Maintenance of Turbine-Driven Generators

2014 Edition

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1. Chapter 1 - Introduction

1.1 Purpose and Objectives of This Book

Beginning in the mid-1970s there was a general contraction in the amount and quality of technical support provided to power-generation companies by the original equipment manufacturers (OEMs). This void has been partially filled by independent service providers. But often, owners have been left uncertain as to the quality and accuracy of the available information. Particularly is this true with respect to determining the cause of a failure since on-site maintenance personnel normally are trained only to test and inspect generators and to perform typical maintenance operations, e.g., stator rewinds, stator rewedging, field rewind. Determining the root cause of a non-obvious failure tends to be an order of magnitude more difficult than the work for which the onsite personnel are trained. In addition, it may be very difficult to obtain qualified assistance from the OEMs.

The purpose of this book is to provide a maintenance manual which will help turbine-generator users remove some of these uncertainties, and thereby work more effectively and efficiently with their service providers in maintaining high reliability of their generators without unnecessary expenditures.

The text is written from a manufacturer perspective, based on an experience background in generator design, manufacturing and service, as well as many years as an independent consultant.

Focus of the text will intentionally be narrowly focused toward including only information directly relating to making optimum maintenance decisions.

For operating companies with strong in-house generator maintenance capability and programs, it is hoped that this text will be of assistance in improving and fine-tuning those programs.

For those large majority operating companies depending primarily on outside technical sources, it is hoped this text will assist in appraising the quality and accuracy of maintenance recommendations being provided.

In both cases, it is hoped that this book will assist owners in implementing more cost-effective maintenance programs for each of their power generators.

1.2 Maintenance Information Sources

Historically, turbine-generator OEMs gave a high level of support to users of their equipment. In addition to a competent staff of factory engineers available for consultation on specific issues, in particular root-cause diagnostics of new and difficult equipment failures, OEMs traditionally have issued three types of maintenance recommendations:

- Instruction Books covering routine assembly and general maintenance of individual units.
- Technical information letters addressing specific maintenance problems on groups or classes of units.
- Individual letters on specific units.

Further, manufacturers have typically supplied personnel for on-site specialized Inspection, Test, and Maintenance services (but not failure root cause assessment) through a fleet of trained, equipped and experienced field generator specialists.

Additional support has been available to users through:

- Professional groups such as IEEE and ASME, although unfortunately OEM technical input to these organizations has greatly decreased, with little OEM input to technical conferences and few industry papers being published by OEMs.
- Industry organizations such as EPRI and ANSI, which continue to provide vital services.
- Articles and books published by utility personnel documenting “best practice” experience of user companies.
- Independent service providers, including independent technical consultants.

It is vital to understand that the field service personnel available from OEMs and independent service providers typically are trained in inspection, test and maintenance. But typically they are not trained and qualified to perform the difficult challenges of failure root-cause diagnostics. Historically this service was provided by OEM factory engineers; however, with the contraction of OEM engineering organizations, OEM engineers qualified for diagnostics are no longer readily available for filling this vital need. As a result, it may be very difficult to find personnel capable of accurately diagnosing a new or unusual failure mechanism. This situation has increasingly led to incorrect and often costly maintenance decisions. It appears that the challenge to plant personnel in dealing with this situation will remain high for some time to come.

1.3 Document Scope and Focus

The text will focus primarily on the generator, although some attention is given to auxiliaries and excitation systems.

Heavy use is made of illustrations and photographs, and color is used throughout where helpful.

Subjects covered will include:

a) Chapter 2. Impact of generator design on component duties and deterioration mechanisms.

b) Chapter 3. Impact of normal and abnormal operation on deterioration modes and rates.

c) Chapter 4. Description of failure modes and failure root-cause diagnostics.

d) Chapter 5. On-line monitoring.

e) Chapter 6. Inspection procedures and equipment.

f) Chapter 7. Test procedures and equipment.

g) Chapter 8. Maintenance practices and general principles, including predictive and condition-based maintenance.

h) Addendum A. Brief informal summary of the 100-year history of generator design.

1.4 Text Updates

Because this book is in digital format, revision is conveniently accomplished, and the text has been updated several times since first written in 1997. The current revision, March 2014, includes significant additions:

- Chapter 5, Monitoring, several important additions to including

    - Expansion of Section 5.2.3.3 to include a discussion of wireless capabilities for monitoring for grounds in rotating rectifier excitation systems
    - Section 5.2.8.4 covering a discussion of the important capabilities of electromagnetic interference (EMI) testing of stator windings
    - Addition of Section 5.3.2 covering extremely important deficiencies of IEEE Standards regarding relay protection for stator and rotor grounds, deficiencies that have cost the power generating industry many, many 100s of millions dollars
- Chapter 8, Maintenance
    - Expansion of Section 8.1.2 to include the importance of upgrading the generator when uprating the turbine generator
- The discussions of vibration sparking and endwinding vibration monitoring are also expanded and updated.
- An addendum has been added. This is a brief history of the evolution to the modern generator design. It is included mainly as casual reading but may be of some interest because the author's first and second hand knowledge of this history dates back about 100 years.

Finally, a personal note. In about 1995 the author for some inexplicable reason became motivated to attempt to document the knowledge he had accumulated working with probably the best assemblage of generator engineers the world will ever see. The result has been this book and 25 technical papers on about 20 different topics relating to turbine-generator operation and maintenance. With this update of the text, the author's 64-year generator career has about come to an end. Come to an end – at age 87 and a minor stroke – with the hope that this library is and will continue to be useful to the succeeding generations of generator personnel.

2. Chapter 2 - Design

2.1 General Considerations

2.1.1 Scope

The focus of this chapter will be on the design features, forces and mechanisms that relate directly to deterioration and failure of generator components. General design considerations will not be covered because of the complexity, magnitude and specialized nature of generator design.

2.1.2 Generator Basics

2.1.2.1 Design and Manufacturing Trends

Regardless of original equipment manufacturer (OEM), all generators in service today have many features and components that are closely similar in nature. Materials used in the same vintage units are often identical. Larger and newer generators tend to work the materials harder, and have low margin in the designs. Older units (pre-1970s) often can have margins as high as 20% with no or only modest changes in operation or components. Various cooling methods and media are used, but in similar vintage and size ranges, commonality is high between manufacturers. Nevertheless, the differences, which are sometimes subtle, may result in greatly different reliability and maintenance needs.

Evolution of design in the past was generally slow, with major changes introduced every 15 or 20 years. Intensified cost pressures beginning in the early 1980s have resulted in more rapid change, particularly toward higher-capacity air-cooled generators. On the electrical insulation systems, trends are toward higher operating temperatures and thinner insulation builds. The combination of these two changes results in much heavier duty on the electrical insulation systems. In addition, design and manufacturing cost reductions and simplifications, and more demanding customer specifications, have tended to result in less margin in the overall capability.

Furthermore, in recent years there has been simultaneous rationalization and expansion of worldwide facilities – rationalization in Europe and North America, and expansion in other regions. For example, the company now known as Alstom is a collection of more than 18 European companies of the 1950s. Figure 2-1.

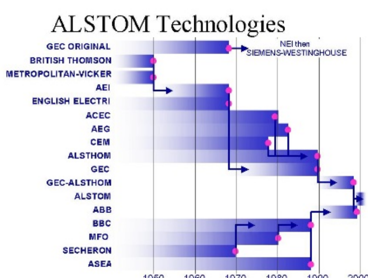


Figure 2-1. European power industry consolidation, from about year 2000.

At the same time, cost and other pressures have resulted in increased fragmentation and out-sourcing by manufacturers.

These changes are significantly impacting performance of newer equipment, purchase of replacement parts, and availability of OEM design engineering service support.

2.1.2.2 Operation

Generators traditionally operate with little concern and attention, thus operators may have little experience in dealing with abnormal situations. Furthermore, performance-monitoring instrumentation provides the operator with limited and sometimes ambiguous information. Thus, occasionally a malfunction which should simply have resulted in a normal shutdown and minor repair becomes a serious, even catastrophic failure.

2.1.2.3 Maintenance

Generators historically have been a relatively trouble-free part of the power generation plant. Figure 2-2 are historic data showing relative forced outage rates for major power plant components. Consequently generators often may receive insufficient attention in planning and budgeting for maintenance.

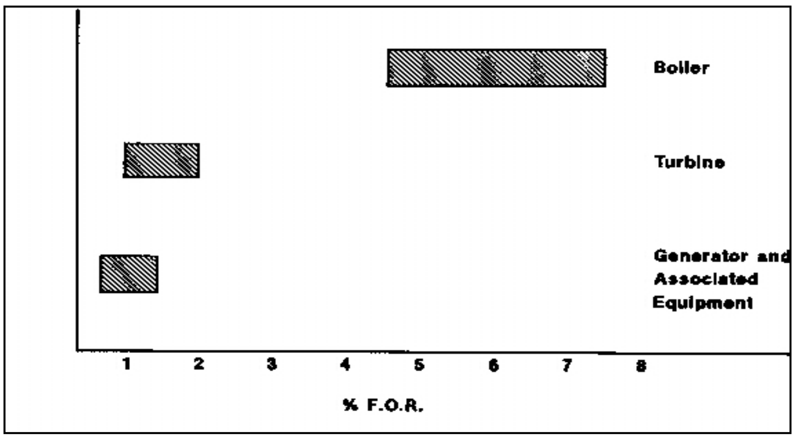


Figure 2-2. Major Power Plant Component Forced Outage Rates

But of course, generator components do wear, and average fleet age which has been always been rather high, is now steadily increasing as fewer new and large units are being installed. (Figure 2-3 and Figure 2-4, are data from about 1990; the situation has been improving somewhat since that date.) Inadequately maintained generators can and occasionally do cause major system impact from forced outages and from outage extensions.

