan that provides a cost-effective balance of system reliability and maintenance tasks. Cost-benefit analysis can be used to determine whether excitation system components should be replaced, upgraded, or maintained for optimal cost-effectiveness. The report provides a detailed description of a cost-benefit analysis.

The information in this report will help plants benefit economically by using appropriate levels of PdM and PM tasks; older plants can benefit as well, possibly through equipment upgrades.

EPRI Perspective

This project provides users with a tool to assess their excitation systems for failure probability and to take appropriate actions to monitor and rectify potential problems prior to failure. Maintenance failure data and analyses will assist users with condition monitoring and maintenance optimization of their excitation systems. This maintenance guide provides a detailed overview of the excitation system and components, failure mechanisms, appropriate maintenance diagnostic and monitoring practices, and recommendations for increasing reliability and efficient maintenance.

Keywords

Exciter
Excitation
Voltage regulator
Generator
Brush
Alternator

ABSTRACT

Generator excitation systems are assumed to have a relatively good reliability and availability. However, the costs of an excitation system failure can be extremely high, forcing a plant shutdown for days, weeks, or even longer. Furthermore, with diminishing budgets and “belt tightening”, maintenance resources are stretched to maintain the reliability and availability of not just the generators, but all systems and equipment in the plant.

Performing the appropriate techniques and technologies at the right times, can increase the excitation system reliability and maintain high availability of the generator. As a further benefit, maintenance manpower, funds, and other resources can be more effectively and efficiently put to use.

This project provides users with a tool to assess their excitation systems for failure probability, and to take appropriate actions to monitor and rectify potential problems prior to failure. The maintenance failure data and analysis assists and directs users with condition monitoring and maintenance optimization on their excitation systems. The maintenance guide contained herein will provide them a detailed overview of the excitation system and components, failure mechanisms, appropriate maintenance diagnostic and monitoring practices, and recommendations for increasing reliability and effective efficient maintenance.

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INTRODUCTION

Generator excitation systems are assumed to have relatively good reliability and availability. However, the costs of an excitation system failure can be extremely high, forcing a plant shutdown for days, weeks, or even longer. Furthermore, with diminishing budgets and "belt tightening," maintenance resources are stretched to maintain the reliability and availability of not only the generators, but all systems and equipment in the plant.

Performing the appropriate techniques and technologies at the right times can increase the excitation system reliability and maintain high availability of the generator. As a further benefit, maintenance manpower, funds, and other resources can be more effectively and efficiently put to use.

Excitation Systems Introduction

The primary purpose of the excitation system, no matter its make up, is to provide excitation to the main generator. The components of any main generator excitation system are: a power supply, a voltage regulator, and a generator field.

Excitation Power Sources

The power supply, or source, provides the energy to drive the excitation. This supply can be electrical or mechanical. The electrical supply can be a transformer taking power from the generator bus, or a station auxiliary bus feeding a motor generator set exciter. The mechanical source is normally taken from the generator shaft, either an alternator or a DC generator. The alternator or generator is normally directly coupled to the generator shaft. However, a gear reduction may be used, especially in the case of a DC generator exciter. Another mechanical power source may be a separate turbine driving the exciter alternator or generator; although this is not a common practice in newer plants.

Main Generator Field

The main generator field converts the current supplied by the excitation system into a magnetic field. All excitation systems have to use a generator field. In almost every case the field is mounted on the generator rotor. The only exceptions are on pilot exciters and small generators that are not included in the scope of this guide. The lines of magnetic flux from the rotating generator field cut though the stator mounted armature winding, inducing an AC voltage on the windings. The field windings themselves may be wound coils mounted on poles on the rotor; a salient pole rotor. This is typical for lower speed generators, often less than 1800 rpm. For higher speed generators the field windings are embedded in the rotor; a nonsalient pole rotor. In this type of rotor the winding conductors are placed in machined slots with wedges to hold the winding in place.

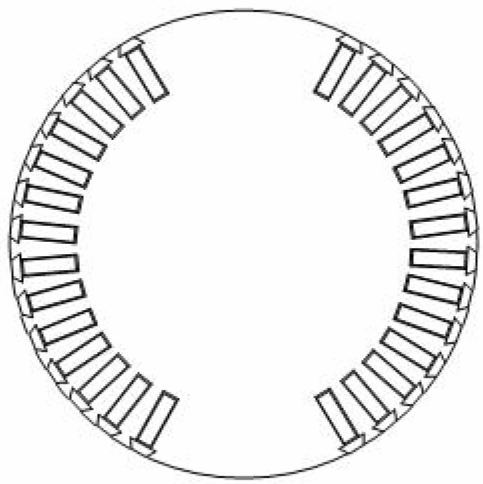


Figure 1-1
Cross Section of a Typical 3600 or 3000 rpm NonSalient Pole Rotor, Showing Winding Slots and Wedges

Voltage Regulators

The voltage regulators control the current supplied to the generator field. The control of the field current may be indirect, such as by controlling the field current to an exciter. The rotating exciter uses mechanical energy to produce a larger generator field current that is proportional to the exciter's own field current. In a direct approach, the regulator controls the actual generator field current; such as in the case of using the secondary current from an excitation transformer to directly supply the generator field current.

The design of regulators has changed significantly over the years, and many variations are in use. An old design was basically a rheostat, which still may be used as a manual control in older systems. Most regulators are much more sophisticated, commonly employing electronic circuits. Newer digital regulator designs use computer software to control the regulation. Nearly all regulators provide automatic control of generator excitation, using feedback from the generator or exciter to control generator field current.

Commonly, two voltage regulators are used in power plants: a manual or DC regulator, and an automatic or AC regulator. The manual regulator maintains a specific current to the generator field and is primarily used during start up, before the generator is connected to the power system. The automatic regulator controls excitation current to maintain a specific generator output, and is normally the primary regulator used doing operation. The manual regulator also serves as a back up to the automatic regulator in case of malfunction or failure of the automatic regulator.

Other Components of the Excitation System

Other components, not necessarily used in all excitation systems, are rotating exciters, collectors, excitation transformers, pilot exciters, exciter drive motors, and diode and SCR bridges. Rotating exciters are either AC alternators or DC generators that provide a field current to the generator. Collectors are a set of rings and brushes that provide a means to apply current to a generator's rotating field. Pilot exciters are basically smaller alternators or generators that supply excitation current to main exciters. They may be driven by the main exciter's shaft, or by a separate motor or turbine. Also, there are static pilot exciters that are transformers and rectifiers that use station auxiliary power to supply the main exciters field current. Diode and SCR bridges convert AC current from an alternator or excitation transformer to DC for the generator field. SCR bridges provide control of the current, while uncontrolled diode bridges only provide conversion. The bridges can also be used to provide and control field current to rotating exciters.

Chapter 2 discusses the different configurations of excitation systems commonly in use. The description and function of the excitation system and the components used are covered in greater detail in that chapter.

2
EXCITATION SYSTEMS

Exciters

The fundamental purpose of the excitation is fairly straightforward; supply a magnetic field to the main generator's rotor to produce the generator output voltage. The basic principal is $V=\omega kB$, where V is the output voltage, ω the rotational rotor speed, k a constant based upon generator design, and B the magnetic field strength. In some applications, permanent magnets built into the generator rotor are sufficient to meet the requirements.

Many small generators used as backup power sources for home and farms rely on such a design. However, power generation plants require a more sophisticated excitation system to maintain generator output within limits, maintain power supply (grid) stability, and to protect the generator and related equipment. One draw back is that the magnetic field is steady. There is no compensation for winding losses as the generator's load current increases. $V = V_{no\ load} - IZ$, where $V_{no\ load}$ is the voltage at zero current, I is the load current, and Z the winding impedance. A further decrease in generator output voltage is caused by rotor field reaction to the stator's magnetic field. As the stator's current increases, it generates a strong magnetic field that tends to decrease the rotor field, thereby causing a reduction in output voltage. Several designs of small generators incorporate a current transformer on the generator output, which through a rectifier bridge provides a boost to the permanent magnetic field, thus compensating somewhat for winding losses and field reaction.

Permanent magnets, though adequate for small generators, are woefully inadequate for large commercial units. The size and speeds of rotors in commercial units would complicate the installation of permanent magnets in a manner that could diminish the structural integrity of the rotor. The magnet's field strength may change, even slightly, thus producing a different output. There would be no means available to rapidly de-energize the generator, and remove the field to clear a fault. Changes in the generator output needed to respond to grid demands and maintain stability are not possible with a permanent magnetic field. A means to provide the magnetic field is needed that will allow for adjustment and removal. This is provided by electro-magnets on all commercial generators. In large commercial plants, only pilot exciters use permanent magnets (referred to as permanent magnet generators or PMGs) and only with certain excitation systems.

Many modern commercial generator rotors are of a solid forging with slots cut into the rotor for field windings. The windings are installed in the rotor slots and held in place with wedges. Retaining rings are placed over the winding end turns to secure the end turns. An exception to solid rotor design is low speed generator rotors that are often salient pole designs, incorporating multi-part construction.

To increase the amount of current that the field winding can handle without overheating, a winding cooling system is employed. Typically channels in the winding provide a path for a cooling medium, usually hydrogen.

A DC current is applied to the winding to create the rotor's magnetic field. Various schemes of excitation equipment have been developed to provide a regulated current to the rotor field. Each of these schemes has mechanisms that not only provide the field current, but also maintains the current within specified limits and control the generator output to maintain system stability and protect equipment.

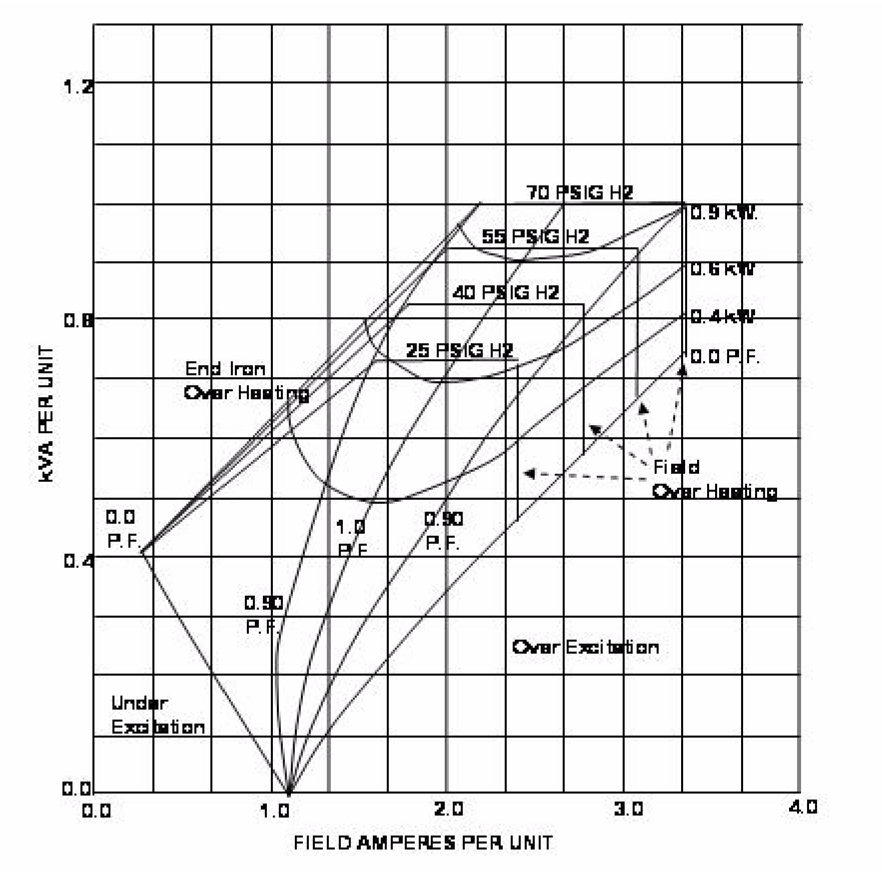


Figure 2-1
Sample Generator Vee Curve

A generator Vee curve (load curve) shows a number of the limits in operating a generator. The Vee curve is supplied by the generator manufacturer and is developed from equations related to the design of the generator. The derivation of the curve is outside the scope of this guide. However, an understanding of the curve is necessary to discern operational limits of the generator and the limits of the excitation system.

The Vee curves will vary from generator to generator depending on design, cooling method employed, and numerous other factors. The Vee curve for one machine cannot be used to determine the limits and capabilities of another machine.

The Vee curve represents generator field current kVA and power factor at rated frequency and voltage. Also represented is the effect of degraded cooling on the generator. As cooling gas pressure is decreased, generator operation is more limited as shown on the Vee curve. For a generator having other than hydrogen cooling, the lines would reflect the relevant cooling parameter, such as ambient air temperature.

Limitations on the generator can be seen on the curve. The maximum field current is shown as the vertical lines on the right side of the figure, extending from the 0.0 leading power factor line to the horizontal rated power line. Several maximum field currents and corresponding rated power lines are shown. Each set represents the limits at different cooling capabilities. The sloping line on the left side of the curve represents the limit to under-excitation due to stator end iron heating. Several lines are shown, each representing the limit at different cooling system capabilities.

The reactive capability curve represents the real and reactive power capability of the generator at rated voltage and frequency. This curve is also supplied by the generator's manufacturer, but can be derived from the Vee curve if necessary. The top region of the curve represents over-excitation of the generator and the limit due to field winding heating. The right side of curve is the limit due to stator winding heating. The bottom of the curve represents under-excitation of the generator and the limit due to stator end iron heating. Several curves are shown, each representing operation with different cooling system capability. The dashed line at the bottom of the curve represents the minimum under-excitation stability limit of the generator. The generator must always operate above both the end iron heating limit and the stability limit.

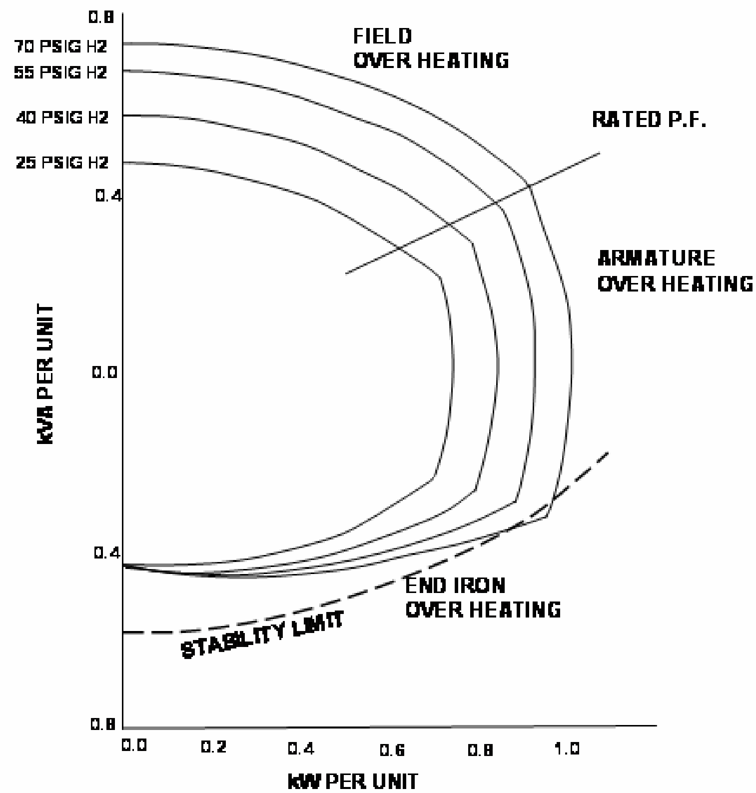


Figure 2-2
Sample Generator Reactive Capability Curve

To automatically ensure that the generator is operated within the limits of the Vee and reactive capability curves, modern excitation systems incorporate limiters. These limiters prevent field current levels that will cause operation outside of boundaries of the Vee curve. These limiters may be electro-mechanical, analog electronic, or digital electronic devices. In newer systems, the limiter may be a software component of the voltage regulator programming code. The limiters are often backed up with protection devices that will place the generator into manual regulation or trip the generator if the limiters fail.

Components

Excitation systems commonly in use today can be described by one of the following:

Table 2-1
Excitation Systems

IEEE 421.1 Category	IEEE 421.1 Type	Exciter Description
dc	dc generator commutator	Motor-Generator Set
	dc generator commutator	Shaft Driven Generator
ac	alternator-stationary noncontrolled rectifier	Alternator – stator armature
	alternator-stationary controlled rectifier	Alternator – stator armature
	alternator-rotating noncontrolled rectifier (brushless)	Alternator – rotor armature
st	potential source controlled rectifier	Excitation Transformer
	potential source controlled rectifier	Generator Auxiliary Windings
	compound source noncontrolled rectifier	Generator Auxiliary Windings and Power CTs on Generator Output
	compound source noncontrolled rectifier	Power PTs and CTs on Generator Output
	compound source controlled rectifier	Power PTs and CTs on Generator Output

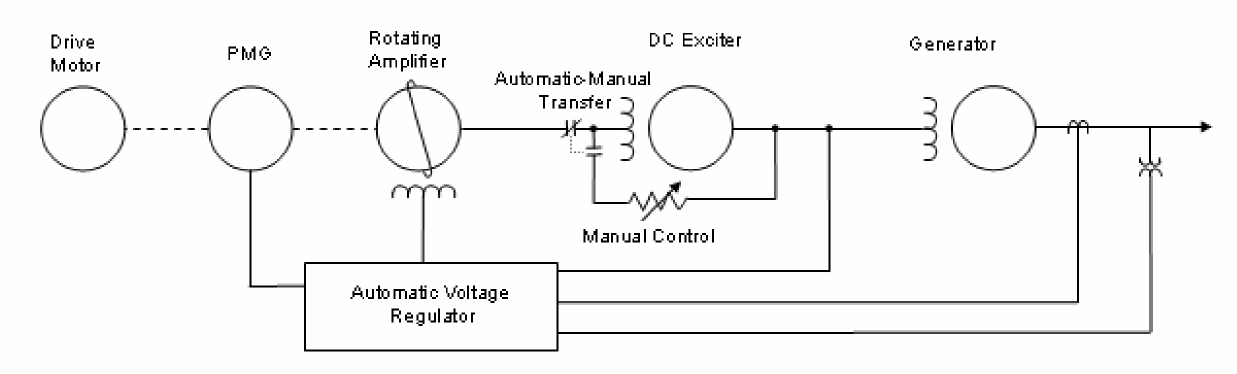


Figure 2-3
Category dc, DC Exciter with Rotating Amplifier

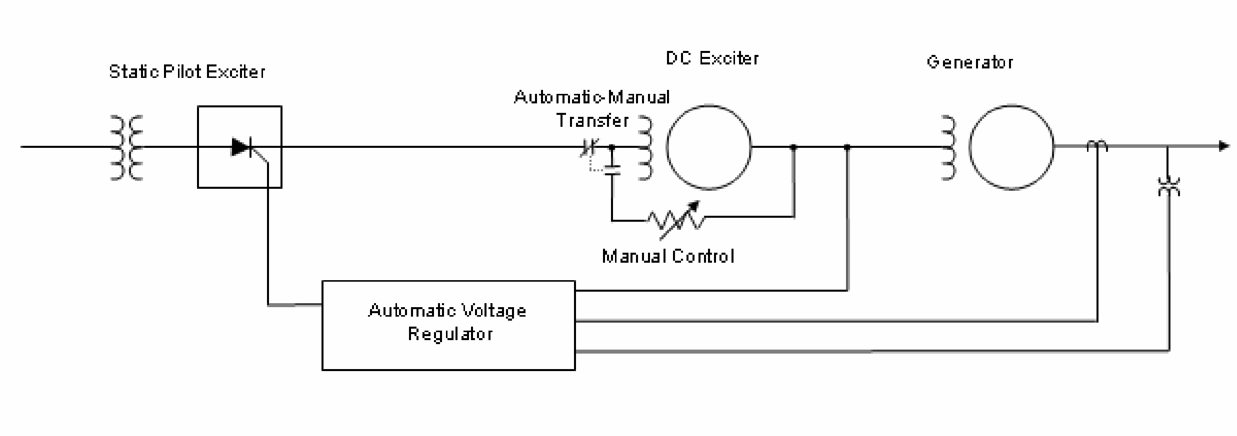


Figure 2-4
Category dc, DC Exciter with Static Pilot Exciter (SPE) or Static Amplifier

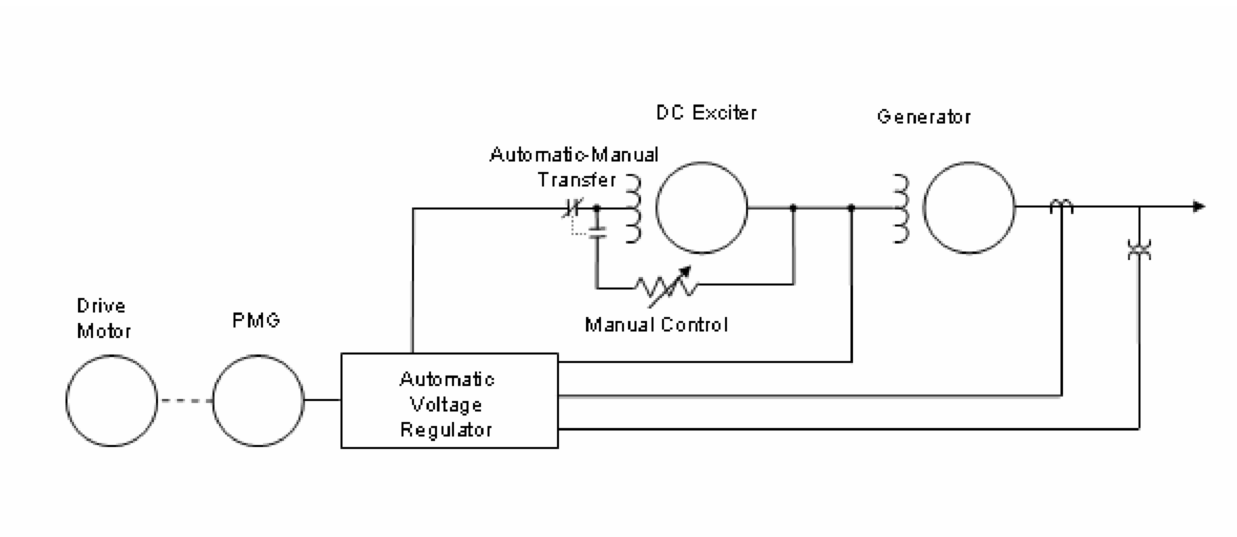


Figure 2-5
Category dc, DC Exciter with Continuously Acting Regulator and Rotating Pilot Exciter

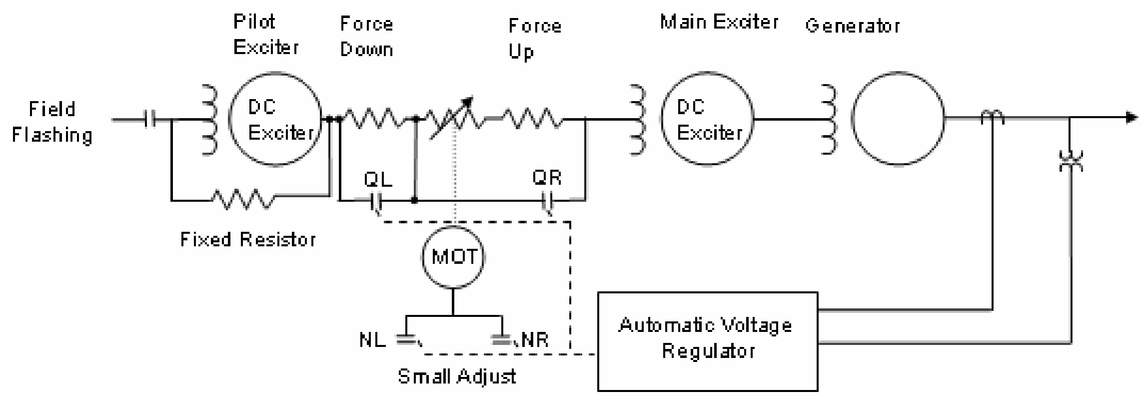


Figure 2-6
Category dc, DC Exciter with Non-continuously Acting Rheostatic Regulator

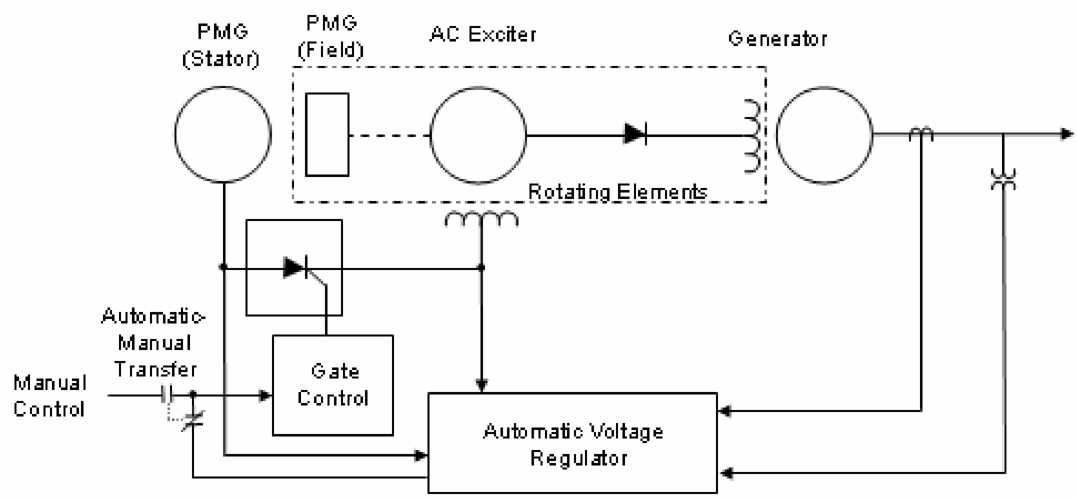


Figure 2-7
Category ac, Brushless Alternator with rotating Noncontrolled Rectifiers

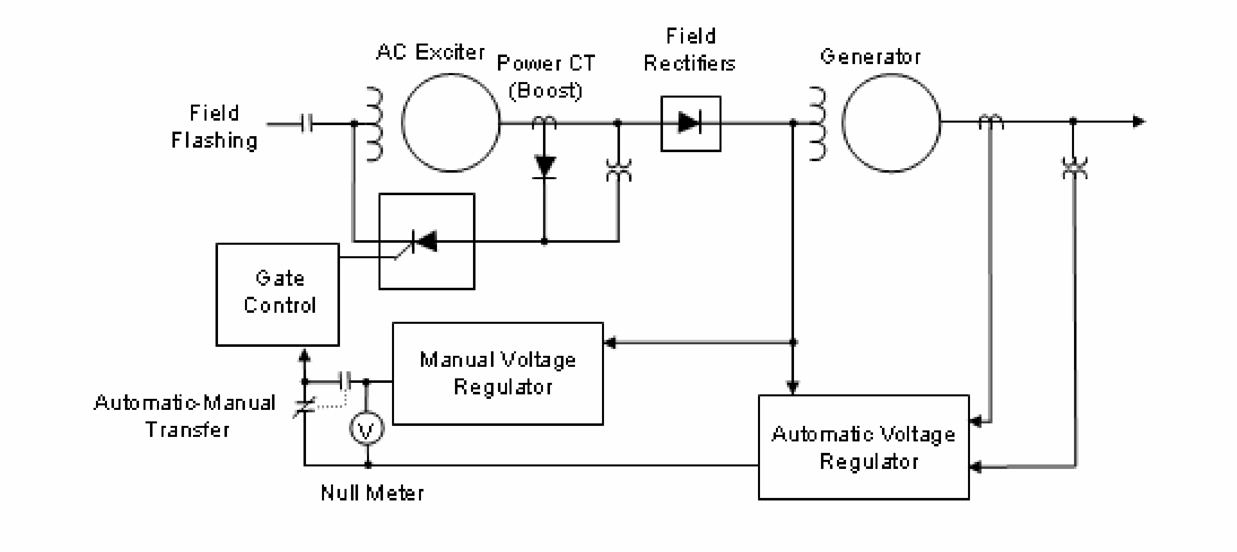


Figure 2-8
Category ac, Alternator with Stationary Noncontrolled Rectifiers

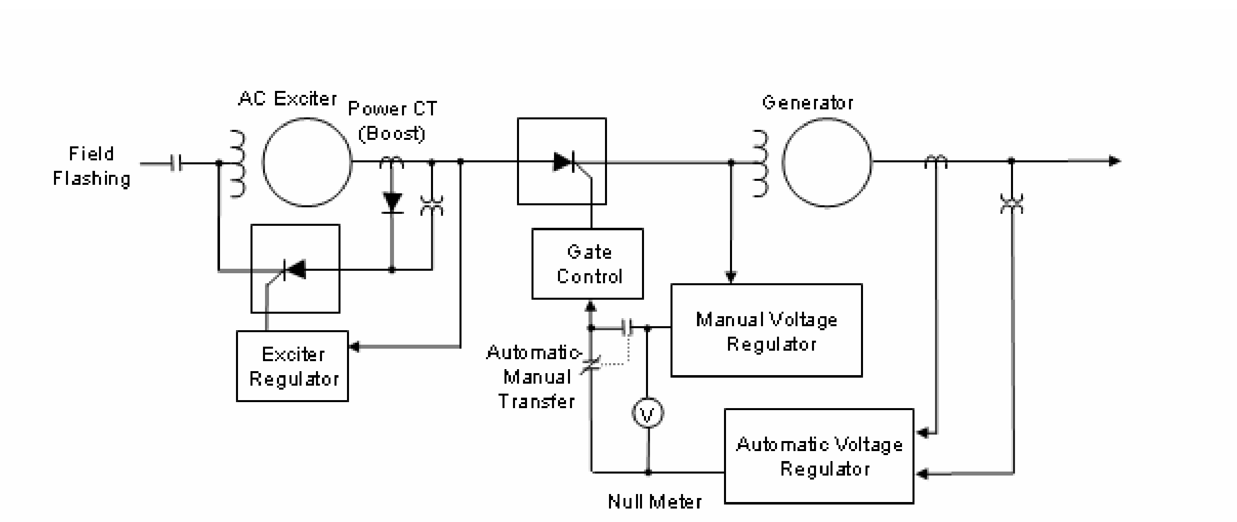


Figure 2-9
Category ac, Alternator with Controlled Rectifiers

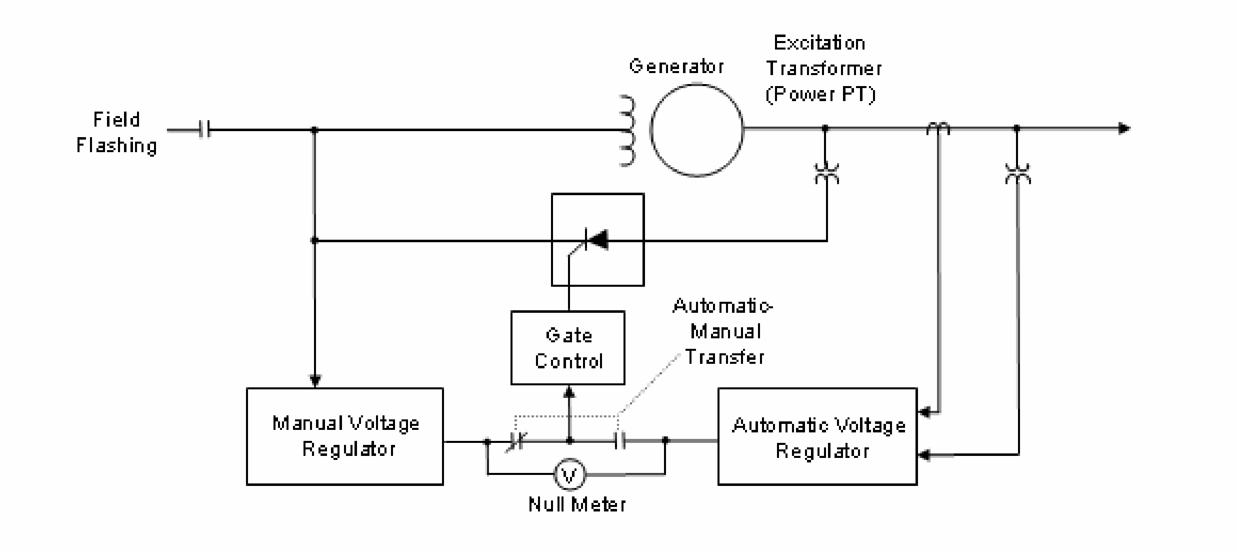


Figure 2-10
Category st, Potential Source with Controlled Rectifiers

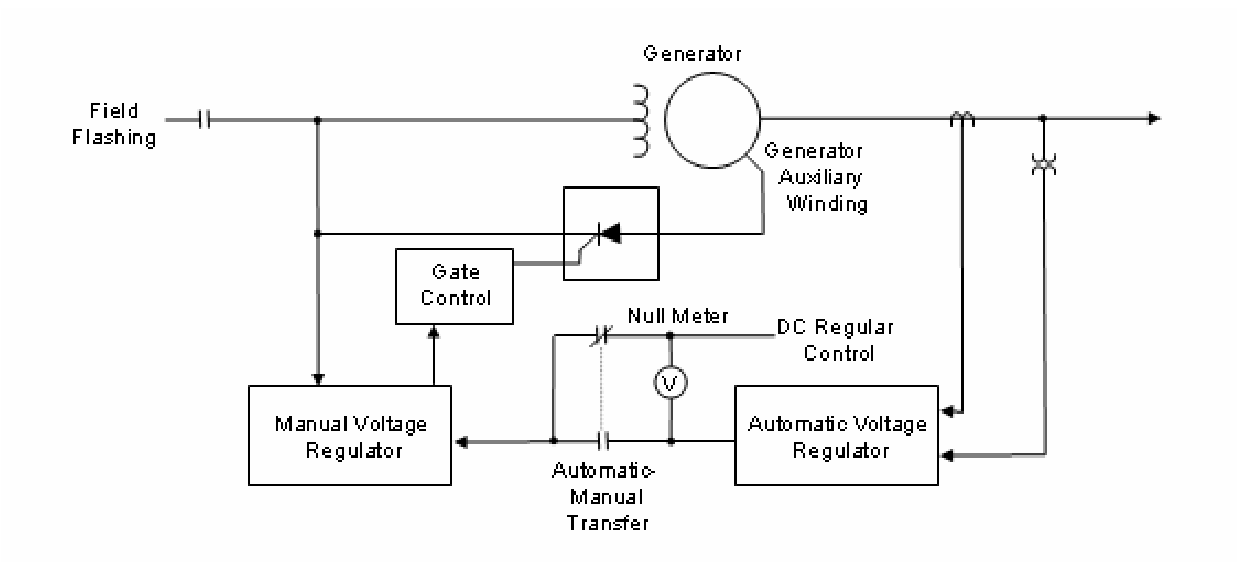


Figure 2-11
Category st, Potential Source with Controlled Rectifiers and Generator Auxiliary Windings

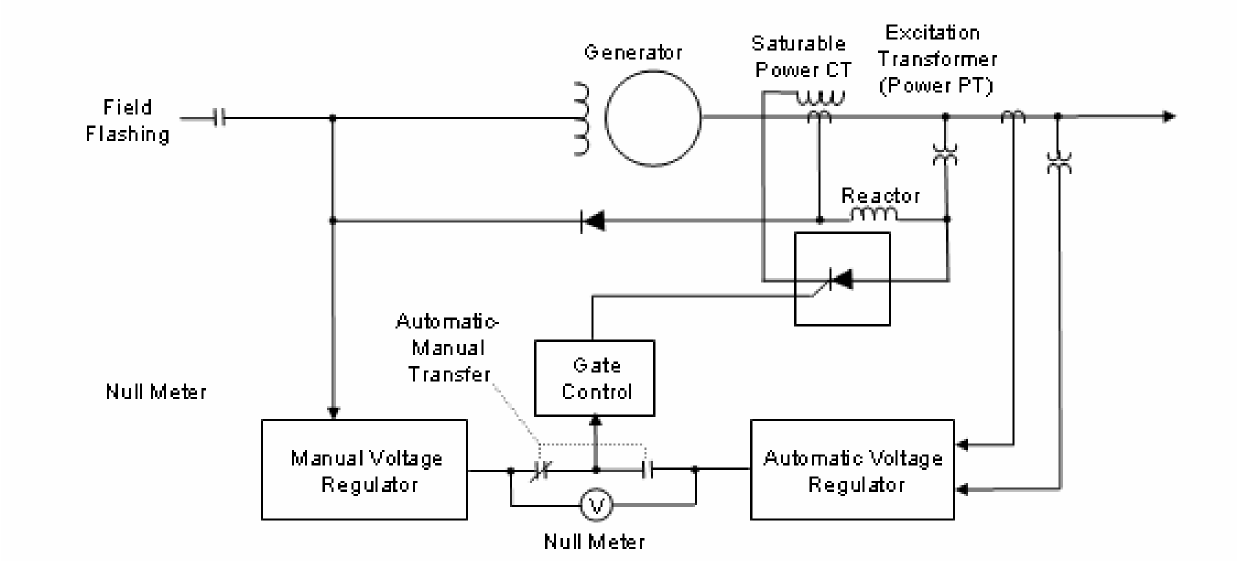


Figure 2-12
Category st, Compound Source with Noncontrolled Rectifiers

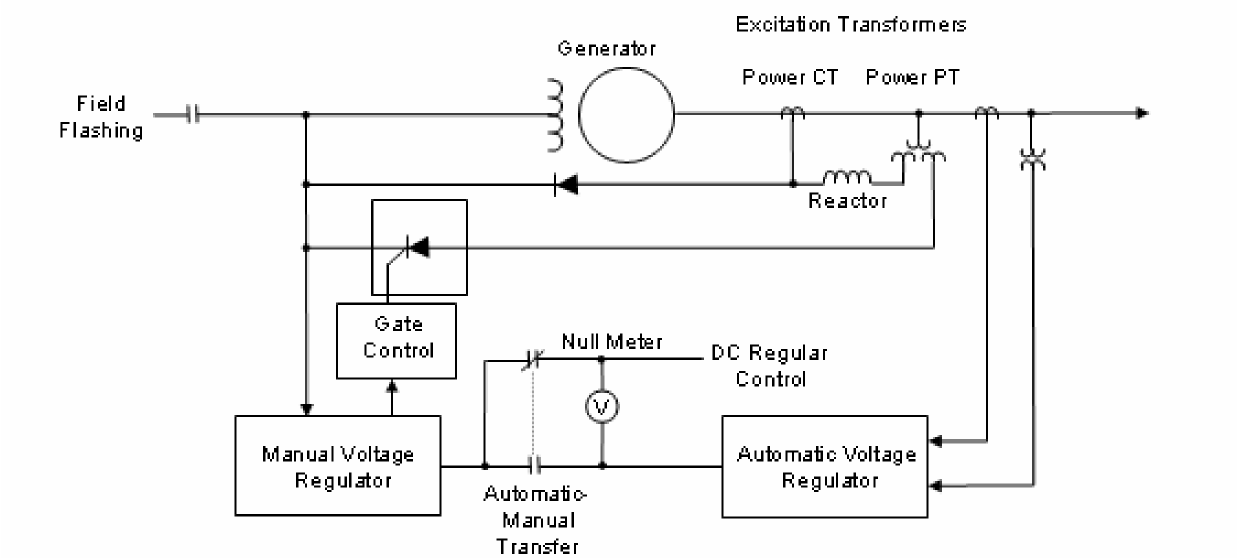


Figure 2-13
Category st, Compound Source with Controlled Rectifiers

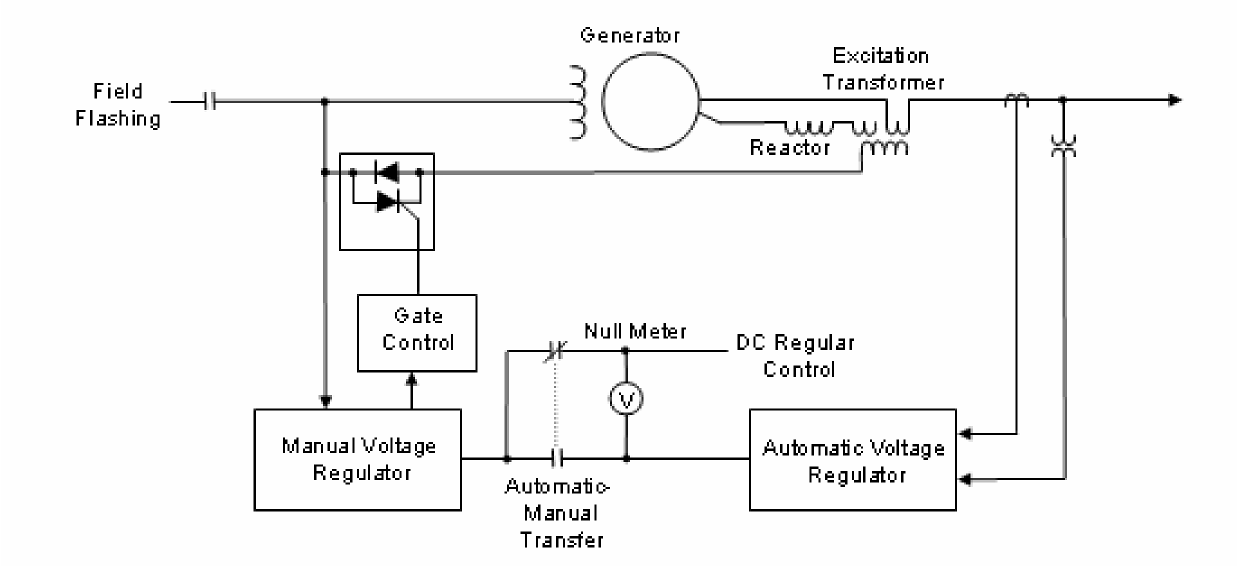


Figure 2-14
Category st, Compound Source with Shunt Controlled Rectifiers

Power Supply

As shown in the previous section, excitation systems can have a variety of power sources. While the power for control, and possibly field flashing, for most all excitation systems is derived from station AC and/or DC buses, the main source of power for supplying the field current depends on the type of excitation system. Obviously, for shaft driven DC generator and AC alternator the exciter takes mechanical power from the turbine-generator shaft to produce electric power. Motor-generator sets take power from a station auxiliary bus to drive the DC generator. Static exciters either take power directly from the generator output or from auxiliary winding in the generator. In rare cases a station's auxiliary busses may supply the power for excitation.