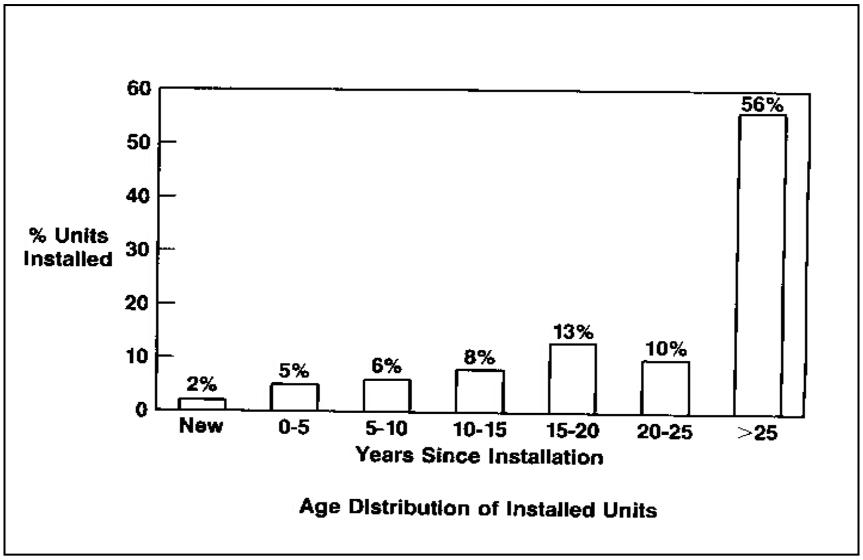


Figure 2-3. Approximate Age Distribution of Installed Units

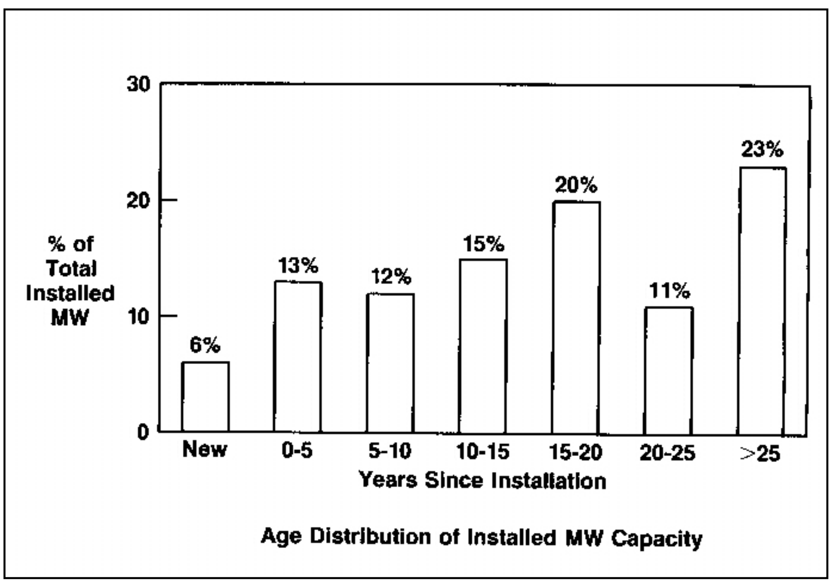


Figure 2-4. Approximate MW Capacity Age Distribution

2.1.3 Business Background

2.1.3.1 Technical Support

Historically, manufacturers provided broad technical support through headquarters engineering and field service organizations. Cost pressures, staff reductions and increasingly diverse and complex designs have combined to substantially reduce the capability of OEMs to provide necessary technical support.

Simultaneously, manufacturers have reduced their involvement in technical organizations such as IEEE and ASME. As a result, manufacturers are providing relatively little basic general technical knowledge to operating companies through these industry organizations.

Numerous small service companies have spun off from original manufacturers, and are providing a degree of additional support to operating companies. Also, operating companies in a few cases have attempted to fill these voids by strengthening their in-house technical and repair capability, although this has become increasingly difficult to accomplish even for large utilities.

The problem of obtaining adequate technical support, particularly for failure root-cause diagnostics, is and will remain a major concern to power company personnel.

2.1.3.2 Generator Design Evolution and History

2.1.3.2.1 Insulation

Insulation systems are the predominant failure location in generators, both on stators and on fields.

Stator insulation has always been mica based, but the binders have evolved through several stages: shellac (1890s to about 1915), asphalt for improved stability and manufacturing producability (1915 to 1970s), 1st generation thermoset polyesters and epoxies for improved mechanical properties (1949 to mid-1970s), 2nd generation thermoset epoxies for water resistance and higher mechanical properties (1970s to present). Currently, 3rd generation thermoset systems are being developed to obtain elevated electrical and heat transfer properties; these systems are particularly used on the new, very large air or hydrogen indirectly-cooled stator windings.

Field insulation had steadily evolved through various mica/asbestos based systems until the mid-1950s. At that time, to obtain more stable mechanical properties, better heat transfer, and improved producability, manufacturers converted to epoxy-glass systems and high-performance thermoplastics such as Nomex.

2.1.3.2.2 Metallic Components

Primary changes have focused on improved field copper mechanical properties and higher strength and more stable field component materials.

Rotor forging evolution was primarily toward improved properties through development of casting and forging techniques that greatly reduced inclusion content. Retaining rings have evolved through many phases to obtain the extreme strength and stability necessary for the most highly stressed mechanical component of the generator. Several grades and types of magnetic steel have been used. On higher magnetic duty generators, several non-magnetic steels have been used: 18Mn-5Cr which is vulnerable to stress corrosion, 18Mn-18Cr which is more stable but costly, and a few special materials such as Gannalloy that never became popular due to intrinsic limitations.

2.1.3.2.3 Cooling Systems

Air-cooling has been used since the beginning of the industry, with various approaches of open air and totally enclosed water-air cooled (TEWAC). Ventilation has been indirect (heat flow through the electrical insulation over-wrap) and direct gas contact with the stator or field copper. Emphasis on large air-cooled generator designs increased greatly in recent years, resulting in very large air-cooled machines at overall efficiencies only about 0.3% lower than those of hydrogen cooling. Air-cooled generators in excess of 400MVA are currently being offered.

The first hydrogen cooled generator was placed in service in 1938 (a few months after the hydrogen-filled Hindenburg zeppelin burned in full view of reporters' cameras). Originally cooling was indirect, but direct hydrogen cooling became common beginning in the late 1950s, both on stators and fields. A few direct oil-cooled stator windings were built, but complete transition to water was made in the early 1960s for liquid cooling of stators. Direct hydrogen cooling of stator windings was developed in parallel with direct liquid cooling of stator windings. On fields, formidable problems associated with direct water and cryogenic cooling have prevented these systems from coming into general use.

2.1.3.2.4 Excitation Systems

A standard DC generator with little evolution was used for the first 60 years of power generation. Beginning with the availability of solid state power rectifiers, evolution came rapidly starting the in 1950s: static systems with collectors, AC generators with rectifiers and collectors, rotating rectifier systems without collectors. Power sources of these modern systems have been AC generators, current and voltage power transformers, rotating shaft-mounted generators, and main-generator "air-gap" windings. These components have been used in various combinations and permutations.

After the 1950s, excitation systems were no longer simple, universal or primitive.

2.1.4 Basic Maintenance Considerations

2.1.4.1 Growing Need for Maintenance

Generators have historically required a minimum of maintenance, and forced outages rates have been low. However, there are growing indications that this basic reliability has been trending downward. Several reasons exist for this adverse trend:

- Design evolution of new machines has proceeded at an accelerated rate.
- New designs tend to be more elaborate and duties placed on the materials have been significantly increased.
- In some parts of the world, particularly the USA, the pool of large, direct-cooled generators is aging by about one year each passing year, since few of these large units are being installed.
- Many machines that exceed 40 years of age are still in regular, daily operation.
- Historic problems are not going away: loose stator wedges, stator core failures, vibration sparking on stator windings, partial discharge on air-cooled stator windings, turn and ground insulation migration, field insulation contamination, field winding turn and ground insulation failures, field wedge and dovetail cracking, field forging cracks, field turn cracking, foreign object damage, general contamination, oil leaks.
- Some more recent problems are requiring significant maintenance effort: stator bar water leaks, stator bar slot vibration, stator end winding vibration, stator core looseness, retaining ring cracking.

- Operator and maintenance errors continue: sudden short-circuits on the stator windings, improper synchronization, damage from foreign material, improper response to alarm conditions, continued operation after alarm, mis-assembly of components, dropped generators and components, over-fluxing incidents, inadequate replacement parts and/or procedures.

2.1.4.2 Inspection Challenges

Inspection is the only known way to find and evaluate certain types of generator problems, and inspection quality is highly operator dependent. At best, proper inspection of a generator is challenging. As the equipment has become more complex and as aging has increased, inspection needs have become even more demanding. Yet concurrently, the availability of skilled personnel has decreased, particularly among generator manufacturer personnel.

Because inspection is so important to assessment of generator condition, and thus to operating reliability, lack of manufacturer support is an important concern. One of the primary purposes of this text is to address this problem by documenting good maintenance practice from the manufacturer point of view.

It should be noted that important progress has occurred through the availability of better inspection equipment: robots, miniature and digital cameras, improved borescopes, thermal cameras.

Inspection is covered in detail in Chapter 6.

2.1.4.3 Test

Most of the electrical tests used in evaluating generators are basically unchanged in 60 years: megohmmeter, high potential (hipot), power factor and power factor tip-up, copper resistance, core ring (high flux) test. Some electrical test evolution has occurred during the last 35 years: airgap flux probe for identifying field shorted turns, low-flux core test, and partial discharge assessment of stator windings. ElCid is the low-flux core test equipment in most common use. On partial discharge, various types of sensors are in use, both for off-line and on-line evaluation. Useful data are being obtained, but basic problems remain primarily relating to isolation of stray noise and interpretation of results.

Mechanical and non-destructive evaluation (NDE) test capabilities are also improving, with significant progress on NDE of retaining rings and other metallic components. Also, equipment is available to quantitatively assess stator wedge tightness.