Field Flashing Circuits

Rotating exciters require a means to initiate the field in the exciter. Typically voltage from a station DC bus is momentarily applied to the exciter's field, flashing the field. Flashing the field creates voltage in the exciter's armature, which then is fed back through the excitation circuitry to provide field current.

Permanent Magnet Generators

An alternative to field flashing is the use of a permanent magnet generator (PMG) to supply field current to the exciter. Many brushless exciters use a PMG mounted at the end of the exciter shaft. Some DC exciter systems also employ a PMG using a commutator to rectify the current. The DC system PMGs are either shaft driven or motor driven. PMGs use permanent magnets to provide the field to generate a voltage in the armature. With brushless alternator systems, the PMG's output is converted to DC through a controlled rectifier and fed to a stationary field winding on the exciter alternator. Typically several permanent magnet poles are used in the PMG and provide a high frequency multi-phase output for cleaner rectification.

Pilot Exciters

Not uncommon on older excitation systems was the use of a small pilot exciter that fed field current to the main exciter. The pilot exciter was typically powered by an AC motor fed from a station auxiliary bus; or in the case of a hydro plant, water powered. The pilot exciter would require a field flashing circuit to initiate its own field or be permanently fed from a station DC bus. In either case, lower current would be required for the small pilot exciter, as opposed to flashing the field of the main exciter.

Static Pilot Exciters (SPE)

The static pilot exciter (SPE) takes a small feed from the station auxiliary buses and supplies a DC field current to the main exciter, either a DC generator or an AC alternator. A number of older units that had rotating pilot exciters have replaced the pilot exciter with SPE. Obsolescence and maintenance are two main reasons for replacing the pilot exciters.

Rotating Amplifiers

The rotating amplifier (Amplidynes™) is a special class of DC generator. It provides an extremely large DC output power that is controlled by a small DC input signal. Much like the pilot exciter, the rotating amplifier provides field current to the main exciter. The advantage of the rotating amplifier is that a small control signal can directly regulate the output current. Motive power for the rotating amplifier is provided either by an AC motor or from the shaft of the main exciter. Rotating amplifiers were common on older DC generator excitation systems.

Rectification

The field current, regardless of the source, has to be converted from AC current to DC current. In DC generator excitation systems, the commutator carries out this conversion. With static and alternator systems a rectifier is used. The rectifier may be an SCR controlled rectifier bridge or an uncontrolled diode rectifier. Even DC generator excitation systems have been retrofitted with bridge rectifiers to supply and control the exciter's field current.

SCR rectifiers provide control of the field current by varying the firing angle of the gate signal. The diode bridges do not control the voltage; just rectify the field voltage. Varying the field of the exciter or pilot exciter provides voltage control. Static excitation systems, by necessity, use SCR bridges to directly control the main generator field current.

Diodes and SCRs in the rectifiers are usually protected from faults by fusing. Blown fuse indication is often provided by indicating lights in the bridge circuitry or by the use of indicating fuses. Redundancy is typically built into the rectifiers so that failure of one branch or portion will not cause a loss of generation. Brushed alternator and static excitation systems normally have redundant banks of rectifiers that allow switching out of a failed bank, and replacement of the blown fuse or failed diode. Brushless systems do not provide for on-line replacement of diodes or diode fuses, but sufficient redundancy is provided to allow the unit to remain in service until maintenance can be conveniently performed. The brushless systems do allow visual inspection of diode fuses through viewing ports; a strobe light is used to visually freeze the fuses for inspection. If blown fuses are discovered, a determination can be made on how long to continue to run and to make more frequent visual inspections.

Enclosures

Exciter housings are as varied as the different types and makes of excitation systems. They are to protect the exciter components, maintain a clean environment, and provide personnel protection. The housing can simply be a shell around the exciter with ports and removable sections for inspection and maintenance. Another housing can be a large walk-in structure housing not only the exciter, but the brushes and rings, excitation system bus work, monitors, and sensors as well. Regardless of the size and form of the housing, it is important to maintain the integrity of the housing. This ensures proper air flow through the housing, prevents foreign material intrusion, including dust and other airborne contaminants, and protects personnel from exposure to rotating and energized components.

Bus Work and Insulators

Exciters have several different voltage systems incorporated within themselves. With rotating alternators there is the AC output of the alternator, the rectified alternator output or generator field voltage, and the alternator’s own field voltage. DC generators have their own field voltage and the main generator field voltage. Static exciters have transformer secondary voltage and the main generator field voltage. Commonly, an arrangement of bus work is employed at least in part to conduct the voltage between components. A typical alternator bus arrangement will have the alternator AC output connected to a three phase bus that runs across the top of the exciter enclosure to the rectifier banks. From the rectifier banks a DC bus carries the power to the brush rigging. Newer machines are not likely to have exposed bus work in areas that personnel can easily access during operation. While this may make inspection of the bus work impossible, it provides increased personnel safety and helps prevent dust build up on the bus.

The bus work should be routinely inspected for dust build up during outages, and during operation if visually accessible. Of particular concern are the bus standoffs and other insulators across which dust may create a conductive path. Extreme care must be exercised, and strictly enforced, by qualified personnel during inspections. Electrical shock, burns, and nearby rotating equipment are hazards in the exciter enclosure. Dust build up may come from brush wear or atmospheric dust if the exciter cooling air is not properly filtered. Brush carbon dust is more of a problem due to the conductive nature of the dust. A routine inspection schedule can be determined by the findings of previous inspections. Unless there is extreme brush wear, or air filters are not employed in a dusty environment, the rate of dust build up should not create a problem in a typical one to two year period between generator outages. However, the operator making daily or weekly rounds as a good practice can do a brief inspection of the bus work and the rest of the enclosure at the same time that brush length is checked. This not only identifies dust build up, but also other possible problems or deficiencies in the exciter enclosure.

Ventilation and Cooling

Several subsystems of the excitation system typically require cooling. In the enclosure these may include rings, brushes, and rectifier banks. Brushes and rings normally use air for cooling. The rectifiers may be cooled with de-ionized stator cooling water instead of air.

Non-conductive Telfon tubing supplies the de-ionized cooling water to the rectifier heat sinks and carries it away. The tubing may need to be replaced every few years as conductive deposits may build up inside the tubing and provide a ground to the rectifiers. The tubing should be cleaned during generator outage to maintain a nonconductive exterior.

Brushes and collector rings in the enclosure commonly have a shaft mounted fan that draws air through the brushes for cooling. Filters in the enclosure air vents provide clean air for cooling. The filters should be checked frequently to ensure that they are not becoming clogged. A periodic inspection should be made at least once a week or more frequently in dusty environments.

Cleanliness

The cleanliness of the enclosure can often be overlooked. Dust, dirt, and other substances can build up slowly and unnoticeably until a failure occurs. The dust may be conductive, or may attract moisture and form a conductive path causing a fault. Of particular concern in all but brushless exciters, is carbon dust from the brushes. The carbon dust develops from brush wear and may settle on the brush rigging, across bus bar standoffs, and on other surfaces where the conductive dust could cause a ground or a short. Normal brush wear over the course of an operating cycle will not usually create sufficient dust to cause problems.

On some systems the brush cooling airflow carries most of the carbon dust away from the enclosure. Keeping the enclosure’s entrances and ports closed, and ensuring that the air filters are in place and clean, greatly reduces external dust from collecting in the enclosure. Routine visual inspections conducted in conjunction with brush inspection or diode fuse inspections will help ensure that a lack of cleanliness is not developing. Routine cleaning during scheduled outages will in most cases prevent dust and dirt buildups on surfaces.

Foreign material exclusion (FME) programs are important, especially in closed systems such as brushless exciters. This will aid in preventing debris and other loose material from causing shorts and other damage.

Personnel Hazards

Enclosures contain energized electrical components and rotating equipment. Serious and fatal injuries and burns are potential hazards. Qualified and thoroughly trained individuals should be the only personnel allowed to work on or enter enclosures. Thorough training has to include the potential hazards, as well as the location and identification of the components in the enclosure, and applicable safety precautions must be taken. All entrances and ports into the enclosure must be marked to indicate the potential hazards that exist.

Failure Incidence

A unit was at 100 percent power when a generator lockout and reactor scram occurred resulting from a loss of generator excitation. Excessive heat and humidity, combined with cold lake cooling water, resulted in a significant amount of condensation build up inside the exciter housing. Moisture came in contact with electrical components in the enclosure, resulting in electrical shorts and exciter failure. A contributing factor was the decrease in exciter house temperature from 45 degrees C to 21 degrees C, which had recently been lowered in order to extend the life of components.

Electrical Shock Incidences

An operator entered the enclosure to replace an oil drip absorbent pad located on the floor beneath the exciter inboard bearing. When the operator reached to remove the pad, his shoulder contacted the end plate of the brush rigging. This end plate is energized with 200-250 DC.

A maintenance electrician was in the process of inspecting the main generator exciter enclosure. During the inspection, the electrician began cleaning up an oil spill near the exciter brush rigging support. While wiping up the oil, the electrician's thumb came in contact with the rigging support and he received an electrical shock.

A plant was shutdown and the turbine generator on turning gear, when two machinists entered the generator alternator housing to view the location where run out checks of the generator rings were to be performed. A work group supervisor and an electrician were escorting the machinists. Without warning, one of the machinists reached out and touched the area where he would be mounting a mechanical indicator. As he touched the component, he felt a slight electrical shock in his forearm.

Although the generator field is technically an ungrounded circuit, each of these incidences show that a shock potential can, and usually does, exist on the circuit. A potential from the field to ground can be caused by the ground detector circuit during normal operation. Furthermore, harmonics from a rectifier bridge can add an AC component to the DC field voltage. This AC component may be grounded by capacitance between the field winding and the rotor iron. Thus, with the inductance of the winding and the capacitive ground reference, an AC potential to ground may exist at the slip rings.

Bearings

Exciter bearings, like many motor and generator bearings, are insulated to prevent a damaging current flow from induced shaft voltage. Typically a grounding brush is applied to the turbine generator shaft to prevent the induced shaft voltage being too high. A common practice, in order to allow testing of bearing insulation, is to have an isolated annulus of metal sandwiched between two layers of insulation. The insulation integrity of the bearing can be verified by an insulation resistance test from the isolated annulus to ground. A low resistance measurement indicates one or both layers of insulation are failing or have failed.

Care must be exercised not to create a short across the bearing insulation. Bearing damage resulting from a shaft current arcing between the bearing journey and sleeve will result. Failures of bearings have occurred from temporary test jumpers, incorrectly installed or designed bearing thermocouples, and tools and material against bearing pedestals. Bearing pedestals with insulation in the base are particularly vulnerable to unintentional ground paths due to their exposure. The insulating bolt sleeves and washers need to be checked for signs of damage and cleanliness when re-assembling bearings.

Vibration

Vibration sensing and monitoring is almost always taken at the bearings. Because the shaft rides in the bearings, vibration from the rotor and shaft are often transmitted through the bearing and can readily be sensed.

Vibration in rotating equipment can be caused or aggravated by a number of different conditions. Pertaining to rotating excitation equipment, vibration can be caused by: unbalance, misalignment, torque variations, unbalanced magnetic fields, loose components, component rubbing, and or resonance. Older units having reduction gears can have vibration caused by damaged or defective gears. Other more subtle causes, such as vibration in nearby equipment exciting a resonance, can create vibration abnormalities.

Vibration is typically described by one or more of its characteristics. These are: displacement, velocity, acceleration, frequency, phase, and spike energy. Frequency of vibration is typically specified in cycles per minute (CPM) as this readily correlates to the rpm speed of the equipment. CPM is related to hertz by 60 cpm = 1 Hz. Vibration will consist of various frequencies across a wide spectrum; the exact frequencies that are prominent will be determined by cause of the vibration. For example, misalignment will have vibration at running rpm and the first and possibly the second harmonics, while unbalance is typically just at running rpm.

Phase is the angular displacement of the vibration to a specific angular point on the rotor, or to the phase of another measured vibration. For example, phase is necessary to properly balance a rotor. The phase of the vibration in relationship to a specific point on the rotor shows the angular location of unbalance to be corrected. Phase is also used in diagnosing and analyzing other vibration problems where the location of the vibration and its relationship to other vibration is important.

Displacement, velocity, and acceleration measurements are the maximum values of the vibration characteristics the machine undergoes. Displacement is typically measured in mils or micrometers, velocity in inches or millimeters per seconds, and accelerator in g's (32 ft or 9.8 m per second squared). Velocity is the preferred characteristic for measuring in the speed range of most excitation equipment. Displacement is more applicable for lower speeds and acceleration for higher speeds. However, displacement is frequently used with installed vibration monitors on many generators and exciters. Displacement will provide sufficient monitoring capability at generator speeds of 1800 and 3600 rpm. In hydro-generators velocity might not be as effective at the lower speed as displacement for indicating vibration.

Spike energy readings are typically taken on equipment with antifriction bearing, sensing the impact of the balls against the race. Like most other condition monitoring techniques the results are compared and trended over time, though obviously bad readings can immediately identify a defective bearing.

Vibration is normally automatically monitored continuously during operation. Probes are installed at the bearings. Care must be exercised when designing and installing vibration probes to ensure that the insulation integrity of the bearing is not compromised. For direct driven exciters, the vibration monitors are usually part of the turbine-generator vibration system. The vibration monitoring system provides alarm on high vibration and should trip the unit if vibration becomes too severe. Turbine-generators typically have one or two resonant frequencies below their running speeds. As generators are brought up to speed, the vibration trips are typically bypassed as the generator is accelerated through the resonant frequencies.

Instrumentation

Bearing mounted temperature probes, thermocouples or possibly RTDs, continuously monitor bearing temperatures. As with the vibration probes, care must be exercised when designing and installing temperature elements to ensure that the insulation integrity of the bearing is not compromised. The temperature monitors typically provide indication and alarm on high temperature, but do not directly trip the unit.

Both bearing temperature and vibration monitors provide only gross measurement of their respective attributes. Though some trends can be identified solely by the monitors, early identification of incipient and progressing component degradation is often best captured by periodic vibration analysis and thermo imaging inspections.

Lubrication

With most excitation systems, the exciter bearing lubrication is part of the turbine-generator lubrication system. Bearings may have sight glasses to visually check proper oil flow in the bearing. Additionally, inadequate lubrication will cause temperature and vibration indications to rise. However, when the indications are noticeable, some damage may have already occurred.

Ensuring a clean properly operating lubrication system and the correct lubricant are perhaps the best means to prevent lubrication related bearing failure. Periodic testing and analysis of the lubricant will identify deterioration of the lubricant and possible bearing degradation. However, the size of the system and number of bearings lubricated will hinder identification of a single bearing as having trouble.

Small and separate rotating components of excitation systems may have a lubrication system apart from the main turbine system. Also they may incorporate bearings that are individually lubricated with oil or grease. Periodic analysis of these lubricants can identify lubricant and bearing degradation.

New lubricant products, such as synthetics, have been developed to improve both the life and the performance of the lubricants. Maintenance to change lubricants on a periodic basis can often be decreased, and therefore reliability of the bearings increases by using the newer lubricants. However, it is important to obtain concurrence of the equipment and the lubricant manufacturers prior to replacing the old recommended lubricant. The capability of the newer lubricant with seals, gaskets, and other components, as well as the bearing, has to be addressed. Components not part of the lubrication system, should be checked to ensure that the oil vapor will not adversely affect them. For example insulation on motor windings may be attacked by certain esters in some synthetic oils.

Oil seals and deflectors maintain the integrity of the lubrication system. The seals typically have a close tolerance fit around the shaft. The portion closest to shaft is made of a softer metal than the shaft to prevent scoring the shaft in the event of a rub. Since a very close fit to the shaft is required to prevent oil leakage, excessive vibration, thermal expansion, and improper installation can easily destroy the seal. The seal may be also be damaged by shaft current if the bearing insulation is compromised.

Bearing Failure Incidences

A turbine tripped when the vibration instrument on an exciter bearing failed, causing a false high vibration trip signal to be generated. The vibration instrument on the bearing, the main generator exciter outboard bearing, failed when a solder connection inside the shaft rider probe came apart. This created a loose wire that made intermittent contact with a coil within the probe. The loose wire contacted the coil such that a false high vibration signal was generated.

With a unit operating at 88 percent power, vibration levels on the main turbine-generator alternator exciter bearings increased. Operator actions in correcting the vibrations were unsuccessful and the unit was manually tripped. The high vibrations occurred when oil deflectors for the vibration probe assemblies, installed at each exciter bearing, rubbed the rotor shaft. The oil deflectors were determined to have an insufficient bore to maintain clearance with the rotating shaft to prevent rubbing. The root cause of this event was that the vendor did not use the correct drawing and manufactured the deflectors with the wrong inner diameter.

A unit was operating at 50 percent power steady state when the generator tripped. Failure of the main generator exciter bearing caused the armature of the Permanent Magnet Generator (PMG) to grind into its stator. When this occurred, the PMG discontinued supplying voltage to the exciter of the main generator. The cause of the event was not performing a weekly generator exciter ground check in which a prolonged ground resulted in the failure of the generator exciter bearing.

Couplings

Couplings not only serve to transmit the torque, but absorb torsional vibration, shaft expansion, and provide a ready means for mechanical disconnection. Flexible coupling allow for some misalignment, however it is not recommended to allow misalignment to go uncorrected. Even with a flexible coupling, misalignment can impose axial and radial loads on the shafts, seals, and bearings that may lead to accelerated wear and early failure.

Couplings require a very minimal amount of maintenance, periodic inspection, cleaning, and replacement of lubricant. Typically these tasks are performed during maintenance when the exciter is mechanically disconnected from the generator (or drive motor). It is during this maintenance that couplings have been damaged due either to improper handling, misalignment, or reassembly.

Coupling Damage Incidence

During a unit outage, the coupling between the main generator and the exciter was dropped while being rigged. The coupling weighs 350 to 500 pounds and was dropped approximately five feet. No injuries occurred as a result of the event. However, the coupling sustained some damage.

Heat Exchanger Filters

Exciter alternators and generators are typically air cooled. Water may be used to cool the air circulating in the exciter. Additionally, air is circulated over the brushes to cool the brushes and rings or commutators. Heat exchanger efficiency can be decreased by deposits of dust and dirt. To keep dust, dirt, soot, and other small particles out of the heat exchanger, and also from contaminating the exciters and brushes, the cooling air is usually filtered. Checking, cleaning, and replacing filters is a periodic task that is required to maintain heat exchanger efficiency and system reliability.

Monitors

Temperature, current, and voltage are important parameters that require monitoring to ensure that the exciter is functioning properly and to warn of developing problems. Bearings typically have thermocouples to monitor bearing temperatures. Alternator stator windings will have embedded thermocouples or RTDs. Field winding voltage and current are monitored and combined to provide a measurement of winding resistance (from Ohm's law, R=E/I). The winding resistance is indicative of the winding temperature. Brushless excitation systems may utilize an optical link to relay temperature readings.

Cooling air temperature and exciter enclosure temperature may be monitored to ensure components have sufficient cooling. When used, cooling airflow monitors are typically differential pressure transmitters or switches. Monitoring airflow provides indication of clogged filters, deflective fans, or flow obstructions. Other than local indication, no signal is usually provided except possibly an alarm. An airflow monitor or alarm can provide advance notification that components could potentially overheat due to insufficient cooling. Though, not deemed necessary by many units, the advance notification can provide time to restore airflow by such means as cleaning or replacing filter elements.

Protective relays monitor current and voltage, and limit damage from potential overloads, faults and electrical stresses. Protective relaying associated with the excitation system often includes loss of field, overcurrent relay, differential current, ground detection, and exciter overvoltage relays. The loss of field to the main generator requires immediate disconnection of the generator from the power system and trip of the generator's prime mover. Ground detection is covered in a separate section. Overcurrents and differential currents result from overload and fault conditions, often requiring immediate de-energization of the exciter and the generator to prevent major damage.

Failed Monitor Incidence

A unit was at 76 percent power; the main generator tripped on a false detected loss of excitation field. The turbine trip signal was caused by the actuation of two protective relays that were installed incorrectly during the refueling outage. The wiring error resulted in actuation of the relays during the unit restart when a loss of excitation condition did not exist. These relays are designed to detect a loss of excitation, trip the main turbine and main generator output breakers, and isolate the generator from the switchyard system. The cause of the event was an error in the design change package. The design change package contained a wiring error and was not detected by subsequent reviews.

Voltage Regulators

A synchronous generator connected to the power system has its output varied in two ways. First the real power output of the generator is controlled by its prime mover: a steam turbine, gas turbine, hydro turbine, diesel engine, etc. To increase or decrease real power output, the prime mover's power has to change. The second way the output is varied is through the generator's field strength. Varying the generator field, while the generator is connected to the power system, varies the reactive power, VARs, which the generator either produces or consumes.

The voltage of a generator that is connected to the power system is determined by the system's voltage. The generator's output can vary the generator voltage, indirectly, by supplying or consuming VARs. The generator's field strength has limited direct effect on the generator terminal voltage. Of course, if a generator was not connected to the power system, the generator's field could be used to directly control terminal voltage.

Almost all large power plant generators have at least two modes of controlling the generator field. One means is commonly referred to as the manual regulator, or DC regulator. This regulator maintains a constant field on the generator. It typically senses generator field current and maintains the field current at a specific value. The value the manual regulator maintains is adjusted manually as needed through the regulator's controls. Older regulators utilized rheostats to adjust field current. Later models utilized a reference signal in their control circuitry, often adjusted by employing a motor driven potentiometer controlled remotely. The latest digital regulators may utilize a software variable in their programming that is set via an operator's terminal to provide a field set point.

The other means to control the generator's field is commonly called the automatic voltage regulator (AVR) or AC regulator. The AVR senses voltage at some point on the power system and controls the field current to maintain a constant voltage at that point. This point could be at the generator terminals, on the high side of the generator transformer, or at some remote location.

Other than at the generator terminals, the point sensed is often simulated; generator terminal voltage is actually sensed and then compensated for current flow through the generator step up transformer and transmission line impedance. Though varying the generator's field doesn't directly control the voltage, the AVR can control the voltage by varying the VAR output of the generator.

Like the manual regulator, the AVR uses a voltage setpoint provided by a reference signal. Depending on the AVR model, the reference signal may be a voltage, such as a voltage controlled by a motor operated potentiometer, or a software variable set by an operator's terminal. System operators or load dispatchers may have limited control of the reference set point from their computers, especially with newer digital regulators utilizing a software reference variable. The means by which a system operator uses to control VARs at a generating station is called Automatic Generation Control (AGC). The AGC is utilized to allow the system operator to maintain system stability by direct control of the VAR production.

Instead of sensing voltage, AVR may be configured to maintain a specific VAR output or power factor of the generator, regardless of the system voltage.

The manual regulator cannot be manipulated accurately or quickly enough to respond to system transients. Thus, the automatic regulator should always be used when the generator is connected to the power system. Most system operators and reliability councils recommend or require the use of the AVR over the manual regulator. Furthermore, the manual regulators do not have all the protective functions of AVRs to prevent generator damage from mis-operation.

Manual regulators are mainly utilized for generator startup prior to synchronizing to the power system, and as a backup to the AVR. The output of both regulators should be kept equal, though only one regulator is in service at a time. This provides for a bumpless transfer when it is necessary to switch regulators. Other than older DC type excitation systems, most excitation systems have a null meter between the control circuits of the manual and AVR regulator. The null meter is often across the outputs of each regulator. However, in systems in which the AVR output is an input to the manual regulator, the AVR output and manual reference signal are compared. The set point of the inactive regulator, the one not in service, is kept adjusted to maintain the null meter at zero and the regulator outputs equal. Newer regulators may have automatic controls that keep the steady state outputs of the regulators equal. The latest regulator may do away with the null meter entirely, and use software to display and maintain equal outputs.

While the AVR has protective and stability features not provided by the manual regulator, both regulators usually have at least some protective functions in common. These include field overcurrent and volts per hertz protection. As frequency is decreased, the iron in the generator and connected transformer's cores can become saturated if voltage is not proportionally decreased with frequency. Hysteresis and eddy current losses in the cores increase with saturation and overheating of the iron, which may cause core and winding damage. At startup and possibly during a generator trip, the generator may be at less than rated speed with the regulator calling for too high of a voltage. The volts per hertz protector provides alarm and generator trip functions. The alarm function first alerts operators of an excessive volts per hertz condition. If the volts per hertz level reaches a predetermined limit, the excitation system and generator are tripped. The trip function may be time delayed to allow a voltage per hertz limiter to run back the AVR or to switch excitation from the AVR to the manual regulator

Sensing

Various potential transformers, current transformers, and transducers provide feedback to the excitation system, as well as to the operators. Most automatic voltage regulators rely on potential and current transformers on the output of the generator to adjust the field current to maintain a proper generator output. Current and voltage measurements of the generator field provide input to the manual voltage regulator to maintain a steady field current. Potential and current transformers on the output of the exciter alternator, before rectification, provide the field voltage and current measurements on the alternator. Furthermore, field current is sensed to ensure that the generator is operated within design parameters for minimum and maximum excitation. Besides current and voltage, frequency is also normally sensed. A frequency transducer is installed across one or more of the potential transformers to provide frequency sensing.

The parameters sensed in the excitation and generator systems are used for many functions that provide control and protection. Limiters are devices that prevent operation in regions that may lead to instability or damage. If a limit set point is exceeded, the limiter, depending on its design, will change the regulators reference signal, bypass the regulator's reference signal with its own reference signal, or bypass the regulator entirely and take control of the excitation, until the adverse condition has passed. Limiters can have an instantaneous single set point beyond which operation of the system is immediately prevented. Some may have a timed set point, allowing operation beyond the set point for a short duration. The time delay set point allows for transient response, but still protects the equipment. The time delay may not be a specific setting, but rather a function of the limited parameter in which the time delay inversely varies with the amount that the limited parameter exceeds its set point.

Protection devices are components like limiters; but rather than limiting the regulator, they act to trip the regulator or the generator. The protection devices operate upon more severe criteria than the limiters, thus providing drastic action to protect the equipment. When there is a limiter for the same parameter as for a protection device, the protection device should serve as a backup to the limiter. A protection device should be coordinated with any corresponding limiter to ensure that the limiter is allowed first to take action to reduce the adverse condition before a trip is initiated. Also, like limiters, protection devices may have multiple set points to provide an alarm before tripping. The trip may also be time delayed both to provide an advance alarm and to provide the limiter an opportunity to operate.

Commonly used limiters, protection devices, and other sensing devices are described in the following subsections. Not all devices that exist are described, as many are of a rather unique function or are not commonly employed. The following descriptions are of devices, though the actual physical characteristics of the devices do vary greatly. In older systems, the devices may be a discrete electro-mechanical device. In later systems, the devices may be electronic cards or modules. In newer systems, the device may actually be a software component.

Maximum Excitation Limiter

Operation of a generator in a region above its reactive capability curve has to be avoided during normal operation to prevent field winding overheating. A Maximum Excitation Limiter (MEL) is often used in conjunction with the AVR to prevent extended operation in this region. To allow rapid response to a power system transient, such as a line fault, the MEL will normally permit short duration excursions into the over-excitation region above the reactive capability curve. As the generator's transient response to supply large quantities of VARs to the power typically lasts at most a matter of a few seconds, until the fault is cleared, the brief over-excitation will cause no harm to the field winding. For power system disturbances requiring excessive VARs and lasting more than several seconds, the MEL will run back the regulator to prevent field winding overheating.

Some MELs will have inverse time or even an inverse time squared feature that limits the duration of an over-excitation condition based on the amount of over-excitation. A small over-excitation excursion requires less field current than a larger excursion and will, therefore, take longer to overheat the field winding. Consequently, with this inverse time feature, a small over-excitation can continue for a longer period of time than a larger over-excitation. The inverse time square feature more closely matches the I^2R heating of the field winding and provides for a closer fit between the over-excitation and field heating.

Since many generators reactive capability curves are based on available cooling, conditions such as low cooling pressure will reduce the capability limits on the curve. Caution must be exercised when the cooling system is degraded, as the MEL may not be providing complete protection.

Typical MEL limits are 135 to 150 percent over-excitation for a few seconds before reducing excitation. However with some high initial response exciters, an over-excitation of 300 to 400 percent excitation may be briefly permitted.

A maximum excitation limiter may also be referred to by the initials MXL, or as an Over Excitation Limiter (OEL).

Minimum Excitation Limiter

Like the maximum excitation limiter, the minimum excitation limiter, or Under Excitation Limiter (UEL), works to maintain the operation of the generator within the reactive capability curve. The UEL prevents operation of the generator in the region below the capability curve. In this region the generator's stator end iron can overheat, and with a reduced field the possibility of the generator slipping a pole is a danger. The UEL allows for generator operation in the lagging region, consuming VARs, but providing a margin of safety above the under-excitation and the generator stability limits.

A minimum excitation limiter may also be referred to as an Underexcited Reactive Ampere Limiter (URAL).

Volts per Hertz Limiter

The volts per hertz limiter serves to protect both the generator and the generator step up transformer if it is connected. The iron core of the generator stator can be become magnetically saturated if the ratio of voltage to hertz is too high. Furthermore, as most generators are permanently connected to their transformer without an intervening circuit breaker, the generator step transformer's iron core can also be saturated. With saturation, core losses greatly increase and can overheat the core, damaging the winding as well as the iron itself.

The limiter will run back the excitation to a safe voltage level if an excessive volts per hertz ratio is detected. Often the volts per hertz limiter has an inverse time function that will allow for maintaining a small volts per hertz increase longer than a larger increase. The volts per hertz limiter typically protects against volt per hertz ratios of 1.05 or more, though the actual value will depend on both generator and transformer.

Exciter Minimum Voltage Limiter

In certain transient conditions, on certain excitation systems that use alternator's AC output for power, the alternator field may be driven so low that SCR bridges will not fire. If this occurs, the excitation system may collapse and not be able to recover from the transient. With these systems, an exciter minimum voltage limiter may be used to maintain a minimum exciter AC voltage.

Generator Field Current Limiter

In addition to, or in lieu of a maximum excitation limiter, some excitation systems may employ a field current limiter. Like the maximum excitation limiter, this limiter protects the generator field. However, instead of relying upon the generator's reactive capability curve, this limiter is normally set for a specific field overcurrent value. An inverse function may also be incorporated into this limiter, allowing longer duration for small values of overcurrent. In some systems a distinction between generator field current and maximum excitation limiters is not made, and the terms might be used interchangeably. A field current limiter for a rotating exciter may also be provided in addition to the limiter for the generator's field.

Loss of Voltage Signal

The excitation system depends on voltage sensing for control and protection functions. As previously stated, the voltage sensing is typically performed with potential transformers for AC voltage. However, some AC voltages may also be sensed with an electronic voltage transducer. The AVR compares the voltage signal it receives for generator terminal voltage, applies any preset compensation for transformer and line losses, compares the voltage signal to the reference signal producing an error signal, and then corrects the generator's excitation to null the error signal. If the voltage signal is lost, the AVR will drive the generator excitation up in order to produce voltage. Limiters and protection devices that depend on a voltage signal, such as the volts per hertz limiter, may not function. Also, generator protective relaying utilizing a voltage signal, such as 21 and 32 devices, may malfunction.

A loss of voltage signal device actuates on the loss of the voltage signal, alarms, and transfers excitation to the manual regulator. Furthermore, undesirable protective actuations that might occur on complete or partial loss of voltage may be blocked.

The loss of voltage signal device is normally more than a loss of voltage relay. The device may take input from more than one set of PTs, and also from CTs, to determine that the voltage signal was due to component malfunction rather than actual loss of generator terminal voltage.

Loss of Field

A loss of generator field either completely or partially can cause the generator to lose synchronism and over speed, creating the potential for destruction of the generator and the prime mover. Even if over speeding does not become a problem, as in the case where a partial field maintains synchronism, the generator will be greatly under-excited and draw excessive VARs from the power system. This condition can cause system stability trouble and cause generator damage.

A voltage relay or other detection devices across the generator's field circuit can detect loss of the field. However, field problems after the collector brushes will not be detected, such as with an open field lead. A current relay or sensor in the field circuit functions better for detecting a loss of field. A more sophisticated technique commonly used, calculates the change in system impedance from the generator's voltage and current. As the generator draws excessive VARs from the system, the impedance value changes. Upon sense of a complete or partial loss of field the generator must be, and automatically is, tripped immediately to prevent both equipment damage and power system problems.

Discrete Electrical and Electronic Components

To list all the components that are employed in every voltage regulator in service at present would be an extremely difficult task and be rather lengthy. Voltage regulators from 60 years or more are still in service. Old DC excitation systems utilizing electro-mechanical regulators with carbon piles to control field current are in use and providing reliable service. Through the years technology has changed the design and construction of regulators: discrete electronic components replacing electro-mechanical components; then printed circuit boards and integrated circuits followed by interchangeable electronic cards; modules and programmable logic controllers taking the function of specific components. Modern systems are often computer based with many of the components actually being a portion of the software running the excitation system. Motor operated potentiometers, commonly used to adjust the set point reference for both the automatic and manual regulators, have been replaced with electronic signals and digital logic.

Some of the common major discrete components used in voltage regulators are:

- Carbon piles, used in older DC systems to control and limit the exciter field current.
- Contactors, used in certain DC systems to provide a buck boost capability, switching in and out resistance to rapidly change exciter field current.