Generator testing is covered in detail in Chapter 7.

2.2 Design Technical Considerations

2.2.1 General

2.2.1.1 Basic Design Challenges

The parameters and constraints are similar for all equipment designers: removal of electrical thermal losses, containment of voltages, flux saturation (effects on frame, keybars, core, end iron, flux shields/shunts, over-flux hazards), core iron flux end-fringing problems and solution (set-back, steps, split iron, shields, shunts, non-magnetic materials), types of core iron and forging steels, mechanically weak mica, high static and rotational forces, concentrated heat generation, hydrogen containment, contaminants, vibration.

Approaches between equipment manufacturers differ in detail, sometimes dramatically. Solutions differ in effectiveness, and success rates vary widely. But generally speaking, most present manufacturers of generators are able to produce a reliable generator most of the time.

2.2.1.2 Scope of Document

From a generator design viewpoint, there are several important forces and duties that contribute to generator component deterioration. Only those design factors ***directly relating*** to deterioration will be considered in this document.

While insulation system breakdown is the most common manifestation of generator difficulty, failure root-cause ordinarily resides elsewhere, i.e., mechanical duties and contamination. However, because of the basic importance of insulation systems, insulation duties will be briefly considered before addressing general design considerations.

2.2.1.3 Duties on insulation systems

Duties on insulation systems can be placed in four categories (**T**hermal, **E**lectrical, **A**mbient, and **M**echanical – **TEAM**):

Thermal: Normally there is considerable thermal margin in insulation systems, and barring design error, insulation systems rarely fail due to thermal degradation. However, heavy contamination, loss of cooling, or overload may result in over-temperature, and if severe, damage can be severe. Rate of deterioration is highly temperature sensitive; a temperature rise of 10C is generally considered to reduce life of a given insulation system by roughly half. Further, equipment thermal life is not a function of average temperature, but rather is primarily a function of hot-spot temperature.

Electrical: Insulation system failure due to purely electrical causes is rare. In most cases of electrical deterioration or ground failure on field and stator windings, the root cause is likely to be mechanical damage or contamination. Core electrical failure is most commonly caused by looseness, mechanical damage, and deficient lamination insulation or over-fluxing.

Ambient: Internal contamination of the generator can significantly contribute to degradation. Common contaminate problems include: dirt buildup, conductive dusts, lubrication oil, water from cooler or stator-bar leaks, buildup of lead carbonates

Mechanical: This is by far the most common type of degradation on most classes of generators. Sources of problems include: foreign material, bar vibration in the slot or end winding, connection ring vibration, short circuit forces, insulation migration, loose parts, broken connections, broken strands, loose stator wedges, failed field components, assembly damage, differential expansions, corrosion.

2.2.2 Stator Winding Design Failure Mechanisms

2.2.2.1 General

Many interacting factors contribute to failure mechanisms in the stator winding: electromagnetic forces in slots and end windings, groundwall electrical stresses, slot groundwall grounding system, endwinding grading system, differential expansions, slot wedging systems, end winding and connection restraint systems, partial discharge, voltage grading, series and phase connections (mechanical and electrical).

Designing and building a reliable stator winding system is a formidable task. But a system without inherent design or manufacturing defects can be expected to give reliable service for 30 or more years, providing abuse does not occur in the form of mechanical damage, overload, or over-temperature operation. Still because the systems tend to be operated at relatively high duty and are inherently vulnerable and complicated, failure does occur.

Note: In this text the words “armature” and “stator” are used interchangeably.

2.2.2.2 Slot Section Electromagnetic Forces on Stator Bars

Flux patterns and magnitudes have a dominating effect on stator bar vibrational forces. Flux patterns also affect stray losses in the armature. Thus it is helpful to review a few basic electromagnetic concepts. The flow of lines of magnetic flux is shown in Figure 2-5 for no-load conditions, where all magnetic flux is from the field current.

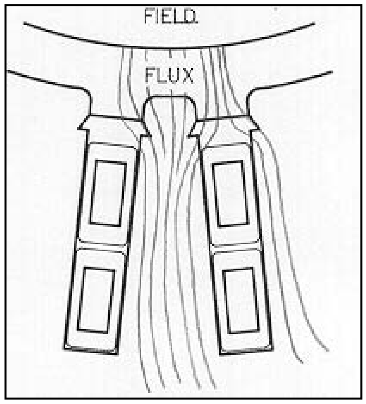


Figure 2-5. Field Flux Cutting Armature Bars under No-load Conditions

In Figure 2-6 the condition of slot cross-flux is shown for load current. Actual flux pattern under load conditions is the more complex vector sum of the two flux sources, but for purposes of this discussion, each can correctly be considered separately. (Figure 2-6 is for slots with both the top and the bottom bar in the same phase of the armature winding. Forces are moderately lower and slightly different for slots combining bars from different phases, and this condition is discussed subsequently.)

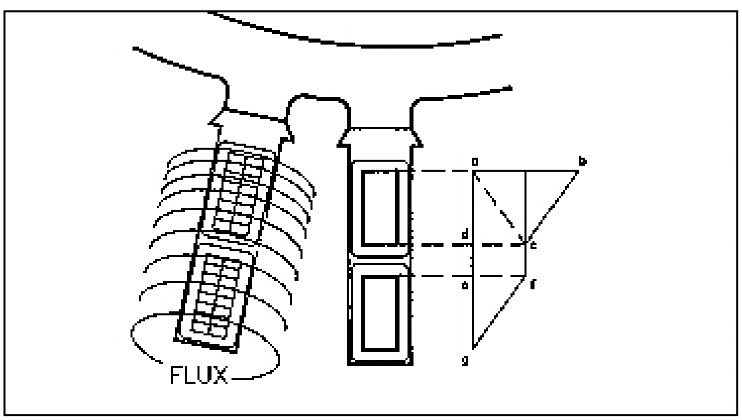


Figure 2-6. Flux Cutting Armature Bars Due to Flow of Armature Current

Electromagnetic force on a conductor is directly proportional to perpendicular flux density and conductor current magnitude. There is no force on a current-carrying conductor unless there is a component of flux perpendicular to the current-flow in the conductor.

Referring to Figure 2-5, without armature current (without load) there is no flux cutting the armature conductor, nor is there armature conductor current, hence there is no armature bar force. (There is a mechanical driving force on the bars due to core vibration, but this force is very small.)

But in Figure 2-6, both current and cross-flux exist. The source of the current is generator load – the source of the flux is that same current in the armature conductor. Thus the flux and the armature current are in phase and reach a peak at double current frequency, e.g., 100 or 120 times/second. The resultant forces range sinusoidally between the peak value and zero, and the force direction is always downward in the slot, since as armature current reverses direction, so does the associated flux.

Figure 2-5 shows that there is a radial flux entering the top portion of the slot, and this flux does cause a side-direction force on a current carrying bar. However, this flux transfers into the iron in roughly the top inch of the slot. (The distance of penetration of radial flux into the slot depends on iron saturation and slot width.)

Radial flux that cuts the top strands will:

1) Generate eddy currents and associated stray losses in the strands, and
2) Cause a vibrational side (cross-slot) force on the strands.

If the top bar is shallow in the slot (perhaps <3/4" deep, depending on slot width), the side vibrational force can be a cause for concern, particularly on soft insulation and unbonded strand packages such as asphaltic insulated bars. Strand vibration may develop, which in turn may damage the groundwall insulation, crack or wear individual strands, or perhaps develop strand shorts.

In large thermal-powered turbine-generators, the top of the top bar is located deep in the slot, and in general, side bar force is negligible. But at the ends of the slots, on some modern generators the top bar may project out of the top of the slot by a significant amount and bar side force may become important. Figure 2-7.

Figure 2-7. Deposit likely due to side vibration of the bar in the slot

Also, there may be a very small side force due to the bars not being exactly located in the center of the slot.)

On small thermal-powered generators and on hydro-powered generators, the top bar generally is near the top of the slot. Significant flux may cut the top strands of these units, and associated problems have resulted.

Density of cross-flux is also shown in Figure 2-6. The total quantity of cross-slot flux cutting the top bar is 3 times that cutting the bottom bar, i.e., the area a-b-c-d is 3 times that of area e-f-g. Hence, since both bars are carrying the same current, the force on the top bar is 3 times that of the bottom bar.

Combined slot force on the top and bottom bars on small generators may range between about 3 and 15 pounds/inch, depending on machine size and design duty. Conductor cooled generators range from as low as perhaps 20 pounds/inch on early low-rated units, to as high as 110 pounds/inch on very large direct-cooled stator bars. All of these values are significant. Consider a liquid cooled stator with a 250" long core, and a bar force of 60 pounds/inch. The combined full-slot force on the top and bottom bars of a single slot is 15000 pounds, or 7.5 tons. Considered from another perspective, since the combined weight of the two bars will be about 3 pounds/inch, the driving force is in the order of 20 g's. Even on a conventionally cooled machine, the driving force may be as high as 6 g's.

The conditions are somewhat different when the two bars in a given slot are in different phases. (Because of winding "pitch factor", roughly 50% of slots will have bars of different phases.) The flux patterns are more complicated. The net result is that the maximum bar force will still be downward, but at about 7/8th that of the maximum of a slot with 2 bars of the same phase. There will also be a small upward force on the top bar, at roughly 1/8th of the maximum downward force of a slot with bars in the same phase. Thus, if the maximum downward force of the same-phase slot is 60 pounds/inch, on a differing-phase slot, the maximum downward force will be about 50 pounds/inch, and the maximum upward force will be about 7 pounds/inch. These values suggest that the restraining-system duty on the two types of slots will not be significantly different, and experience confirms this to be true.

The variation of force acting upon the slot portion of stator bars is shown in Figure 2-8. The "A/A slot" curve, Figure 2-8a, is for a slot with both bars in the same phase. The "A/B slot" curve, Figure 2-8b, is that of a slot with the two bars from differing phases.