- Motor driven rheostat to provide small adjustment to the exciter field current.
- Manual rheostat to provide manual adjustment of the exciter field current, in lieu of a manual regulator.
- Hand operated potentiometer to provide reference signal adjustment.
- Electro mechanical relays that provide control logic, and protective relaying functions.
- Silicon Controlled Rectifiers (SCRs), used in later DC systems and AC systems, provide solid state control over exciter field current, and later, directly controlling generator field current in some excitation systems.
- Magnetic amplifiers, or mag-amps, controlled by the voltage regulator provide SCR firing angle control.
- Motor operated potentiometers, provide adjustment of reference signal with control signals from a remote location.
- Instrument transformers, such as PTs and CTs, though not typically co-located with the voltage regulators, provide sensing of exciter and generator voltages and currents.
- Small power transformers and power supplies provide operation and control power to the voltage regulators.
- Fuses, though often overlooked as a component, provide equipment protection.

Cards

Electronic circuit cards and modules have been replacing discrete electrical components of the voltage regulators since the 1960s. The small size and lower power consumption of the electronics allow for placing entire circuits in individual boards and modules. Cards and modules provide sensing, firing angle control, limiter functions, signal compensation, and comparison, etc., in individual packaging.

Instead of stocking spare parts of many individual components, a few cards could be procured as spares. With cards and modules, troubleshooting and replacement at the circuit level instead of component level often provide faster restoration times if spare cards and modules were stocked. Critical cards and modules should be stocked as spares.

The cards and modules have to be securely mounted with tight connections. Vibration from power plant equipment has caused looseness and open connections in circuits that may be difficult to isolate when the plant is shut down. Ventilation is often more critical for electronics than for electrical devices. Care should be exercised to ensure adequate airflow to provide cooling, and to ensure that heat producing components are not located such that overheating of the electronics could occur.

Cards were at first often mounted on the interior surface of the regulator panels. Later placing the circuit cards into drawers, slotted cabinets, or compartments provided better protection for the cards and better control of the cards' environmental conditions.

PLC

Programmable Logic Controllers (PLC) have been incorporated in fairly recent regulators. Like circuit cards and modules, the PLCs replaced many discrete components, incorporating the functions of one or more circuits. The PLCs are programmable, which allows identical PLCs to provide some of the different functions in the voltage regulator. Set up and adjustment of a PLC, typically through its control panel or a data link, can be faster and more accurate. Instead of adjusting potentiometers on a circuit card, a set point can be programmed into the PLC. Troubleshooting and replacement, if necessary, is often easier and quicker than with discrete components or circuit cards. Since identical PLCs may be used to provide different functions in the voltage regulator, the number to maintain as spares can be less than with specifically designed circuit cards and modules. Many PLCs incorporate diagnostic capabilities and can present error codes to indicate specific problems, often retaining errors codes in memory.

Problems with heat and vibration can also adversely affect PLCs. Care needs to be exercised in design and installation of the PLCs and nearby components.

Dedicated Microprocessors

The microprocessor is readily programmable either through a control panel or a computer port. The functions and features of the microprocessor are software or firmware code, and do not depend on the physical characteristics such as resistance or inductance to provide output. Upgrades and other changes can often be made through software changes rather than a hardware change. Diagnostics and functional testing are capabilities often built into the software. The software code is often proprietary property of the excitation system's manufacturer; the user is often limited to program changes that the manufacturer allows. Different software components or modules can be procured and installed to provide different features. As with other electronic devices, heat and vibration are concerns. The microprocessor is typically installed in a cabinet that is designed to afford the best protection and environmental control.

Software Based Systems

The newest voltage regulators expand upon the microprocessor, incorporating almost all the control, sensing, compensation, reference, error detection, limiting, and protection functions. All these functions are software based. The software based system can be networked to other computers, providing control to operators in a remote control room via a digital link. Reference adjustments can be made through the computer network as well as other changes such as regulator transfer. As with the dedicated microprocessors, upgrades are made through software changes. Features can be installed as software modules. Diagnostics and testing capabilities can be performed via computer interfaces.

High current and voltage circuits are still discrete components. Exciter or generator field current is controlled with a SCR bridge. SCR firing angle is controlled via a gate control module, which is in turn controlled by the computer. Instrument transformers and transducers are used to provide voltage, current, power, and other signals. A contactor is employed to provide field flashing. Still by taking over many of the voltage regulator functions, the software based system can provide reliability and operability above what previous systems had obtained.

Calibration

Periodic testing of the voltage regulators is necessary to ensure proper function in all steady state and transient conditions. Minor variations such as set point drift and other small problems may not be noticeable during normal operation. Transient operation rarely occurs, and as time passes, confidence that a minor abnormality in the regulator may prevent proper transient response decreases. Periodic calibration serves to both correct small abnormalities, such as from set point drift, and to maintain confidence that the system will respond correctly to any normal or transient condition.

Several different types of calibration and maintenance are performed on voltage regulators, depending on the type of regulator and experience with the regulator. Also, the amount and frequency of calibration and maintenance depends upon the type of regulator and experience with the regulator. A regulator in which experience shows to have set point drift close to unacceptable limits within a specific time period has to be calibrated within that time period. Likewise, if experience shows that drift or other problems have not developed within the current calibration period, then the calibration period might be extended. However, the calibration period will often have to coincide with a scheduled plant outage window.

Static Testing

Static or open loop testing involves a function check of the voltage regulator with the generator down. No feedback signal is provided from the exciter or the generator. Inputs are simulated as necessary. Regulator function without feedback is checked and verified to be properly operating. Set points and limits are set as needed. Signals and parameters such as SCR firing angles are often included in the test, depending on the type of regulator. Voltage and current measurement of different signals are normally taken and verified to be within the specified tolerance. An oscilloscope may be required to check SCR firing or other parameters. A recording oscilloscope is useful for producing a permanent record.

Dynamic Testing

Dynamic testing is conducted with the generator operating and under load, typically at 80 percent load. Reactivity control, stability, and limiter functions are checked and verified, though some simulated inputs are required to provide transient signals. The regulator is verified to maintain the generator within the reactive capability curve limits for nontransient conditions operation. Coordination with the power system operator or load dispatcher is necessary, as VAR production load will be varied. Also with the static test, signals and other parameters, such as SCR clipping, are normally checked.

Both the static and dynamic test should be proceduralized, incorporating manufacturer recommendations and requirements. Test results, “as found” set points, and “as left” set points should be recorded for trending and future reference. Any replacement or repair should also be recorded for trending and reference.

Regulatory Testing

Voltage regulator testing may be required by power pool or system reliability council requirements and insurer requirements. The requirements of each may vary depending on the parties involved. A typical set of test requirements from a region reliability council in the USA is as follows.

Generator reactive capability is to be tested every 5 years, or sooner if generator owner desires to do so. The test is to be performed with the generator in its normal operating condition.

Generator stability model verification testing will be performed every 5 years, or sooner if generator owner desires to do so. An IEEE 421.5 model of the generator, or a vendor supplied model, will be used for the test. Simulated or actual inputs will be used during the test. The test may be performed offline using simulated signals.

An open loop or static test will be performed every 5 years, or sooner if generator owner desires to do so.

Records of the tests and the data collected typically have to be sent to the entity requiring the test.

In the USA, the reliability councils are shown in the following table.

Table 2-2
USA Reliability Councils

	Reliability Council	**Internet Address**
NERC	North American Electric Reliability Council	www.nerc.com
Regional Councils		
ECAR	East Central Area Reliability Coordination Agreement	www.ecar.org
ERCOT	Electric Reliability Council of Texas	www.ercot.com
FRCC	Florida Reliability Coordinating Council	www.frcc.com
MAAC	Mid-Atlantic Area Council	www.maac-rc.org
MAIN	Mid-America Interconnected Network	www.maininc.org
MAPP	Mid-Continent Area Power Pool	www.mapp.org
NPCC	Northeast Power Coordinating Council	www.npcc.org
SERC	Southeastern Electric Reliability Council	www.serc1.org
SPP	Southwest Power Pool	www.spp.org
WSCC	Western Systems Coordinating Council	www.wscc.com

Power System Stabilizer

With an interconnected electrical grid, a disturbance can cause one or more of the connected generators to oscillate in response to the disturbance. These oscillations are cyclic variations in power flow that can develop between a generator and the power system, or between generators, and are typically in the range of 0.1 to 3 Hz. A strong power system, with low impedance to the generator, will tend to dampen oscillation; but if the system is weak or is weakened by loss of lines and other generators, the dampening is decreased. Fast response voltage regulators tend to decrease oscillation damping. The ability of the voltage regulator to quickly respond to sudden power system voltage changes, and the field current lag time due to generator field inductance, can cause the generator to aid rather than oppose the oscillations. Instead of decreasing voltage regulator responsiveness to aid stability, an additional excitation system component, the Power System Stabilizer (PSS), is employed.

The PSS, depending on type and model, measures one or more generator parameters, and adjusts the voltage regulator’s output to produce a field current to oppose power system oscillations. The simplest PSS models use one parameter to detect oscillations. The commonly monitored parameters are generator speed, power, voltage, accelerating power, and terminal frequency. Often, these parameters are derived from terminal voltage and current signals.

The PSS produces a signal that alters the voltage regulator’s set point reference, and takes into account generator parameters such as field inductance, and the magnitude and the phase of oscillation. The term phase lag is used to describe the delay in phase position between the input signal into the voltage regulator and the actual occurrence of the generator field change associated with the input signal. Phase lead, or phase compensation, is time lead provided by the PSS to compensate for phase lag. The PSS’s signal increases or decreases generator field current, thereby increasing or decreasing the reactive power, thus altering the torque angle. By varying the torque in response to speed changes, according to the phase lag in the excitation system and in phase opposition to the speed changes, the PSS dampens the oscillations.

The PSS signal is limited to maximum and minimum values so as not to place the generator into a region in which damage can occur, or that the regulator’s own limiters will function. Coordination between the PSS limits and the maximum and minimum excitation limiter is necessary to ensure that the PSS does not cause an unnecessary generator trip or a transfer to the manual regulator. It is not uncommon for a PSS to be automatically prevented from operation if generator voltage is above a maximum value. Also, a timer may be employed to remove PSS function on high voltage over a specific time period. These overvoltage schemes are to protect the generator from operating in a range that may cause damage or a generator trip. An alarm should indicate removal of PSS function.

Low frequency torsional vibration may be excited by PSS response, especially if the PSS is using shaft speed as an input. Filters to block shaft torsion frequency are sometimes required in the input to the PSS to prevent the PSS from reaction and exciting the torsional vibration.

As with other voltage regulator components, the PSS may be an analog, digital, or even a software component of the excitation system.

The typical method of tuning a PSS utilizes phase compensation. Phase compensation is accomplished by adjusting the PSS to compensate for phase lags through the generator, excitation system, and power system such that PSS provides torque changes in phase with speed changes. These results need to occur when system configurations and operating conditions result in the least damping, and do not introduce instability under all other normal operating conditions as well as expected fault conditions.

Regulatory Requirement for System Stability

Reliability councils, system operators, and power pool policy often require use of PSS on generating stations. Calibration or tuning of the PSS is often required every five years, or whenever a sufficient modification has been made to the excitation system, generator, or power system that would affect the functionality of the PSS.

PSS Related Failures

During testing of the PSS after a scheduled unit outage, a test lead accidentally fell and grounded out a power supply in the voltage regulator. The power supply fed regulator circuit boards for both the manual and automatic regulator. Excitation was lost and the generator tripped.

In another plant, a PSS modification was installed. An undetected wiring error caused the generator to oscillate during operation. The unit had to be brought down and the problem was investigated, identified, and repaired.

Calibration

Calibration and tuning of the PSS differs, based on model, number and type of inputs, and the required response as based on power system stability analysis. However, there are basic tenets that apply to most PSS.

All components of the PSS should be checked to ensure proper operation; this includes switches, relays, potentiometers, and alarms.

Phase compensation should be adjusted to provide the best minimal phase lag in the modes of oscillations that are of concern. Local mode oscillations occur between the unit and the power system; interarea mode occurs between the unit and other units in part of the power system; and interunit mode occurs between generators in the same plant or nearby plants. The frequency of oscillation is often determined by the mode. Local mode oscillations are commonly in the range of 0.7 to 2 Hz; interarea oscillations are typically a lower frequency at 1 Hz or less; and interunit oscillations are higher in a range of 1 to 3 Hz. The phase compensation required for each mode’s frequency may be different. The system operation agency may place a maximum limit on uncompensated phase lag for interarea oscillations.

The gain is adjusted after phase compensation is set and the generator should be under load. A typical procedure is to adjust the gain until small oscillations are detected in system output. This maximum setting at which oscillation occurs should be recorded. The gain is backed to a percentage of this maximum gain setting depending on the system, though 33 to 50 percent are often used. The output of the PSS should be monitored to ensure that the limiters are not clipping the signal; otherwise, a false maximum gain setting maybe obtained. Generator and exciter shafts may need to be monitored for torsional vibration, if this is a concern, to ensure that the PSS does excite this mode of vibration.

The PSS output limits are set to prevent the PSS from attempting to drive the generator beyond allowable over-excitation and under-excitation conditions, or actuating the voltage regulator's limiters. Typically, limit settings of plus and minus 5 to 10 percent of rated generator voltage are used.

Brushes

Collectors, commutators, and brushes provide the means to transfer electrical power between stationary components and rotating field windings. Commutators have the added task of converting AC power to DC. The actual transfer of power occurs at the interface between the brushes and the collector or commutator. Two important aspects of the interface are friction and electrical resistance.

Brushes need to be held against the ring. The force of the brush against the ring, taking into account the cross sectional area of the brush, is referred to as brush pressure. Typical brush pressure is between 3 and 4 psi. Proper brush pressure ensures good electrical contact between the brush and the ring, reduces chatter, and promotes even current distribution between the brushes. The force for brush pressure is provided by a spring on the brush holder. Most brush holders in use today employ constant pressure springs. Previously, brush holders utilized springs that decreased in tension as the brushes wore and the spring relaxed. This created a situation where the brush spring tension had to be checked frequently and adjusted. Constant pressure brush holders employ helical springs that maintain a fairly consistent force over the range of brush wear. Many owners of older systems that had employed non-constant pressure springs have upgraded to brush holders with constant pressure springs.

Though a good ring surface film and proper brush pressure will extend the life of brushes, the brushes will eventually wear down and have to be replaced. A typical part of daily operator rounds is to visually inspect the brushes, and if needed, replace the ones that are too short. Older machines may still have brushes with bolted connections, though most units today are designed with, or have been modified for, online brush replacement. The older bolted connections are a safety hazard, both to personnel and equipment, and should be upgraded.

A certain number of brushes can be replaced without pre-arcing the new brushes. The limit of how many brushes can be replaced without pre-arcing is based upon the equipment and brush manufacturers' recommendations, though ten percent of the brushes is a common figure.

When a new brush is installed with a flat contact surface, without pre-arcing, the flat brush has only a minimal contact area with the round ring, thus is an area of high resistance. As the brush wears in, its surface will gradually conform to the round surface of the ring. To replace all or a significant number of the brushes, the brushes must be pre-arced. Pre-arcing maximizes the electrical contact area of the brush to the ring. A simple pre-arcing rig consists of fine sand paper mounted on a form cut to match the curvature of the rings. A lever holds the brush in the correct alignment while moving the brush's contact surface across the sandpaper. This job produces much carbon dust and the brushes should be thoroughly wiped clean to remove dust and grit. Many brush manufacturers will provide brushes pre-arced. Purchasing pre-arced brushes saves the time and the mess of performing this task in house.

Care must be exercised not to intermix brushes of different manufacturers and models. Although several styles or models of brushes may be specified for use on a particular machine, only one style or model of brush can be used at a time. The different characteristics of the brushes will likely cause unbalanced current flow through one style or model of brush. The brushes having the higher current flow overheat, creating a host of potential brush and ring failures. If a different manufacturer, model, or style of brush is to be used, all the brushes on the machine must be changed at the same time; obviously with the machine offline.

The voltage produced from SCR bridges may add a high AC content to the DC voltage. The inductive field of the generator presents a high impedance to the AC voltage and smoothes the field current. Small distributed capacitances of the generator field windings and leads to ground provide a circuit for the AC voltage. Some caution should be taken in changing the brushes, since there may be an AC voltage from the field terminals to ground.

Fans

Due to the heavy current carried by the brushes, much heat is developed in the brushes and on the collector rings. A shaft mounted fan cools the brushes and rings, reducing wear and damage caused by high temperatures. The fan also helps maintain cleanliness of the brush area by extracting the carbon dust from the brushes.

Fan Failure

A unit was in normal operation, when the exciter enclosure smoke detector alarmed. The generator tripped soon after smoke alarm. Investigation revealed that brush rigging had shifted and was rubbed by the cooling fan. It was determined that brush rigging was not properly installed and a dowel pin was missing. The improperly installed brush rigging shifted into the fan creating smoke before grounding out.

Collector Rings and Commutators

As the brushes ride over the surface of the rotating ring, a small amount of carbon is worn from the brush, and a small amount of metal is worn and vaporized from the ring. The carbon and ring metal combine with moisture from the humidity in the air to form a film on the surface of the ring. This film is important to the performance and the longevity of the brushes. The film on the ring creates a low friction surface. Without this film, the operating temperature of the brushes increases, the wear of the brushes dramatically increases, and the life of the brushes is greatly reduced.

The performance and condition of the film can be adversely affected by a number of factors. The humidity of the air provides the moisture needed to form and maintain the film. Low humidity, as found in arid regions or in overly cooled air, can lead to the reduction or elimination of the film. Without a proper film providing a low friction surface, the brushes wear quickly, sometimes in a matter of days. In arid regions, the air in the brush enclosure may have to be humidified to enhance film formation, or brushes specially made for arid environments may be necessary.

Oil and other contaminants can destroy the film or at least adversely affect its desirable qualities. Oil can create a high resistance surface on the film, causing localized heating of the brush ring interface. Furthermore, oil tends to prevent the film from adhering to the surface of the ring, thus destroying the film. Other chemical contaminants can react with the metal and carbon elements of the film, thus destroying the film. Contaminants can also provide conductive paths that may cause shorts and grounds. Sources of oil vapors and other airborne chemical contaminants near the brush area should be eliminated to prevent possible contamination of the film. During shutdowns, handling of the rings should be kept to a minimum and the rings wiped completely free of fingerprints prior to startup. Oils and other substances from hands can create localized areas of contamination of the film.

Dust, grit, and other abrasives will erode the brushes, the rings, and the film. An abrasive that gets imbedded in the brush will act as a lathe tool, first abrading away the film and then cutting into the ring surface. Rings and brush assemblies must be enclosed, not only for personnel safety, but to prevent intrusion of dust and other abrasives. The brushes and ring areas must be thoroughly cleaned after any work, especially work that may generate abrasives. Cooling air supplied to the brush area should be filtered, and the environment around the area should be maintained as clean as possible.

The surface of the collector rings and commutator has to provide a smooth surface for the brushes to ride. Eccentricity and roughness can cause brushes to hop and arc. Brush hop is not often visible due to the speed of the generator. However, the arcing is visible, and frequent periodic inspections should check for arcing and other brush problems. Also, during generator outage the commutator and ring should be inspected and checked for eccentricity early in the outage. If excessive roughness or eccentricity is discovered, then the rings or commutator will have to be stoned to provide a smooth surface.

The collector rings can be stoned in place using the turning gear to rotate the rings; or the ring may be removed and stoned in a shop where higher rotational speed is possible. Most often the ring will be stoned in place to save time and expense. Commutators are almost always stoned on the shaft. Before stoning, the diameter of the ring or commutator has to be measured. Manufacturers typically provide a minimum diameter for their rings, below which the brushes will not ride properly. After stoning, the commutator bar insulation may need to be cut. Manufacturer literature should provide the required depth and shape of the insulation. When stoning is complete, the rings or commutators should be thoroughly cleaned, as well as the surrounding area.

3
FAILURE MECHANISMS

Failure Description

Windings

The EPRI Power Plant Electrical Reference Series Volume 16, "Handbook To Assess the Insulation Condition of Large Rotating Machines", is an excellent resource on winding insulation. In excitation systems, winding failures affect the rotating exciter, generator field, rotating pilot exciters (including PMGs), excitation transformers, static pilot exciters, exciter driven motors, and other motors such as those that may be used in fans and positioners. The size, power, and voltage ratings of all these windings vary greatly. However, there are some similarities in failure modes that affect all, from the smallest to the largest. Familiarity with how the different failure modes affect each winding is important to understanding and meeting the maintenance needs of each component.

The main concern and primary cause of winding trouble is insulation failure. Conductor failures, internal to the windings, can occur. An open circuit, however, is rather rare. The typical winding failure occurs due to insulation failure, leading to a ground fault or a short. Insulation degradation can come from several different factors, or a combination of factors. These factors are: age, temperature, contamination, mechanical abrasion, and vibration.

Age in and of itself usually does not lead to failure of the insulation. However, it does make the insulation more susceptible to other failure factors. As the insulation ages, chemical changes occur in the insulation. Varnish, employed in older systems to bind insulation together, becomes dry and brittle. Other binding materials also may weaken. It is usually the binding material, the varnish or epoxy, that degrades with age; not the actual insulation material. Factors such as temperature and vibration tend to prematurely age insulation.

Temperature contributes significantly to the ageing of the insulation, particularly with older insulation. A rule of thumb for older insulation systems was that the life of the insulation was reduced by half for every 10 degrees Celsius that the winding is operated above its temperature rating. Though newer insulation systems are not as susceptible to thermal ageing, they too are degraded by high temperature operation and have decreased life due to high temperature.

Besides accelerated ageing, temperature also affects the insulation in other ways. As the winding heats up or cools down, the copper winding expands and contracts more than the iron core in which it is mounted. The expansion and contraction puts mechanical stress on the insulation. Cyclic stress can cause separation of the insulation that develops into permanent cracks and voids. Machines that are frequently subjected to unloading and loading will obviously undergo more thermal cycles, and thus be more prone to this type of failure.

Overheating (exceeding the temperature rating of the winding) not only greatly accelerates the ageing, but also causes further damage. Again, the binding material is most susceptible, though the actual insulation material itself may be damaged. Overheating causes irreversible changes in the insulation, breaking down the insulation and leading to oxidation and carbonization of the insulation.

Small localized damage to the insulation allows interturn or ground leakage current to flow. The leakage current further heats the damaged insulation, causing more damage; thus causing more leakage current, more heat, and eventually failure. The initial localized damage may be caused by general overheating of the winding, a manufacturing defect, a voltage spike, or mechanical damage. An interturn short, not usually being a solid electrical connection, in a winding produces I^2R losses that heat the area around the short. This heat over time will typically damage the ground wall insulation, eventually leading to a ground fault failure. Less common, although possible, is that the heat from an interturn short will melt the conductor creating an open winding.

Abrasion of the insulating material results from mechanical wear either from a moving object in contact with the insulation, or from the insulation itself moving against an object. As mentioned, thermal expansion and contraction of the winding causes portions of the winding to move; thus creating the possibility of the insulation wearing against the core and winding supports. Winding conductors are typically held tightly in position by such means as slots, side packing, and wedges in the core iron; or, in salient pole machines and transformers, by bracing and supports.

A number of forces act on the winding conductors. These include vibration from the exciter and generator, and the magnetic force. In rotating exciters and transformers, the magnetic force on the AC winding is at twice the synchronous speed. Any looseness in the wedges or winding supports will allow the winding to vibrate at the location of the looseness. This vibration not only creates cyclic stresses in the insulation, but also can allow rubbing and abrasion of the insulation against the core iron or the support. A typical indication of this abrasion is dusting. The wearing of the insulation creates dust particles of the insulation material. The insulation dust may collect moisture from the air or cooling medium, and appear as a grease-like substance.

Extreme incidences of abrasion occur when a rotating element physically touches and abrades the winding. Typically, this will be caused by mechanical looseness of a part or bearing failure. A failure of a bearing can allow the rotor to shift in its radial direction and make contact with the stator, damaging the stator and rotor winding, as well as the core iron. These extreme incidences, though of short duration, can cause sufficient damage to both the winding and the core. One plant had a metal file left in the generator's air gap after an overhaul when adequate Foreign Material Exclusion (FME) precautions were not taken. Upon start-up of the generator, the rotor iron and winding were so severally damaged that a replacement rotor had to be obtained.

Particles such as dirt, dust, soot, etc., create problems in several ways. One way is that small particles can abrade the insulation. Particles that get between the winding and the core or supports, act like sandpaper grit wearing away more insulation through vibration. Another mode is that the particles attract moisture and form a conductive path to ground. Some particles, such as carbon dust, are conductive by themselves. While the insulation between the conductor and the particles will prevent a direct ground fault, the conductive path formed by the particles can lead to tracking of some current, which may lead to further insulation degradation.

If a significant amount of particles collect on the winding, it can form a thermal barrier that hinders winding cooling, particularly on windings relying directly on air or gas as a cooling medium, such as end-turns. With a thermal barrier hindering cooling, the winding insulation can more easily be overheated.

Moisture reduces the resistance of the insulation. Moisture, creating a conductive film on windings, allows tracking of current, leading to insulation degradation. Furthermore, a ground path can develop from tiny cracks in the insulation through moisture. As dust and other particles can attract moisture, moisture too can cause particles to adhere to surfaces. During operation, the warm winding will typically evaporate out the moisture; so moisture tends to be more of a problem during start-up. However, moisture that has been absorbed into the insulation will take a significant amount of time to be driven out of the insulation. Furthermore, an excessive amount of moisture can create grounds during operation. For example, a water leak can thoroughly wet a section of the winding, weakening the insulation, and developing a fault.

Electrical spikes can over stress a portion of the winding, creating a ground fault and a short. Due to the winding's impedance, a spike cannot typically travel far into a winding; thus damage from spikes tend to affect the first several turns. Electrical spikes develop from lightning strikes, switching transients, and solid state components. SCR bridges produce nonlinear waveforms that can create voltage transients that can exceed the nominal DC voltage. Of particular concern is the SCR bridge in static excitation systems. In these systems, the bridges control higher voltages and deliver higher energy than the bridges in rotating excitation systems. An electrical spike overstresses the insulation and causes a breakdown. While a single spike usually will not create a fault unless the insulation was already weakened, repeated spikes can, over time, weaken the insulation and develop a fault.

Winding insulation is susceptible to chemical deterioration. Different chemicals that might be in the surrounding area can attack the insulation. These include fly ash, lubricating oil, hydraulic fluid, and other organic substances. The chemicals weaken the binding material used in the insulation, allowing movement or separation of the insulation that leads to failure.

Normally the generator and exciter fields are protected from ground fault by being ungrounded circuits. A single ground will not cause a fault. However, if a second ground develops, the field circuit will effectively be shorted between the two ground points. If the ground points are located well into the field windings, only a portion of the field will be shorted out, allowing the generator to continue without a trip. However, with the reduced field, the voltage regulator will attempt to increase current to raise excitation; possibly reaching a limiter set point. The current flowing through the grounds will likely produce high localized heating, further damaging the field winding and possibly the rotor iron. The shorted field will likely be unbalanced and cause increased vibration which varies with load. Similarly, an interturn short in the field winding without a ground will produce the same reduced excitation and vibration as a double ground fault. As a short is normally not a solid electrical connection, the short will create a localized hot spot on the field. If left undetected and uncorrected, an interturn short will eventually become a ground as its heat damages the winding ground wall.

Field windings may be damaged by any of the following:

- over-excitation, excessive field current;
- under-excitation, slipped pole that induces current in the field winding and rotor iron;
- negative sequence current from a system fault or unbalanced load , inducing current in iron and high voltage on field;
- asynchronous operation, inducing current in iron and high voltage on field;
- sudden loss of field current, inducing high voltage on field from the collapsed magnet field;
- voltage spikes from failed semiconductors or fuses in the rectifier bridge;
- thermal stress at startup, especially on older machines, rapidly applying field current creates uneven heat distribution and expansion of the winding and the rotor iron.

Induced rotor iron currents are particularly damaging to wedges, retaining rings, and supports. These components suffer from heating at their boundaries from discontinuous electrical paths. The current flowing across the edges encounters higher resistance, and therefore, will generate more heat at these locations.

Extended time on turning gear can lead to field winding problems also. Turning gear operation at low speed does not produce centrifugal force to press rotor windings against their supports; thus, windings/bars may move in their slots. Copper dusting results when separate conductors in the field winding turn rub against each other producing copper dust . The copper dust, being conductive, can lead to interturn failure and ground faults.

Laminations

Core laminations in magnetic circuits of exciters, transformers, and motors are constructed to minimize circulating induced currents. Induced current, if not minimized, will generate heat in the iron, weakening the core and damaging the windings. Making the laminations thin and coating each with a thin insulating film minimizes the induced currents. Damage to the lamination insulation permits excessive current that can overheat both the laminations and windings.

Mechanical impact on the laminations is the most frequent cause of damage. Work performed on exciters and motors, particularly during removal and installation of the rotor, can score or crush the ends of the laminations together if not carefully done. Abrasive particles and other foreign material striking the ends of the laminations can wear off the insulating film and form a conductive path across laminations. Bearing failures can cause the rotor to rub against the stator core, damaging the laminations. A winding fault may produce enough heat to damage the adjacent laminations. If the laminations are not repaired along with the bearing, winding, and other components, heat from induced core currents will eventually cause another failure.

Loose core laminations will vibrate from the magnetic forces, and also in response to any machine vibration. The vibrating laminations can wear off their insulating film, and also can abrade the winding insulation. Hydro generators, with their large bores and relatively short lengths, are more susceptible to flexing and loosening of the laminations.

Core laminations can suffer damage from exceeding the voltage per hertz ratio of the exciter or transformer. If the voltage per hertz ratio of the winding is exceeded, the core can be driven into magnetic saturation and the core losses greatly increase, producing heat that can damage the lamination insulation and eventually the laminations themselves. The heat generated will likely damage the windings as well.

Commutators and Collectors

Commutator and collector rings do not typically suffer age related problems. However, they are not immune from other failure modes. Since the commutator and collector rings are metal, they do not wear significantly in comparison to the brushes, but they do suffer some wear. Wear can be accelerated by dirt and other particles, which if embedded in the brushes, will cause scoring. Brush arcing can pit and burn the surface. Usually a small amount of arcing is acceptable and will not cause damage. But significant arcing can and will damage the surface of the collector or commutator, and create further arcing.

As the rings wear, an eccentricity can develop. Several high and low spots along the diameter of the rings can develop. While the high and low areas may not be visible to the eye, they can cause the brush to hop or bounce during operation. This hopping breaks the current path of the brush and creates arcing. The higher the speed of the generator, the more significant the eccentricity becomes.

Machine vibration also can play a role in brush hopping. Typical machine vibration alone normally cannot cause brushes to hop off the ring and create arcing. The brushes having low mass are not likely to obtain enough momentum to overcome spring tension from typical vibration associated velocities and accelerations. Excessive vibration will more than likely trip the generator and exciter before causing damage from brush hop and arcing. However, conditions such as eccentricity or weak brush springs, in addition to vibration, may produce brush hop.

Arcing can further damage the commutator by creating conductive paths of metal and carbon across bar insulation, effectively shorting the bars together.

The film that develops on the surface of the rings is an important attribute. The condition of the film directly affects the condition of the rings and the brushes. Too thin, or a nonexistent film, increases friction between the brushes and rings, and significantly accelerates the wear of the brushes and rings. While a newly cleaned ring will not have a film at first, one should develop within several days of start up. Causes for an inadequate film are low humidity, chemical vapors in the air, too low of a current density in the brushes, or the brush used is too abrasive. Too thick of a film increases the electrical resistance and also is prone to patching, where sections of the film erode off the ring. The patching of the film can lead to hopping, chattering, and arcing of the brushes. A thick film can be caused by using a brush that is not abrasive enough.

Oil vapor diminishes the film since the oil can prevent adhesion of the film to the ring, as well as increasing the electrical resistance. Chemical vapors attack the film, or prevent the formation of the film, by reacting with the elements that make up the film, particularly the ring metal.

Foot printing is the formation of an outline of the brush on the ring. Brush hopping is a cause of foot printing. High current at the area of the foot print alters the hardness of the ring at that location. High spots or vibration can vary the brush pressure, and hence, vary the electrical resistance of the brush to ring interface and the current through the brush. With foot printing, the rings' eccentricity or vibration often causes brush hop at the same location on the ring surface; thus the foot printing actually occurs over time by repetitious brush hops. Applying field current while the rotor is at a standstill, such as during testing, only heats the ring area under the brushes and may create a foot print. Foot print wear creates high and low spots as the rings wear, leading to more brush hopping and chattering.

Brushes

Brushes are the most frequently replaced items in excitation systems, except in brushless systems. Brushes usually have to be replaced after three to six months of service due to wear. Some plants experience brush life longer than 6 months, and many plants suffer from less than 3 month of brush life. The brushes are designed with a finite life in order to promote electrical conductivity and minimize ring wear. Factors that can adversely affect brush life are brush pressure, contact surface, vibration, cooling, and ring film.

Proper brush pressure ensures that the brush maintains electrical contact with the ring. Too much brush pressure increases the friction between the brush and the ring, causing accelerated brush wear and erosion of the ring film. Too little brush pressure causes increased electric resistance between the brush and the ring, which also can accelerate brush wear. Furthermore, insufficient brush pressure may allow the brush to hop. To ensure equal current distribution among the brushes, equal brush pressure has to be applied to all brushes. Unequal brush pressures may cause brushes having higher pressure to carry more current, and those with less pressure less current.

Current density of the brushes is important. Too much current will overheat a brush and increase both brush and ring wear. Too little current will hinder the formation and maintenance of the ring film, also leading to increased brush or ring wear. The number of brushes on a machine should normally allow for proper current through each brush at rated excitation. If a machine is run for an extended period of time with low excitation, the ring film can erode away and brush wear will increase due to low current density in the brushes. Some plants, if going into extended periods of low excitation, will remove brushes to maintain current density in the remaining brushes.

The brushes should have even current density throughout their cross sectional area. If the brush faces do not fully contact the ring, current will be concentrated in the small contact areas of the brushes. This leads to overheating of the brush and increased electrical erosion of both the brush and the ring. Eventually the brush face will wear down to make full contact with the ring. However, film erosion and possible ring surface damage may have already occurred.

A small number of brushes can be replaced without significantly affecting the film or ring, approximately 5 to 10 percent of the brushes. The increased electrical resistance, due to the smaller contact area, will shift current to the majority of the brushes having full contact. If a large number of brushes are replaced without being pre-arced to fit the ring, there may not be enough brushes remaining to provide sufficient contact area with the ring.

Brush chatter is caused by friction with the ring and the brush not being held securely in its holder. Chatter can lead to chipping and arcing of the brush. Low brush pressure, holder misalignment, and excessive ring clearance for the holder are other causes of chatter. Typically, a holder has 1/8 inch clearance from the ring, though manufacturers may specify other clearances. Too little clearance could cause the ring to strike the holder when in operation.

Replacement of brushes that are of a different model than the remaining brushes will likely accelerate brush wear and failure. Due to the differing characteristics of the two brush models, one model will likely carry significantly more current than the other. The brushes could overheat and fail, resulting in arcing and possibly a flashover.

Flashovers can also occur when a brush that is being replaced accidentally drops onto brushes of the opposite polarity while its shunt (pigtail) is still electrically connected to its rigging. Older machines employing pigtail connections bolted to the brush rigging are particularly susceptible to this type of mishap.

Brushes have to slide smoothly in their holder so that adequate brush pressure is maintained as the brush wears. Insufficient clearance inside the brush holder can cause binding of the brush. Carbon dust can build up between the brush and its holder, further restricting brush movement. Too much clearance can also bind the brush, but by different means. Brushes can become cocked inside their holder if there is excessive clearance. Chattering and vibration can wear a ridge on the side of the brush that catches the edge of the holder and prevent movement of the brush. When the brush is prevented from sliding through its holder, brush pressure decreases and eventually the brush loses contact with the ring, resulting in arcing.

On commutators, the brushes need to be aligned so that all the brushes of the same polarity contact the commutator bars at the same time. Otherwise, with unaligned brushes making contact with different bars, several bars may be shorted out by the brushes. Furthermore, the brushes have to be aligned as close as possible to the neutral axis of the exciter when it is under normal load to minimize arcing.

Brush Holders and Rigging

If the brush holders and brush rigging hardware is not properly re-installed, tightened, and secured, the holders and the entire rigging may shift. Frictional force between the ring and brushes, and vibration, can shift the rigging and holders enough to alter alignment of the brushes. Furthermore, if the rigging shifts significantly, it may contact the rings and other components such as the collector cooling fan.

As brushes wear, carbon dust is generated and can collect on surfaces of rigging and bus bar insulators. Cooling fans may keep dust from collecting on the rigging directly, but can blow the dust into other areas of concern. The carbon dust is conductive and can lead to grounds and shorts if allowed to collect in significant quantities. Typically, cleaning does not have to be performed more frequently than normally scheduled plant outages, a 1 to 2 year cycle. However, excessive brush wear or inadequate air flow may allow dust buildup that can lead to flashover of the rigging or grounding of the field circuit.

Rectifiers

Rectifier banks used to create a DC field current for either the exciter or the generator field are most likely to suffer age and temperature related failures. As with all current creating devices, I^2R losses in the rectifiers produce heat. Excessive heat damages the diodes or SCRs in the rectifier by breaking down the semiconductor and creating either a short or an opening in the device. Heat can be produced by an overcurrent or a loose connection to the device. Insufficient cooling will also allow excessive heat to build up in the device, causing a failure. A loose mounting of a semiconductor on its heat sink creates a twofold problem. The loose mounting does not provide a good thermal path to cool the device, and, since the heat sink often serves as an electrical connection, the loose connection generates additional heat.

Rectifiers, being semiconductors, have decreasing electrical resistance with increasing temperature. A localized hot spot will have lower resistance than surrounding cooler areas in a semiconductor. Therefore, the current through a semiconductor will tend to concentrate at a localized hot spot. The increased current in a hot spot will generate more heat, thus lowering the resistance of the hot spot further and creating the condition of thermal runaway. High current, inadequate cooling, or a poor connection can lead to overheating that may produce hot spots in a rectifier. Excessive heat also affects semiconductors by migrating molecules of the doping substance through the substrate, altering the characteristics and performance of the device. An insufficiently torqued bolt, a weak spring, damaged or corroded mounting hardware, oxidation, or corrosion of the mounting surface can cause loose connections.