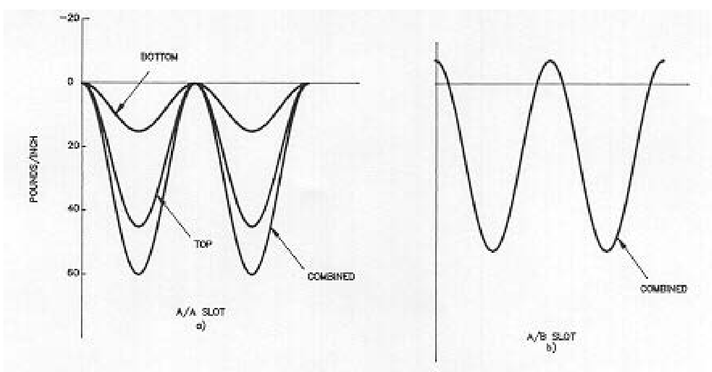


Figure 2-8. Typical 120Hz Sinusoidal Vibration Forces on Armature Bars of a Large 60Hz Generator

2.2.2.3 Stator Bar Slot Vibration Control

With these forces in mind, it becomes clear why the electromagnetic forces on stator bars in the slots cannot be held without a restraint system that is properly designed and correctly assembled, and maintained in good condition.

Almost all manufacturers use designs that attempt to hold these forces by applying a downward pressure with wedges and fillers. An exception is those machines using global vacuum pressure impregnation (global VPI). If a winding is VPId with a process that does not result in the bars being solidly bonded in the slot, small radial and side clearance will inevitably exist in the slot between the bars and the core iron. These clearances will result because of thermal differential expansion differences between the core iron and the bar copper/insulation materials. Unless the design incorporates methods of maintaining restraint on the bars, bar vibration may develop over time and can result in vibration sparking which can be very damaging and cause service failure in a relatively short time, perhaps less than 2 years of operation.

In the more common design approach of wedging after bar assembly (non-VPI), clearances may also develop and permit bar vibration, particularly if the slot retaining system is at all marginal.

Manufacturers attempt to hold these forces by applying a downward pressure with wedges and fillers. But wedging materials and stator bar non-metallic materials creep and shrink to some extent under application of force and temperature. A very small amount of creep and shrinkage of materials can leave a radial clearance in the slot. Upward travel of bars may then result from mechanical rebound or from the relatively low electromagnetic upward force on top bars in slots with bars of differing phases. As a result, on most modern machines manufacturers have added supplemental restraining in the form of spring systems.

Figure 2-9 shows a radial spring supplemental wedging system. If radial clearance does not occur under either the top or bottom bar, and if design deflection limits are maintained on these springs, vibration will be prevented. If clearance exists under the bar(s) of the assembled system, the radial spring system will not prevent vibration from occurring.

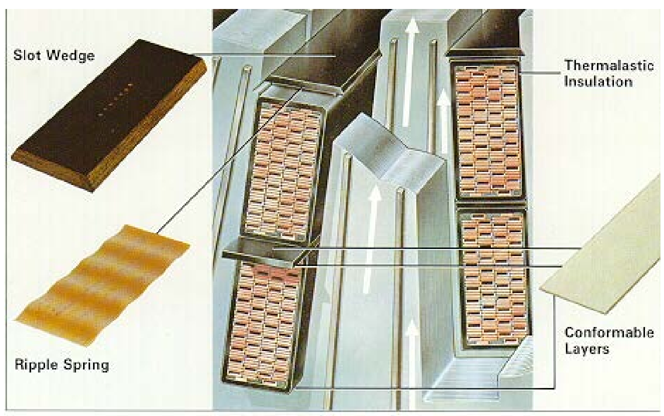


Figure 2-9. Typical Stator Slot Wedging System. (SW)

An alternate supplemental approach to preventing vibration is the use of side pressure springs, Figure 2-10. The side ripple spring is highly effective in eliminating mechanical rebound and controlling the low upward electromagnetic force. But the damping force of the spring cannot be relied on to prevent vibration if clearance exists under the top or bottom bar. Since wear can occur with only a few mils of bar movement relative to the core iron, even small clearances, e.g., 1 or 2 mils, may be fatal.

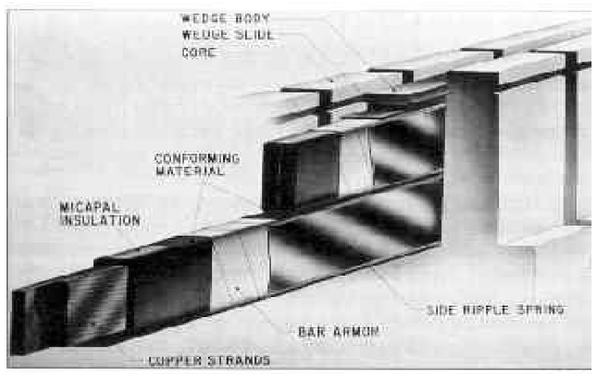


Figure 2-10. Slot Wedging System with Side Pressure Springs (GE)

This side ripple spring system was developed using a slot model capable of forces three times higher than used in service by the manufacturer. Figure 2-11. Even at these high test forces, vibration could not be initiated unless the bars were held off the bottom of the slot.

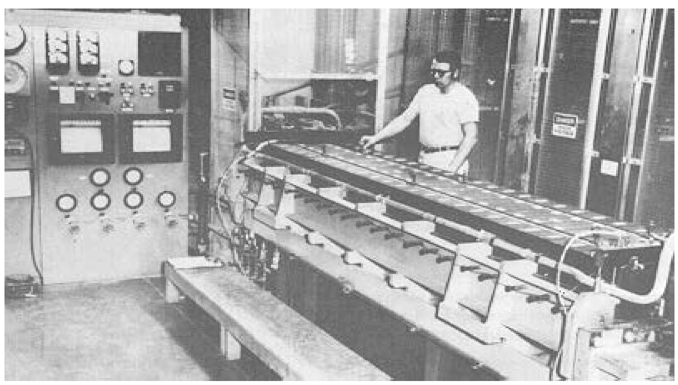


Figure 2-11. Slot Wedging System Laboratory Development Model

Design and assembly of a quality stator wedging system has historically been challenging. In addition to the above restraining system considerations, there are three other areas of interest:

First. All slot restraining systems rely to some degree on frictional forces between the bar and the core iron. Thus, oil ingress can reduce the reliability of all stator-wedging systems. Oil saturation would be a concern where slot clearance exists and where bars are not fully seated in the slots. Since the side ripple spring supplemental system specifically relies on friction for damping of vibration, oil ingress could be a concern on this system. Figure 2-12 is a photograph of a stator with oil leak and serious bar vibration resulting from clearance under the bars at the ends of the slots.

Figure 2-12. Insulation/Oil "Grease" Deposit from Stator Bar Vibration in an Oily Machine

Second. In the event of sudden short circuit, armature currents can be very high. Since forces will be related to the *square* of armature fault current, forces can be extremely high. On faults internal to the stator winding, depending on location of fault and phase of the two bars in a given slot, the top bar force may be radially upward. These extreme forces have occasionally thrown the top bar through the restraining wedges and out of the slot into the air gap, Figure 2-13.

Figure 2-13. Stator Bar Thrown from Slot by Sudden Short Circuit Force

Third. On gas cooled bars exposed to sudden short circuit, fault current forces may collapse the ducts upon themselves, giving the appearance of high vacuum in the duct. Figure 2-14.

Figure 2-14. Stator Bar Ventilation Ducts Collapsed by Armature Current Forces of a Sudden Short Circuit

2.2.2.4 End Winding Electromagnetic Forces on Stator Bars

Flux and force patterns are much more complicated in the end winding than in the slot. Because there is no magnetic iron to give low permeability, forces between *adjacent* bars are lower but still very significant – about one-third to one-half of those in the slots. Because the top and bottom layers of bars are at near perpendicular angles to each other, forces between layers would be quite low.

Two concerns arise relative to end winding forces: normal load vibration, and sudden short circuit forces. The force patterns for both conditions are complex and beyond the scope of this document. Normal load forces are the more bothersome, as they are not low; designing and manufacturing of adequate restraining systems for these forces has proven to be difficult and numerous service problems have been experienced. Circumferential forces during a severe sudden short circuit can be very high and troublesome, but fortunately this type of malfunction is not common.

Low-force, conventionally cooled stators have historically used glass cord (or glass roving) and composite blocking to tie and restrain the end windings. These systems have proven to be generally reliable, although some retying may be required from time to time, and a severe sudden short circuit is likely to break ties and/or crack stator bar groundwall insulation. The system shown in Figure 2-15 relies heavily on bonding of the (glass roving) ties to the conductor insulation. If a dry material rather than a wet roving is not used, the ties may de-bond and can cause severe wear to the insulation. Figure 2-16. (The “wet” tie is made by drawing an unwoven glass tie material through a resin bath as the ties are made. The “dry” tie uses a commercially available pre-impregnated and dried (slightly cured) tape for the tie.)

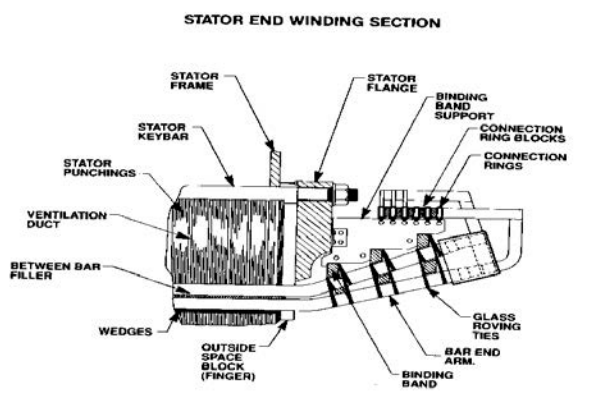


Figure 2-15. Typical Stator End Winding Support System for Conventionally Cooled Stator

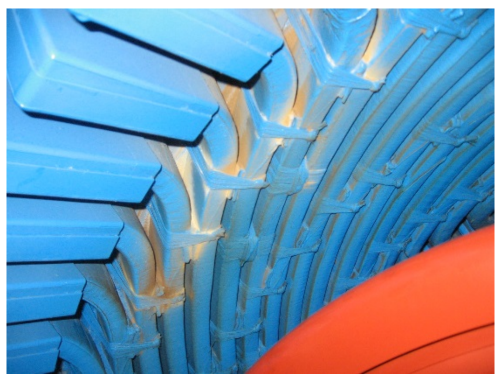


Figure 2-16. Dust generation from wear of stator bar insulation due to de-bonded dry ties.

However, these low-force support systems were found incapable of holding the high running and short circuit forces of a direct-cooled stator, and all manufacturers have gone to more elaborate end winding support systems for large generators. The original General Electric system developed in the 1960s is shown in Figure 2-17; the inner ring has now been replaced with a set of ties that has improved the capability of this system, particularly against running forces. Figure 2-18 is a more recently developed Westinghouse system.

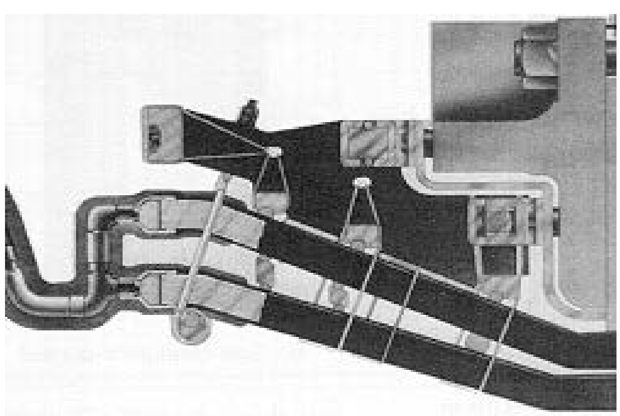


Figure 2-17. General Electric High-force Stator End Winding Support System

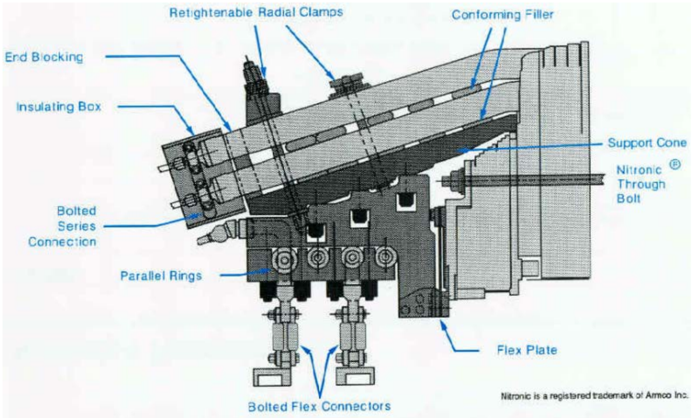


Figure 2-18. Westinghouse High-force Stator End Winding Support System

Because of the complexity of the structures and forces, these systems were developed empirically and with extensive and costly laboratory testing. Figure 2-19 is the fourth version of end winding test models constructed by General Electric in the process of developing their high-capability system during the 1960s. These designs evolved partially by trial and error and partially from early operating experience.

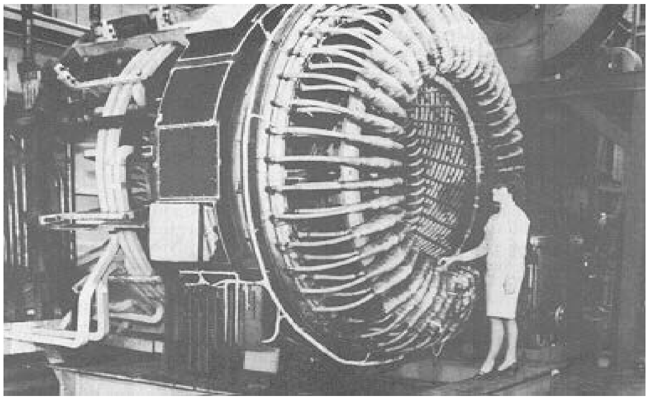


Figure 2-19. General Electric Sudden Short Circuit Model IV.

The present high-force systems will hold all but the worst sudden short circuit. (Probably no endwinding system in use today can withstand a worst-case short circuit without some damage to the stator bars and endwinding support system.) These systems also perform well against normal load duties, but over time may develop local or general looseness. Re-tightening and other repair may be required on all systems.

Normal load conditions, and design error, can also result in resonant conditions of portions of the end winding, or the complete end winding structure. It is possible to build an end winding that is resonant at near driving frequencies, e.g., 100/120 Hz, but to a lesser extent 50/60 Hz. Furthermore, an end winding that has good natural frequency characteristics when new and at room temperature (above about 135 Hz on 3600 rpm machines), may become tuned at operating temperatures and as the inevitable loosening occurs during operation. These resonances can cause rapid deterioration and local or widespread damage. Localized deterioration may occur, for example, at a single interconnection between a phase bar and connection ring, or isolated vibration between individual components, Figure 2-20.

Figure 2-20. Evidence of Localized End Winding Vibration

As previously indicated, sudden short circuit forces can be very high, depending on location of fault and instant of occurrence in the voltage cycle. On a short circuit outside the winding, bars within a phase belt are attracted to each other, and may therefore close up circumferentially on one another. At the phase breaks, the forces are repellent, and large gaps can develop on poorly supported systems. Figure 2-21 shows minor displacement of series loops caused by a sudden short circuit; while the condition may look benign, the winding was seriously damaged and required replacement. But even with no apparent displacement, tiny hair-line cracks may have occurred; mica insulation systems crack about like glass. These cracks are likely to be completely through the groundwall insulation and would constitute winding failure. Figure 2-22.

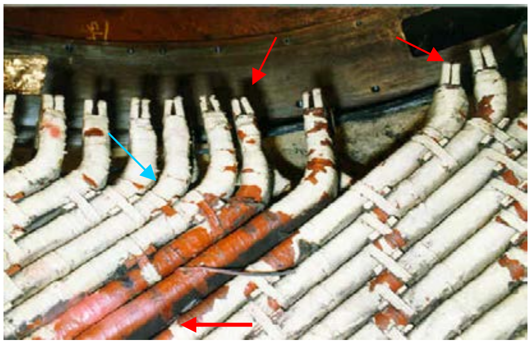


Figure 2-21. End Winding Displacement (red arrows), Insulation Cracks (green arrow) and Broken Ties Due to Sudden Short Circuit

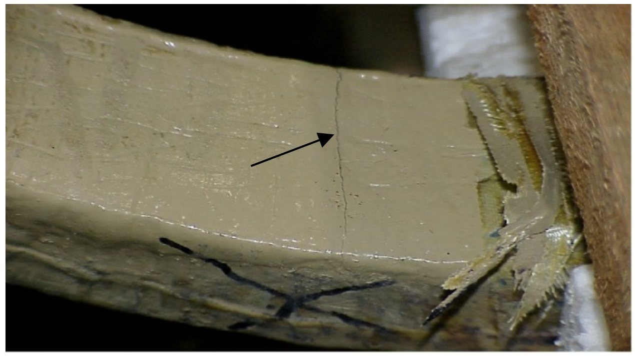


Figure 2-22. Severe crack in stator bar groundwall insulation.

In summary, most modern high-force end winding restraint systems will adequately support the armature bars against all but the worst of short circuit conditions. But the string tie systems may require retying or rewind even after a relatively minor fault.

2.2.2.5 Groundwall Electrical Stresses

The development and performance of groundwall insulation systems is a complicated subject, far beyond the scope of this document. However, a few comments may be useful in understanding the nature of the failures that periodically occur.

Manufacturers have always used mica in the stator bar groundwall, as mica is the only material known to be highly partial discharge resistant in the presence of high electrical stress and voids. (No one has yet found a way to make armature bars with no voids.) Binders have evolved: shellac, asphalt, polyester resins, and epoxy resins. But mica has stayed, only varying between high-grade natural mica splittings just as dug from the ground (found in limited quantities primarily in India), and mica paper fabricated from lower-grade natural mica (found in quantity worldwide).

Note that because mica constitutes the bulk of the groundwall, and because mica is a brittle, non-elastic material, when a stator bar is subject to high bending forces, the groundwall will tend to crack and will crack more or less as glass cracks, i.e., all the way through.

Internal grading systems and partial discharge resistant resins are now being used. These systems are being introduced to reduce stress concentration affects from corners and other discontinuities, and to attenuate the impact of the inevitable voids. Typical bar cross sections are shown in Figure 2-23.

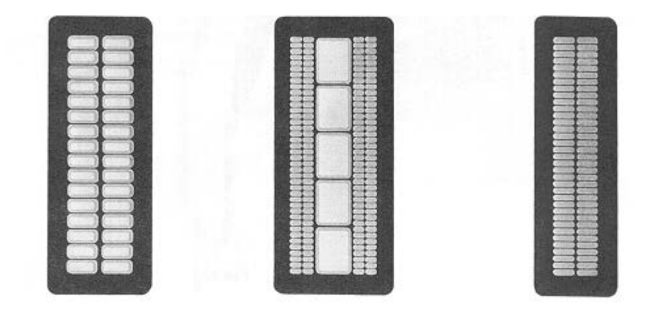


Figure 2-23. Stator Bar Cross-sections – left, direct water cooled; middle, direct as cooled; right, indirectly cooled.

Groundwall stresses have evolved upward with time as improved mica binders have been developed: about 45 volts-per-mil (vpm) with asphalt, 50-55 vpm with polyesters, 60-70 vpm with epoxies, and trending substantially upward beyond 90 vpm as improved voltage grading and partial discharge resistant fillers are being developed and implemented. These increases may not seem dramatic, but rate of aging on the groundwall insulation is about a 9^{th} power function of electrical stress, e.g., increase the stress by only 20% and the duty increases 1.2^9 or about 500%, all other things remaining equal. While the stress levels used up to now have rarely if ever resulted in a purely electrical failure of stator windings, as the trends toward higher stresses continue, failure from purely electrical root-cause will eventually finally come.