Voltage surges can break down the semiconductor, creating a shorted device. Surges or spikes can come from the power source in a static system, even from transients and lightning strikes outside of the plant. A trip or even a rapid decrease of the excitation system can cause the residual magnetism in the field to develop a voltage that may stress the rectifier components. Faults out in the power system create negative sequence currents which can induce damaging voltages in the field. A de-excitation device, such as a crowbar device, aids in preventing damage from these types of overvoltages.

Even without overcurrent or overvoltage, a diode or SCR will eventually fail after years of normal service. These failures are generally impossible to predict, though some data is available to give probability of failure for specific devices over an expected lifetime of the device. Higher temperature and voltage stress, even if not excessive, raises the probability of failure, thus shortening the life of the device.

Other components in the rectifier bridge, such as capacitors and fuses, lead to rectifier failure. Capacitors and resistors commonly are used to provide surge protection and filtering to the bridge. While the capacitors typically do not carry heavy currents, they are subject to heat from other components of the bridge. Inadequate ventilation can allow heat buildup in the bridge and possibly damage the capacitor.

Capacitors are also subject to damage from voltage surges and spikes. Some capacitors may have a relatively short life. The probability of failure increases after a certain length of time, usually several years of service. Typically, capacitor failure occurs from breakdown of the dielectric between the plates of the capacitor, creating a short through the capacitor. It is this dielectric which is stressed and possibly weakened or damaged by excessive voltage. Even if a voltage spike does not immediately cause a failure of the capacitor, the dielectric may be weakened so that the life of the capacitor is significantly shortened.

Fuse failure is probably the most frequent trouble in the rectifiers. Fortunately, fuses almost always fail open; though in rare cases fuses were found to have failed to blow. Heat is the most likely cause of a fuse's failure. A high ambient temperature lowers the current rating of the fuse, creating the situation of a fuse blowing with a current less than rated. A loose connection to the fuse, such as loose spring fingers or a loose bolt, creates a localized hot spot due to I^2R losses. The heat migrates into the fuse causing the fuse to blow.

Rectifier banks typically have disconnect switches on their AC and DC sides to isolate them for maintenance. Though switch failure is unlikely during generator operation, failures have occurred due to improper maintenance. Application of the incorrect grease on the contacts can create high resistance across the contacts. Loose fingers on the contacts also can create high resistance. The heating from the high resistance damages the contact surfaces and can lead to burning and arcing between the contacts.

Cooling

Several different methods of cooling are used in excitation systems. The most common and widely used is air cooling. In its simplest form, vents allow air to circulate freely through the cabinet or component, picking up and removing heat. Forced air systems use fans, either to force air through components, to force more air through a component to provide more heat removal, or both. The fans can be powered by their own motors or attached to a machine's shaft, such as with an alternator, using a small fraction of the rotation energy of the shaft to move the air.

Motor driven fans, typically used in cabinets and transformers, are subjected to bearing and winding failures. The shaft driven fans, such as those to cool rotating exciters and collectors, are subject to misalignment and damage during overhauls. Shaft driven fans should last as long as the alternator or generator. The life of a motor driven fan, on the other hand, depends on the failure rate of the bearings and windings of the drive motor. Abrasive substances in the air can cause wear on the fan blades. However, it is rare that fan blade failure will occur without failure of other components from the abrasive particles. Fans have also been damaged by loose components and foreign material left near the fan.

Dirt can restrict the flow of cooling air, and also coat internal components, preventing adequate heat transfer to the air. Heat producing equipment located too close to intakes heats the cooling air and thereby makes component cooling less effective.

Filters are commonly used to prevent dust and other particles from entering components. The most common failure of filters is restricted air flow due to filter clogging from excessive dust buildup. In an extreme case, the differential pressure across a clogged filter may collapse a portion of the filter, allowing in not only unfiltered air, but the dust that was trapped on the surface of the filter.

Water is used in certain excitation systems to provide cooling to rectifier bridges. The water is de-ionized to prevent electrical conduction, and Teflon tubes are used to connect the copper pipes to the rectifier's heat sinks. Failures in the water cooling systems include loose fittings and build up of conductive deposits in the Teflon tubes. Over time, copper corrosion by-products are deposited on the inside of the Teflon tubing which, if allowed to continue, would create a conductive path.

Loose fittings typically do not cause a functional failure of the cooling system, but can cause failure of other components from the leaking water. Typically, loose fittings are from maintenance on the cooling tubing where inadequate tightening or faulty replacement parts are the cause of the leaks.

Connections

Loose electrical connections create high resistance in power and control circuits, producing localized heating at the connection. The localized heat can increase to the point of failing the connection, or burning nearby insulation and creating a flashover.

Power circuit connections are subjected to cyclic thermal stresses as the current through them increases and decreases. The thermal expansion and contraction of the connection materials can work a connection loose. Aluminum lugs and conductors are particularly susceptible due to creep and flow of the aluminum metal. Proper torque of the bolts and, if required, use of new lock or Bellville washers should prevent the connections from working loose. However, if the bolts are inadequately pre-stressed by torqueing and/or have worn washers, the connection may expand and contract enough to become loose. As the connection loosens, the electric resistance increases, raising the temperature of the materials and further loosening the connection. Eventually, the connection will fail, creating arcing across its parts, burning the connection and possibly nearby components. A failing connection in the field circuit requires the voltage regulator to increase field voltage to maintain excitation, which may accelerate the failure.

Vibration can also create loose electrical connections. If a connection is not properly pre-stressed by torqueing, the vibration may induce enough movement in connection hardware to further loosen the connection. The loose connection will fail, similar to one loosened by cyclic thermal stresses.

Vibration, and sometimes cyclic thermal stresses, can create fatigue failure of the connection and conductors. Generator field leads have cracked open due to cyclic fatigue stress. The voltage regulator will increase field voltage as needed to maintain field current, further worsening the damaged field lead.

Breakers

Excitation system breakers fail in the same manner as other breakers. Generator and exciter field breakers are DC rated breakers. Static excitation systems may use AC breakers to control the excitation power. AC breakers are also used elsewhere in the excitation system for control power, but these typically are not remotely operated as are the field breakers.

Dirty, pitted, or burnt main contacts increase contact resistance, causing further burning, arcing, and pitting of the contacts. Dirty, burnt, or corroded auxiliary contacts can prevent proper operation of the breaker and of other equipment relying on breaker position.

Breaker interlocks, if out of adjustment, can prevent closing of the breaker. Some breakers have door interlocks that have to be made in order for the breaker to close. A warped or misaligned door may prevent make up of the interlocks to allow breaker closure. If the breaker is not racked in correctly, secondary connections and interlocks may not be made up. Main connections may arc and burn if the breaker is not racked in correctly.

Often a field discharge resistor is connected across the field whenever the field breaker is opened or racked out. Failure of a breaker interlock may keep the field discharge resistor connected when the breaker is racked in and closed. Leaving the resistor connected across the field for an extended time will overheat and eventually burn and damage the resistor. At one plant, the tab that opens the resistor circuit when the breaker is racked in, was not reinstalled after a breaker overhaul. The resistor then remained connected across the energized field and eventually failed.

Misaligned linkage and improper lubrication of the linkage can prevent operation of the breaker. The breaker linkage operates the main contacts, breaker interlocks, and auxiliary contacts. Wear on breaker components can alter the adjustment of the linkages. During maintenance of the breaker, not readjusting and checking the operation of the linkage can result in failure of the breaker to operate correctly. Binding of the linkage can occur from old lubricant, the wrong lubricant, or no lubricant. At one plant, after a breaker would not trip electrically, it was discovered that the breaker's trip bar was not lubricated during maintenance, resulting in the leakage binding. The breaker trip coils are often not rated for other than instantaneous operation. Energizing the coil for longer than necessary to trip the breaker results in overheating the coil. Failure of the breaker's linkage or auxiliary contacts to de-energize the trip coil after the breaker opens can burn the coil.

Control wiring problems can interrupt the control circuit and prevent operation. Loose connections have caused openings in the control circuit that prevent breaker function. Wiring errors have caused nonfunction or malfunction of the breaker.

Bearings

The bearings and couplings used on exciters and their failure modes are much the same as those used on other components in a plant. Bearing failure modes include: vibration, lack of lubrication, electrical currents, misalignment, and manufacturing defects.

Vibration is often sensed at the bearings, though it often does not originate in the bearing. The bearing, since it supports the shaft, readily transmits vibration through its housing and is a convenient point to monitor vibration. A number of problems can cause vibration, these include unbalance in the rotor, shorted field turns, bent shaft, misalignment, or a resonance. Bearing problems such as oil whirl and bearing damage or defect are sources of vibration internal to the bearing.

Journal bearings are commonly used in rotating exciters. Vibration can cause deformation of the sleeve, separation of the sleeve, and in extreme cases, wiping the bearing. When the bearing no longer maintains radial position of the shaft, the journal makes contact with the babbit lining of the sleeve, wiping and destroying the babbit. The journal is usually scored from contact with the bearing housing. Furthermore, without the bearing maintaining radial position, the rotor can rub against the stator, causing iron and winding damage in both. In the case of PMGs, stator winding and rotor magnet damage can result.

The failure of the journal bearing that causes the journal to contact the sleeve is brought about in several means. The journal rides on a wedge (or wave) of oil in the bearing that prevents the journal from contacting the sleeve. Oil is typically pumped into the bearing where the rotation of the journal further forces the oil into a wedge upon which the journal rides. Normally, the location of the wedge is stationary, though oil is continuously flowing into the bearing, through the wedge, and then out of the bearing. Disruption of this oil wedge permits contact of the journal and sleeve, resulting in damage to the bearing and the machine.

An obvious disruption of the oil wedge is the lack of oil flow into the bearing. The lack of oil flow can be the result of lube oil pump failure, clogged oil lines and ports, or an oil line leak. The most typical cause of a clogged oil line is foreign material, such as a piece of a rag in the oil system. Oil of the wrong viscosity will not create an adequate wedge that can support the shaft. Age, heat, and contaminants can alter the oil's viscosity. Oil whirl is a condition typically brought on by low viscosity in which the oil wedge is not stable. Magnetic forces on the rotor, such as from the magnet center not aligning with the mechanical center of the rotor, also may cause oil whirl. With oil whirl, the location of the wedge is not stable and moves around the circumference of the journal, leading to shaft vibration at close to half running speed. As the oil wedge and the point of shaft support shifts, the journal may make contact with the sleeve material, resulting in eventual wiping of the bearing.

Minor damage to the bearing can also disrupt the wedge and hinder maintaining the radial position of the shaft. Electrical currents, if allowed to flow, will arc between the sleeve and journal, pitting both. If arcing continues, the surface damage to the bearing's internals accumulates to the point that smooth oil flow through the bearing is disrupted and an adequate wedge is not maintained. Chemical contaminants, either externally introduced or byproducts of oil ageing, can attack the surfaces of the sleeve and journal, resulting in damage to these surfaces that disrupt oil flow. Small particles, either from wear products or external contamination, circulating through the clearance between the sleeve and journal impinge on the sleeve and the journal, causing pitting and scoring. Larger particles may be embedded in the soft babbit lining of the sleeve and act like a cutting tool on the rotating journal.

Vibration forces may distort the sleeve, or even loosen the sleeve, thus worsening the detrimental effects of the vibration. A distorted or loose sleeve cannot maintain an adequate stable oil wedge, thus leading to a bearing failure. These initial vibration forces are often, but not always, caused by problems external to the bearing; such as misalignment, unbalance, rotor eccentricity, loose machine foundation, or from vibration in nearby machinery.

Electrical currents flowing through a bearing will arc as they cross gaps in the bearing. This arcing causes pitting of the bearing, burning of the lubricant, and possibly hardening of bearing parts. As mentioned in chapter 2, bearings are typically insulated to prevent current flow from induced shaft voltages. However, if the insulation is damaged, contaminated, or otherwise failed, potentially damaging current may flow. Also, the insulation may be shorted out by: improper installation or design of temperature and vibration probes; by improper assembly in which insulation components are omitted or damaged such as bolt sleeves and insulation washers; or by test leads, or other tools and material, left on the bearing housing.

Smaller machines, such as pilot exciters and cooling fan motors, may employ anti-friction bearings instead of journal bearings. These bearings rely on rolling elements (i.e., ball bearings) to maintain radial position of the shaft. However, adequate lubrication is also essential for proper operation and life of these bearings. Old grease or oil can contain oxidation, other age related by-products, or contaminants that can attack the surfaces of the rolling elements and the races. Electrical currents can cause arcing that damages the rolling elements and races. External vibration and existing damage to the bearing can harden, or brinell, the rolling elements, resulting in possible cracking, chipping, and further damage.

Couplings

Couplings serve a number of functions: transmit torque between different machines, provide a means to disconnect the machines for maintenance, and help dampen torsional vibration. Except for flexible couplings, they do not make up for misalignment of the machine and may be damaged from the misalignment. The misalignment may result during reassembly, not allowing for tolerances to account for thermal expansion of the machine shaft, or a loose machine foundation.

Flexible coupling have internal components, such as discs or diaphragms, which may be subjected to wear and stress. Although flexible couplings can tolerate some misalignment, an excessive amount can severely damage the coupling. A primary cause of flexible coupling failure in cyclic fatigue. Incorrect assembly or inadequate lubrication can lead to deterioration of the coupling and cause coupling failure.

Large couplings, typically, should be lubricated on a periodic basis and after disassembly. The lubrication provides corrosion protection and facilitates small movements in the coupling due to vibration. A lack of lubrication, or a lubricant that has solidified or broken down, can lead to both corrosion and wear of the coupling parts. Flexible coupling should be disassembled, cleaned, and inspected during outages. During operation, periodic machine vibration measurements and infrared thermography scans can detect potential coupling problems.

Excessive torque can damage the coupling. The sudden torque from synchronizing a generator out of phase, slipping a pole, or a large electrical fault, can impact the coupling enough to damage it. Torsional oscillations or vibration can create fatigue failure of the coupling components. One source of possible torsional oscillation is a malfunction of the Power System Stabilizer (PSS). If the PSS's input is not adequately filtered for effects from torsional oscillation, the PSS's response may drive further torsional oscillations.

Voltage Regulator

There are many models and types of voltage regulators used throughout the power industry; from electro-mechanical to digital controls. The failure modes are almost as diverse as the regulators. However, there are certain failure modes that are common to particular types of regulators.

Dust and dirt on contacts can prevent relays and switches from properly functioning or cause them to function erratically. Potentiometers also can function erratically due to dust interfering with the contact of the wiper arm. Motor operated potentiometers and rheostats have failed to provide linear regulation due to dust. Corrosion and oxidation of the contact surfaces can cause the same effects. In addition to preventing good conduction, fouled contacts can cause current arcing and pitting of the contacts. Arcing and pitting may not only permanently damage the contact surface and prevent proper conduction through the contacts, the contact may stick, or weld, in the closed position. Stuck contacts can cause a motor driven potentiometer to pass its upper and lower limiter, prevent transfer from the manual to the automatic regulator, and other sporadic malfunctions.

Dust and dirt can attract moisture and form a conductive path, resulting in shorted or grounded circuits. Some kinds of dust, such as carbon dust or metal filings from work in the cabinet, are conductive by themselves. Dust can also thermally insulate components, causing overheating of those components. If the regulator cabinets have cooling air filters, a clogged filter can cause high temperatures that may overheat components in the cabinet.

Harmonics and voltage transients in the power supply of the regulator can cause erratic performance and possible damage to components. Overheating and voltage spikes have caused damage to semiconductors, capacitors, and other components in the regulator. A failed capacitor often may not become immediately apparent. However, if noise and harmonics can be picked up on sensing, reference, and error circuits that are no longer adequately filtered, the result is fluctuating regulation.

Solid state analog and digital regulator components can be particularly sensitive to voltage and temperature conditions. Often a failed circuit is replaced without the knowledge of what caused the card to fail. Problems due to a manufacturing defect, overheating, voltage transients, or vibration can cause a card to fail. The conditions that cause the failure may have occurred at some time prior to the failure. The conditions may have only prematurely aged or minimally damaged a component on the card, thus setting in place a future failure.

Vibration causes looseness in the voltage regulator. Electrical connections, and even solder joints, have failed after extended periods of vibration. Circuit card edge connectors have been rattled loose. Oxidation on the card connectors has also caused malfunction of the card.

A main failure mechanism in voltage regulators is personnel errors; either during testing, maintenance, modification, or design. Wiring errors, either from design or mistermination, have caused protective relay actuation, instability, mis-operation, and malfunctions of the excitation system. Dropping of test leads with un-insulated tips has caused shorts and mis-operation in the regulator. Test jumpers and lifted leads left in the regulator have caused regulator mis-operation at start-up. In one instance, grounding straps were left on the input to a static exciter's regulator, resulting in destruction of the regulator and personnel injury. Inexperience and inadequate training have resulted in maladjustment of regulator controls. Often an incorrectly adjusted limiter, stabilizer, or protective device does not become apparent until a transient occurs, and the excitation system does not function correctly to mitigate the transient and remain in service.

Certain fairly-recent digital regulators rely on EPROM memory chips to retain their factory default setting, while using volatile RAM memory chips to retain field adjustments. A loss of control power, even a brief loss, can cause the regulator to revert to its default settings. Digital circuits can be susceptible to electromagnetic interference when not properly shielded. Standing in front of the cabinet with the door open and keying a radio has caused several sporadic operations. Also, unshielded circuits or improper grounding can allow stray signals and noise to be induced into the regulator, causing mis-operation.

Nearby components have caused voltage regulator failures. A nearby steam or water line leak can wet the regulator and cause shorts and grounds. Hydraulic lines and actuators have sprayed oil on cabinets. Hydraulic fluid has a tendency to flow and coat all components and surfaces in the cabinets. Heat and vibration from nearby equipment can have a detrimental impact on the regulator components.

Early failure of new components, though not frequent, is not unusual. Manufacturing defects that are not discovered during inspection and testing cause failure after a short service time. Heat, vibration, and other service conditions stress the defective component enough that failure soon occurs. The failure probability of a component over time follows what is typically called a bathtub curve. There is an initial high failure probability, followed by a normal life of low failure probability, and then a rise to high failure probability at the end of service life.

It is not unheard of for a replacement component to fail soon after installation. Though it is likely that an adverse condition, such as excessive heat, may have caused the failure of the original replacement part, there is also a chance that the replacement part was defective. If a thorough investigation of component failures is not performed, there is a risk of not knowing whether the original and subsequent failures were due to defects or to an adverse ambient condition.

As calibrated systems are subjected to thermal cycles, vibration, repeated operations, etc., the set points at which the system was calibrated will drift or shift. Digital systems have reduced the set point drift. However, ageing of other components in the system may necessitate adjustment of the set points. Normally a tolerance range around each set point is determined, in which the set point can drift without adverse system impact. A missed or extended calibration cycle may allow one or more set points to drift beyond the allowable tolerance; creating the possibility of instability, erratic operation, false or inadequate protective response, poor regulation, and excitation system failure.

Cabinets

Cabinets are not typically thought of as items with failures. However, there are potential direct and indirect failures associated with equipment cabinets and panels. Door switches provide alarm and circuit interlocks. Malfunction of the switch or door can create a false alarm or undesirable circuit actuation. Several incidences occurred in which a misaligned or a warped door prevented an interlock from closing, resulting in a nonfunctioning field breaker.

Vibration can loosen connections and components mounted in a cabinet. If the cabinet is not firmly and squarely mounted, vibration from other equipment can be amplified in the cabinet. Components mounted on cabinet doors can be subjected to vibration when the doors are opened and closed. If a door is bumped, banged or closed too forcibly, susceptible components may be loosened or may actuate.

Improper design may cause unrelated circuits to be cross tied. If lighting and convenience receptacles are tied into the power supply for other components in the cabinet, a possibility of interference or an overload on the receptacles could cause malfunction of a system component.

Dirt and dust can build up in a cabinet over time, especially if the cabinet is air cooled and in a dusty environment. As in other components, dust buildup decreases the effectiveness of the cooling air, creates the possibility of shorts, and can interfere with electrical contacts in switches and relays.

Blockage of the cabinet vents can lead to overheating of components in the cabinet. Installation of heat producing equipment may overheat other components in the cabinet. Placement of a transformer below a printed circuit card is an example of how heat rising off one component may adversely affect another component.

Sensors

Failure of excitation system measurement and sensing components can cause problems ranging from false alarms to tripping of the system and the unit.

Generator and exciter vibration is typically monitored with displacement vibration probes. Failure of the probe can cause either a loss of monitoring or false erratic vibration readings. Loose signal lead connections or damaged conductors are often the cause of probe failure. Improper reconnection of the leads and damage to the conductors usually results during maintenance outages. Dropped or otherwise damaged probes are other failure modes, though age related and manufacturing defects are also possible.

Temperature elements, RTDs and thermocouples, suffer failures similar to vibration probes. However, is it often an age-related failure of the element that causes loss of signal. Age, heat, and vibration can eventually cause an open circuit in the element.

Failure of a vibration or temperature element can allow an adverse condition in equipment to go undetected. The lack of routine monitoring of element output for presence and consistency of the signals may allow a detectable minor equipment abnormality to worsen into equipment failure.

Failures in Potential Transformer (PT) and Current Transformer (CT) circuits can cause loss of protection and feedback to the voltage regulator. An open CT circuit can have dramatic results, though in recent years CT protection devices have been employed to clamp voltage from an open CT circuit. CT failures are rather infrequent, mostly caused by mis-wiring a circuit conductor. Age and heat may cause shorted turns in a CT, resulting in a decreased turns ratio.

PT circuit failures have been brought about by mis-wiring and shorted turns, similar to CTs. A more common failure mode for a PT circuit is a blown fuse. A loss of voltage sensing from the generator terminal to the AVR, may result in over-excitation as the AVR drives excitation to the maximum limit to recover voltage. Many excitations systems employ a loss of voltage sensing circuit to detect fuse failures and prevent the undesired AVR response. However, older systems may not have this detection and could be subjected to over-excitation resulting from a blown fuse. Additionally, other protection and control circuits can be affected by a PT circuit failure, such as directional overcurrent relays, metering, watt, VAR tranducers, etc.

Failure Modes

The following are common failures in the equipment used in excitation systems. Not all the equipment and failures will apply to every excitation system.

Pilot Exciters and PMGs

Bearings and Couplings

Bearing, overheating
Bearing, wear or mechanical degradation
Bearing, electrical arcing
Bearing, seal failure
Bearing, lubrication failure

Coupling, internal wear and failure
Coupling, improper assembly
Coupling, hardened grease
Coupling, cracked disc

Windings

Armature winding, insulation ageing
Armature winding, looseness
Armature winding, mechanical wear and abrasion
Armature winding, overheating
Armature winding, dust buildup

Armature iron, lamination damage
Armature iron, lamination looseness
Armature iron, lamination overheating

Field winding, insulation ageing
Field winding, looseness
Field winding, mechanical wear and abrasion
Field winding, overheating
Field winding, dust buildup
Field winding, shorted turns

PMG rotor, permanent magnet looseness

Exciters: Alternators and DC Generators

Bearings

Bearing, overheating
Bearing, wear or mechanical degradation
Bearing, electrical arcing
Bearing, seal failure
Bearing, lubrication failure

Coupling, internal wear and failure
Coupling, improper assembly
Coupling, hardened grease
Coupling, cracked disc

Windings

Armature winding, insulation ageing
Armature winding, looseness
Armature winding, mechanical wear and abrasion
Armature winding, overheating
Armature winding, dust buildup

Armature iron, lamination damage
Armature iron, lamination overheating
Armature iron, lamination looseness

Field winding, insulation ageing
Field winding, looseness
Field winding, mechanical wear and abrasion
Field winding, overheating
Field winding, dust buildup
Field winding, shorted turns

Collectors and Commutators

Brushes, excessive wear
Brushes, excessive arcing
Brushes, breaking or chipping

Ring, excessive wear
Ring, eccentricity
Ring, inadequate film
Ring, damaged surface

Brush rigging/bus bars, excessive dust buildup
Brush rigging/bus bars, insulation failure
Brush rigging/bus bars, loose connection

Commutator, shorted bars

Rectifiers

Diode or SCR, open circuit
Diode or SCR, short circuit
Diode or SCR, looseness

Capacitor, open circuit
Rectifier, overheating
Rectifier cooling, water leak
Rectifiers cooling, conductive deposits
Disconnect switch, overheating
Disconnect switch, contact failure

Coolers

Air filter, clogged
Cooling line, clogged
Cooling line, valved out
Fan, blade failure
Fan, drive motor failure

Excitation Transformer

Winding, insulation ageing
Winding, looseness
Winding, overheating
Winding, dust buildup

Laminations, looseness
Laminations, damage
Laminations, overheating
Armature iron, lamination looseness

Bushings, dust buildup
Bushings, loose connection

Field Breaker

Breaker, contacts dirty or damaged
Breaker, fail to open
Breaker, fail to close

Field discharge resistor, overheated
Field discharge resistor, circuit fails to open
Field discharge resistor, circuit fails to close

Generator Field

Collectors

Brushes, excessive wear
Brushes, excessive arcing
Brushes, breaking or chipping

Ring, excessive wear
Ring, eccentricity
Ring, inadequate film
Ring, damaged surface

Brush rigging/bus bars, excessive dust buildup
Brush rigging/bus bars, insulation failure
Brush rigging/bus bars, loose connection

Grounding brush, excessive wear
Grounding brush, fails to maintain shaft contact
Grounding brush, nonconducting

Winding

Field winding, insulation ageing
Field winding, looseness
Field winding, mechanical wear and abrasion
Field winding, copper dusting

Field winding, overheating
Field winding, dust buildup
Field winding, shorted turns

Crowbar

Resistor, overheated
Circuit, shorted

Voltage Regulator

Voltage regulator, component overheating
Voltage regulator, dust buildup
Voltage regulator, erratic operation
Voltage regulator, loose components
Voltage regulator, loose connections
Voltage regulator, set points, drift
Voltage regulator, PT or CT circuit failure
Voltage regulator, contracts oxidized or dirty
Motor driven potentiometer/rheostat, erratic operation
Motor driven potentiometer/rheostat, exceed limits
Transfer circuit, fails to transfer to AVR or to manual
Switches and relays, contacts fail to close or open
Field voltage, excessive harmonics and spikes
Cabinet, condensation

4
DIAGNOSTIC AND INSPECTION TECHNIQUES

Tests, inspections, and monitoring tasks are performed to ascertain the condition of the components in the excitation system. They not only determine if the system is suitable for continued service, but also if part of the system is deteriorating or operating outside of acceptable parameters. Many of these tasks not only monitor the present condition of the system, but also are often predictive in that many can indicate in advance of a possible failure or malfunction.

Certain tasks can only be performed online while the equipment is running, as they assess some operating parameter of the system, such as vibration. Other tasks can only be performed offline due to inaccessibility or the presence of dangerous voltages and rotating elements, such as insulation resistance measurement. Certain tasks can be performed either online or offline, such as brush inspection. However, the degree to which the task can be performed or achieved often varies between the online and offline version of the task.

This chapter provides an overview of the common condition monitoring and predictive tasks routinely performed on excitation systems. Not all tasks will be applicable to every excitation system. A number of the tasks can be used as diagnostic tools in order to investigate a known or possible failure or malfunction with the system. If a failure or malfunction is found or suspected, additional tasks can be used to assess the cause of the problem, and also whether the system can continue to operate in its present condition.

Online Tasks

Vibration Monitoring and Analysis

Periodic vibration monitoring should be performed on the rotating element of the exciter, PMG or vibration sensitive equipment such as the Exciter Control Cabinet.

Vibration Monitoring and Analysis, Data Acquisition

The systematic acquisition of data should be accomplished on a scheduled basis. Typically, vibration data is collected monthly with adjustments for equipment condition and problem severity. Two time frames are useful for periodic monitoring: (1) a time period for equipment in good machinery health, usually monthly or quarterly; and, (2) a shorter time frame for equipment with adverse conditions that require closer observation.

Data acquisition should be initiated by the Plant's Computerized Maintenance Management System (CMMS). This type of notification will ensure a consistent and reliable means of initiating data collection.

Measurement Locations

Vibration data should be taken on equipment bearing casings or housings, using portable data collection equipment; or in the case of larger and more modern equipment, using permanently installed monitoring equipment. The most effective and commonly used device to detect vibration is the non-contact proximity probe, which can be permanently installed in the bearing caps for journal type bearings, or velocity and acceleration pickups for anti-friction bearings. As the rotor vibrates, the vibration energy is usually transferred to the bearings and bearing housings. The bearings actually offer a good transmission path from the rotating elements to the bearing housing.

It is important to know the location of the radial bearings, the type of bearings, and the location and type of thrust support, before determining measurement point locations and attempting to acquire data on equipment. Once this information is known, data can then be gathered in the appropriate locations and directions. A cross-section mechanical drawing of the machine is helpful if the bearing locations are not obvious.

In horizontally oriented machines, the radial bearings support the weight of the rotating shaft assembly, as well as any dynamic radial loads. The thrust bearing, or thrust collar, supports the dynamic thrust load. In vertically oriented machines, the radial bearings support the radially directed dynamic loads, and the thrust bearing supports the rotor weight and any dynamic thrust loads.

In most cases, regardless of the machine orientation, only one thrust vibration reading is necessary; however, it is recommended that two radial readings be taken at each bearing/housing, with orientations as shown in the figure below. The 90° separation is essential for determining the exact location of the maximum vibration reading vector; and, it is especially useful when determining phase relationships.

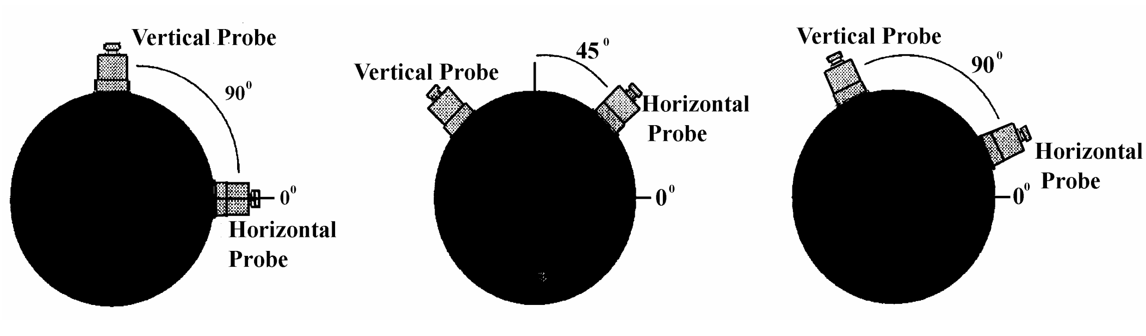


Figure 4-1
Typical Vibration Probe Configurations

Note: Although it is ideal to space the probes 90 degrees apart, it is not always achievable. In these cases, place the probes as close to a 90-degree orientation as possible.

Data Interpretation

It is very important to establish baselines and trends on all monitored equipment to detect developing faults. All anomalies should be documented and tracked for further deterioration until correction. Once baselines and trends are established, and equipment problems are defined and short-term critical anomalies addressed, the monitoring periodicity may be altered.

Coordination of vibration monitoring results with other technologies and information, such as thermography, oil analysis, and/or performance monitoring, is essential for program success. For example, one technology may serve to confirm a developing fault detected by another technology, thereby significantly increasing the overall program reliability.

Periodic vibration monitoring can detect faults in rotating equipment and other vibration sensitive equipment in their early stages of deterioration. Early detection and early repair of these defects can enable equipment and components to last longer. Keep in mind that some faults should be watched for progression, such as bearing faults. These faults must be detected very early and should be trended for the optimum time for replacement.

A vibration monitoring program is considered successful if faults such as imbalance, misalignment, and bearing defects are detected accurately. A more advanced vibration monitoring program can detect resonance problems, structural defects, and gear faults.

Acceptance Criteria

General vibration severity charts are widely available to aid in determining the overall condition of rotating excitation equipment. However, a rule of thumb when dealing with overall readings in displacement, mils, peak to peak, is: an exciter with sleeve bearings operating at 1800 rpm, less than or equal to 0.8 mils (0.02 mm) is considered to be operating in the “Good” range; an exciter operating at 3600 rpm, less than or equal to 0.4 mils (0.01 mm) is considered to be operating in the “Good” range.

For rotating components with anti-friction bearings, a measure of velocity is generally applied with acceptance levels of “Good” being 0.0392 – 0.0785 ips (0.996 – 1.99 mm/s), “Fair” being 0.0785-0.157 ips (1.99 – 3.99 mm/s), and “Slightly Rough” being 0.157 – 0.314 ips (3.99 – 7.98 mm/s). Any readings above 0.314 ips (7.98 mm/s) are considered to be in the “Rough” to “Very Rough” region of operation.

Torsional Vibration Monitoring

Torsional vibration monitoring typically requires transmitters attached to the shaft and detectors mounted stationary off the shaft. The detectors pick up slight variations in the shaft’s rotational speed. The transmitter can be actual devices emitting an electromagnetic signal, or simply be a tooth wheel or even reflective tape. The sensors vary depending upon the type of transmitter attached to the shaft. Proximity probes are often used with toothed wheels, and an optical sensor with reflective tape. The detectors feed signals into the torsional vibration analyzer, which provides indication of torsional vibration.

Torsional vibration monitoring is not typically performed as a routine task, due to the sophisticated equipment often required to get accurate results, and the small probability of occurrence. However, in recent years plants have installed monitors as the test equipment becomes more practical to use. The monitors provide indication of the presence of, and the severity of, torsional vibration from which the appropriate actions can be taken (i.e. trip, load reduction, etc.) and a determination into the cause of the vibration, such as a malfunctioning power system stabilizer.

Collector, Commutator and Brush Inspections

The following periodicities are suggestions only. Periods should be adjusted per manufacturer recommendations and plant's trend data and experience. Generator, exciter, and shaft grounding brushes should all be checked as follows.

Daily

Inspect brushes for abnormal arcing, chatter, dust buildup, and short length. Typically manufacturers provide a slot or another point on the brush holders that give visual indication of a brush's length being too short, such as when the rivet or top of the brush lines up with the point. Log brushes that are replaced, noting brush position and length.

Check that the brush spring clips or mechanisms are not caught or otherwise hung up on the holders. The shunts, or pigtails, of the brushes should be visually inspected for overheating, loose connections, wearing against the rigging and other damage.

Visually inspect collector/commutator area for dust and debris build up, loose connections, oil or water leaks, foreign material, and proper air flow.

Weekly

Pull up on each brush to verify freedom of movement. An insulated tool is recommended for attaching to and pulling on the brush or its pigtail instead of just using insulated gloves. Check alignment of the brushes to ensure that the holders or the rigging have not shifted during operation. Varying loads of the generator may cause shifts in the axial displacement of the shaft and rings; ensure that brushes are not riding over the edge of the ring.

Monthly

Remove one brush from each ring. Examine brush for raking, chipping, scoring, and dust accumulation. Inspect holders of removed brushes for dust accumulation. Replace brushes back into their original holders.

Using a hand held vibration probe with an insulated rod, measure vibration of several brushes on each ring. The measured brushes should cover the complete width of the ring, otherwise it is not necessary to measure more brushes. However, the same brushes should be checked every month to provide more accurate trend data. It is not unusual for brush vibration to trend slightly upwards. Monthly data should be trended and checked for sudden increases in vibration and a vibration trend that is more rapidly increasing.

On non-constant pressure spring brush holders, measure spring pressure and adjust as necessary.

Perform a thermoscan of brushes, rings, rigging, bus bars, and collector area. Note hot spots and any brushes that appear cold. If a thermoscan is not performed, measure current through each brush to ensure that no brush is carrying excessively more or excessively less than its share of current.

Strobe Inspection

Ascertain ring condition with a strobe light to freeze or slow down the image of the rings. Advancing or retarding the strobe pulse allows the inspector to view the entire ring from one advantage point and "freeze" the ring as necessary to view a specific area.

Check surface condition for pitting, foot printing, grooving, threading, burnt or overheated areas, and film condition. Commutators should also be checked for alignment of brush with respect to bars on commutators, copper dragging, signs of burning and arcing between the bars.

Infrared Thermography

Infrared Thermography (IRT) is a non-intrusive, predictive and diagnostic technology. IRT is applied to the generator excitation system and its components as it is with other power plant systems and components. IRT plays an equally significant role in Predictive Maintenance (PdM) programs for electric power producers, as do other PdM technologies.

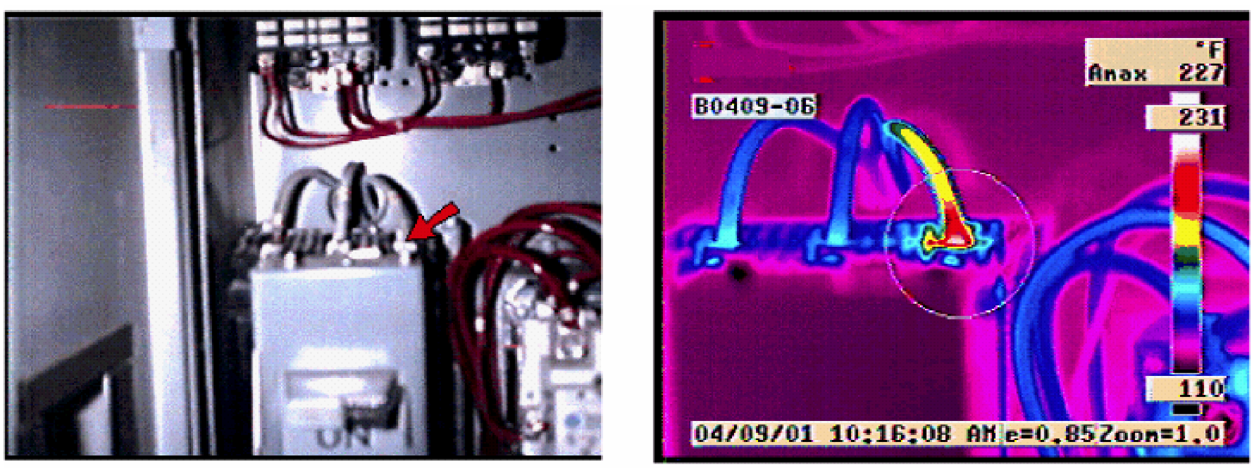
An IRT program involves performing a periodic inspection survey of critical equipment in the excitation system, including the brushes and brush rigging, bus bars, electrical connections, rectifier banks, field circuit breaker, mechanical couplings, cooling water lines, voltage regulator cabinets, and power and control cable connections. These components may exhibit an abnormal thermal pattern, at some point in time, prior to functional or operational failure. An inspection made with an infrared thermography camera can detect these abnormal thermal patterns. Abnormal thermal patterns, observed on any given piece of equipment, are referred to as "thermal anomalies."

An infrared thermography camera uses infrared sensors to make simultaneous temperature measurements of multiple points on the surface of a piece of equipment (a target), without making physical contact with the target. The measurements of the target surface are taken from a distance. IRT is not an "x-ray" technique. It will not make measurements through an object. IRT inspections must be done while the equipment is under normal operating load, and after a period of run-time sufficient enough to allow a component to reach normal operating temperatures. IRT data is displayed in the form of a picture. The pictures are commonly referred to as thermograms, or thermal images. Thermal images can be analyzed in real time, or stored electronically and analyzed at a later time. The images are analyzed to determine whether the thermal pattern is normal or abnormal.

An infrared thermography program conducted as part of a comprehensive PdM program that involves other predictive and diagnostic technologies, such as vibration analysis, oil analysis, etc., will provide benefit for a power station that must maintain the excitation system in proper working order. An effective IRT program will foster more effective maintenance planning in addition to helping to avoid catastrophic excitation equipment failures that lead to unscheduled downtime and the associated costs.

Reading a Thermal Image

It is necessary to understand how to properly read a thermal image before it can be analyzed. There are various manufacturers of infrared systems and, therefore, many different types of systems available for use in the field. Infrared systems (cameras) are operated differently, and they display their data in slightly different formats. There is a learning curve necessary to gain familiarity with each one. Even though these differences exist, there are also similarities. Infrared systems are all designed to yield the same result; the thermal pattern of a target. Therefore, an evaluation of a thermal image taken with one type of camera should be sufficient to foster a basic understanding of how to read a thermal image. An example evaluation is provided with the figure below.



Visual Image #1 **Thermal Image #1**

Figure 4-2
Thermo Image of a Hot Connection, With Visual Image for Comparison

The visual image (above, left) and the thermal image (above, right) were taken of a 480 volt circuit breaker. The red arrow, superimposed on the visual image, provides a match location with the corresponding location on the thermal image. Focusing on the thermal image, observe the numerical information on the vertical color palette toward the right side of the picture. The value of 110º F, displayed at the bottom of the scale, quantifies the low-end value of this particular level and span setting. Any areas of the image that show up in black are near or below the low-end temperature value, near 110º F (43º C) or below. Moving up the color scale toward the high-end temperature value, the magenta, blue, green, yellow and red colors represent temperature values increasing, linearly, from the low-end temperature value of the scale, 110º F (43º C), to the high end temperature value of the scale, 231º F (111º C); 231º F (111º C) is the high-end temperature value of this particular level and span setting.

Any areas of the image that show up in white are near, or above, the high-end temperature value; near 231º F (111º C) or greater. The setting for this thermal image allows for the measurement of temperatures between approximately 110º F (43º C) and 231º F (111º C). The span for this setting is the difference between the low-end temperature value, 110º F (43.33º C), and the high-end temperature value, 231º F (110.56º C); or 121º F (67º C). The level is adjusted by increasing or decreasing the low and high-end values simultaneously. Most infrared instruments are versatile enough to allow changes to the temperature span and level, or the color palette, depending upon necessity dictated by the temperatures of the targets being inspected, and/or personal choice. Regardless of the color palette, span, or level, the method of interpretation remains as described above.

The thermal image also employs the use of a common analytical tool. The white circle, superimposed on the image, is set for the "Amax" mode. In this mode, the tool will indicate the highest temperature measured within the circle. This temperature is displayed in the upper right hand corner of the image, Amax 227º F (108º C). The "hot spot" temperature measured on the right phase connection, at the line side of this circuit breaker, is 227º F (108º C). Other useful data displayed on the image are date, time, image number, emissivity, etc.

Analyzing a Thermal Image

Thermal data is often analyzed comparatively. A reference point has to be identified. When a reference point is identified, the temperature of the reference point is compared to the temperature of the component being analyzed. A reference point can be a spot on a piece of equipment that is similar to, or identical to, the component being analyzed. The logical basis for this type of analysis is that since the components are similar, the reference component and the component being analyzed would be expected to exhibit similar thermal patterns. An assumption must be made when using similar service equipment as a reference. This assumption is that amp load, run time, and external environmental conditions are the same for the reference component as they are for the component being analyzed. For example, if the reference component is loaded at 100 amps, then the component being analyzed should also be loaded at approximately 100 amps. If this is not the case, the comparisons of the two components will be unreliable.

A baseline thermal image of a component could be used as a reference point. Baseline data is taken when a component is under normal loading conditions, and when the station is receiving the performance it expects from the component. Ambient air temperature, and the load at the time the data is taken, should be recorded and kept with the baseline data. If accurate baseline data of a component is available, then a comparison of subsequent data taken on a component to its baseline data can be made. Ambient air temperature can also serve as a reference temperature. Ambient air, for example, is commonly used for referencing comparisons with electrical connections. Whatever reference point is chosen, thermal characteristics of the reference point are compared to thermal characteristics of the component being analyzed. Then an assessment is made.

It has already been determined that the temperature measured on the right phase connection, at the line side of the circuit breaker in the thermal image of Figure 4-2, is 227º F (108º C). Before maintenance can be planned, this condition has to be analyzed, and a severity classification has to be assigned. A severity classification can be assigned after considering the calculated temperature rise. If a circuit breaker connection is terminated properly, and the component is being operated under amp load conditions recommended by specifications, the temperature of the connection should not greatly exceed the temperature of ambient air. Assume that the temperature of the ambient air at the circuit is 100º F (38º C). This serves as the reference point. Using this reference point, the temperature rise is calculated to be 127º F (71º C),
227º F - 100º F = 127º F (108.333º C – 37.778º C = 70.56º C).

The circuit breaker, illustrated in the thermal image, is generating an abnormal amount of heat. There is, most likely, a high resistance connection at the right phase. Based on the temperature rise calculated above, a severity classification of this problem would be assigned according to published guidelines. A typical guidelines are shown in the following.

Table 4-1
Severity Guidelines

Temperature Rise	Severity Classification	Action
18º F (10º C) or less	Minor Problem	Address as part of routine maintenance.
19º F – 63º F (11º C – 35º C)	Intermediate Problem	Trend temperature. Repair within 1 month.
64º F – 135º F (36º C – 75º C)	Serious Problem	Trend temperature. Repair within I week.
136º F (76º C) or greater	Critical Problem	Repair Immediately

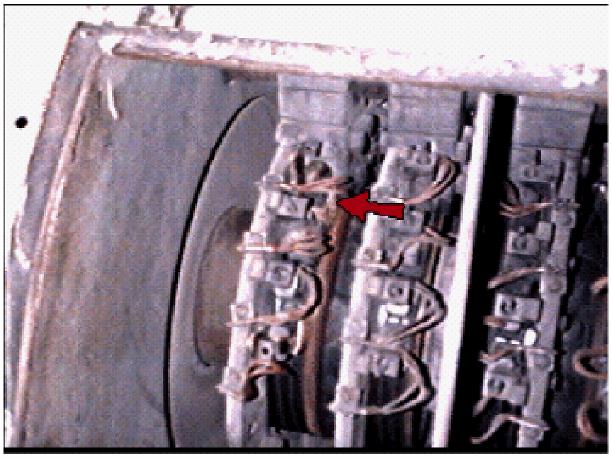
It is important to note that these are severity guidelines. They are not to be strictly adhered to. Temperature rise must be taken into consideration and should only be used as a benchmark reference. A judgment is then made as to what level of severity should be assigned. Also, it must be understood that these severity guidelines pertain to electrical connections.

When evaluating equipment other than electrical connections, severity classifications will then be almost exclusively based upon the experiences and interpretations of the analyst. The interpretations are made in light of the function of the component being analyzed, on a case by case basis. In these instances, comparisons to similar service equipment and baseline data are heavily relied upon.

In the case of the thermal image in Figure 4-2, if it was determined that the equipment being serviced by this breaker was critical to production, the temperature rise of 127º F (71º C) would require that a severity classification of “Serious” be assigned.

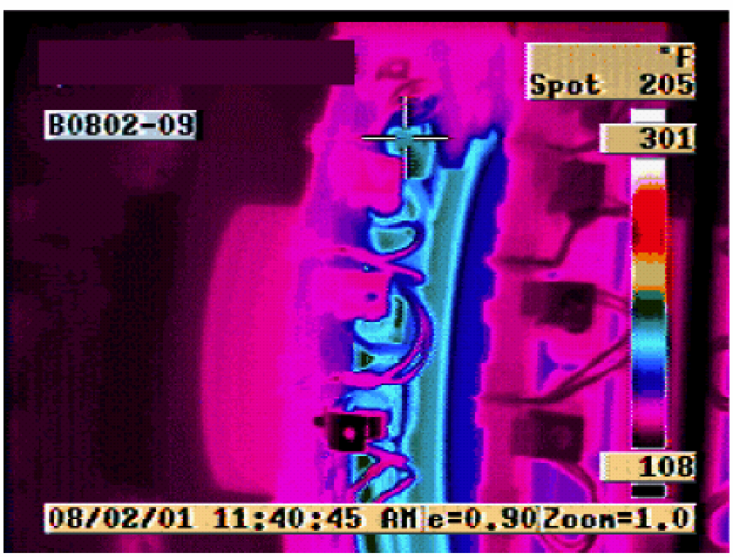
Specific Application of IRT

A visual image of the brush compartment of a generator exciter is shown in the following figure. In the figure, thermal image 3-80 shows that the brush contact temperatures are measured at nearly 300º F (149º C). Although heat is certainly generated by friction from contact with the exciter shaft, 300º F (149º C) is excessive. When the unit was taken off line, the contacts were observed to have been making poor contact with the shaft. The contacts were machined so they would mesh properly with the shaft. When the unit was returned to service, a post-maintenance IRT inspection was done. A thermal image of the results of the post-maintenance test is shown in image 3-81 of the following figure. The temperature decreased by nearly 100º F (56º C).



3-79

3-80



3-81

Figure 4-3
Thermo Images Of Brushes Before And After Repair, With A Visual Image For Comparison

Bearing Insulation Checks

Many exciters have bearings with two layers of insulation and metal between them. This provides a ready means to test bearing insulation during operation. An insulation resistance test should be performed across each layer of insulation. Typically, readings over 1 megohm are considered acceptable; though the readings should be compared to previous readings to note any excessive drop in insulation resistance.

Bearings having a single layer of insulation can be checked online, although not as accurately as those with double layers. Measuring shaft voltage across the bearing insulation indicates that the insulation has totally failed. Generator load should be recorded with shaft voltage measurement, as shaft voltage can vary with load.

Another test is to measure shaft ground current. At the location of the shaft grounding brush, connect one end of the ammeter to ground and connect a number 10 AWG (2.5 mm) lead to the other end. Hold the free end of the 10 AWG (2.5 mm) wire against the shaft and remove the ground brush (or strap). The presence of measurable current indicates the possibility of failed bearing insulation. Replace the grounding brush and remove ammeter lead. A clamp on ammeter can be used instead of a series meter to detect shaft current through the #10 AWG (2.5 mm) wire. Do not attempt to measure current at a location other then next to the grounding brush, as possible large circulating current may be created. This test does not identify which bearing has defective insulation, only that the insulation on at least one bearing is bad or that the insulation on all bearings is good.

Lubricating Oil Analysis

Most rotating exciter lube oil systems are integral to the main turbine-generator lube oil system. As such, this discussion will focus on an oil monitoring and testing regiment consistent with current industry standards regarding turbine-generator lube oil. However, much of this section can be applicable to isolated lubrication in stand only equipment.

Oils used in a turbine-generator-exciter lube oil system are petroleum based derivatives, which possess the characteristics of stability and load carrying capability required of large rotating machinery. Synthetic oils have gained popularity in applications of this type; however the OEM of the equipment should be consulted for compatibility with certain materials used in the lubricated train, such as gaskets, seals and even bearings. Also, oil vapors from synthetics may adversely affect insulation on exciter and generator windings, as well as other items such as paint, rubber, etc.

Oils used for lubrication also have other chemical additives that are used to enhance the natural properties of lube oil. These additives fall into several categories such as:

- Antiwear additives, which aid the oil's load carrying capabilities and coats moving parts for scuff prevention;
- Inhibitor additives, which slow oxidation, rust and corrosion;

- Special additives, which are used to enhance certain characteristics in the oil such as pour, bacteria resistance, viscosity adjusters, thermal conductivity, etc.

Oil not only functions as a lubricant, but also provides cooling for bearings. The oil flows through the bearing to remove heat away from the bearing and shaft area. Oil coolers are typically employed to keep the oil cool and to extend its useful life.

Oil degradation is caused by two general mechanisms; contamination and chemical breakdown. Contamination is the primary cause for oil breakdown. The sources of contamination are both external and internal. Dirt, water, air entrapment, and other materials can enter the machine from faulty seals or gaskets, condensation, and improper maintenance. Contamination can also occur from internal sources, such as metallic wear from moving parts; bearings, shafts, gears, etc.

Chemical breakdown can have many causes, but the usual source is excessive heat. Heat usually promotes chemical changes in the oil, such as additive separation and oxidation. These changes deplete the lubricating properties of oil. Changes in oil properties are useful in trending oil quality or indicating signs of bearing degradation.

Oil sampling is the key essential element in a predictive maintenance lube oil program. It is a necessary tool used in the effort to diagnose the condition of machinery. Oil is sampled for the following reasons:

- To ensure the correct oil is being used
- To ensure equipment is clean and in good operating condition
- To provide trending data that can indicate lubricant breakdown
- To provide trending data that can indicate bearing wear
- To detect cooler leaks

In an effort to prevent or predict component failures such as bearings, it is important to establish a baseline condition for the equipment and the lubricating oil.

Once a machine has been placed in service, periodic sampling is required to establish the condition of the lubricating oil. The oil should be monitored and trended over a period of time to determine if any deviations in measured properties are occurring or have occurred since the last sample. These sampling routines become helpful for planning equipment service intervals. Typical warning limits for changes in oil properties can be found in NMAC publication NP4916, “Lubrication Guide.”

Before the approximate condition of any oil can be determined, a proper sample must be taken. Oil should be sampled when the system is stable, upstream of any filters in the system, and before any oil is added or made-up to the system. Sampling exciter bearing oil can be a challenge because convenient sample points do not generally exist. Typically, there is a sight glass in the bearing drain line to enable oil flow to be observed. However, sampling is not easily performed at this location. It is therefore necessary to perform sampling where the collective bearing oil drains return to the lube oil reservoir. If this is the chosen sample point, be aware that the sample is not specific to the exciter bearings oil drains, rather to the entire unit. Regardless, a sample should be taken with the utmost care making sure the sampling device is clean and that the container into which it is deposited is also clean and free of contaminants. The American Society of Testing Methods (ASTM) provides standards and instructions for sampling such as ASTM D4057, "Practice for Manual Sampling of Petroleum Products" and ASTM D4177, "Method for Automatic Sampling of Petroleum and Petroleum Products."

A variety of tests can be performed as a result of a well structured oil sampling program and range from very simple and inexpensive to more sophisticated and costly. Basic sight and smell tests are the simplest and can aid in determining if more in depth testing should be performed. Oil that has a sudden change in clarity, color, or odor signals the need to have further testing performed. Such tests may include water content, viscosity, neutralization number, alkalinity, spectroscopy, particle count, direct reading ferrography and analytical ferrography.

The following tables provide a tabular presentation of the types of tests available to address various symptoms along with their associated costs, as well as a recommended test periodicity.

Table 4-2
Oil Analysis Table

Symptoms	Possible Cause	Test	Cost
Viscosity Change	Water or High Temperature	Water Content	Low
		ASTM D445, Viscosity	Low
Viscosity Change, Color Change	Oxidation	ASTM D974, Neutralization Number	Low
		ASTM D664, Neutralization Number	Moderate
		ASTM D4739, Alkalinity	Moderate
Particles	Bearing Deterioration or Foreign Matter	Spectroscopy	Low
		Particle Count	Moderate
		Direct Reading Ferrography	Moderate
		Analytical Ferrography	High

Table 4-3
Oil Analysis Test Period

Test	Period
Water Content	3-18 Months
Viscosity	3-18 Months
Oxidation	3-18 Months
Spectroscopy	3-18 Months
Ferrography, Direct Reading or Particle Count	3-18 Months
Ferrography, Analytical	12-24 Months (or as needed for problem determination)

Filter and Cooler Inspections

Routine frequent checks of the excitation systems cooling are necessary to ensure that system components do not overheat. Important cooling aspects to check are air flow, filters, cooling water flow, and cooling system integrity. For the most part, excitation systems rely on air for cooling, while some components such as rectifiers may be cooled by water.

On a daily basis, air filters should be visually checked for excessive build up of dust. The exhaust cooling air from components, if possible, should be felt to verify that air is flowing and that the air is picking up heat from the component. Do not place hand directly against exhaust vent, as fast moving air may carry particles that might cause injury.

Visually check that equipment or material, for example a tarp, is not blocking air flow into or out of the component. Also, that heat from nearby permanent or temporary equipment is not directed in such a manner to be drawn into an excitation system component. Verify that there is not a collection of dust, debris, or other substances that can be drawn into the air cooling and filters.

Inspect cooling water lines and surrounding areas for signs of water leaks. Verify that condensation is not building up and dripping on components. Visually check for signs of component overheating. Also, be alert for odors that indicate overheating.

On a weekly basis inspect inside cabinets, and as much as possible inside other components, for dust build up, cooling water leaks, condensation, and signs and odors of overheating. Do not look directly into vent exhausting forced air, as possible eye injury could occur.

Additionally, perform the thermography inspections described in this guide. As well as checking for overheating, thermography can be used to detected clogged or restricted cooling lines. The supply lines should be cool, while the return lines will be warm. The actual temperatures of the lines should be determined from trending or by comparison to similar equipment.

Rectifier Indicators

Many field rectifier banks have lamps or LED indicators wired into the rectifier circuit. These indicators show if each rectifier leg is operating properly, or if a short or open has occurred. A daily check, or preferably a once per shift check, should be made to ensure that the rectifiers are functioning correctly. A malfunctioning rectifier bank can be removed from service in many excitation systems, either with or without a load reduction. The sooner a problem rectifier bank is identified, the quicker it can be repaired and the less chance of increased failure.

Brushless excitation systems often have indicating fuses. A flag or post pops out when the fuse blows. A strobe light is required to inspect the rotating diode fuses. Some manufacturers include a strobe lamp for making online diode fuse inspections. Though most generators can operate with one or possibly a few diode fuses blown, a weekly inspection provides warning of potential trouble. Once a blown fuse is detected, daily inspections should be performed in case one or more of the remaining fuses should blow.

Finding DC System Ground On Line

Though it is not recommended to run a generator or exciter having a field ground, it may be more practical or economical to operate the generator for a few days until an outage can be conveniently implemented. For example, if the ground occurs during a peak load period, the cost of removing the generator from service may exceed the risk of further damage to the field. Especially if the ground is in the field windings, the rotor will have to be removed anyway for repair. Of course if a second ground would occur, additional winding damage and iron (or rotor forging) damage will likely result.

To run a generator for several days after a field ground occurs is probably justifiable in a risk analysis. Delaying removal of the generator from service allows for planning, maintaining generation for the load demand on the system, and testing to determine the location and nature of the ground. A brushless excitation system does not lend itself to online ground locating. Therefore, further testing cannot be performed until the machine is taken out of service.

A field ground does not necessarily have to be located in the generator or exciter field. It may be external to the field, such as on the brush rigging, bus bars, or rectifiers. The first step after receiving a ground alarm is to make several attempts to reset the ground detector. If the ground detector resets, inspect the collector ring area for foreign material, dust build up, or ongoing work in the area that might have caused an intermittent ground. Also inspect other areas of the DC field circuit, such as the rectifier banks, for similar causes of an intermittent ground. Dust build up, especially carbon brush or coal dust, combined with moisture from high humidity or other sources can be a major cause of tracking to ground. If discovered, foreign material and dust build up should be removed; but only by qualified personnel exercising the appropriate safety measures for the energized and rotating equipment.

If the ground detector does not reset, perform the inspection as described in the preceding paragraph. If no cause is discovered by the inspection, then measure the voltage to ground on both polarities of the field circuit. The brush rigging may be the most convenient location for this inspection. The ground detector may have to be disconnected from the circuit in order to remove its ground reference, depending on the type of detector used. The voltage to ground from each polarity should read close to zero with the field circuit isolated from ground. An initial reading of close to full field voltage may first appear, but this should decrease slowly to zero. Some excitation systems have a built in test switch and circuit for assessing field ground voltage.

A set of readings having zero on one polarity and full field voltage on the other, indicates that the polarity with zero volts is grounded and likely external to the field winding. A split of the field voltage indicates the ground is likely in the field winding itself. The ratio of the measured voltage to total field voltage provides an indication of how far through the field winding the ground is located from each polarity. These readings are not conclusive, although will indicate a probability of ground location. Since a split voltage measurement does not provide conclusive proof of a grounded field winding, the following external circuit checks should still be performed.

For an external circuit ground, check wiring for field voltmeters, ammeters, and the temperature monitor. Isolate, one at a time, meters and devices fed from the field circuit that can safely be taken out of service with the generator running. After isolating each device, measure polarity to ground voltage. Readings that show the ground is cleared, zero volts from each polarity to ground, indicate that the isolated device was causing the ground. Devices found to have grounds should remain out of service until repaired.

If the external ground is still not located on excitation systems having a manual or standby regulator with a separate power circuit, such as the DC system shown in Figure 2-5, switch to the manual or standby regulator. In many excitation systems it is not possible to perform this task as the same exciter or bridge is used with both the manual and automatic regulator. But in those systems having separate power circuits, switching the regulator and clearing the ground will show the fault to be in the automatic or primary regulator. If the ground clears after switching, the defective regulator should remain out of service until the ground is repaired.

Systems employing field rectifier banks that can have at least one bank removed from service at a time should be checked for a ground in the rectifier banks. Open the disconnect switch for one bank at a time. Check both polarities of the field to ground. If the ground clears when a bank is disconnected, the ground is in that bank. If the ground does not clear, return the rectifier bank to service and check the next bank. A rectifier bank found to have a ground should remain out of service until repaired.

OEM drawings and documents should provide additional information on possible ground location for their specific excitation system. If the ground is still not located, the generator will have to be taken out of service to further test for the ground location. When the generator is taken offline, perform an insulation resistance test of the field circuit during coast down to determine if the ground condition is speed related. Once the generator has stopped, the offline test should be performed.

Monitoring

Excitation System Voltages and Currents

The field voltage and current produced by the excitation system is like the system's pulse. While not indicative of all the trouble that can be present, they provide an indication that the system is operating normally at the time. In steady state operation, for a given generator output, the field voltage and current are normally steady and consistent over time.

Shorted field turns will produce less magnetic flux at a given current, less turn-amperes. To compensate for the shorted turns, and resultant reduction in generator output, the regulator will drive up the field amps. Thus an increase in field amps for a given VAR output of the generator can indicate possible turn to turn shorts in the field. Likewise, a similar situation for shorted turns in the exciter's field may be detected by monitoring exciter field current.

An increase in field voltage can be due to loose connections, brush problems, and rectifier failure. However, a voltage increase due to loose connections or brush problems will likely have to be almost unnoticeably small, for the problems not to produce enough heat to cause further damage. However, a slight increase in voltage should be immediately investigated to ensure that damage is not being done.

A failed diode or SCR in a rectifier can cause additional harmonics in the field voltage and also require the voltage regulator to increase voltage in order to maintain the field current. Also, a failure in the regulator or a sensing circuit (e.g. generator terminal PT) could cause both field current and voltage to change.

Monitoring and trending the field current and voltage of the generator, and if applicable the exciter, provides assurance that the excitation system is performing its primary function without major trouble. Unexplained changes in either the current or voltage should be investigated, and may be useful for discovering intermittent faults.

Generator Field Temperature

The generator field temperature monitor typically senses field voltage and current and computes field temperature. The resistance of the field winding is a function of temperature; thus as temperature increases or decreases, the field resistance increases or decreases. Using Ohm's law, $V=IR$, and an algorithm for temperature and resistance, the monitor outputs a temperature signal. On brushed excitation systems the current and voltage are typically sensed at or near the brush rigging. A shunt is often used to sense the DC field current. Brushless systems may employ a wireless transmitter to convey the field temperature signal from the rotor.

The primary function of the temperature monitor is to provide indication that the field winding is at the proper temperature and that the winding is not overheating. Failures of the generator cooling systems or plugged rotor cooling passages and vents could cause the field to overheat. Also, the monitor provides a means to monitor the heat of the field during start up, especially on generators where rapid temperature rise is a concern.

Another function that the temperature monitor provides is indirect indication of field voltage and current. Often the monitor feeds a recorder that produces a continuous record of field temperature. Any variation in field voltage and current, since these are inputs to the monitor, will be recorded as a temperature change. Intermittent field winding faults and brush trouble can be monitored by this means. Short turns or loose connections effectively alter the resistance of the field, even for brief intermittent occurrences. Intermittent field problems can show as spikes of the temperature recorder. The increased brush resistance that can cause brush arcing will produce an indicated temperature increase on the recorder. The arcing adds a series of spikes to the indicated temperature, so that the recorder's plot of temperature looks like strokes from a paintbrush. In fact the term "Paint Brushing" is used to describe this indication.

Exciter Armature Winding Temperature

An increase in winding temperature can be to due to several different circumstances. Perhaps the most common being dust build up in the exciter. As mentioned previously, dust build up on winding creates a thermal barrier and hinders cooling. Furthermore, dust and other particles collecting in cooling passages and vents can restrict cooling air flow.

High ambient temperatures or heat producing equipment near the exciter will also raise the exciter's temperature. However, if the winding temperature is approaching the maximum allowable limit, it is quite possible that another factor, such as dust build up, along with a high ambient, is causing the high winding temperature. Reducing load until the ambient temperature decreases is only a temporary fix. An exciter overhaul and cleaning will likely be necessary during the next outage.

High loads will raise temperature, but like the high ambient temperature in the preceding paragraph, it is likely that dust build up or another problem is affecting the cooling. Again reducing load is a temporary solution until the next outage or until ambient temperatures decrease.

High winding temperature may also be caused by shorts in the winding; although a short typically creates localized heat of one spot in the machine. Unless a shorted turn is near the temperature sensor, it is not very likely that the short is directly causing the high temperature. However, a short or a loose connection in one phase of an AC machine could cause the other phases of the winding to draw more load, thus overloading those phases. A check on all three phase currents can confirm this.

If the machine has other temperature elements installed, these can be checked to verify an element showing a high temperature. Also, a thermoscan or an external temperature measurement may be helpful in confirming a high temperature reading.

Fortunately, most temperature related problems progress slowly (though not always), and provide time to assess the situation and plan a corrective action. To take advantage of the time provided, routine monitoring and reviewing of temperature data needs to be performed.

Bearing Temperature

Bearing temperature is typically monitored and recorded, as with winding temperature. High bearing temperature may be due to low lubrication, poor lubricant quality, misalignment, cooler failure, or a defective bearing. Temperature is not a root cause of a bearing problem, but a symptom. Bearings that have an upward temperature trend need to be further investigated to determine the cause of the temperature rise. Diagnostic techniques such as lubricant analysis and vibration analysis can be used to identify the cause of the bearing problem. An excessive high temperature is cause for taking the machine off line to prevent not only further bearing damage, but potential damage to the journal and the rest of the machine.

Voltage Regulator Null Voltage

The automatic voltage regulator and manual or backup regulator must be kept at the same setting. A null voltmeter monitors the voltage difference of the outputs of the regulators; a voltage shown on the meter indicates a discrepancy between the setting of the two regulators. The regulator that is not controlling excitation has to be adjusted to match the in service regulator.

Normally the discrepancy will be due to manual or automatic adjustments to the in service regulator for maintaining generator output at the appropriate level. Adjusting the regulator that is not in service to null or zero the voltmeter will ensure a bumpless transfer, if necessary. A failure of the controlling regulator or another problem may require a transfer to the backup or manual regulator at any time. A discrepancy between the regulators can create a large sudden excitation transient on transfer. Thus maintaining the regulators' output equal will prevent the transfer transient.

Problems in either regulator can cause the output to drift and vary. This will be seen on the null voltmeter. Unexplained and inconsistent drift of either regulator's output should be immediately investigated and repaired to ensure both regulators are capable of maintaining generation.

Monitoring the null voltmeter is not typically a maintenance or system trending task. It is normally an operations function to keep the plant lined up in a normal condition. However repeated deviations in the null voltmeter should be investigated and, if needed, trended to determine the cause of the deviations.

Offline Tasks

Brush Examination

Verify brushes are free to slide in holder. Verify brushes do not have side to side movement or a loose fit in holders. Remove brushes from holders, and examine for cracks, chips, gouges, ridges, or other damage. Verify that the brush face is smoothly worn to make full contact with the ring. Check brush face for burnt areas or signs of over heating. Measure length of brush. Record brush exam data. Brushes that are worn close to minimum length or shorter should be replaced. Some stations replace all brushes during major outages to minimize online brush change outs, especially soon after the outage. When brushes are installed, ensure leads (pigtails) do not interfere with or rub against other brushes and the rigging. Also ensure that the pigtails are not too tight or too short to allow for brush wear.

Replacement brushes should be pre-arced, or pre-contoured, to match the contour of the ring. Brushes can often be purchased pre-arced from brush vendors. If the replacements aren't pre-arced, the station has to do so. A coarse sand paper can be used to contour the brushes. Emory cloth or other abrasives that contain conductive material must not be used. Furthermore, the arcing of the brushes should be done away from the collector so that grit and excessive carbon dust do not accumulate on the rings and rigging. A jig should be used that is built with the contour of the ring and with a swing arm is best. The brush holder attached to the swing arm holds the brush again the sand paper on the jig and maintains the correct alignment for the brush. After arcing, scrape face of brush with a knife or similar tool to remove any embedded grit, and wipe dust off of the brush. Much carbon dust is created, dust masks/respirators and gloves should be worn.

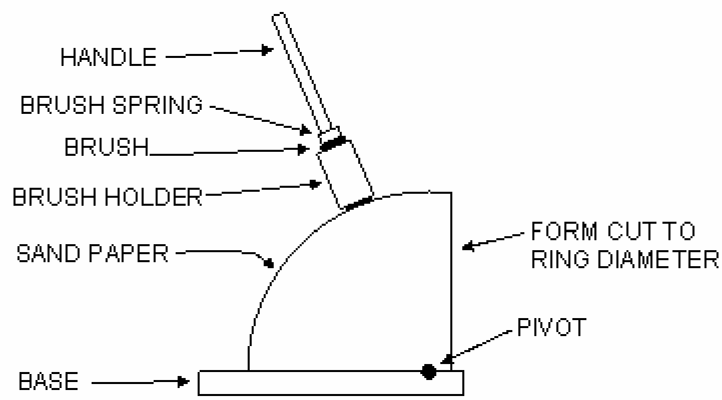


Figure 4-4
Diagram of a Jig for Pre-arcing Brushes

Brush Pressure

Brush pressure is typically between 2½ psi (17 kPa) to 5 psi (34 kPa). Actual values will vary based upon brush model, and the collector and the brush manufacturers' guidance. A minimum pressure limit is required for maintaining ring contact and adequate electrical conduction. A maximum pressure limit prevents excessive mechanical friction and wear, for optimal brush life. The brushes on the same polarity should be adjusted, if possible, as close to the same pressure to provide equal current sharing among the brushes.

The actual technique to connect a spring scale or other force gauge depends upon brush and brush holder configuration. The collector manufacturer should have provided guidance on the technique for measurement in the equipment documentation. A generic procedure is to attach the force gauge to the brush or the brush spring mechanisms. First verify the brush is free to move up and down in its holder. Pull the brush up off the ring. Keep the gauge in line with the brush, allow the brush to move slightly back down to approximately 1/8 inch (3 mm) from the ring, but not contacting the ring. Then measure the force to hold the brush stationary. The brush pressure is equal to the force divided by the cross sectional area of the brush. The cross sectional area is the width multiplied by the thickness of the brush, and should not take into account the curvature of the brush face, nor any slant in the alignment of the brush.

Constant pressure/tension brush holder spring tension is best measured with the spring near the minimum brush length position. This may be done with the brush removed or with a short test brush. This will ensure that at least the minimum brush pressure is achieved at the lowest brush position, or near the end of spring travel. Nonconstant spring pressure brush holders, which will require later readjustment for brush wear, should be measured at a position just off the installed brush's length.

Any brush found outside the acceptable limits of brush pressure should have the brush spring adjusted if possible, or the brush holder and spring replaced. On constant pressure/tension brush holders, the spring is part of the holder and not adjustable, thus the holder has to be replaced.

Record the brush tension and/or pressure for each brush measure and the location of the brush. This provides a trend record for future analysis.

Brush Rigging

Check rigging for looseness, cracks, missing or loose hardware, excessive amount of dust, areas of overheating, signs of arcing, damaged insulators, and other defects. Inspect brush holders for the same, as well as for alignment to ring, clearance to ring, and tightness of electrical clips or terminations (if applicable). Brush axial alignment at standstill must be offset on the ring to allow for shaft expansion. Manufacturer data should provide the necessary offset information, though it may be better to observe brushes during operation to ascertain the axial displacement required. Commutator brush holders should be aligned so that the leading edge of each brush on the same polarity contacts the same commutator bar at the same time. Record defects and damage found. Thoroughly clean rigging and brush holders with rags and vacuum cleaners.

Collector and Commutator Inspection

Brush holders and rigging may have to be removed to examine and clean rings. Examine ring surface for film condition, threading, scratches, pitting, burns, brush foot printing, and other defects. Slight defects can be removed with fine sandpaper, but stoning or grinding the ring may be necessary. Do not use emery cloth, and ensure all grid and metal dust are removed after any sanding. Examine commutators for insulation that is not below the surface of the ring.

Take runout readings of the rings. The manufacturer usually provides maximum allowable runout dimensions. Typically, higher speed machines have lower allowable runout. The readings should be taken over the entire circumference of the ring, as opposed to just 4 locations, to identify any high or low spots. If the rings were previously stoned at rated speed, the rings may have a slight elliptical shape. This is due to the vibration of the machine, and is preferable to a more circular shape, because at speed the elliptical shape added to the machine's vibration presents a more circular surface to the brushes.

Clean the ring after examination, and any work that was performed, with a cloth coarse cloth. Alcohol, or manufacturer recommended solvent, can be used to dampen cloth if needed. Do not touch rings with bare hands, as moisture and oil from the hands can affect film formation.

Inspect connections from the ring to the field or armature and the associated leads for looseness, abrasion, cracking, and other defects.

Bearing Insulation Checks

Bearing insulation should be checked at the beginning of an outage in which generator or exciter bearing work is being performed to determine if repairs are necessary. Insulation should also be checked prior to start up after any generator or exciter work was performed. Double layered insulation is tested as described in the online test. Single layer insulation can be tested when the bearing is rolled out of its housing. Another method used to check single layer bearing insulation without complete bearing disassembly, is to raise the shaft just enough to lift the journal off the bearing and slide a thin insulating sheet between the journal and sleeve. Then the test can be made across the permanent bearing insulation.

Electrical Tests

Electrical testing provides indication of condition of the insulation and conductors in major components of the excitation system. The tests described in this section are the most common performed. Test frequency should correspond with scheduled plant outage on an 18 to 36 month frequency. As with other periodic testing, the electrical test frequency should be adjusted as necessary for equipment condition and failure history.

Insulation Resistance

Insulation Resistance (commonly referred to by the trade mark Megger). IEEE 43 provides recommendations for testing insulation resistance. The test consists of applying a fixed DC voltage across the insulation and calculating the insulation's resistance from the current flow. Almost all insulation test instruments are scaled to read out resistance instead of current. The applied voltage is determined by the voltage rating of the insulation. For most components in the excitation system, 500 VDC is used. IEEE 43-2000 recommends 500 volts for components rated less than 1000 V. The primary side of excitation and instrument transformers because of their higher voltage rating may require a test voltage of 1000 VDC or higher.

Table 4-4
Recommended Test Voltage Level

Voltage Rating	Test Voltage (volts DC)
less than 1000	500
1000 to 2,500	500 to 1,000
2,501 to 5,000	1,000 to 2,500
5,001 to 12,000	2,500 to 5,000
greater than 12,000	5,000 to 10,000

A range of test voltages is provided so that a value appropriate for the available test equipment, and a value consistent with previous tests, can be used. Insulation resistance tests should be performed at the same test voltage as past tests to provide consistency for trending.

The current created by the application of the test voltage consists of 4 components. These current components are: capacitive current; conduction current; absorption current; and leakage current.

Capacitive current is due to the capacitance between the winding and ground, and typically goes to zero within a few seconds after applying the test voltage. Conduction current flows through the insulation material does not decrease with time, and is typically a very small component of total current.

Conduction current is a normal characteristic of the insulation materials used. No substance is a perfect insulator, and conduction current is not a result of damage to the insulation.

Absorption current is caused by the molecules in the insulation aligning themselves with the applied electric field, and typically decreases close to zero within a few minutes.

Leakage current is the surface current flowing from the insulation, and is constant over time. Insulation damage, defects, moisture, and other conductive contaminates can greatly increase the leakage.