2.2.2.6 Stator Bar Surface Grounding and Grading

Internal groundwall stress is not the only duty that increases as thinner builds are applied. So does the amount of capacitive energy transferred across the groundwall. And so does the stress in any air gap or void that may exist on the outside groundwall surface. Thus external surface voltage grounding and end grading of surface voltages become significantly more difficult to control.

Surface grounding is accomplished by applying relatively low resistance “semi-conductive” paint or tape to the surface of the bar in the slot portion. (The term “semi-conducting” implies the material is neither high resistance nor low resistance.) To control the surface voltage gradient at the end of the slot, a semi-conducting, *non-linear* high-resistance paint is used. The nature of the non-linear resistance characteristic of the paint is such that it actually accomplishes a more linear gradient of surface voltage. If the grading is inadequate or deteriorates in service, arcing at the end of the slot grounding paint will occur and serious damage to the ground insulation may develop.

Figure 2-24 shows approximate voltage profiles for conditions of proper grading, Curve 1. Voltage distribution without grading is shown in Curve 3. The no-grading condition is in fact not a discrete curve, but rather there will be severe arcing at normal operating voltages, and there will be flashover if voltage is increased to hipot levels. (Curves 2 and 4 show hipot voltage distribution with 0.1Hz and DC; these curves are discussed in Section 7.2.1.7.3.)

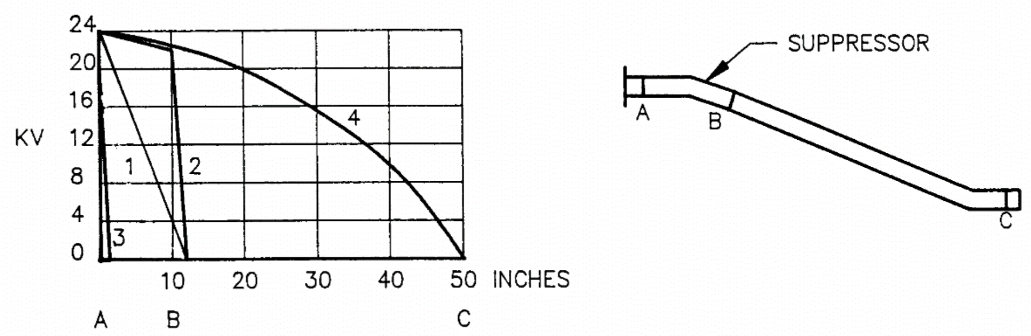


Figure 2-24. Voltage Stress Gradient Effects for Various End Arm Voltage Grading Conditions

The design, application, and durability of the electrical ground, clearance and grading systems are vital even on relatively low duty generators. On highly stressed insulation systems, these factors are critical.

2.2.2.7 Stator Bar Groundwall Partial Discharge ("Corona")

2.2.2.7.1 General

Regardless of how well a stator winding is designed and manufactured, there will be some internal and external voids in the groundwall insulation system and thus electrical discharge (often incorrectly called "corona"). Because these discharges are confined, and do not of themselves result in flashover or machine failure, they are referred to as "partial discharge".

In a good system, the voids will be very small, <1 mil, and internal partial discharge activity insignificant. In a well-designed system PD activity external to the bar insulation will be negligible. The inherent properties of mica will resist this internal and external degradation over a very long period, 50+ years. But during operation, the mechanical, electrical, ambient and thermal duties on the bar may tend to enlarge any pre-existing internal voids, create internal delamination, and in extreme cases, crack the groundwall.

External to the groundwall, the bar motions and electrical stresses associated with normal operation may abrade the semi-conducting surfaces, degrade electrical junctions between grading and grounding systems, and otherwise create or enlarge voids in the high stress gradient regions of the slot or end winding portions of the bar. These actions individually or collectively can lead to significant voids or discontinuities, and thereby reach sufficient partial discharge energy levels to begin serious deterioration of the winding.

While the mica-bearing insulation systems may resist this action indefinitely, non-mica insulation may fail in a short time, i.e., less than 1 year of service.

Because the degradation associated with partial discharge is considered to be an important cause of generator deterioration, efforts to understand, measure and assess partial discharge activity have been high. Equipment has been developed during the last 40 years to measure and analyze partial discharge activity on stator windings. Several types of equipment are in use.

2.2.2.7.2 Forms of Partial Discharge

The physics of the nature of pulses or discharges associated with partial discharge is an intricate subject that has been studied since the inception of high voltage generation and transmission, i.e., above about 4000 volts. The discharge itself can take many forms, depending on void length or diameter, type and pressure of associated gas (typically air or hydrogen), and the nature of the surfaces at the discharge site. Within a given generator there will be many partial discharge sites.

Several physical manifestations are associated with partial discharges: electrical pulses, radio frequency noise, acoustic noise, light, and chemical reactions. Electrical pulses and radio frequency noise can be sensed by selected electrical pickups as simple as an AM radio or as complicated as specially designed sensors and elaborate laboratory instruments. Acoustic noise can often be heard as a buzzing sound during hipot test, and can be detected by sensitive instruments when minor. During hipot test, light from surface discharges can be seen as "lightning" streamers in severe cases, or if minor, as small glow areas in a darkened room. Surface discharge can also be readily seen with a "corona scope" in normal ambient light. Chemical reaction in the air can produce the familiar ozone smell. Products of chemical reactions may be observed on the insulation at highly stressed surface locations of stator bars (slot and end winding) or connection rings. These products may appear as a whitish powder, as a "burnt sugar" solid material, or as dark semi-liquid decomposed oil.

2.2.2.7.3 Methods of Detection

Successful segregation and analysis of the partial discharge electrical signal is required in order to determine the nature and severity of the discharge. This has proven to be difficult. Specialized sensors and high quality equipment are required for most of the detection systems. But more particularly, interpretation of results has proven to be somewhat subjective, and sometimes indeterminate.

Several types of sensors are used to detect the electrical and physical manifestations of discharges. On-line sensors include: capacitive coupling to line terminals, under-wedge slot couplers, radio frequency current transformers at neutral terminals, ozone monitors. Off-line sensors for use during hipot include: capacitive coupling, inductive-matched capacitor coupling, electromagnetic probe bridging individual slots, acoustic probe, and radio frequency probe.

Some of these sensors are standard devices, but more commonly they are small-use products or custom-built for the particular application.

2.2.2.7.4 Measuring Instruments

Signals from the various electrical sensors can be measured by a variety of instruments: oscilloscopes, spectrum analyzers, integrating current detectors, peak-reading pulse meters, pulse height analyzers, phase analyzers. Standard laboratory instrumentation may be used, but also specialized instrumentation has been developed and incorporated to facilitate ease of data collection and interpretation.

2.2.2.7.5 Interpretation of Results of Partial Discharge Tests

Both on-line and off-line testing have advantages and disadvantages. Generally speaking, interpretation of off-line data can be more accurate since spurious noise is substantially reduced. However, on-line data can be valuable as a condition-monitoring tool. Since the two situations complement each other, both on-line and off-line testing may be advisable.

On-line monitoring may allow trending of actual machine in-service condition, but interpretation of data is difficult and tends to require the more complex instrumentation. Off-line testing tends to be more time consuming and expensive. Off-line test instrumentation is less complicated, but there are major drawbacks: machine must be out of service, separate partial-discharge-free power source required, no electromechanical forces are present, and all parts of the winding are at elevated voltage and therefore not at normal operating voltage conditions.

Neither test of itself should be considered as a conclusive indication of machine condition, when either high or low readings are obtained. But the tests individually or in tandem may give valuable information to assist in assessing stator-winding condition. (A winding should probably never be condemned on the basis of partial discharge readings alone.)

Partial discharge is covered in more detail in Chapter 5.

2.2.2.8 Stator Bar Vibration Sparking

2.2.2.8.1 General

Vibration sparking (also called “spark erosion”) is a similar but actually completely different deterioration process from partial discharge. The mechanism is driven by the excitation flux in the core and whereas partial discharge can only occur on higher voltage bars, vibration sparking (VS) can occur at any point of the winding, including on the neutral bar.

The first instances of vibration sparking occurred during the late 1950s, when hard (polyester and epoxy) insulation systems were first introduced. The vibration was vertical in the slot and was corrected by use of improved wedging systems which eliminated vertical bar movement. In more recent time, side vibration has occurred on large air-cooled generators with deep, narrow slots.

The root causes of vibration sparking are too low a resistance of the slot conductive coating, together with vibration of the stator bar. The current loop is axially along the bar, radially through the core laminations, axially along the keybars at the back of the stator core, and radially back to the bar. If a bar is allowed to vibrate, the current in this loop will be interrupted at a contact point to the core iron, and the interruption of this current will form an arc to the core. If the conductive coating of a bar is low, this current will be of significant magnitude and the resulting arc can damage the groundwall insulation, probably by a mechanical erosion process.

The energy available to drive the vibration sparking mechanism is substantial, in that there is up to about 160 V per meter (50 volts/foot) along the length of a bar in a high-flux designed turbine generator. It is believed that the resistance of the slot conductive coating should be no lower than perhaps 200 ohms per square to prevent the mechanism.

Vibration sparking is a relative fast deterioration mechanism and has caused service failure in a relatively short time, i.e., many months or a few years.

2.2.2.8.2 Differential Expansions

One of the more troublesome challenges of stator design results from differential expansion caused by differing temperatures and differing expansion coefficients. Radially in the slot, expansion differentials between the core-iron tooth and the bar copper and insulation tend to cause loosening of wedging systems. As previously indicated, radial springs in the wedging system are an attempt to deal with this condition.