The standard method of testing insulation resistance is to apply the test voltage for 1 minute and then record the resistance measurement in megohms, often referred to as simply megs. At 1 minute the test current consists mainly of absorption current and leakage current. The absorption current is not affected by insulation defect or surface contamination, but the leakage current is.

A low meg reading indicates high leakage current and possible insulation trouble. Often the low meg value is due to moisture on, or in, the winding. Applying a low heat, blowing dry air, or sending a DC current through the windings are methods used to dry out damp windings. With sending a DC current through the windings, a power source such as a welding machine is used. The current must be limited to well under the rating of each winding through which it flows.

Regardless of the method used to dry the windings, the insulation resistance should be checked every few hours to chart the progress of the drying.

Initially, the resistance measurement will likely decrease as insulation resistance decreases with temperature increase. Winding temperature should be monitored during the drying process to ensure that the winding is not being overheated and also that adequate heat is being applied. After reaching an acceptable resistance measurement, as corrected for temperature (see below), the drying process can end and the winding be allowed to cool. Once the winding reaches a normal temperature, the insulation resistance should be performed again.

High winding temperatures can also cause a low resistance measurement. Insulation resistance measurements should be correlated to a resistance value at a standard temperature. A temperature of 25 or 40 degrees Celsius is often used as a standard temperature, IEEE 43-2000 recommends 40 degrees Celsius. Unlike conductors, insulation typically becomes more conductive with temperature. The effect of temperature on insulation resistance varies with the material used in the insulation. A trend of resistance and temperature data from previous tests for a particular machine can provide a correlation between temperature and resistance that may be useful. The resistance versus temperature curve is logarithmic. A plot of temperature on a linear axis and resistances on a logarithmic axis should produce a fairly straight line to extrapolate a resistance value.

If insufficient or inconsistent data points are available for plotting the relationship between temperature and resistance, a standard formula for the correlation can be used:

$$R_{40} = R(0.5)^{(40-T)/10}$$

Where R_{40} is the resistance at 40 degrees C; R is the measured resistance; and T is the winding temperature in degrees C. For a standard temperature of other than 40 degrees C, such as 25 degrees C, replace 40 with the desired standard temperature in the equation. This formula is only an approximation and its accuracy varies for different insulation materials.

All insulation resistance measurements should be correlated to the standard temperature to provide consistent test results for trending by eliminating the effects of temperature. Along with the resistance value the following should be recorded; winding temperature, humidity, and test voltage

Other factors affect the resistance; especially humidity, for which the measured value cannot be adequately corrected. These factors will cause the temperature corrected insulation values to vary; however the resistance measured should remain within an order of magnitude of the average value. Exceedingly low values in comparison to previous values should be investigated for high moisture, contamination, dust build up, or damage. For machines with no previous data, 5 megohms is a typical minimum acceptance value.

As previously mentioned, temperature decreases the insulation resistance. Also, the insulation may be polarized; molecules aligned to an electrical field from a previous voltage, such as prior to shut down. Windings being tested should be allowed to cool off and grounded to drain absorption current prior to testing. After completion of testing for personnel safety, the winding should be grounded for at least 3 times the length of time for which the voltage was applied, with a minimum of 30 minutes.

Polarization Index

IEEE 43 provides recommendations for measuring Polarization Index (PI). As described in the previous section on insulation resistance, the current through insulation consists of 4 components. Of these 4, only leakage current and absorption current are significant after a few seconds. Leakage current remains constant over time and absorption current decreases over several minutes. The absorption current is the alignment or polarization of the insulation molecule with the electrical field of the applied test voltage.

Leakage current is affected by the size, the surface area, and geometry of the windings. A large winding will normally have higher leakage current than a smaller winding of similar construction. The absorption current is also affected by the size, surface area, and geometry of the winding. Furthermore, the absorption current is not affected like leakage by dampness, contamination, and other defects. Comparing leakage current to the absorption current offsets the affects of winding size and geometry. This comparison is performed by the PI test.

The PI test is performed by applying the test voltage for 10 minutes and taking insulation resistance measurements at 1 minute and 10 minutes. The PI is equal to the ratio of the 10 minute reading over the 1 minute reading. Unless the leakage current is abnormally large, the PI should be greater than 1. For most windings the value should be greater than 2.

For large values of insulation resistance, greater than 5,000 megohms, the PI value is not considered significant. An exceptionally good insulation resistance measurement with a poor PI is acceptable. Other components, such bearing insulation and short conductors, may have low PI readings. This is acceptable as long as the insulation resistance value is good and the PI is 1 or greater.

The raw insulation resistance values, uncorrected for temperature, may be used to calculate PI. The effects of temperature on PI are minimal in most circumstances. The PI value should be recorded with the data from the insulation resistance tests.

Winding Resistance

A measurement of the DC resistance of a winding ensures continuity of the winding, detects possible loose connections in the winding, and may detect winding shorts. IEEE standards 115 and 118 provide recommendations for resistance measurements. Most windings in the excitation system will be low resistance, as defined by IEEE 118-1978. A bridge instrument is used to provide an accurate measurement.

Measurements on each winding on three phase components should be compared to each other. A difference in resistance of more than 5 percent should be of concern. A low value indicates a short in the winding. A high value indicates a bad connection or a damaged conductor.

Measurements on fuses, such as those on a brushless excitation system's diode wheel, should be compared to each other. A higher than normal resistance can indicate necking down of the fuse element.

Resistance measurements should be recorded and compared to previous readings. It is important, especially on inductive components, to allow the resistance measurement to reach a steady state value before recording the measurement. Also, temperature changes the value of a conductor's resistance; the measurements should be converted to values at a standard temperature. Typical standard temperature is often either 25 or 40 degrees C. Whatever value is used for the standard temperature, it should be used consistently for all resistance measurements. This allows for comparison of data that may have been taken at different temperatures. The formula used to correct resistance measurements for temperature is:

$$R_S = R(T_S + k)/(T_M+k)$$

Where R_S is the resistance at the standard temperature: R is the measured resistance; T_S is the standard temperature in degrees C; T_M is the winding temperature in degrees C; k is a constant depending on the conductor material. For copper, k is 234.5 degrees C; for aluminum k is 224.1 degrees C.

Resistance measurements cannot find all winding conductor troubles. Shorted turns are seldom direct shorts and may have high resistance. Loose connections and conductor damage may still have a low enough resistance to be undetected, especially at standstill. However, the resistance measurement can still provide an assurance that a serious conductor problem is not present.

Impedance Test

An impedance test is often performed on DC windings such as the field of the generator or exciter. It provides a better indication of shorted turns than does the resistance measurement. The impedance test applies an AC voltage across the winding and subjects each turn to a higher voltage than the winding resistance measurement.

A variable AC source, such as a variable transformer, that can supply 5 to 10 amps, and up to 120 to 150 volts, is used. A maximum voltage of 120 volts AC is normally used; however, some plants use 150 as a maximum voltage to apply a little more voltage across the turn-to-turn insulation. A voltmeter and ammeter are used to measure the voltage and current, as shown in the figure below. The voltage is applied in steps, typically in 4 or 5 equal steps to the maximum of 120 or 150 volts. At each step the current is allowed to stabilize and both the current and voltage are recorded.

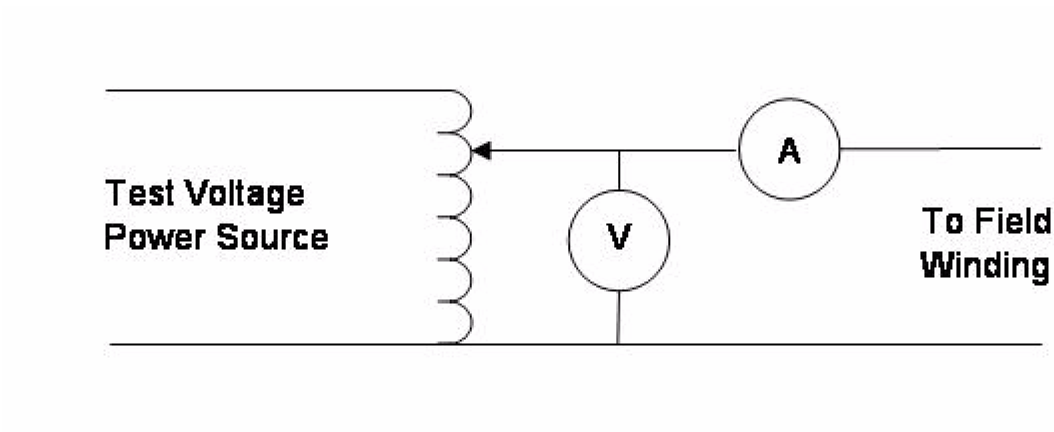


Figure 4-5
Simplified Diagram of Variable Transformer and Meters for Impedance Test

A plot of the current and voltage at each step is made; the slope of the line represents the winding's impedance. Plants may plot voltage on the horizontal axis; then the slope of the line is the reciprocal of the winding's impedance, or admittance. Although it is expected that the impedance or admittance will remain constant at each step, the value will likely change slightly as voltage is increased. However, a sudden rise in current, or a sharp decrease in impedance, between steps indicates a shorted turn. The plot of current and voltage should also be compared to plots done previously to determine if there is a significant change in the windings impedance.

Recurrent Surge Oscillography

Recurrent Surge Oscillography (RSO) is used to identify and locate faults in generator and exciter field windings. RSO is a variation of the Time Domain Reflectometry (TDR) method to locate faults in cables. The field must be isolated from the rest of the excitation circuit in order to perform a RSO test. Removing the brushes from the slip rings is the easiest method to isolate the field. The RSO test set is connected to the slip rings and identical pulses are injected into the field from both rings. If the field winding and its connections are in good condition, the reflections from both pulses as they go through the field should be identical. A ground condition or an interturn short will present a change in impedance at the fault location. This impedance change, as with TDR, causes a partial pulse reflection from that location that can be detected by the test set. The timing of the reflection indicates how far into the field winding the fault is located.

Special RSO test equipment is required to perform this test, as well as training for the technician who will conduct and interpret the test results. Many plants may not have the equipment or in-house expertise for this test. However, a service shop or a testing company with the equipment and expertise can be brought in during an outage to perform the RSO test, along with other tests and services.

High Potential Test

A high potential (hi pot) test verifies the integrity of ground insulation and phase-to-phase insulation, similar to the insulation resistance test. However, unlike the insulation resistance test, the hi pot test stresses the insulation above the electrical stress experienced under operating conditions.

There are two types of hi pot test; a DC test and an AC test. The AC test, applying an AC voltage on the insulation, more closely matches the type of alternating stresses that the insulation normally experiences. However, due to large capacitive charging current associated with AC voltage, an AC hi pot test set for large windings can be heavy and bulky, and require a significant power source (e.g. a 480 volt feed). Also the AC hi pot is strictly a go/no-go test, because the charging current masks the leakage current.

The DC hi pot test is more typically performed, due to the aforementioned disadvantages of the AC hip pot. However, on excitation systems' low voltage components (rated less than 1,000 volts), a DC hi pot is not normally a routine test. The primary side of transformers are an exception, often being rated above 1,000 volts. The generator field may be hi pot tested to locate a ground fault, or after work has been performed on the rotor to ensure winding insulation integrity.

The hi pot test voltage is typically between 1.25 and 1.50 times 1.7 times the rated voltage of the winding. This value is for routine tests, factory and new winding tests often will be at higher values. The 1.7 factor is to create a DC stress on the insulation that is fairly equivalent to the AC stress. Note: the 1.7 factor is not related to RMS value of AC voltage, but due to the differences in AC and DC electric stresses on the insulation. Equipment manufacturers should provide guidance on allowable hi pot voltages. Before hi potting a field winding, the manufacturer should be consulted for guidance.

Prior to performing a hi pot test, an insulation resistance and polarization test must be performed to ensure that the insulation can withstand being overstressed by the hi pot. Furthermore, ensure tools, materials, etc,. are moved away from the component being tested. An abnormal electrical stress can be created on the winding by a foreign object creating a point ground on the exterior of the insulation. As with all electrical testing, but especially for a hi pot, the area around the component being tested must be taped off and posted for personnel safety.

The DC hi pot is steadily ramped up to the test value, while watching the leakage current. Hi pot test sets typically have a maximum leakage, above which they trip. A common trip value is 5 mA. Raising the hi pot voltage too quickly can cause a large charging current to trip to the set. Voltages and test times should follow the guidance in IEEE standards, such as 4, 95, and 115. For most equipment the test voltage is held for 1 minute; however, for cables the test voltage is held for 15 minutes.

During the ramp up and the hold period the leakage current is monitored. If the leakage suddenly spikes upward, the test voltage should immediately be decreased and the test aborted. Otherwise, at the conclusion of the hold period, record the leakage current and test voltage. Temperature and humidity data should also be recorded as part of the test record.

Decrease test voltage, allowing the built up charge to bleed through the test set. Note, the current meter should be flipped to the upper scale to prevent pegging meter. After the voltmeter indicates that voltage is reduced to a safe level, with the test set still connected, apply a grounding jumper to the component. The test set can then be disconnected and removed. The grounding jumper should remain connected to bleed the absorption (or dielectric) charge for at least 3 times the length of the period that voltage was applied, but for not less than 30 minutes.

DC hi pot test results should be compared to past test results. A marked increase in leakage current is indicative of dirty, contaminated, or damp insulation.

Step Voltage Test

A variation of the DC hi pot test is a step voltage test. Instead of ramping up to the test voltage, voltage is increased in 1000 V increments with the voltage being held at each step for 3 minutes. The leakage current is recorded at the end of each 3 minute increment and the voltage is raised to the next step. A plot of leakage current versus voltage gives the conductance (reciprocal of resistance) at each step. As in the impedance test, the conductance will likely vary slightly at each step. However, a sharp rise in conductance with increasing voltage can indicate possible insulation damage, dampness, and dirt build up.

Transformer Turns Ratio Test

The ratio test verifies the tap setting of the transformer and that there are no solid turn-to-turn shorts in the transformer winding. In the simplest test method, a test voltage is applied to the high side winding and the low side voltage is measured. A test voltage, as high as practical, up to rated voltage, should be used to most closely match operating conditions. The ratio of the test of high and low sides is the transformer's ratio. It is recommended to apply the test voltage to the high side winding as a matter of personnel safety, although at times it may be more practical to apply the test voltage to the low side.

This simple ratio test doesn't provide indication of winding polarity, which can be important for new and disconnected transformers. A simple polarity check is to apply a DC voltage briefly across the high side winding, and definitely for safety reasons, not across the low side. A large 6 V lantern battery is usually sufficient. An analog voltmeter is connected across the low side winding. An analog meter is required to show the inductive kick when the DC voltage is applied and removed. The positives of the DC voltage and the voltmeter should both be connected to the same polarity on their respective windings; likewise for the negatives.

When the DC voltage is applied to the high side, a voltmeter connected across the low side winding should show a positive kick of the needle. When the battery is removed, the needle should kick negatively. If not, the polarity between the high and low side is reversed.

A second method to test ratio, and also polarity at the same time, is with a bridge circuit. A simplified schematic of the test set up is shown in the figure below.

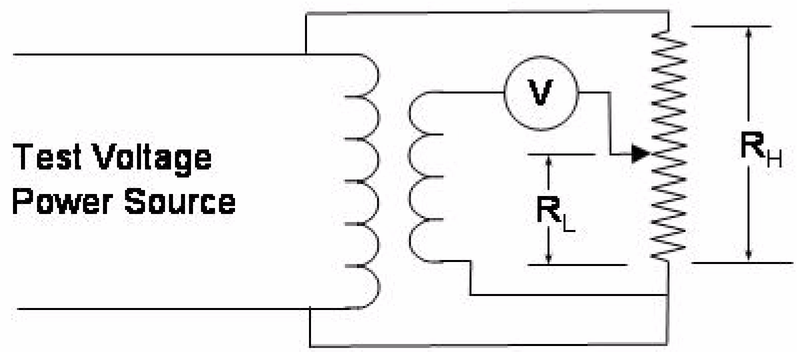


Figure 4-6
Transformer Turns Ratio Test Method With a Bridge Circuit

The transformer ratio is determined by the ratio of R_H to R_L when the voltage meter is nulled. A reversal of the winding polarity will prevent the voltmeter from being nulled. A calibrated potentiometer is employed for R_L and R_H. Obviously, this method is not used for medium voltage rated transformers, except with a reduced test voltage.

Commercially available Transformer Turns Ratio (TTR) test sets provide the most accurate check of ratio and polarity. More sophisticated test sets can perform three phases simultaneously, and account for winding configuration and possibly for slight phase angle shifts due to winding impedance.

Power Factor Test

Power factor testing applies an AC test voltage across the insulation and measures the power factor of volt-amperes flowing through the insulation. Doble Engineering is the known provider of equipment for this test. In this test a high AC voltage is applied between the conductor and ground; the majority of the current should be capacitive. The leakage current, in respect to the capacitive current, should be very small. Therefore, the power factor, or ratio of leakage current to total current, should be rather small. A power factor of 0.005 to 0.01 is typical, although actual acceptable values will depend on the type of component being tested, and previous test data.

Finding Field Grounds Off Line

With the generator and exciter offline and still, remove all the brushes from the generator or exciter, obviously depending on which machine has the ground. On brushless excitation machines disconnect field leads, diodes or fuses to open field circuit. Perform an insulation resistance test on the field winding from the collector rings.

If the field tests indicated no ground, the brush rigging bus bar, cable, and rest of the external circuit should be tested and inspected. Insulation resistance tests should be made as much as possible on the external circuits. Remove fuses, open links, and open switches to isolate portions of the circuits in order to isolate the ground. Maintain a lifted lead log and determinate wiring as needed to further isolate the ground. Manually actuate switches and relays to connect or disconnect portions of the circuit. Ensure that operation of the switches and relays does not cause an adverse action in other plant systems through a review of excitation system drawings.

The excitation system documents and drawings should be used to develop a plan of attack prior to the actual investigation work being performed. Major portions of the circuit to be isolated, identification of isolation components, and precautions to prevent adverse conditions in other systems should be included in the plan. Plants may have developed procedures to track and isolate grounds in order to have a pre-approved plan.

Rotor In Generator

If the insulation test shows the ground to be on the rotor, the voltage reading taken while the generator was on line will help locate the ground. If one polarity was near zero volts to ground, and the other close to full field voltage, the ground is probably at the end of the winding, on the polarity having zero volts to ground. Additionally, a voltage reading of zero could indicate that the ground is on the ring or the field lead. Thus, the collector ring or diodes, and field lead corresponding to the polarity having zero volts to ground, should be inspected and cleaned. If possible, disconnect the field leads and perform an insulation resistance test separately on the collector ring or diode wheel and the field.

If voltage readings to ground from each polarity were not done or were inconclusive, resistance and voltage checks can be performed at standstill. From the field leads, or the collector rings, if leads are not available, measure the resistance to ground from each polarity. The ratio of each measured resistance to the total field resistance should provide how far through the winding the ground is located from each polarity, or if the ground is located at on end of the winding. Obviously, if the ground is not solid, then the resistance measurements may not provide useful data.

A DC welding machine or other DC power source can be used to locate a ground in the field winding. The voltage is applied across the field leads, or rings, and adjusted to approximately 30 VDC. Measure voltage to ground from each polarity. The ratio of the measured voltage to the applied voltage will indicate how far through the winding is the ground. As before, a reading close to zero on only one polarity indicates the ground is on the ring, the lead, or the end of the winding.

If the generator or exciter can be opened, inspect the field windings. If possible, check for dust build up and foreign material, cracks, and other damage to field leads, worn and damaged winding insulation, and loose windings. The resistance and split voltage tests can be performed again, this time checking the resistance or voltage to ground at each pole. Obviously this paragraph will not be applicable to most nonsalient pole rotors

If the ground had cleared during coast down of the generator and is no longer present at standstill, it may be speed related. Centrifugal forces or vibration may have caused the ground. However, it is likely the component being grounded, i.e. a winding coil, has defective insulation and is close enough to grounded metal that the centrifugal forces or vibration can cause contact. Then resistance and split voltage tests cannot detect the ground at standstill because of the small clearance between ground and the defective component. A high potential (hi pot) test may able to bridge the clearance and confirm the presence of a ground on the rotor. OEM guidance and recommendations must be clearly followed on hi potting the field to avoid further damage. If the generator is open at the time of hi potting, qualified personnel standing a safe distance away can watch the rotor for signs of arcing indicating location of the ground. The lighting on the generator will obviously have to be dimmed during the test in order to be able to observe any arcing.

A ground in the rotor also can be detected by injecting an identical electrical pulse at both slip rings. In a healthy rotor, the travel time of the pulse through the winding would be identical, as would reflections of the pulse back to the slip rings. If ground or shorted turn fault exists, the impedance at the fault is smaller, causing some of the pulse energy to be reflected back to the slip rings and changing the input pulse wave form in a way that depends on the distance to the fault. This variant of the Time Domain Reflectometry (TDR) method to locate faults in cables is called Recurrent Surge Oscillography (RSO). It requires the field winding to be isolated from the exciter. Special equipment is required to perform RSO test. Reference the "Electrical Tests" section of this chapter

Rotor Removed

If the ground has not been cleared, but has been determined to be on the rotor, the rotor will have to be removed. If not already done, a request for OEM assistance to locate and assess the field ground, and to recommend a repair solution, should be made. Once the rotor is removed it can be more thoroughly inspected for defect or damage. The windings and field leads should be checked for cuts, cracks, looseness, abrasion, and other damage. Nonsalient pole rotors should be checked for copper dusting, and signs of arcing or overheating on the rotor iron. A hi pot test can be performed, with qualified observers a safe distance away to watch for arcing during the test. Again the lighting will have to be dimmed to facilitate observation of any arcing. Ensure that no test equipment, leads, ladders, or other tools are touching or are near the rotor during the hi pot test. Objects on the rotor during the test can provide leakage paths and possibly cause further damage.

Maintenance Testing Program Description

An optimized maintenance program should not only improve plant reliability, but also improve plant availability and provide for minimizing maintenance costs. Reliability is the measure of a plant's, or a specific component's, ability to remain functioning and to perform its intended task when called to do so. The intended task of the excitation system is basically to provide and control excitation to the generator. Anytime that the system fails to provide adequate excitation when required is a decrease in reliability.

Availability is the measurement of a plant's, or component's, ability to be in service to provide its intended function. It is the percentage of time that the plant or component is available. An excitation system that is removed from service for frequent and long scheduled maintenance will have low availability.

Reliability and availability are not the same. The excitation system that is removed from service for frequent and lengthy maintenance may be highly reliable and never fail in service. But the cost of the low availability can be nearly as detrimental as the cost of low reliability. Both cause lost production, although unreliability does incur additional forced outage costs. Maintenance costs, both manpower and material, eat into a plant's budget. Maintenance that is applied excessively to one system is unavailable for maintaining other systems.

A proper maintenance plan will use diagnostic and predictive techniques to optimize the maintenance performed on the excitation. Optimizing maintenance requires the understanding of the costs and benefits of reliability, availability, and maintenance to enhance all three. Balancing the costs and benefits of each against the other two will optimize production and reduce total costs. Each plant will have to adjust the maintenance plan to best suit the type of excitation equipment they have, the availability of maintenance personnel and equipment, and the historical maintenance data and trends for their equipment. Manufacturer warranty requirements, insurance requirements, and regulatory requirements also have to be factored into the maintenance plan.

An integral part of an effective maintenance optimization effort for the excitation system is the application of a comprehensive set of predictive maintenance tasks; the most effective and commonly applied technologies are vibration monitoring and analysis, lube oil analysis, electrical testing, and thermography. These technologies, in conjunction with routine monitoring and inspections, can provide an effective optimized maintenance program.

Periodic monitoring using these technologies will aid in determining the condition of the excitation system and it's components to ensure early and accurate fault detection, which will generally minimize equipment damage and aid in maintenance planning. It is very important to establish baselines and trends on all monitored equipment for the various technologies employed to aid in the detection of developing faults, and to track the progression of the fault until timely corrective action can be taken.

Many times, it is especially useful to have data on a particular component from a combination of all technologies, in addition to certain equipment operating parameters, that can be used collectively to further predict when a failure is imminent. For example, certain faults may not be apparent with vibration data alone, but in combination with a detectable adverse trend in lube oil analysis results, or perhaps an anomaly detected by thermography, an impending failure could be averted.

A successful plant maintenance organization will ensure that data is collected on a scheduled basis, driven by a plant's Computerized Maintenance Management System (CMMS), for a consistent and reliable means of initiating data collection.

Interpretation

Most test result data provides two types of information. First is a pass/fail or go/no-go; the data indicates whether the equipment is suitable for service. The second type of information is trending; this indicates whether the equipment is approaching a failure or malfunction. For example, an insulation resistance test of a winding resulted in a measurement of 50 megohms. This result is a pass in a strict pass/fail criteria; however, if past readings were over 200 megohms, the low reading should be of some concern. This downward trend indicates a possible problem with the winding, possibly dust build up or dampness.

With a downward trend, a determination should be made if the equipment should remain in service, or whether correcting the condition is necessary prior to returning to service. Additional testing and inspection will often help make this determination. If no repair is immediately made, more frequent testing and inspection can help ensure that the equipment is not deteriorating significantly.

Application

Determine and select appropriate maintenance diagnostic and inspection tasks based upon: type of excitation system; equipment condition; risk based maintenance; manufacturer recommendations and requirements; regulatory and insurance requirements; equipment trends; and industry experience.

The type of excitation system and the equipment used will determine whether some of the tasks given in this guide will be of use. An obvious example, a brushless excitation system will not require collector inspection. Tasks for major excitation system components are given in the table at the end of this section. Not all excitation systems will have all the components that are listed.

Equipment condition is a major factor in determining tasks and the frequency of the tasks. If a component is in good condition and without adverse trends in performance, some task frequencies may be extended. Furthermore some portions of certain tasks may be eliminated in the case where the parameter monitored or inspected is covered by other tasks. Of course historical maintenance data such as past failures and defects, industry experience, and regulatory requirements have to be considered. For equipment in which an adverse trend is discovered or has had past deficiencies, the maintenance task frequencies may need to be increased to adequately forewarn of potential equipment problems.

An optimized maintenance plan should consider the risk of equipment failure. A failure mode, that is determined to be extremely unlikely for a particular component, and or would have minimum impact on production, is low risk. Conversely, a failure mode that is likely to occur within a few years and will adversely affect production carries a high risk. Failures with high risk should carry the highest priority for diagnostic testing and inspection; while those with the lowest risks may rate only minimal or no maintenance.

Cost Benefit

An expense can be assigned to risk, to determine the cost benefit ratio of performing maintenance. The benefit will be the expense of the risk avoided or minimized by performing the diagnostic tests and inspections. The risk expense is the probability of a defect developing undetected into failure, times the sum of the cost of lost production and repair costs.

$$\text{Expense}_{risk} = \text{Probability}_{risk} \text{ X } (\text{Lost}_{production} + \text{Expense}_{repair})$$

Typically the risk expense is based on a per year basis. Benefit is determined by how effectively the task minimizes the risk. For example, a daily brush inspection may be nearly 100 percent effective in eliminating the risk of brush failures; a weekly brush inspection may be only 80 percent effective. The benefit for daily inspections is 1.0 times the risk expense for brush failure, while weekly inspections will only be 0.8 times the expense. These given values are arbitrary; the exact task effective values have to be determined for the particular equipment.

The cost of performing a specific task is determined on a yearly basis, and the cost to benefit ratio is determined. A task may cover several failure modes, thus the benefit of the task is the sum of the benefit of each mode. Also, the costs of several tasks can be combined and compared to the sum of the benefit of minimizing a number of risks. Thus, a cost benefit analysis can be made for a maintenance plan that includes a number of tasks, and also compares different maintenance plans in order to select the optimal plan.

The cost benefit ratio for effectiveness has to be less than 1; the smaller the ratio the more effective is the task or plan. Plans or tasks with a ratio greater than one cost more to implement than the benefit they provide.

Obviously, tasks required for regulatory agencies, manufacturers, insurers, and for personnel safety fall outside strict determination by cost benefit analysis. However, cost benefit analysis still may be used to select the most effective tasks and plans to meet the imposed requirements, even if all the cost benefit ratios are greater than 1.

Trending

Trending of system data, and the results of tests and inspection, provides information regarding the possibility of component deterioration and failure. A steady normal trend in most parameters ensures that the equipment is functioning satisfactorily and unforeseen trouble is not likely. An adverse trend indicates the possibility of a failure developing. When an adverse trend is found, actions include: continue monitoring the trend, increase the frequency of inspections, and perform additional tests and inspections. For example, if brushes are wearing at an increased rate, a reasonable action would be to continue daily inspection, and perform strobe and thermography inspection on the brushes and rings.

Trend data is also used in determining risk factors, for cost benefit analysis. For example, if a particular component is found to be deteriorating at a certain rate, that rate can be used to develop a basis for a failure probability of the component.

External Reliability Data

Data from other plants, and the power industry in general, can also be utilized to aid in the development of failure probability. Information from EPRI surveys, INPO databases, and other industry sources can provide specific failure information for various components. However, industry data must be carefully evaluated to prevent grossly overestimating the failure risk. Frequently only specific failures are reported; not the percentage or age of components that failed. Information of the total population and years of services prior to failure need to be accounted for in determining a failure probability from outside sources.

Task Table

The following table on the next several pages is an aid for determining the application of the diagnostic inspection and monitoring tasks. Tables in the appendices of commonly performed tasks and component failure data will also assist. The data for the tables in the appendices was from 155 units using an industry wide survey and industry databases.

Table 4-5
Failure Mode Testing and Detection

		Trendable Tests								Inspections									
Component	**Failure Mode**	**Infrared Thermography**	**Temperatures:Bearings/Winding**	**Generator Field Temperature**	**Voltages & Currents**	**Vibration Monitoring**	**Vibration Analysis**	**Oil Analysis**	**Electrical Tests**	**Visual Inspection**	**Brushes & Rigging Inspections**	**Strobe Inspection**	**Collector Ring and Commutator Inspections**	**Bearing Insulation Checks**	**Filter & Cooler Inspection**	**Rectifier Indicators**	**Field Ground Detection**	**Calibration**	**Functional Test**
Pilot Exciters & PMGs																			
Windings	Shorted Turns (Field)		x				x		x								x		
	Insulation ageing								x	x									
	Looseness						x			x									
	Mech.Wear & Abrasion						x		x	x									
	Overheating	x	x							x									

Component	Failure Mode	Trendable Tests								Inspections									
		Infrared Thermography	Temperatures:Bearings/Winding	Generator Field Temperature	Voltages & Currents	Vibration Monitoring	Vibration Analysis	Oil Analysis	Electrical Tests	Visual Inspection	Brushes & Rigging Inspections	Strobe Inspection	Collector Ring and Commutator Inspections	Bearing Insulation Checks	Filter & Cooler Inspection	Rectifier Indicators	Field Ground Detection	Calibration	Functional Test
	Dust Buildup		x						x	x									
Armature Iron	Lamination Damage	x	x				x			x									
	Lamination Overheating	x	x							x									
	Lamination Looseness						x			x									
Coupling	Internal Wear & Failure	x				x	x			x									
Bearings	Overheating	x	x			x	x	x											
	Wear or Mech. Degradation	x				x	x	x		x									
	Electrical Arcing							x		x				x					
	Seal Failure									x									
	Lubrication Failure	x	x				x	x											
PMG Rotor	Permanent Magnets Looseness					x	x			x									
Alternators & DC Generators																			
Bearings	Overheating	x	x			x	x	x											
	Wear or Mech. Degradation					x	x	x		x									

Component	Failure Mode	Trendable Tests								Inspections									
		Infrared Thermography	Temperatures:Bearings/Winding	Generator Field Temperature	Voltages & Currents	Vibration Monitoring	Vibration Analysis	Oil Analysis	Electrical Tests	Visual Inspection	Brushes & Rigging Inspections	Strobe Inspection	Collector Ring and Commutator Inspections	Bearing Insulation Checks	Filter & Cooler Inspection	Rectifier Indicators	Field Ground Detection	Calibration	Functional Test
	Electrical Arcing							x		x				x					
	Seal Failure									x									
	Lubrication Failure	x	x				x	x											
Coupling	Internal Wear & Failure	x				x	x			x									
Windings	Insulation ageing								x	x									
	Looseness						x			x									
	Mech.Wear & Abrasion						x		x	x									
	Overheating	x	x							x									
	Dust Buildup		x						x	x									
Armature Iron	Lamination Damage	x	x				x			x									
	Lamination Overheating	x	x							x									
	Lamination Looseness						x			x									
Collectors & Commutators																			
Brushes	Excessive Wear									x	x								

		Trendable Tests								Inspections									
Component	**Failure Mode**	**Infrared Thermography**	**Temperatures:Bearings/Winding**	**Generator Field Temperature**	**Voltages & Currents**	**Vibration Monitoring**	**Vibration Analysis**	**Oil Analysis**	**Electrical Tests**	**Visual Inspection**	**Brushes & Rigging Inspections**	**Strobe Inspection**	**Collector Ring and Commutator Inspections**	**Bearing Insulation Checks**	**Filter & Cooler Inspection**	**Rectifier Indicators**	**Field Ground Detection**	**Calibration**	**Functional Test**
	Excessive Arcing	x								x	x		x						
	Breaking or Chipping									x									
Ring	Excessive Wear									x			x						
	Eccentricity						x						x						
	Inadequate Film									x		x	x						
	Damaged Surface									x		x	x						
Brush Rigging/Bus Bars	Excessive Dust Buildup									x	x								
	Insulation Failure								x	x	x								
	Loose Connection	x							x	x	x								
Commutator	Shorted Bars	x							x	x		x	x						
Rectifiers																			
Diode or SCR	Open Circuit	x			x				x			x				x			x
	Short Circuit	x			x				x							x			x
	Looseness	x			x							x							
Capacitor	Open Circuit								x										x

Component	Failure Mode	Trendable Tests								Inspections									
		Infrared Thermography	Temperatures:Bearings/Winding	Generator Field Temperature	Voltages & Currents	Vibration Monitoring	Vibration Analysis	Oil Analysis	Electrical Tests	Visual Inspection	Brushes & Rigging Inspections	Strobe Inspection	Collector Ring and Commutator Inspections	Bearing Insulation Checks	Filter & Cooler Inspection	Rectifier Indicators	Field Ground Detection	Calibration	Functional Test
Rectifier Cooling	Overheating	x																	
	Water Leak									x									
	Conductive Deposits								x	x									
Disconnect Switch	Overheating	x								x									
	Contact Failure	x								x									
Coolers	Air Filters Clogged									x					x				
	Fan,Blade Failure					x	x			x									
	Fan,Drive Motor Failure	x				x	x	x		x									
Excitation Transformer																			
Winding	Insulation ageing								x	x									
	Looseness						x			x									
	Overheating	x	x							x									
	Dust Buildup		x						x	x									
Laminations	Looseness						x			x									
	Damage	x	x				x			x									
	Overheating	x	x							x									

		Trendable Tests								Inspections									
Component	**Failure Mode**	**Infrared Thermography**	**Temperatures:Bearings/Winding**	**Generator Field Temperature**	**Voltages & Currents**	**Vibration Monitoring**	**Vibration Analysis**	**Oil Analysis**	**Electrical Tests**	**Visual Inspection**	**Brushes & Rigging Inspections**	**Strobe Inspection**	**Collector Ring and Commutator Inspections**	**Bearing Insulation Checks**	**Filter & Cooler Inspection**	**Rectifier Indicators**	**Field Ground Detection**	**Calibration**	**Functional Test**
Bushings	Dust Buildup								x	x									
	Loose Connection	x							x	x									
Field Breaker																			
Breaker	Contacts Dirty Or Damaged	x								x									
	Fails to Open									x									x
	Fails to Close									x									x
	Loose Connection	x								x									x
Field Discharge Resistor																			
	Overheated	x								x									
	Circuit Fails to Open																		x
	Circuit Fails to Close																		x
Generator Collector																			
Brushes	Excessive Wear									x	x								
	Excessive Arcing	x								x	x		x						
	Breaking or Chipping									x									

		Trendable Tests								Inspections									
Component	**Failure Mode**	**Infrared Thermography**	**Temperatures:Bearings/Winding**	**Generator Field Temperature**	**Voltages & Currents**	**Vibration Monitoring**	**Vibration Analysis**	**Oil Analysis**	**Electrical Tests**	**Visual Inspection**	**Brushes & Rigging Inspections**	**Strobe Inspection**	**Collector Ring and Commutator Inspections**	**Bearing Insulation Checks**	**Filter & Cooler Inspection**	**Rectifier Indicators**	**Field Ground Detection**	**Calibration**	**Functional Test**
Ring	Excessive Wear									x			x						
	Eccentricity						x						x						
	Inadequate Film									x		x	x						
	Damaged Surface									x		x	x						
Brush Rigging/Bus Bars	Excessive Dust Buildup									x	x								
	Insulation Failure								x	x	x								
	Loose Connection	x							x	x	x								
Grounding Brush																			
	Excessive Wear									x	x								
	Fails to Maintain Shaft Contact				x					x	x	x							
	Non-Conducting								x	x									
Field Winding																			
Winding	Insulation ageing								x	x									

Component	Failure Mode	Trendable Tests								Inspections									
		Infrared Thermography	Temperatures:Bearings/Winding	Generator Field Temperature	Voltages & Currents	Vibration Monitoring	Vibration Analysis	Oil Analysis	Electrical Tests	Visual Inspection	Brushes & Rigging Inspections	Strobe Inspection	Collector Ring and Commutator Inspections	Bearing Insulation Checks	Filter & Cooler Inspection	Rectifier Indicators	Field Ground Detection	Calibration	Functional Test
	Looseness						x			x									
	Mech. Wear & Abrasion						x		x	x							x		
	Copper Dusting								x	x							x		
	Overheating			x					x	x									
	Dust Buildup									x									
	Shorted Turns			x		x	x		x	x							x		
Crowbar																			
Resistor Circuit	Overheated	x								x									
	Shorted	x																	x
Voltage Regulator																			
Regulator	Component Overheating	x								x									
	Dust Buildup									x									
	Erratic Operation	x			x	x													x
	Loose Components	x								x									x
	Loose Connections	x								x									x

Component	Failure Mode	Trendable Tests								Inspections									
		Infrared Thermography	Temperatures:Bearings/Winding	Generator Field Temperature	Voltages & Currents	Vibration Monitoring	Vibration Analysis	Oil Analysis	Electrical Tests	Visual Inspection	Brushes & Rigging Inspections	Strobe Inspection	Collector Ring and Commutator Inspections	Bearing Insulation Checks	Filter & Cooler Inspection	Rectifier Indicators	Field Ground Detection	Calibration	Functional Test
Motor Driven Potentiometer/ Rheostat	Set Points Drifting				x													x	x
	PT/CT CircuitFailure				x													x	x
	Erratic Operation				x					x								x	x
	Exceed Limits				x					x								x	x
Transfer Circuit	Fails to Transfer to AVR or to Manual																	x	x
Switches & Relays:	Contacts Fail to Close or Open	x																	x
Field Voltage	Excessive Harmonics & Spikes																	x	x
Cabinet	Condensation									x									

5
MAINTENANCE PRACTICES

An effective maintenance program for any power plant equipment should be developed from an approach that embraces some form of Reliability Centered Maintenance (RCM) methodology. Emphasis should be placed on Predictive Maintenance (PdM) and Preventive Maintenance (PM) tasks that are performed in order of least intrusive in nature to those that require some sort of internal inspection activity.

This means that the most desirable category of maintenance tasks to perform are those that are most predictive in nature; such as vibration monitoring, thermography, oil analysis, etc., and any other form of trendable test, including monitoring and trending operational parameters that may indicate the onset of equipment failure. The next category of maintenance activities include time directed tasks; such as instrument calibrations, filter inspections, external visual inspections, and cleaning activities. The least desirable of all maintenance tasks are those that require some disassembly to perform an inspection activity that is required by vendor recommendation, insurance requirement, or regulatory requirement.

The most effective maintenance program will consequently yield the least amount of unplanned activities, resulting from unexpected equipment failures. This is the goal of all best performing plants in the industry.

Predictive and monitoring tasks were covered extensively in chapter 4 of this report. This chapter discusses those maintenance tasks that are mainly time directed and intrusive.

Routine

Many routine maintenance tasks are mainly time driven, as opposed to condition driven. These are tasks necessary to ensure reliable operation of the system and its components. Many of these tasks normally cannot be performed with the system in operation. They will, therefore, have to be scheduled for performance during planned system outages. Although it is preferable to perform maintenance on a condition based approach, tasks that require a system outage often will have to be performed on a time based plan.

The application and frequency of time based tasks are influenced by condition monitoring results. Condition monitoring may indicate that the frequency of the task should be increased or decreased. Results from previous performance of routine tasks also provide indication of the proper task frequency. For example, if during past filter replacements it was found that the filters were not dirty, then perhaps the frequency of filter replacement could be decreased.

Manufacturer recommendations, and requirements for warranties, insurance, and regulatory bodies may dictate specific tasks at certain frequencies. Thus, the maintenance plan should include input from requirements, condition monitoring, PdM results, and the results from past performance of routine tasks.

Cleaning

During operation it is not possible to keep all of the equipment perfectly clean. Energized and rotating components prevent cleaning of certain parts. Covers and shrouds prevent access to all areas in the equipment. With the equipment safely de-energized and tagged out, a thorough cleaning of components should be performed. Dust and other debris in components absorb moisture, blocks cooling air, may cause electrical grounds and shorts, may interfere with equipment operation, chemically react with components, and create personnel safety issues. Based upon equipment history and monitoring, the equipment should be thoroughly cleaned at a frequency that will ensure acceptable levels of cleanliness throughout the entire operational time period between cleanings.

The collector area of generators and exciters can collect significant amounts of carbon dust from brush wear. Air flow may sweep much of the dust away; but deposits can gather in crevices, on insulators, behind bus bars, and elsewhere. The carbon dust, being conductive, can produce a ground or short if allowed to build up. During every scheduled maintenance outage the collector or commutator, brush holders and rigging, bus bars, and insulators should be wiped clean and vacuumed as necessary to remove the carbon dust. Compressed air may be used to clean difficult locations; however, care must be exercised to avoid blowing dust into other areas, and to prevent injury to personnel.

Cabinets and other enclosures should be inspected on a routine basis. Excessive dust in cabinets, as pointed out in a previous chapter, can lead to heat build up and possible grounding and shorting of energized components. Cleaning of cabinets and enclosures should be performed during scheduled maintenance outages to ensure reliable operation. The use of compressed air for cleaning should be avoided if possible, as dust may be blown into other components, and equipment damage may occur.

Filters

Most filters can be inspected, cleaned, and if necessary, replaced during operation. However, in some circumstances it may not be possible or desirable to clean and replace a filter online. All air filters should be inspected, cleaned, and if necessary, replaced during the outage to ensure trouble free performance after start up. Even if a filter is not excessively dirty it should be cleaned or replaced during the outage to avoid having it clog during operation.

Cooling Tubing

Copper and other substances dissolved in cooling water form deposits on the walls of tubes over time. These deposits can be and often are conductive. The cooling tubes for rectifier diodes are made of Teflon or other nonconductive material so that they will not ground or short out the rectifier circuits. If allowed to build up, the deposits will form a conductive path, grounding the rectifier circuits.

The cooling tubes should be inspected on a routine basis for internal deposits. Inspection frequency should be based upon manufacturer recommendations and on the results from past inspection. Once every 3 to 6 years is a range of typical inspection frequencies. If deposits are minor, some cleaning of the tube may be possible. However, if significant deposits are found, the tubing should be replaced. One manufacturer has recommended routine replacement of its rectifier cooling tubes to prevent grounds from copper deposits.

In practice it is often more effective to replace the tubes if deposits are found, rather than attempting to clean the tubes. Since the labor to remove the tubes is already performed for inspection, it is the difference between the cost of material for new tubes versus the labor cost for cleaning that can make replacement more cost effective. Add to this that cleaning will not likely remove all the deposits. Replacement ensures the tubes are deposit free when the system is returned to service.

Collector and Commutator Measurements

Though commutator and collector rings wear slowly, unnoticeably small high and low areas develop around the circumference of the rings. These high and low areas cause brush vibration, chatter, and accelerate both brush and ring wear.

Ring runout measurements should be taken during each scheduled maintenance outage with dial indicators. The measurement should be of the entire ring circumference and taken along several points across the width of the ring to ensure that the track of each brush is measured. For a 3600 rpm machine runout of less than 3 mils is desirable; although runouts of up to 6 mils may be acceptable. Slow speed machines allow for higher runout. The manufacturer recommendation for runout should be the deciding factor in whether a runout measurement is acceptable or not.

If excessive runout is measured, the rings should be stoned or ground, as discussed in chapter 4. The stoning or grinding of the rings may be done at low speed while on turning gear, or at rated speed. At rated speed, vibration and machine unbalances are present which will cause the ring surfaces to the vibrate in the pattern of the machine. These surface patterns will actually provide accurate circular surfaces for the brushes during operation. The patterns of vibration at rated speed are essentially eliminated as the grinding or stoning will provide a ring surface that corresponds to the vibration pattern. However, if the machine vibration changes after the ring surfaces are ground, the correspondence of the ring surface to the vibration pattern is lost, and may be made worse than if no grinding or stoning was done. Also, it may be difficult for some plants to run the generator or exciter at rated speed unloaded for an extended period of time.

If the machine is well balanced with no noticeable vibration patterns, grinding or stoning the ring at low speed should also produce accurate circular ring surfaces for the brushes at rated speed. Typically the grinding or stoning is done with the machine on turning gear. For separate exciters, a small chugger motor may be temporarily attached to the shaft to turn the rotor and rings at low speed.

Some rings may be removed from the generator or exciter to be ground. The rings then can be accurately ground on a lathe or similar machine. Great care must be exercised to ensure that the rings are accurately centered and balanced on the shaft when reinstalled.

Runout measurements should always be performed after grinding or stoning, regardless of the method used, to ensure quality of work and to provide an “as left” record. Thorough cleaning of the rings and surrounding area is required to remove all metal filings and abrasive grit. The rings should be measured to ensure that they are not under the minimum ring diameter given by the manufacturer. On commutators, the interbar insulation should be inspected, and cut as necessary, to ensure that it remain below the surface of the bars.

Part Replacement

As preventive maintenance tasks, certain items in the excitation system will need to be replaced to maintain reliability of the system. As previously mentioned, Teflon tubes used for rectifier cooling may require periodic replacement. Collector and commutator brushes should be replaced during outage, especially if they are worn significantly. This will help minimize online brush replacements.

Capacitors are another component that are often periodically replaced. Failure of the dielectric is often unpredictable and may occur much more frequently after a certain number of years in operation. This is especially true of large electrolytic capacitors, often used for filtering. Several plants routinely replace certain capacitors after 10 years of service. Manufacturer recommendations, failure histories, and industry experience should provide guidance on which capacitors should be replaced and the frequency of replacement.

Semiconductors such as diodes and SCRs often have a finite life. MTBF data is often available for many semiconductors; a good reference is “EPRI ASD Applications Guide”. This guide is available from Jarsco Publishing Company, and may be purchased on line at www.jarscopublishing.com. Replacing diodes and SCRs prior to reaching end of life can help prevent a failure and possible excitation system malfunction. However, many systems have sufficient redundancy built into the rectifiers, and a limited number of in-service failures can be tolerated. Again, manufacturer recommendations, failure histories, and industry experience should provide guidance on which semiconductors should be replaced and the frequency of replacement.

Other components that exhibit certain failure patterns should possibly be replaced on a routine basis. Consideration on routine replacement should involve MTBF data, failure history, impact of failure on system performance, ease of replacing, cost of replacement parts, and whether failures are predictable. If the failure of a component can be reasonably predictable by periodic inspections and tests so that a replacement can be performed during the next schedule outage, routine replacement is unnecessary. Furthermore, if the failure would not adversely impact system performance, and repair could easily be performed on line, then routine replacement may also be unnecessary. An example of this last statement could be redundant rectifier banks that are frequently monitored for diode failure. In this example, redundancy and fuse protection provides for maintaining the field if a diode fails, and the bank can be switched off and the diode replaced without system impact.

Exciter Overhaul

An overhaul is a major maintenance task. It is necessary for performing certain inspection, cleaning, and replacement tasks. Typically an overhaul is not frequently necessary; perhaps once every 10 years. During an overhaul; windings, bearings, core iron, and other internal components can be thoroughly cleaned, inspected, tested, and measured. The winding and core iron inspections in chapter 4 of this guide are performed during an overhaul. EPRI has published guidelines for general maintenance of Westinghouse brushless excitation systems and General Electric Alterrex systems. These guidelines are in EPRI CD 1006780 “Guidelines for Reducing the Time and Cost of Turbine Generator Maintenance Overhauls and Inspections. Repair Procedures”.

Outside organizations that are experienced in performing exciter overhauls are frequently brought in to direct, and depending on labor agreements possibly perform, the work. Typically these organizations are from the manufacturers’ service departments or shops, although other independent organizations can be as effective in performing the overhaul. Plants with exciters that are small enough may elect to ship the exciters out to a shop for overhaul.

Overhauls are not frequently performed. The work involved is a major cost, and the possibility of incorrect or inaccurate work, foreign material, and component stressing can cause equipment malfunction when returned to service. Typical overhaul frequencies are once in ten years or longer.

Manufacturer recommendations and possibly insurer or regulatory requirements may be factors in determining the overhaul frequency. Condition monitoring and PdM techniques play an important role in determining overhaul frequency; they could possibly extend the frequency, or show a need for an overhaul to be performed sooner. Electrical testing, temperature monitoring, vibration analysis, visual inspection, and voltage and current monitoring are techniques that may be helpful in determining when overhauls should be performed. Findings from past overhauls on the same exciter or similar exciters should be considered in determining when the next overhaul should be performed.

Periodic Calibration

Many components of the excitation system require periodic calibration to ensure that they function within limits, and that they will respond properly to transients. Component ageing, wear, thermal cycles, vibration, and other factors can affect calibrated set points. All set points have a tolerance that allows for slight deviation above or below the set point. The goal of the periodic calibrations is to ensure that no set point will drift outside its tolerance band during system operation. Often calibration frequency can be extended if it is found that all set points have been remaining well within their tolerance bands. Conversely, the calibration frequency might have to increase if set points are found to have drifted outside of their tolerance band.

Of course, there are factors to consider when determining calibration frequency. The frequency of scheduled maintenance outages in which the calibrations has to be performed is an important consideration. Also, reliability councils may have recommendations or requirements for periodic testing and calibration of the voltage regulator. A five year calibration and test frequency for voltage regulators is a common requirement.

Voltage Regulator Calibration

The voltage regulator is not just one component, but consists of a number of limiters, protection circuits, an automatic regulator, and a manual regulator. Typically two calibration and test procedures are performed for the voltage regulators and associated components. First an open loop calibration and test is performed. This is done with the generator out of service. Second a dynamic performance test and calibration is performed. This is done with the generator in service and running.

Voltage Regulator Open Loop Testing

The calibration is broken into a number of steps or subtasks. These commonly are: component inspection, recording "as found" settings, test equipment set up, manual voltage regulator, automatic voltage regulator, limiters, and recording "as left" settings. Additionally, functional testing of the field flashing circuit and verifying SCR bridge waveforms may be part of the calibration where applicable.

Inspection of Components

Voltage regulator components are inspected for dust build up, overheating, loose connections, and damage. Potentiometers, including motorized potentiometers and rheostats, should be verified to have smooth linear operation. Switches should be checked to verify correct operation without sticking or difficult operation. The potentiometers and switches can be checked prior to, or during the performance of, the test and calibration.

Record "As Found" Settings

Recording the "as found" setting serves several purposes. It provides an indication of any settings that have been altered since the last calibration. If any portion of the calibration has to be re-performed, the recorded values provide starting points. Comparison with the "as left" data provides indication of component drift and adverse trending.

Test Equipment Set Up

Connect power supplies, voltmeters, and other test equipment to the regulator. Single phase and three phase variable transformers are commonly used to provide simulated feedback from the generator, and if applicable, the alternator. Slide wire resistors or DC power supplies are commonly used to simulate generator field feedback. A resistor or carbon pile is commonly used as a load on regulator output to simulate the field winding or load loads. Procedural control of test equipment installation, jumper placement, lead lifting, and switch operation is necessary to control correct set up and to ensure proper restoration. Correct polarity and grounding (or isolation from ground) of simulated signals and loads is necessary for proper test and calibration.

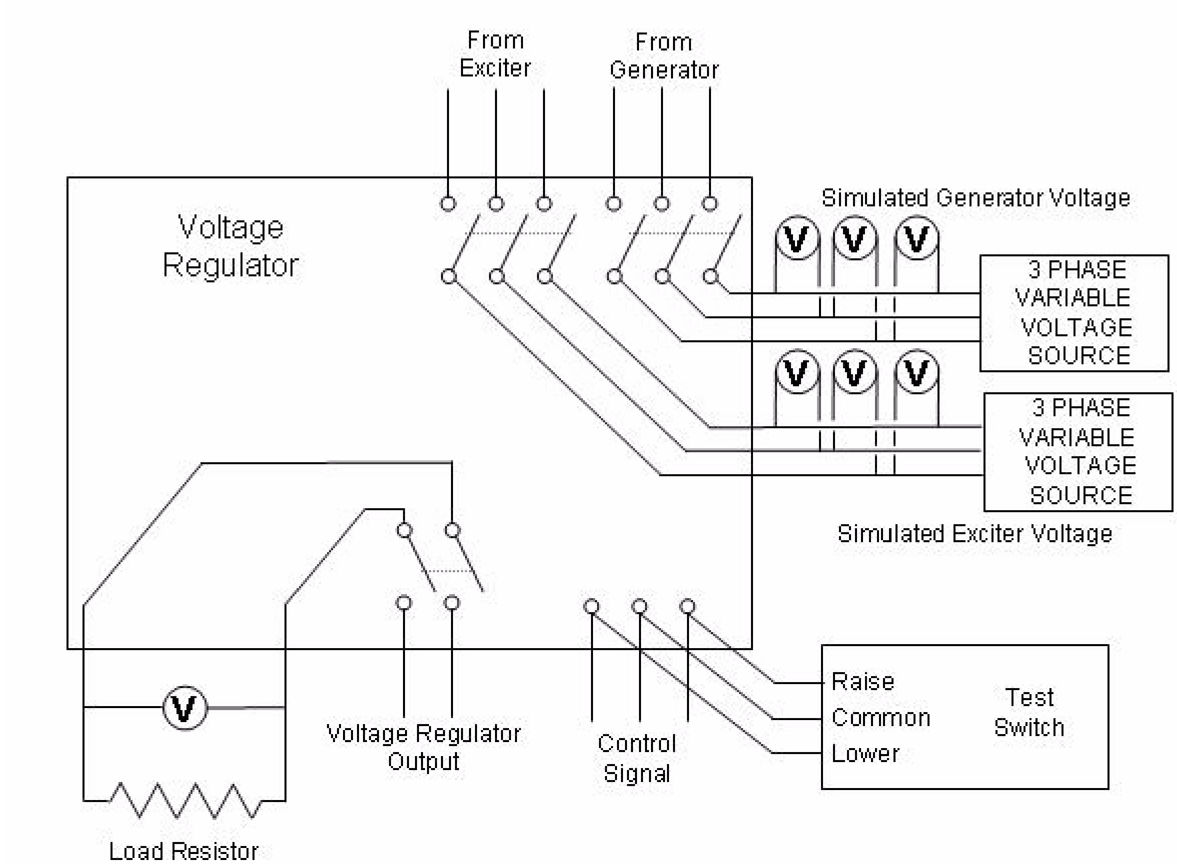


Figure 5-1
Typical Open Loop Test Set Up for a Type AC Excitation System Voltage Regulator

Field Flashing Circuit

Test the field flashing circuit, if applicable. Operate field flashing circuit and verify appropriate voltage applied to output. Ensure blocking diodes are functioning properly. Verify that the timing device or voltage build up relay disengages the field flashing circuit.

Manual Regulator Calibration and Test

Power is applied to the regulator and it is allowed to warm up prior to continuing the test and calibration. Simulated feedback from the field and or exciter is applied to manual regulator. Regulator input is varied from minimum to maximum, and regulator output is verified to be within limits. Also the simulated exciter feedback signal is varied, and regulator response is verified. Internal regulator signal levels are verified and adjusted as necessary. Permanent regulator output voltmeter and other instruments are verified to read correct values.

Automatic Regulator Calibration and Test

Power is applied to the regulator and it is allowed to warm up prior to continuing the test and calibration. Simulated feedback from both the generator and the exciter is applied to the automatic regulator. Regulator input is varied from minimum to maximum. Reference, error, and feedback signal circuits are measured for correct signals and adjusted as necessary. Regulator output is verified to be within limits. Also, the simulated generator feedback signal is varied, and regulator response is verified. Internal regulator signal levels are verified and adjusted as necessary. Permanent regulator output voltmeter and other instruments are verified to read correct values. If present, the de-excitation circuit function is tested and verified.

SCR Bridge Waveform

Regulator input to the bridge is varied. Firing circuit signals are verified with oscilloscope to be of the correct waveform (period, width, and amplitude of pulses) for the various regulator inputs. Clipping of the firing circuit pulses is verified to be within limits. Output of bridge may be viewed to verify correct waveform.

Calibration and Testing of Limiters

The limiters in the excitation system are basically tested and calibrated in a manner similar to that of the voltage regulators. Simulated signals are used to provide inputs to the limiters. Voltage signals are often substituted for current signals at appropriate points in the limiters. However, a calibrated current source at the point of insertion into the limiter circuit will provide a more complete and accurate simulation of the current signal. Internal limiter signal levels are verified and adjusted as necessary. Limiter response is measured and corrected as needed. Alarm, runback, transfer, and trip set points are tested and verified

Record "As Left" Settings

The set point values of potentiometers and other components, whether they were adjusted during the calibration or not, should be recorded. Parameters set for digital systems also should be recorded. The "as left" values should be compared to the "as found" values and values from previous test for trending.

Any repairs should be recorded with the test results to provide historical record of regulator condition, and for trending.

Excitation Dynamic Performance Testing

The calibration is broken into a number of steps or subtasks. These commonly are: test equipment set up, exciter unloaded, exciter loaded, limiters, and stability. Additionally, functional testing of the field de-excitation circuit may be part of the calibration test where applicable.

Test Set Up

Actual feedback signals from the exciter and generator are used in most of the dynamic tests. Recorders, meters, and an oscilloscope will likely be necessary to verify system response. Some simulated feedback may be required in certain portions of the test to provide adverse or transient inputs. Procedural control of test equipment installation, jumper placement, lead lifting, and switch operation is necessary to control correct set up and to ensure proper restoration.

Dynamic Test, Exciter Unloaded

This portion of the test verifies exciter output only and does not produce generator field excitation. Typically the generator field is open circuited during this test section. Field rectifier bank disconnect switches may be opened on systems employing them. The generator output, and feedback from the generator are not concerns with this portion of the test. Signals are verified in the regulator to ensure proper values of feedback, reference and error. Verify exciter output and that it is of the correct voltage. Vary the regulator reference signal between minimum and maximum values, and verify system response. Exciter field breaker, if applicable, is operated to verify function. Exciter field de-excitation circuit is also function tested and verified, again if applicable.

Dynamic Test, Exciter Loaded

The generator field circuit is energized in this portion of the test. Generator output is monitored and generator feedback to the voltage regulator is verified. The manual regulator is tested first. With the generator disconnected from the power system, excitation is applied and generator terminal voltage is verified. The manual regulator is adjusted for various generator terminal voltages. The generator terminal voltage, generator field voltage, and field current are verified to be of the correct values and are recorded for each adjustment of the regulator. The automatic regulator is adjusted to match output of the manual regulator, and control is transferred to the automatic regulator. The automatic regulator is adjusted for various generator terminal voltages.

The regulator setting that provides the normal generator output voltage is verified and recorded. Care must be exercised during adjustment of either the manual or automatic regulators in order not to exceed the volts per hertz rating of the generator, and if connected, the generator step up transformers.

Stability

A regulator transfer transient is intentionally caused to verify the automatic regulator's ability to dampen system oscillations. An oscilloscope or recorder is connected to monitor generator output voltage. The excitation is transferred back to the manual regulator. The manual regulator is adjusted to a specified lower generator voltage without adjusting the automatic regulator. The excitation system is transferred back to the automatic regulator, which was left at the slightly higher voltage setting. The generator output is checked to verify that system oscillation was dampened within the required time limits.

Limiters and Protection Circuits

Some circuits may require simulated inputs for testing. For example, field current may have to exceed recommended values to adequately test and calibrate the current limiter. Thus, a simulated signal may be necessary. The limiters and protection circuits should be tested and calibrated in normal configuration as much as possible. The voltage regulator is adjusted up and down as necessary to provide the appropriate inputs to the limiters and protection circuits.

Simulated Inputs and Feedback Test Sets.

Commercially available test sets are available for most excitation systems. These test sets provide the input signals and output monitoring circuits necessary to perform most of the dynamic tests. Preprogrammed sets can perform a number of the test steps automatically and can greatly simplify the test and calibration process.

An excitation test set can greatly simplify the set up and conduction of open loop and dynamic voltage regulator testing. Separate variable transformers, power supplies, slide wire resistors, meters, and their individual connection are done away with for the most part. Care has to be exercised to ensure that the correct system parameters are used in the test set. Also thorough knowledge of the voltage regulators is still necessary to make correct adjustments to the regulator and to prevent unwanted system actions from occurring.

Sensor and Inspection Calibration

Potential Transformers (PTs) and Current Transformers (CTs) are the most common devices used to monitor the voltages and currents of the excitation system. DC field current is often monitored by a shunt link in the field circuit, which produces a DC voltage proportional to the current. Both AC and DC voltage and current transducers are used to convert voltages and current into signals for use in instrumentation and metering circuits.

Instrument transformers are not calibrated, but tested to verify accuracy. The transformers normally are robust, and do not fail often. Typical testing frequency of excitation system instrument transformers is once every 5 to 6 years. The IEEE standards C57-13 and C57-13.1 provide guidance on instrument transformers. Both CTs and PTs are typically ratio tested by applying a test voltage to the low (secondary) winding and measuring the induced primary winding voltage. On CTs particularly, this induced voltage is rather small since the primary is often just one turn, a conductor through the center of the transformer. A dual channel oscilloscope is useful for the ratio test in that it can measure both the voltage levels and the phase shift of the transformer. The phase shift measurement should be performed on a potential transformer to verify that it is within specifications.

Winding resistance and insulation resistance tests should also be made on the instrument transformer. Winding resistance measurements should be within specifications and should be compared to previous measurements and measurements of other transformers of the same model. Insulation resistance should be above 1 megohm.

An excitation current measurement should be done on the CTs along with the ratio test. With the CT primary circuit open, a test voltage is applied to the CT's secondary and the secondary current is measured. This excitation current measurement is performed for a series of different voltages, including voltages that saturate the CT. A plot of the voltage versus excitation current is created from the measurements. The excitation, typically at the saturation knee in the curve, is compared to specification, previous test measurements, and similar CTs.

Voltage, current, and other transducers are calibrated by applying the appropriate simulated input and measuring the transducer output. Normally a series of different input values are applied and the output is verified to be linear and within the accuracy specifications of the transducer. Calibration adjustment to the transducer is made as necessary, and the "as found" and the "as left" data recorded.

Protective Relay Calibration

Many excitation systems in service use some type of protective relays. The relays most commonly used provide overcurrent, loss of field, and volts per hertz protection. These relays may be the older electro mechanical models or newer solid state relays. The calibration of these relays is no different then that for protective relays used elsewhere in the plant, such as the generator protective relays.

Often protective relays are calibrated during outages. However to make better use of limited manpower during outage, it may be desirable to calibrate the relays while online. Many relays have disconnect and test switches that permit in place calibration and test of the relays without disturbing the rest of the system. A second method involves removing the relay and replacing it with a temporary relay. This method causes less interruption of the protective function, as the temporary relay provides this function during the calibration.

As with the voltage regulators, test equipment to simulate voltage and current is used for the calibration and testing of the protective relay. Relay test sets that provide variable voltage, current and frequency, and often with three phases, are commercially available to simplify the set up and conductance of the relay calibration. A well known provider of relay test sets is Multi-Amp.

Outages

Outages are required to perform maintenance on plant equipment that cannot be done on line. Typically plants will schedule a maintenance outage once every 18 to 24 months. The maintenance outage may last one month or longer.

In between the scheduled maintenance outages, a plant may have minor outages. These minor outages can either be scheduled or forced. The scheduled minor outage typically has duration of a few days and is performed at times when load demand is low. A recent trend is to take minor outages on weekends and other low load demand periods before a maintenance outage, in order to reduce the work load and duration of the maintenance outage.

Forced outages occur due to equipment malfunction or failure that takes the plant off line. Typically the forced outage lasts until the failed equipment is repaired; however, it may be extended to allow other emergent work to be performed. A good practice is to maintain a list of maintenance items that can be performed during forced outages, thus full advantage can be taken of the downtime and the scheduled outage work load can be reduced.

Planning and Scheduling Routine Tasks

A successful maintenance organization can gain a 30 to 40 percent improvement in manpower utilization by incorporating planning and scheduling best practices into their work management system. During the planning stages for scheduled outage work activities, a work package must be created that will allow a maintenance team to execute the work with minimal delay from start to finish. A number of details must be accounted for and incorporated into a work package well in advance of actual execution to make an outage evolution a success.

First, an accurate description of work to be performed is essential to allow a work planner to fully understand the scope and nature of the task that must be planned. Once the planner understands the nature of the work request, a logical task sequence must be developed in detail, from accepting and signing a work order to performance of post maintenance testing and returning the equipment in operable condition to operations personnel.

The latest and most accurately controlled drawings that are pertinent to the job must be referenced or included in the work package, depending on the complexity of the task to be performed. Also, any repair specifications that apply to the work need to be included in the package to give the necessary details to the craft to ensure that the work will be performed correctly. Any procedures that are necessary to ensure the work crew will completely understand the details of the job need to be either identified for reference or included with the work package, again depending on the complexity of the work to be performed.

Any unique craft skill training and qualification requirements must be identified so that a work supervisor will be able to ensure that the workers assigned to the job will be successful. Special tools, if any, that are known to be required for the job must be identified so that there are no surprises when the work crew actually starts in on the task. The correct parts to accomplish the identified work must be specified, procured, and made available for inspection by the work crew in advance of the job to ensure that the job won't be aborted because of a parts problem. Any known safety issues that the craft workers need to be aware of to successfully perform their task needs to be pointed out so that there is the proper awareness level before work begins.

The most successful organizations will maintain both an online schedule, and an offline or outage schedule. Online scheduling is arranged in a rolling fashion with anywhere from 4 weeks to 13 weeks of work identified and loaded into the plant's Computerized Maintenance Management System (CMMS) in advance. All of the organizations that are required to provide resources to the schedule must accomplish their necessary support functions at the appropriate time in the schedule sequence to ensure that when the actual work execution week approaches, the work is ready to be sent to the field in a ready to work status.

Outage scheduling should be maintained by a completely separate organization so that the focus on the outage work is not lost in the day to day schedule routine.

Emergent Work

Emergent work is maintenance that must be performed due to equipment deterioration or malfunction, and typically cannot wait until a scheduled time frame to be performed. Work of an emergent nature must be controlled by the work management organization such that the normal schedule is not unduly disrupted by potentially whimsical inclusion of work into the work week's schedule. One of the most significant disruptions to a well planned schedule comes from operating crews that feel their own operating concerns far outweigh those of the schedule. For this reason, there must be someone assigned the responsibility to act as gatekeeper for unscheduled work of an emergent nature to be added to the work week. Successful organizations maintain emergent work at less than 10% per work week.

6
REPAIR/REFURBISH/REPLACE DECISION

Excitation system performance and reliability can be improved by upgrading or replacing the system or some of its components. This can be especially true for older excitation systems. However, it often is not cost effective to install an upgrade or replacement. In many instances refurbishment of system components will provide additional years of reliable service. To determine if the excitation should be upgraded, replaced, refurbished, or just continued to be maintained in its current condition, a cost benefit analysis can be performed.

Cost Benefit Calculation

The decision to repair or refurbish major equipment versus replacement can often be aided by performing a cost benefit calculation. A particularly strong case can be made for replacement if the equipment under consideration is in direct support of power production or is a contributor to a significant personnel safety risk. If the equipment directly supports power production and has been a significant maintenance burden or operational challenge to power production, then a fairly simple calculation can be performed to help justify the cost to replace the equipment.

The plant should assign an individual that is knowledgeable of the equipment and of plant operations who can query the plant's maintenance management system for the number of megawatt loss or reduction events due to equipment malfunction. The same type of search can be performed on operating logs for events that lead to load reduction or shutdown due to some sort of failure or malfunction.

A tabulation can then be performed by event; logging the power reduction (MW) as a result of the event, the duration of the event in hours, and the duration of the loss during peak and off peak hours. The dollar value of a MWhr can then be assigned to each event and the sum total of all events will be the loss attributed to the equipment failure.

Similarly, a calculation by event can be performed to determine the maintenance costs associated with the event. Tabulate the cost of the parts required to repair the equipment, along with the number of man-hours required to perform the repairs. Multiply the man-hours by the labor rate, add the cost for parts per event. Perform a summation of all events for the total maintenance expense attributed to the Equipment.

Obviously the total operational (MWhr) loss plus maintenance expense attributed to the equipment will then help determine if the equipment is a candidate for replacement. The reduction in loss and expense is considered a benefit that can be compared to the cost of refurbishment or replacement.

Other important factors to examine when considering whether to repair/refurbish or replace a major piece of equipment should be the cumulative cost to upgrade or replace the equipment, increased operational reliability that can be achieved with replacement, decreased maintenance, and seemly intangible factors such as increased personnel safety.

Another factor not yet discussed that can make the replacement decision somewhat simple is the factor of equipment obsolescence. If repair parts for a machine are no longer available or are only available through a single source provider, then prolonged outages, especially forced outages, become a strong possibility while waiting for replacement parts or an entirely new equipment assembly from a different manufacturer.

Once all of the benefits and cost factors are considered, the cost benefit justification for refurbishment, replacement, or maintaining the current system can be performed. This is simply a comparison between the benefits and costs of one of the actions. To implement an upgrade and replacement, many companies require a benefit to cost ratio that is much greater than one. They require a large benefit to cost ratio to offset possible errors and inaccuracies in the cost and benefit analysis.

High Cost

Replacing or upgrading the excitation system is a major capital expense. Furthermore, the demolition and removal of the old system, plus the installation and set up of the new system, may add significantly to the scope of an outage. The cost of an upgrade or replacement has to consider not just the material cost, but also the installation labor, possible extended outage time, capital cost versus maintenance expense deductions, new spare parts inventory, training for operators and technicians, writing new procedures for operations and maintenance, design engineering, and preparation of new drawings and documentation.

Although the cost can be rather significant, especially when all the other various expenses are considered, often the upgrade of an older system can still be cost effective due to the increase in reliability and decrease in maintenance costs. It is important that all expenses and costs are considered to ensure an accurate cost benefit justification can be prepared.

Increase Reliability

Solid state and digital components have shown themselves to be highly reliable. This is especially true in systems that offer component redundancy. With redundancy, if a component fails, a backup can take over its function and a repair can be made online.

Rotating and other mechanical components suffer wear to some extent. Static and solid state components do not have mechanical wear. However, even electrical and electronic components have a finite life. As the system ages, the possibility of component failure may increase. In many older systems, a consideration has to be made of the remaining life in many of the components.

An assessment of the probability of failure with the old system provides a risk factor. Normally a risk factor of lost production per year is convenient to use. The total probabilities of failure for the system multiplied by the average time to repair gives the potential lost production due to failures. This lost production plus the potential repair expense provides risk cost for the probability of failure. Reference "Maintenance Testing Program Description" in chapter 4.

The risk cost of the new system or components has to be calculated as well. Then the actual risk cost due to failure of not installing the upgrade or replacement is the risk cost of the old system minus the risk cost associated with the new components.

Decrease Maintenance

A new system or component may reduce the amount of maintenance that has to be performed to maintain the reliability of the system. A plant with an older system that requires significant maintenance manpower to repair worn components can definitely benefit with an upgrade. A new system can also eliminate certain routine maintenance tasks. A new static excitation system eliminates tasks associated with rotating exciters such as vibration monitoring and oil analysis tasks. A brushless excitation system eliminates brush inspections and other tasks associated with collectors.

The total expense of the maintenance tasks, including operator inspections, for the new system should be subtracted from the total maintenance expense of the old system. This provides a value benefit for making the upgrade or replacement that can be used in the cost benefit justification.

In cases where the old system will be kept and maintained as a backup, the benefit will likely be negative, an added cost rather than a benefit. However, the benefit of the increase in reliability from having a maintained backup can usually offset the added cost of maintenance.

Intangible Benefits

Intangible aspects which include personnel safety issues and regulatory requirements also influence the upgrade decision, often a positive influence. Often there may be no direct value to benefits from intangible aspects of an upgrade. However, certain indirect methods of determining an intangible benefit value can provide input into the upgrade decision.

An upgrade often provides enhancement to personnel safety. For example a new collector may incorporate safety features, such as barriers, insulated or shielded bus bars, and a safer brush holder design, that reduce personnel exposure to energized parts. Another example is a replacement to a brushless system eliminates the shock and burn risks from collector entirely.

No one likes to place a value on safety; however the possible reduction in personnel injury has to be accounted for in the decision process. Many companies have a standard figure for calculating the value of increased safety. While it is not possible to put a value on injury, the cost of lost time due to injury and insurance rates may be used to determine a number for the decision, if no standard figure is available.

Another intangible factor is regulatory requirements. Reliability councils and power pool operators may require certain equipment enhancements that may not be possible with old excitation system components. An example could be a fast response voltage regulator with a power system stabilizer that could handle system transients better. Compliance with the requirements often does not provide a direct monetary benefit. However, levies, unfavorable rates, and other such action for noncompliance do reflect a benefit value for use in the decision process. Also, as with personnel safety, companies may have already determined a standard figure for computing the benefit of regulatory compliance.

Component Obsolescence

Another factor in considering an upgrade or replacement of the excitation system is the availability of spare parts. Manufacturers can go out of business, merge with other corporations, or simply stop supporting older products. Older equipment parts may not be available, and will tend to be more difficult to obtain in the future. The risk of not being able to obtain needed parts, and the cost of finding and procuring the available parts, can be used for the justification of excitation system upgrade or replacement.

The risk of component obsolescence can be determined by the cost of obtaining or manufacturing needed spare parts. Also, the potential lost production, while waiting for a needed part to be obtained or fabricated adds to the risk. Potential lost production is determined from the probability of failure as discussed in the previous section “Increase Reliability”. As with the other risks and benefits discussed, the risk of component obsolescence should be considered in the justification for upgrading or replacing the excitation system.

List of Suppliers

There are a number of suppliers that provide upgrades or replacements for existing excitation systems. The OEM of the existing excitation system can usually offer newer components and a modern system, if they are still in business. Other major OEMs often offer upgrades that cover most major excitation system regardless of which manufacturer produced the existing system. Also, non-OEM manufacturers can provide component upgrades and replacements for certain components such as voltage regulators. Several major manufacturers of excitation system upgrade and replacement components are:

- Basler
- General Electric
- Cutler Hammer (Westinghouse voltage regulators)
- ABB
- Siemens
- Hitachi
- Toshiba
- Mitsubishi

A
COMMON MAINTENANCE TASKS

The following table lists the tasks reported in excitation system maintenance survey data. The task rank indicates the commonness of the task. Rank 1 was performed by the most number of units, while rank 106 was performed by the least.