Axially in the slot, the problems are manifold. The length of the core is set by the temperature of the core iron, and the keybars and/or through bolts. (A long core with enameled lamination insulation contains several cumulative inches of compressible material, making calculation of core axial expansion imprecise.) The unrestrained armature bar length is set by bar copper temperature. On most designs, the copper operates at higher temperature than the keybars; also copper has an expansion coefficient about 50% greater than steel: approximately 16 Vs. 11 x 10^{-6} inches/inch/C. The normal load cycling will result in relative movement, which can migrate fillers and wedges, and on soft insulation, plays a dominant role in the tape migration phenomenon.

On direct cooled windings, if cooling is restricted or lost to individual bars, the starved bar(s) will get much hotter than the remaining bars. A temperature differential of only 100C between a non-cooled bar and the remainder of the winding on a 250” core will give a total differential of about 450 mils between the starved bar and the remainder of the winding. This 225 mil expansion out each end of the slot will fracture the groundwall insulation at both ends of the bar at the first radius, typically with disastrous results.

Differential expansions also affect the end windings, but to a lesser degree. Interpretation of evidence of expansion effects may be difficult. Most end winding support systems are designed to incorporate a floating mechanical interface to the core end flange, in order to accommodate the large slot-portion axial expansion. But this feature does not alleviate the complex end arm expansions.

Hairline cracks are often observed in the paint on end windings; if caused by end arm differential expansion, these usually are insignificant. But mechanical working of the series loops may contribute to cracking of series connection copper. Differential expansion, wear and vibration may loosen the end winding blocking, and deteriorate the interface between bars and end winding support components. Also, differential expansion actions may help to loosen the endwinding, thus reducing the natural resonant frequencies to a point where local resonances may develop.

Before leaving this topic, it should be pointed out that it is difficult to distinguish between insignificant and serious indications of cracking. Surface imperfections and local differential expansion cracks are likely to be only in the surface paint or between blocks and bars; these are inconsequential. The potentially very serious cracks are caused by mechanical damage, short circuit forces, or slot differential expansion. These indications may also appear as a minor surface condition, but actually be the manifestation of a crack deep into the groundwall. The key to interpretation is the location of the crack. Circumferential cracks going around the bar, either full circumference or partial circumference, must always be investigated, even those that have a minor hairline appearance. Stator bar cracking is covered in more detail in Chapter 6.

2.2.2.9 Connection Rings and High Voltage Bushings

Many of the deterioration mechanisms that apply to stator end windings also apply to some degree to connection rings: differential expansion, partial discharge deposits, vibration, loosening of clamps and ties, lost or inadequate cooling. However, the electrical and mechanical duties tend to be lower than on end windings. Problem manifestation may be similar. Resonant vibrations may occur locally or in the entire structure in either end windings or connection rings. Figure 2-25 shows vibration on a pair of connection rings.

Figure 2-25. Connection Ring Support, with Vibration Activity.

Because of the strong commonality, typically the end winding support and the connection ring support have been developed and tested simultaneously.

2.2.2.10 Series and Phase Connections

There are numerous basic approaches to series and phase electrical connection design: lead-tin solder, silver solder, strand-to-strand, strand bundles, incorporated transpositions, clips, plates, indirect liquid cooling, direct liquid cooling, bolted. Some examples are shown in Figure 2-26, Figure 2-27 and Figure 2-28. All approaches can give reliable service if properly designed and assembled, and if resonant conditions do not occur. In any of the approaches, proper assembly is essential to reliable service; because the work of assembly is often tedious and/or technically difficult, failures do occur.

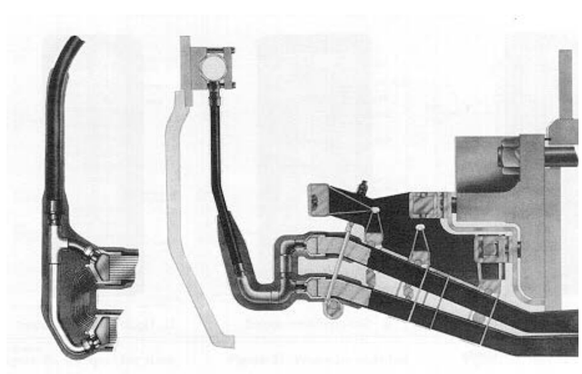


Figure 2-26. General Electric Series Loop Connections, Non-Direct Cooled and Direct Cooled Series Connection Copper.

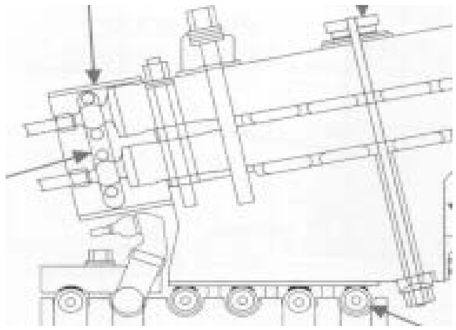


Figure 2-27. Westinghouse Bolted Series Loop Connection

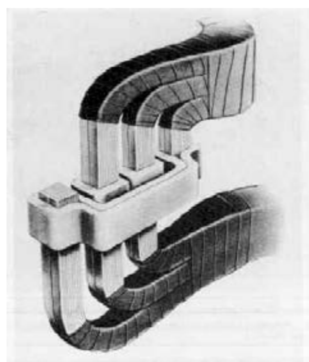


Figure 2-28. Westinghouse Series Loop Connection with Transposition

Approaches to insulating of the connections also vary fundamentally: mica tapes, non-mica tapes, fillers, boxes and potting compounds, wide physical spacing, barriers. Examples are shown in Figure 2-21, Figure 2-29 and Figure 2-30. Except for the boxes and spacing/barrier approaches, the work of assembly tends to be tedious and/or complicated. Failures may occur on any type of connection, but are much more likely to be widespread on the designs that rely on physical spacing alone, without potting compound sealant.

Figure 2-29. General Electric Taped Insulation (with 3 Loops Prepared for Leak Test)

Figure 2-30. Westinghouse Taped Insulation on Gas Cooled Stator (after Service Failure and Insulation Damage)

Use of wide spacing at phase breaks provides for simple assembly procedure, but numerous failures have occurred in the past. In the event of winding arc resulting from broken lead or failing joint or flashover between phases, the cooling gas becomes ionized. Ionized gas is a poor insulator and the voltages will trigger flashover of the isolating gaps, including both the series as well as high-voltage phase breaks. Failure of this type will cause complete destruction of the armature winding and thorough contamination of the field, core, frame and other components.

Insulating boxes and potting compound are commonly used to insulate connections on modern machines. While not as high intrinsic capability as mica-taped joints, this type insulation system has been quite adequate for long-time reliability, providing physical spacing between joints is sufficient to prevent partial discharge at these locations during normal operation. If physical spacing is inadequate, i.e., less than about 3/8", partial discharge will result and electrical failure can be expected.

2.2.3 Field Design Failure Mechanisms

2.2.3.1 General

Field winding life expectancy tends to be shorter than stator winding life, typically in the order of 15 to 25 years before major repair or rewind may be needed. This shorter life results from the inherently high mechanical and electrical duties placed on field components. Almost all mechanical components, steel or insulation, are subject to high static and cyclic forces. The insulation systems, in addition, are typically designed to rely heavily on clean electrical creepage paths, and these surfaces are vulnerable to contamination from dust, metallic particles, and moisture.

2.2.3.2 Centrifugal Duties on Retaining and other Shrink Rings

The retaining rings typically are the most highly stressed component of the generator. Larger-diameter rings operating in excess of 8000 g's, i.e., a one pound weight becomes an 8000 pound load. Over 60% of the load carried by a retaining ring can be from the mass of the ring itself, with only 40% of the load being the field winding copper, insulation and blocking. For this reason, on modern generators, rings are typically designed with the absolute minimum of stress risers: no drilled holes, large radii, polished surfaces free from tool marks, Figure 2-31. However, in the past there have been many machines built with stress risers of various sorts, and large numbers of these machines will still be in service.

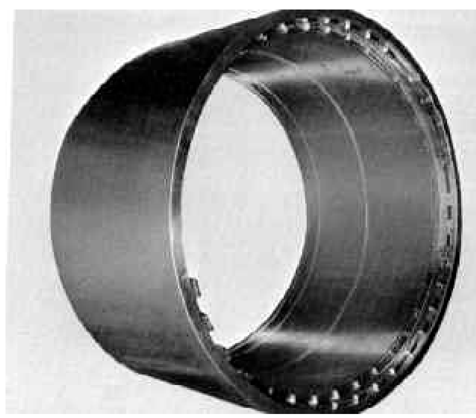


Figure 2-31. Typical Retaining Ring

Other rings and structures mounted to the field are avoided so far as possible, particularly at the larger diameter locations. This approach is taken because of the inherent danger and the catastrophic nature of failure of a high-energy rotating component. At smaller diameter locations, rings are common: fans, centering rings for retaining rings, collectors. Bursting failure of these devices has been rare.

Shrink fits are used to keep rings in proper radial location. The shrink on these fits must be high in order to maintain contact at normal speed as well as at test and load-rejection overspeed conditions. Shrink loads are so high that there actually have been cases of retaining ring fracture at standstill due only to the shrink-fit mechanical load on the steel.

High axial thrusts result from thermal forces within the field winding. These forces are commonly restrained, both at rated and overspeed conditions, by use of breach locks or snap rings of one form or another, except on earlier designs. Early designs may hold these thrusts with keys, and these keys may not be fully effective.

2.2.3.3 Field Forging Mechanical Duties

Field forgings are massive in size and are machined in complex configurations. Certain portions of the forgings are inherently highly stressed. Particularly high stresses are placed on the tooth areas, where stress conditions are accentuated because of the necessity of using wedge grooves, ventilation holes and other discontinuities. Forging quality has evolved in line with industry need, although in the 1950s the standard ingot pouring processes caused inclusion problems in the final forgings. These flaws resulted in several catastrophic field bursts, Figure 2-32.