Table A-1
Common Excitation Maintenance Tasks

Component	Task	Rank	Manhour Average	Periodicity Average (days)
Collector/Commutator Exciter	Clean, Inspect, and Measure Eccentricity	73	2	1095
Collector/Commutator Exciter	Inspect	84	2	14
Collector/Commutator Exciter	Clean, Inspect, and Stone	51	2	1916
Collector/Commutator Exciter	Send Out for Overhaul	85		3650
Collector/Commutator Exciter Brushes	Inspect	23	2	7
Collector/Commutator Exciter Brush Holders	Clean and Inspect	56	0.5	1095
Collector/Commutator Exciter Brush Rigging	Clean and Inspect	35	5.6	949
Collector/Commutator Exciter Collector Ring	Clean and Inspect	104	8	730
Collector Generator	Clean, Inspect, and Measure Eccentricity	72	6	1095
Collector Generator	Inspect	16	3	130
Collector Generator	Clean, Inspect, and Stone	100	6	1095

Component	Task	Rank	Manhour Average	Periodicity Average (days)
Collector Generator	Thermoscan	88	0.66	540
Collector Generator Brushes	Check Tension	34	8	90
Collector Generator Brushes	Inspect	3	2	11
Collector Generator Brush Holders	Clean and Inspect	55	1.5	1095
Collector Generator Brush Rigging	Clean and Inspect	92	2	180
Collector Generator Brush Rigging	Disassemble and Inspect	57	24	1095
Collector Generator Leads	Thermoscan	37	2	365
Collector Generator Collector Ring	Clean and Inspect	9	12	1068
Collector Generator Collector Ring	Strobe Inspection	62	0.25	7
Collector Generator Collector Ring	Thermoscan	63	1.75	51
Collector Generator Wiring	Clean and Inspect	79	0.25	548
Diode Wheel	Strobe Inspection	102	0.5	7
Diode Wheel	Check Diodes	5	3.75	775
Enclosure Exciter	Clean	82		551
Excitation System	Functional Test	98	12	1095
Excitation System	Monitor Current and Voltage	101		1
Excitation System Breaker	Clean and Inspect	54	1.5	365

Component	Task	Rank	Manhour Average	Periodicity Average (days)
Excitation System Cabinet Metering	Clean and Inspect	93	4	365
Excitation System Cable	Thermoscan	76	0.25	548
Excitation System Metering Circuit	Test and Calibrate	42	4	1000
Excitation Transformer	Clean and Inspect	2	9	780
Excitation Transformer	Thermoscan	8	0.47	858
Excitation Transformer Air Filter	Clean and Inspect	53	3	1095
Excitation Transformer Bus Bar	Clean and Inspect	59	40	1095
Excitation Transformer Fan	Replace Bearings	65	24	1095
Exciter	Clean and Inspect	13	68	1078.1
Exciter	Overhaul	22	80	3129
Exciter	Thermoscan	87	2	365
Exciter	Vibration Analysis	27	2.4	45
Exciter Air Filter	Clean and Inspect	75	4	35
Exciter Bearing	Clean and Inspect	28	24	1369
Exciter Bearing	Insulation Resistance Test	32	0.5	1000
Exciter Bearing	Oil Change	33	4	1000

Component	Task	Rank	Manhour Average	Periodicity Average (days)
Exciter Bus Bar	Clean and Inspect	58	4	1095
Exciter Cable	Inspect, Test, and Check Termination Tightness	36	2	1000
Exciter Commutator	Clean and Inspect	38	4	90
Exciter Field Flashing Circuit	Signature Analysis	39	8	2000
Exciter Heater	Test and Inspect	41	0.5	365
Exciter Thermocouple	Inspect	96	16	365
Exciter Winding	Clean, Inspect, and Test	44	24	1000
Exciter Winding	Electrical Tests	46	14	1000
Exciter Winding Armature	Clean, Inspect, and Test	68	4	2190
Exciter Winding Armature	Electrical Test	47	1	1000
Exciter Winding Armature	Inspect and Electrical Tests	69	16	2000
Exciter Winding Field	Clean, Inspect, and Test	70	4	2190
Exciter Winding Field	Inspect and Electrical Tests	106	16	2000
Exciter Cooling	Eddy Current Test	49	4	2190
Exciter Cooling	Inspect	99		7
Exciter Cooling Air Filter	Change	89	1	91
Exciter Cooling Air Filter	Clean	17	0.96	245

Component	Task	Rank	Manhour Average	Periodicity Average (days)
Exciter Cooling Air Filter	Inspect	11	1.20	10
Exciter Motor Feed Breaker	Clean, Inspect, and Test	91	16	365
Field Breaker	Clean, Inspect, and Test	48	5	1460
Field Breaker	Inspect	4	13	916
Field Breaker	Overhaul	19	20	1383
Field Breaker	Test	30	0.2	1000
Field Breaker	Thermoscan	31	2	365
Field Exciter Winding	Electrical Test	97	8	2555
Field Generator Resistor	Inspect and Test	77	8	730
Field Generator Winding	Clean, Inspect, and Test	78	4	365
Field Generator Winding	Clean and Inspect	45	0.1	14
Field Generator Winding	Electrical Tests	21	3.6	762
Field Rectifier Bank	Calibrate and inspection	80	10	540
Field Rectifier Bank	Clean	81	8	91
Field Rectifier Bank	Inspect	83	4	7
Field Rectifier Bank	Thermoscan	52	0.6	316
Field Rectifier Bank Air Filter	Clean	90	20	91

Component	Task	Rank	Manhour Average	Periodicity Average (days)
Field Rectifier Bank Cabinet Power	Thermoscan	103	4	182
Field Rectifier Bank Diode	Forward and Reverse Conductance	18	2.9	791
Field Rectifier Bank Fuse	Inspect for Blown Fuse	40	2	1022
Field Rectifier Bank Switch	Clean and Lubricate as Needed	25	2.9	860
Field Rectifier Cooling	Clean/Inspect	12	12	714
Field Rectifier Cooling Cooling Tube Teflon	Inspect	64	8	1095
Field Rectifier Cooling Cooling Tube Teflon	Replace	94	160	2920
Ground Detector Exciter Field	Inspect and Test	7	0.96	784
Ground Detector Generator Field	Calibration	71	4	1460
Ground Detector Generator Field	Inspect and Test	74	0.75	15
Voltage Regulator	Calibration	1	36	864
Voltage Regulator	Clean	10	0.5	912
Voltage Regulator	Clean and Inspect	26	8	852
Voltage Regulator	Dynamic Maintenance and Calibration	6	31	931
Voltage Regulator	Functional Test and Inspection	15	13	488

Component	Task	Rank	Manhour Average	Periodicity Average (days)
Voltage Regulator	In Service FFT	50	64	730
Voltage Regulator	Thermoscan	86	0.33	540
Voltage Regulator Cabinet	Clean and Inspect	24	15	626
Voltage Regulator Cabinet	Thermoscan	60	2	180
Voltage Regulator Cabinet Power	Clean/Inspect	14	12.6	1095
Voltage Regulator Cabinet Power	Thermoscan	61	0.5	1095
Voltage Regulator Fuse	Clean/Inspect Holders	66	1	730
Voltage Regulator Maximum Excitation Circuit	Calibration	67	8	2190
Voltage Regulator Power System Stabilizer	Calibration	43	41.6	1217.2
Voltage Regulator Power System Stabilizer	Clean and Inspect	105	16	730
Voltage Regulator Relay	Calibration	95	16	365
Voltage Regulator Relay	Clean and Inspect	20	10.5	2190
Voltage Regulator Transducer	Calibration	29	6	955

B
FAILURE DATA

Table B-1
Reported Voltage Regulator Failure Rates by Make and Model

Excitation System	Failures per Unit-Year	Forced Outage Days per Unit-Year
ABB Static w/ ABB UNITROL@P Voltage Regulator	0.12	0.39
Allis Chalmers M-G Set w/ WDR 2000 Voltage Regulator	0.3 *	0.84 *
Allis Chalmers M-G Set w/ WTA Voltage Regulator	1.5 *	4.2 *
AEI M-G Set w/ Associated Electrical Industries (AEI) Voltage Regulator	0.023 *	0.29 *
AEI M-G Set with static pilot exciter w/ AEI Automatic Voltage Regulator	0.16 *	2.04 *
General Electric Alterrex Exciter w/ ABB UNITROL@P Voltage Regulator	0.14 *	6 *
General Electric Alterrex Exciter and Voltage Regulator	0.036	0.23
General Electric Alterrex Exciter w/ WTA Voltage Regulator	0.33 *	4.7 *
General Electric Amplidyne w/ Alterrex Voltage Regulator	0.13 *	0.31 *
General Electric GeneRex Exciter	0.16 *	0.49 *
General Electric M-G Set	0.011 *	4.8 *
General Electric Static Exciter	0.38 *	1.3 *
Westinghouse Brushless Exciter w/ WTA Voltage Regulator	0.067	6.7
Westinghouse M-G Set w/ PRX-400 Voltage Regulator	0.11 *	0.64 *
Westinghouse M-G Set w/ WMA Voltage Regulator	0.058 *	0.34 *
Westinghouse Static w/ WDR 2000 Voltage Regulator	0.1 *	1.7 *
Westinghouse Static w/ WMA Voltage Regulator	0.038 *	0.46 *
Westinghouse Static w/ WTA Voltage Regulator	0.064 *	0.4 *

* Failures per Unit-Year and Forced Outage Days per Unit-Year marked with an asterisk are based upon a limited amount of data, and may not be statistically accurate.

Table B-2
Reported Voltage Regulator Failure Rates, by Type

Type	Excitation System	Failures per Unit-Year	Forced Outage Days per Unit-Year
DC	M-G Set with Amplidyne	0.25 *	0.107 *
DC	M-G Set	0.29 *	0.054 *
AC	Alternator (Brushed)	0.38	0.039
AC	Alternator (Brushless)	0.025	0.025
ST	Static	0.52	0.14

* Failures per Unit-Year and Forced Outage Days per Unit-Year marked with an asterisk are based upon a limited amount of data, and may not be statistically accurate.

C
RECOMMENDED MAINTENANCE

Table C-1
Recommended Maintenance Tasks and Frequencies

Test or Task	Frequency or Periodicity	Trend and Analyze Results
Vibration Monitoring	Continuous	Weekly
Vibration Analysis	Yearly	Coincides with Test
Oil Analysis	Once/3 Months	Coincides with Test
Infrared Thermography	Once/3 Months	Coincides with Test
Bearing Temperature Monitoring	Continuous	Weekly
Exciter Winding Temperature Monitoring	Continuous	Weekly
Generator Field Winding Temperature Monitoring	Continuous	Weekly
Excitation System Voltage and Current Monitoring	Continuous	Weekly
Bearing Insulation	18 to 36 Months	Coincides with Test
Insulation Resistance	18 to 36 Months	Coincides with Test
Winding Resistance	18 to 36 Months	Coincides with Test
Field Impedance Test or RSO	18 to 36 Months	Coincides with Test
Transformer Turns Ratio	18 to 36 Months	Coincides with Test
High Potential Test of Medium Voltage Transformer	18 to 36 Months	Coincides with Test
On Line Brush Inspection	Daily	Monthly
On Line Collector/Commutator Strobe Inspection	Monthly	When Trouble is Discovered
Brushless Exciter Diode Fuse Strobe Inspection	Monthly	When Trouble is Discovered
Rectifier Bank Visual Inspection	Daily	When Trouble is Discovered

Test or Task	Frequency or Periodicity	Trend and Analyze Results
Collector/Commutator Area Cleanliness Inspection	Daily	When Trouble is Discovered
Excitation System Cleanliness Inspection	Weekly	When Trouble is Discovered
Excitation System Cabinet Inspection	Monthly	When Trouble is Discovered
Cooling Air Filter Inspection	Daily	When Trouble is Discovered
Voltage Regulator Open Loop Calibration and Test	5 Years	Coincides with Test
Voltage Regulator Dynamic Calibration and Test	5 Years	Coincides with Test
Protective Relay Calibration and Test	2 Years	Coincides with Test
Ground Detector Functional Test	Monthly	Coincides with Test

D
COST BENEFIT ANALYSIS

Accurate and believable cost benefit analysis is critical to a successful optimized maintenance program. Currently, it is up to each organization to determine internal costs, develop an analysis method, and convince their management of the validity of their results. Unfortunately, these figures can be dismissed as biased or inflated, and do not result in the intended support from management for the program, especially for the Predictive Maintenance (PdM) portion of an optimized maintenance program.

Cost Benefit Analysis for Predictive Maintenance Programs

From the first day that the expensive equipment of a diagnostic technology is purchased, or the contract to outsource the service is signed, the individuals responsible for overseeing the program constantly fight the battle to justify the expenditure of funds and commitment of manpower. Even in those cases where an organization enjoys the sponsorship of a key individual in upper management, the day soon comes when that sponsor has moved on, and the new management begins to question every aspect of the organization.

Unlike capital generation equipment, the benefits of applying diagnostic technologies to monitor the generation process are not easily assessed for financial impact. In order to generate megawatts, it can be determined that a plant must be acquired or designated, that generation equipment must be purchased and installed, and that the fuel must be obtained and processed. The “direct” costs include the production manpower and the fuel. The “indirect” costs, commonly referred to as overhead, include the sunk costs of facility construction and the labor and part costs of production machinery maintenance.

Not only is the PdM program an indirect cost, but the effects on the per unit cost of generation are extremely difficult to ascertain. Managers are trained and educated to use existing economic and accounting models to assess production efficiencies and costs to make sound management decisions. These decisions are nearly always made in the context of the known or anticipated effect on the per unit generation cost or impact on overhead costs. It is not logical to take on increased indirect costs, unless it can be shown that there is an anticipated reduction in direct costs, or increase in productivity. PdM programs are no exception, and are subject to the same scrutiny as other financial management decisions. It is not enough to “wow” people with the diagnostic capabilities of technology, unless it can be shown to provide the needed return on investment.

Investment or commitment to PdM programs can begin in a number of ways. Sometimes the vision or insight of key company personnel is enough to convince management of the need to invest in diagnostic technologies. Other times, the response to chronic failures or other generation problems initiates the search for technology based solutions. Whichever the initiating event, it is inevitable that in the long-term the commitment to the program is likely to be challenged, and the challenge will always include the need to financially justify the manpower and funding invested in the program. At these times it is critical for the PdM program manager to be able to provide reliable, believable financial data on the impact of the use of diagnostic technologies.

By calculating the total cost savings from direct and indirect sources, and subtracting the program costs, we arrive at the net benefit for the investment in the program. This is a common method of expressing the cost benefit of a PdM program, by tallying the net benefit and reporting it on an annual basis, to influence company funding to maintain or possibly expand the program. These calculations can also be used to illustrate financial benefit in more traditional managerial accounting parameters such as IRR (internal rate of return) and cost benefit ratio. Most importantly, the company management must believe that the methods used to calculate these values are based on sound, conservative (not exaggerated), and accurate data inputs and algorithms.

Calculating Program Costs

While program costs may seem to be a fairly straightforward calculation, there are hidden costs that must be accounted for in order for this to be accurate. Program costs typically include equipment, supplies, manpower and overhead. The equipment costs are either rental fees or a depreciated capital investment schedule. Rental fees are a simple direct cost, for the time period of payment. The capital investment in equipment must be depreciated on a typical useful life time period to arrive at an annual or monthly cost. Supplies, both consumable and durable, must be calculated on anticipated usage and consumption rates. Manpower can be the most easily accounted for, but one must be careful to allow for all hours in support of the program, and they must be calculated using the company's internal manpower costs for the job classification of the individuals working in the program. Finally, overhead, which is the most difficult to account for, must include support services, supplies, and other benefits provided to the program which would otherwise be utilized productively elsewhere.

The calculation of program costs is the first step in establishing the cost benefit model, and is usually reduced to a time period that corresponds to the reporting period for management. If management requires a quarterly accounting of the program benefit, then the program costs are calculated for a typical 3-month period, and included in the cost benefit analysis. A query of expenses and costs are used to create an average monthly expenditure for maintaining the program, factoring out seasonal variations. The program costs should be recalculated whenever there is a significant change in any of the variables, such as an increase or decrease in manpower, acquisition of new capital equipment, or the assignment of additional or competing responsibilities for team members.

Direct Cost Savings

Sometimes referred to as the "hard" money, direct cost savings are the backbone of the financial benefit for a PdM program. Even the most skeptical of pundits has difficulty refuting the benefits cited for a program which reduces annual insurance premiums, or comprises the sole justification for revising the frequency or eliminating the task altogether for Preventive Maintenance (PM) activities. These savings are recurring, and are factored in as an annual direct cost reduction. In some cases, proposed and budgeted design changes can be tabled or cancelled based on new information generated by diagnostic monitoring. These are generally one time reductions, but the savings can be significant. A core value for direct cost savings is developed based on the recurring insurance premium reduction, and the permanently removed PM activities. This core value is modified as additional credits for insurance are granted, or as a program of continuous optimized maintenance provides additional reductions in PM tasks. Occasionally, diagnostic data indicates the need for increased PM, and in those cases, that must be subtracted from the benefits assigned for reduced PM. The trade off is then manifested in the indirect cost savings of increased equipment reliability.

Online CBA Calculator

An internet Cost Benefit Analysis (CBA) calculator is available at www.elubes.net/cbalogin.asp. A log in ID is required, but the ID can be obtained on line at no cost.

Cost Benefit Analysis Spreadsheet

The EPRI M&D Center has developed a spreadsheet for calculating cost benefit. This spreadsheet was developed for the Electric Motor Predictive Maintenance program and provides a documented analysis for the cost benefit of PdM programs.

The spreadsheet is used to calculated the cost benefit of a failure or malfunction of a specific component or system. Four categories of failure are calculated; these categories are:

- Major, damage requiring full replacement or extensive repair.
- Moderate, failure resulting in repairable damage.
- Loss of Performance, fault causing minor damage or a reduction in its availability.
- Actual, an actual occurrence of a failure or malfunction. The data for this category is to be based on an actual failure or malfunction. Cost benefit is not calculated for this category. This category is intended to provide a comparison for the cost benefit of the other three categories

The spreadsheet is divided into 2 sections; the first is mainly for user entered data, the second section is for automatic cost benefit calculations and results. The spreadsheet sections are design to provide a printable report for each calculation performed.

The actual spreadsheet will contain blank fields. However in the following tables showing the spreadsheet section the fields are numbered to provide field descriptions. Fields number 1 through 14 for user entered data. The remaining fields are for calculated values. Most fields are self explanatory, the field list below the tables provides a description of the data for each field.

Table D-1
First Section of CBA Spreadsheet

Utility / Station / Unit:	(1)	Date:	(1)
Equipment:	(1)	Description:	(1)
Occurrence No.:	(1)	Case History No.:	(1)

	Utility Input Data
Average Replacement Power Costs (Peak) ($/MWH) =	(2)
Average Replacement Power Costs (Off-Peak) ($/MWH) =	(3)
Average Fuel Cost plus Incremental O&M ($/MWH)=	(4)
Average Labor Rate ($/HR) =	(5)
Max. Rated Load (MW) =	(6)

	(a)Major	**(b)Moderate**	**(c)Loss of Performance**	**(d)Actual**
Fault Scenario Descriptions	(7)	(7)	(7)	(7)
Loss of Generating Revenue				
Loss of Generation (Yes =1 No =0)	(8)	(8)	(8)	(8)
Power Reduction (MW)	(9)	(9)	(9)	(9)
Hours at Peak (Hrs) (hrs * No. of days)	(10)	(10)	(10)	(10)
Hours at Off-Peak (Hrs) (hrs * No. of days)	(11)	(11)	(11)	(11)

Maintenance Costs				
Cost of Parts ($)	(12)	(12)	(12)	(12)
Labor Hours (Hrs)	(13)	(13)	(13)	(13)

Probability of Fault Occurrence (%)	(14)	(14)	(14)

	Calculated Savings
Total Cost Benefit for this Occurrence	(15)
Maintenance Costs Savings ($):	(16)
Impact on EFOR (%):	(17)

Table D-2
Second Section of CBA Spreadsheet

Occurrence No.:	(18)	Case History No.:	(18)	
	(a)Major	**(b)Moderate**	**(c)Loss of Performance**	**(d)Actual**
	(19)	(19)	(19)	(19)
Loss of Generating Revenue Costs				
Peak				
Total Lost MWH Peak (MWH)	(20)	(20)	(20)	(20)
Avg. Replacement Power Cost Peak ($/MWH)	(21)	(21)	(21)	(21)
Fuel Cost + Incremental O&M Avg. ($/MWH)	(22)	(22)	(22)	(22)
Penalty Rate Peak ($/MWH)	(23)	(23)	(23)	(23)
Lost Revenue Peak ($)	(24)	(24)	(24)	(24)
Off Peak				
Total Lost MWH Off-Peak (MWH)	(25)	(25)	(25)	(25)
Avg. Replacement Power Costs Off - Peak ($/MWH)	(26)	(26)	(26)	(26)
Fuel Cost + Incremental O&M Avg. ($/MWH)	(27)	(27)	(27)	(27)
Penalty Rate Off-Peak ($/MWH)	(28)	(28)	(28)	(28)
Lost Revenue Off-Peak ($)	(29)	(29)	(29)	(29)
Total lost Generating Revenue ($)	(30)	(30)	(30)	(30)
Potential Contribution to EFOR	(31)	(31)	(31)	(31)
Probability	(32)	(32)	(32)	

EFOR Benefit	(33)	(33)	(33)	
Total EFOR Impact	(34)			
Maintenance Costs				
Parts ($)	(35)	(35)	(35)	(35)
Labor Hours (hrs.)	(36)	(36)	(36)	(36)
Labor Rate ($/hr)	(37)	(37)	(37)	(37)
Labor total ($)	(38)	(38)	(38)	(38)
Total Maintenance Costs ($)	(39)	(39)	(39)	(39)
Total Maintenance Cost Impact ($)	(40)			
Total Costs				
Total Costs ($)	(41)	(41)	(41)	(41)
Actual Diagnosed Event Costs ($)	(42)	(42)	(42)	
Benefit Differential ($)	(43)	(43)	(43)	
Probability	(44)	(44)	(44)	
Occurrence Benefit	(45)	(45)	(45)	
Total Benefit ($)	(46)			

CBA Spreadsheet Field Descriptions

1. Plant and equipment data used to identified the analysis for a specific component.
2. Rate information to be used in calculation.
3. Rate information to be used in calculation.
4. Rate information to be used in calculation.
5. Rate information to be used in calculation.
6. Rated unit output, used to calculate effect on the Equivalent Forced Outage Rate (EFOR) for each category.

7. Enter a short description of the failure or malfunction for each category.
8. Enter a 1 if the category affects generation, or a 0 if there is no lost generation for the specific category.
9. The amount of lost generation for each category.
10. The number of peak rate hours generation is lost or reduce for the specific category.
11. The number of off-peak rate hours generation is lost or reduce for the specific category.
12. The cost of the parts and materials to repair the failure or malfunction in each category.
13. The manhours of labor required to repair the failure or malfunction in each category.
14. Enter the percent probability of occurrence for each of the first three categories. The fourth category, Actual, is left blank. Use a percentage, not a decimal.
15. The total cost benefit saving returned from the second section.
16. The total calculated maintenance cost for the first three categories, returned from the second section. This is the sum of material and labor costs, multiplied by the probability of occurrence for each of the three categories summed together.
17. The sum of the calculated percentage impact on the Equivalent Forced Outage Rate for the three categories, returned from the section.
18. Data copied from first section
19. Category failure or malfunction description copied from first section
20. The product of field 9 times field 10
21. Copied from field 2
22. Copied from field 4
23. Field 21 minus field 22
24. The product of field 23 times field 20 times field 8
25. The product of field 9 times field 11
26. Copied from field 3
27. Copied from field 4
28. Field 26 minus field 27
29. The product of field 28 times field 25 times field 8

30. The sum of field 24 and field 29
31. Is the result of equation:
    [(Field 9) X (Field 10 + Field 11)/(Field 6)] X (yr/8760 hrs) X (Field 8) X 100%
32. Field 14 times 0.01, to convert the percent probability to a decimal probability.
33. Field 31 times field 32.
34. The sum of field 33 for first 3 categories minus field 33 for the fourth category.
35. Copied from field 12.
36. Copied from field 13.
37. Copied from field 5.
38. The product of field 36 times field 37.
39. The sum of field 35 and field 38.
40. The sum of field 39 for first 3 categories minus field 39 for the fourth category.
41. The sum of field 20 and field 39.
42. Copied from fourth category field 41.
43. Field 41 minus field 42.
44. Field 14 times 0.01, to convert the percent probability to a decimal probability.
45. The product of field 43 times field 44.
46. The sum of field 45 for the first 3 categories.

E
GLOSSARY

ASTM, American Society for Testing and Materials.

AC Regulator, see Automatic Voltage Regulator.

AGC, see Automatic Generation Control.

AVR, see Automatic Voltage Regulator.

Absorption Current, the current during an insulation resistance test that results from the molecules in the insulation aligning themselves with the applied electric field, and typically decreases close to zero within a few minutes.

Alternator, an AC generator, typically refers to small AC generator used to supply excitation power to the main generator field.

Amplidyne, see Rotating Amplifier.

Armature, the AC windings of a generator or motor.

As Found Data, the parameters, settings and test results before any adjustment, calibration or repair is performed. The condition of the system or component prior to performance of work.

As Left Data, the parameters, settings and test results after all adjustment, calibration or repair is performed. The condition of the system or component after performance of work.

Automatic Generation Control, the system that allows a load dispatcher or other party to control generation at a plant from a remote location.

Automatic Voltage Regulator, controls main generator field current to produce the required generator output.

Brush, typically a carbon based block used to transfer electrical current between the stationary and rotating components of a generator. Also see collector and commutator.

Brush Pressure, the pressure on a brush that forces the brush against the rotating collector or commutator to maintain electrical contact. Equal to the spring force applied to the brush divided by the brush's cross sectional area.

Brushless Excitation System, an excitation system that employs an alternator with a stationary field and a rotating armature, so brushes are not required to contact the alternator's output to the generator's rotating field. Shaft mounted diodes rectified alternator's output to DC for the generator field.

CBA, see Cost Benefit Analysis.

CT, see Current Transformer.

CMMS, see Computerized Maintenance Management System.

Capacitive Current, the current during an insulation resistance test that results from the small distributed capacitance across the insulation of a winding, and typically decreases close to zero within a few seconds. Generally, any current resulting from applying a voltage across a capacitor or a component having capacitance.

Collector, a component in many generators and alternator for transferring current between stationary and rotating elements. The collector consists of rotating slip rings and stationary brushes that provide low mechanical friction and low electrical resistance.

Commutator, a component of DC generators and motors that transfers current to and from the rotating armature. The commutator in generators converts the AC armature current to a DC output current, and in motors converts the applied DC current to an AC current for the armature.

Computerized Maintenance Management System, a computer software program used to create, control, and store work orders, work planning, spare parts inventory, material requisitions, and other aspects of maintenance.

Condition Based, maintenance performed on a component only when necessary, as determined by the condition of the component. Also see Time Based.

Conduction Current, the current during an insulation resistance test that results from applying a voltage across a material. In insulation resistance tests, conduction current is a normal characteristic of the insulation materials, as no substance is a perfect insulator. Conduction current is not a result of damage to the insulation.

Controlled Rectifier, a component that converts an AC voltage to a DC voltage, and control the level of DC by varying the its conduction time (firing angle) of each applied AC cycle.

Copper Dusting, the result of the copper conductors in a field winding rubbing and wearing against each other.

Cost Benefit Analysis, the process of determining the net economical results of implementing a particular maintenance task or plan.

Crowbar, a component used to limit the voltage across the field winding. Works by conducting at a set voltage value to bleed off current through a discharge resistor.

Current Density, the number of amperes of current through a specific cross sectional area.

Current Transformer, an instrument transformer used to accurately sense current flow. Typically selected to operate in a range of 0 to 5 amps of secondary current for the entire range of primary current.

DC Voltage Regulator, see Manual Voltage Regulator.

De-Excitation Circuit, a circuit used to rapidly remove the generator's excitation field. Typically a discharge resistor that is applied across the generator's field circuit when the generator is tripped.

Differential Current Relay, a protective relay that sense the current flowing into and out of a component. A mismatch in the current indicates a fault in the component and the relay actuates.

Dusting, the result of material rubbing and wearing. Winding insulation rubbing against core iron can produce insulation dust as a wear product. Also see copper dusting.

Dynamic Testing, a test performed while the component and system are in service and under load.

EPRI, Electric Power Research Institute.

Equivalent Forced Outage Rate (EFOR), the percentage of time that a plant is unavailable because of equipment failure. The higher the forced outage rate, the more likely the unit will be unexpectedly out of service when needed.

Emergent Work, work that is not scheduled, but appears during operation and needs to be performed before it can be fitted in a schedule maintenance period.

Excitation Transformer, a power transformer that supplies the electrical power for the excitation system to produce the main generator's field current.

Exciter, the alternator or DC generator that supplies the electrical power for the excitation system to produce the main generator's field current. Generally, any component that supplies the electrical power to produce the main generator's field current.

FME, see Foreign Material Exclusion.

Ferrography, a technique and associated technology that analyzes the wear and contaminate particles in lubricating oil.

Field the DC winding of a generator, produces the magnetic field for generator excitation.

Field Breaker, a DC circuit breaker that interrupts the field circuit of a generator or exciter.

Field Discharge Resistor, a resistor that is applied across the generator's field circuit to rapidly de-energized the field winding during a generator trip.

Field Flashing, a momentary application of DC current to an exciter field to provide initial excitation to an exciter during startup.

Foot Printing, the imprinting of a brush face on the surface of a collector ring, due to brush hop or the application of a high current while at standstill.

Foreign Material Exclusion, the practice of preventing material, tools and other substances from entering and being left in a closed system during maintenance.

High Potential Test or Hi Pot Test, an electrical test that applies a voltage above the normal operating voltage rating of a component in order to electrically stress test the component's insulation.

IEC, International Electrotechnical Commission.

IEEE, Institute of Electrical and Electronics Engineers.

IRT, Infrared Thermography, see Thermography.

Impedance Test, an electrical test of DC field winding that applies of series of AC voltages to check for interturn shorts in the winding.

Insulation Resistance Test, an electrical test that assess the condition of electrical insulation by applying a fixed DC voltage across the insulation.

Intangible Benefits, in cost benefit analysis, the benefits that do not have an obvious monetary value, such as regulatory compliance and personnel safety.

Interturn Short, an electrical short between adjacent turns of a winding.

Leakage Current, is the surface current flowing from the insulation, and is constant over time. Insulation damage, defects, moisture, and other conductive contaminates can greatly increase the leakage.

Limiter, a component or circuit that functions to prevent the system from operating in a prohibited mode.

Manual Voltage Regulator, controls and maintains main generator field current at a specified value.

Maximum Excitation Limiter, prevents the excitation system from causing the generator to operate in the over excited mode. May permit some over excited operation for short time durations for transient response.

MEL, see Maximum Excitation Limiter.

Minimum Excitation Limiter, prevents the excitation system from causing the generator to operate in the under excited mode.

Motor Operated Potentiometer, a potentiometer that is adjusted by a electric motor to allow for remote operation from the control room.

MXL, see Maximum Excitation Limiter.

NEMA, National Electrical Manufacturers Association.

NMAC, Nuclear Maintenance Application Center, organization established by EPRI in 1988 as part of the general industry effort to improve plant maintenance.

Noncontrolled Rectifier, a component consisting of diodes, that rectifies AC voltage into DC voltage, does not control the level of DC voltage. See Controlled Rectifier.

Null Voltmeter, a voltmeter that measures the difference between two voltages. Typically used to ensure that the outputs of the automatic and manual regulators are equal.

OEL, Over Excitation Limiter, see Maximum Excitation Limiter.

OEM, Original Equipment Manufacturer.

Ohm's Law, the relationship between voltage, current, and resistance: voltage across a component is equal to the current flow through the component multiplied by the resistance of component (V=IR).

Open Loop Test, a component functional test that is performed without normal system feedback.

Over Excitation, the generator operational mode in which too much field current is applied. Causes the generator to operated above its design limits.

Overcurrent Relay, a productive relay that sense current and actuates when the current exceeds a set value. May be time delayed to allow short duration overcurrents.

PdM, see Predictive Maintenance.

PM, see Preventive Maintenance.

PMG, see Permanent Magnet Generator.

PSS, see Power System Stabilizer.

PT, Potential Transformer.

Paint Brushing, the trace of a generator field temperature recorder produce from brush arcing.

Pilot Exciter, a small alternator or DC generator used to produce excitation power for the main exciter.

Permanent Magnet Generator, a pilot exciter that uses permanent magnets to supply its excitation field, instead of relying on a field winding and an external power source.

Polarity, in a transformer refers to secondary winding terminal in which current flows out of when current is flowing into the corresponding terminal of the primary winding.

Polarization Index, an electrical test that compares a 1 minute insulation resistance measurement to a 10 minute insulation resistance measurements. In effect, compares the leakage current (10 minute) to the sum the leakage current and the absorption current (1 minute).

Potentiometer, a continuously variable resistor.

Power Factor Test, an electrical test that measures the power factor of insulation. Good insulation will typically have a very low power factor.

Power System Stabilizer, a component or circuit that automatically alters voltage regulator output to oppose power system oscillations.

Pre-arcing, the process of shaping the face of a brush to match the contour of the collector ring or commutator.

Predictive Maintenance, test and inspection techniques and technologies that are performed to assess component condition and predict possible future failure or malfunction of the component. The intent of predictive maintenance is forewarn of equipment deterioration early enough that corrective actions can be planned and implemented prior to an actual failure or malfunction.

Preventive or Preventative Maintenance, maintenance tasks that are performed to prevent malfunction or failure of a system or component, prior to any actual indication of a trouble.

RCM, see Reliability Centered Maintenance.

RSO, see Recurrent Surge Oscillography.

Reactive Capability Curve, a plot of a generator's VA capability versus its watt capability. Provides design limits for generator's VA and watt output.

Recurrent Surge Oscillography, an electrical test of a field winding that sends voltage pulse through both ends of the field and compares the reflections of the pulses. Localized impedance changes due to shorts are faults will alter reflection of pulses indicating a problem.

Regulatory Testing, testing and calibration required or strongly recommended by regulatory agencies, reliability councils, insurers, manufacturers, etc.

Rheostat, a continuously variable electrical resistor used to regulate current.

Rotating Amplifier, a rotating machine similar to a DC generator, except the brushes are shorted together and a second set of brushes are added at the location for output from the resultant armature reaction field. Produces a large current that is controlled by a relatively small field voltage.

Rotor, the rotating element of a generator or motor.

SCR, see Silicone Control Rectifier.

SPE, see Static Pilot Exciter.

Salient Pole, a protruding pole piece on the rotor, upon which a winding coil is mounted. Non-salient pole machines have the winding coils installed in slots in the rotor. Salient poles machines are typically low speed, while non-salient pole machines are normally used at 1500 rpm or above.

Set Point Drift, the amount that a set point changes from its calibrated value.

Silicone Control Rectifier, a semiconductor, similar to a diode except that it has to be electrically turned on (gated) to conduct. Used to controlled to level of DC voltage produced from an AC voltage, see Controlled Rectifier.

Slip Rings, metal rings on a rotor used to pick up current from stationary brushes. Also see Collector.

Spectroscopy, analysis of the spectrum of light emitted from a burning sample to determine composition of the sample.

Static Pilot Exciter, serves the same function as a pilot exciter, but does not contain rotating parts. Typically a small transformer and rectifier to provide field current to the main exciter.

Static Testing, testing performed with the component or system out of service. Typically involves only control circuits or regulators with the generator and exciter at standstill.

Stator, the non-rotating core of a generator or motor.

Step Test, an variation of the DC high potential test in which voltage is applied in a series of step until the maximum test voltage is reached.

Thermography, the science and technique of obtaining and analyzing thermal images of components.

Thermoscan, a thermal image or the process of non-contact temperature measurement.

Time Based, maintenance performed on a component at specific time intervals, instead of when determined by the condition of the component. Also see Condition Based.

Torsional Vibration, oscillations in the rotational speed of a component.

Transformer Turns Ratio Test, an electrical test that measure the turns ratio of transformers.

Trending, the process of reviewing data to determine if a component's parameter over time is headed in a direction indicative of component deterioration.

TTR, see Transformer Turns Ratio Test.

UEL, Under Excitation Limiter or minimum excitation limiter.

Under Excitation, the generator operational mode in which too field current is applied. Causes the generator to operated beyond its lower design limits. May be cause generator to slip out of synchronism.

URAL, Underexcited Reactive Ampere Limiter or minimum excitation limiter.

VA, apparent power, the product of voltage times current. For balanced three phrase components, it is the product of the line current times the phase-to-phase voltage divided by the square root of three. A complex value composed of a real component (watts) and an imaginary component (VARs).

VAR, reactive power or Volt Amps Reactive, the imaginary component of apparent power (VA). It is equal to VA multiplied by the sine of the phase angle.

Vee Curve, a plot of generator VA capability versus generator field current. Lines are drawn for various power factors and various cooling system conditions. Provides design limits for generator over excitation and under excitation as well as field current limits.

Vibration Analysis, the techniques and technology for collecting and analyzing vibration data. Used not only to determine if accepted vibration limits are exceed, but also to determine the location and cause of vibration problems.

Vibration Monitoring, routine monitoring of vibration levels of a component to determine if acceptable levels are exceeded or if an adverse trend is developing.

Volt per Hertz, the ratio of voltage to frequency. Is frequency decreases, the voltage must decrease proportionally to avoid saturating and overheating the magnetic core in generators and transformers.

Voltage Regulator, a component that controls the field current to the generator. See Automatic Regulator and Manual Regulator.

Watt, real power, the real component of apparent power (VA). It is equal to VA multiplied by the power factor or cosine of the phase angle.

Winding Resistance Test, an electrical test that measures the electrical resistance of a windings conductor. Checks for shorts and opens in the windings.

F
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Steam Turbines, Generators, and Balance-of-Plant

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