Figure 2-32. Results of Field Forging Fracture

Designers have been able to control localized stresses at discontinuities by use of radii, and by locating stress concentrators in relatively low stress areas. Figure 2-33 shows typical field forging discontinuities, including cross slots, winding slots and sub-slots, wedge dovetails, ventilation slots, end of field body. Nevertheless, cracks have developed in the high stress tooth dovetail areas, particularly at the ends of the body. There have also been cases of circumferential forging cracks near the body axial centerline, and field forging cracking in the high stress area at a journal.

Figure 2-33. Machined Field Forging

2.2.3.4 Slot Wedge Mechanical Duties

Field slot wedges are highly loaded and complicated in shape. Furthermore, for electromagnetic reasons, designers may use non-ferrous materials for wedges in portions of the slots. By careful control of fit, radii and finish, wedges normally will function without mishap. When problems occur, generally the result is cracking, yielding, heat softening or burning. Figure 2-34.

Figure 2-34. Wedge Body Burn Resulting from Rotor Body Current

2.2.3.5 Forging Thermal Duties

During certain mis-operation conditions of the generator, for complicated electromagnetic reasons, current will flow in the surface of the rotor body and slot wedges, and in the retaining rings if body mounted. These currents result from unbalanced armature phase current loading or from asynchronous operation. The latter can range from the slight overspeed associated with loss of excitation current, or the gross condition of placing a generator across the line at standstill or at less than synchronized speed.

Because these currents can be large, and concentrate near the body surface, heating effect can be intense. Further heat concentration results from field surface discontinuities: pole-face cross slots, poor electrical connection between wedges and field forging, rotor body end effects. (The end effects are intensified by the difficult path the current sees as it flows circumferentially 180 electrical degrees around the end of the rotor body either in a body mounted retaining ring or in the slot end wedges. On larger and modern ratings, designers often use amortisseur windings to assist in handling these currents.)

The worst case scenario is that of accidentally placing the generator across the line at standstill, or on turning gear. The huge armature current flow is mirrored as a huge current in the field forging surface, and if all three phases are connected, this iron current is in such a pattern as to cause the generator to act as an induction motor, thus bringing the field up in speed. If the condition is maintained for several seconds, the combination of heat from immense field body current and from centrifugal mechanical loadings will result in catastrophic failure of the field and loss of the entire turbine-generator, Figure 2-35. (If the closure is single- or two-phase and at standstill, the high currents will flow but there will be no torque on the field, and thus the field will not accelerate. Nevertheless, fatal damage to the generator field (and stator) is likely to result if the fault is allowed to persist more than a few cycles.)

Figure 2-35. Residue of Stator and Field Windings after 3-phase Breaker Closure with Generator at Standstill.

2.2.3.6 Mechanical Duties on Field Copper

Copper is not a high-strength material, nor are the fatigue properties good. Yet the mechanical duties on the electrical conductors are substantial. These problems can be addressed in several ways: 1) use of high-strength copper alloys, 2) generous radii on corners and holes, 3) avoiding abrupt cross section changes, 4) care in making of brazed connections, 5) annealing to hardness that is appropriate to the location in the coil, 6) maintaining constant cross-section at bend locations, 7) controlling coefficients of friction between copper turns and between copper and insulation, 8) avoiding excessive operating temperatures, 9) avoiding excessive temperature rises, 10) avoiding temperature discontinuities between portions of a given coil, 11) care in selecting blocking arrangements under retaining rings.

It is not possible to simultaneously address each of these field design concerns with an optimum solution. Thus it is perhaps not unreasonable to expect that service life on generator field windings will be more limited than that of stators. And it is probably reasonable to expect the occasional service failures, which do occur.

2.2.3.7 Field Ground Insulation Electrical Duties

There are two basic approaches to field insulation systems; these are categorized by the field cooling methods: “indirect” and “direct”. Example slot cross sections are shown in Figure 2-36, in Figure 2-37a, and in Figure 2-37b.

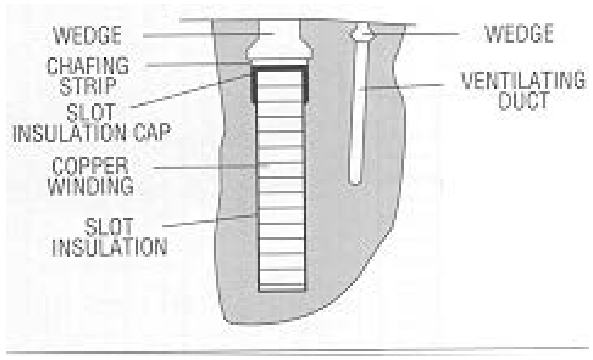


Figure 2-36. Typical Slot Cross Section of "Indirect Cooled" Field. (General Electric Company)

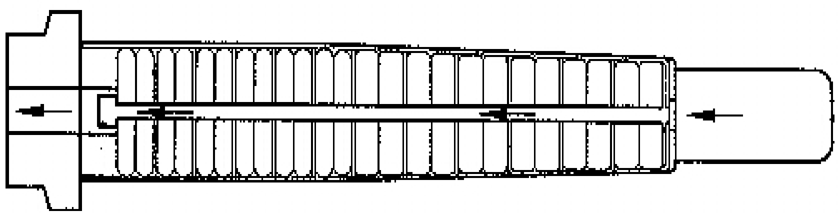


Figure 2-37a. Typical "Direct Cooled" Field Design with Axial Sub-slot Gas Feed. (General Electric Company)

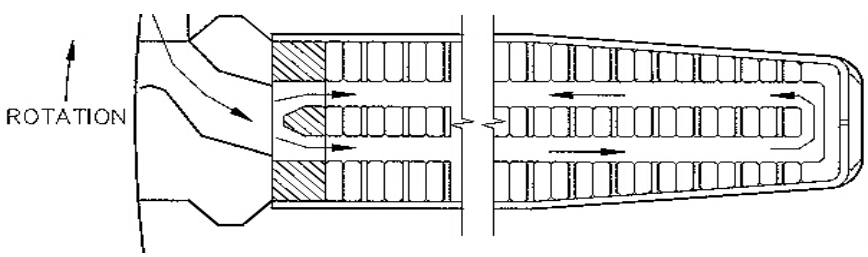


Figure 2-37b. "Direct Cooled" Field Design with Airgap Pickup. (General Electric Company)

Indirect cooling is likely to be used on small or older units. (The thermal losses generated in the field copper must be transferred across a thermal barrier into the cooling gas.) Basically the slot portion of the field coils is enclosed in an electrical (and thermal) wrapper, and voltage (and heat) must penetrate this wrapper to reach ground. Under the retaining rings, the coils are likely to be insulated by taped layers of insulating material. This design is relatively less sensitive to contamination than direct-cooled designs.

Except on small generators, direct cooling is used on most machines presently being built. In this type design, extensive use is made of electrical creepage paths to hold field voltage: at sides of creepage blocks at top and bottom of slot, gas entrance holes at bottom of slot, gas exit holes at top of slot, end of slot liner under retaining rings, between coils and ground under retaining rings, and between coils under retaining rings. If these creepage surfaces become contaminated with a conductive material, it is unlikely that insulation integrity can be restored without full rewind with new insulating materials. However, because this approach to cooling the field is so powerful, machines operating in a totally enclosed ventilation system commonly will be designed as indicated in Figure 2-37a and Figure 2-37b. (If the cooling system is not totally enclosed and tight, and the surrounding atmosphere is not clean, operating problems from severe contamination can be expected with a direct cooled field insulation system in a matter of months or a few years at most.)

Field circuits are generally designed to be electrically isolated from ground throughout the complete system: exciter, interconnecting cables and busses, collector, brush holder rigging, rotating rectifiers, controls, instrumentation, field winding. (This ungrounded approach is permissible because the voltages are low and lack of a solid ground is not troublesome. However, ground-detection circuits are recommended, and this circuit will control the field apparent ground location as well as detect a specific, unwanted ground.)

If an isolated ground does occur on an ungrounded field system, ground current will not flow and no immediate problem results. However, if a second ground develops (which may be more likely than the first), this is another matter altogether. If both grounds are low resistance, the field current will bypass the affected portion of the field winding. This current flow may burn the forging. In addition, current bypass of a portion of the winding may unbalance the field thermally and may unbalance the magnetic circuit, Figure 2-38. Either condition can cause high vibration. A serious magnetic unbalance can immediately cause destructive vibration. This fear of a second ground developing has led manufacturers to recommend against operating with a single ground in a field circuit. (This first ground may be an indication of a weak insulation system, vulnerable to further ground faults.)

On the other hand, if the “single ground” has resulted from arcing at shorted coils or a broken turn, a single ground may be a very great concern. The arc may severely burn the retaining ring or field forging. Whenever a field ground develops, it is preferable to immediately remove the unit from service and determine the cause of the field ground.

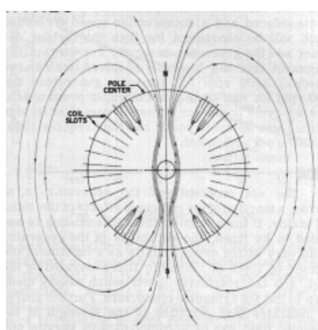


Figure 2-38. Normal Flux Pattern on 2-pole Field Design

2.2.3.8 Field Turn Insulation Electrical Duties

Because voltage between turns is very low, typically 1 to 7 volts per turn, creepage paths are almost always used in field turn insulation design. These surfaces will be degraded by contaminates which degrade ground insulation creepage paths, but failure of the ground insulation paths due to general contamination can normally be expected prior to actual trouble developing on turn insulation.

However field turn shorts do often occur, primarily from mechanical duties on the thin turn insulation. Typically a field can operate safely with one or two shorted turns, although there is concern that high local temperatures at the short location may cause peripheral damage. But as additional turn shorts develop, operation may become restricted or not possible. Higher field current will be required to maintain a given load condition. But more important, thermal unbalance may develop, particularly if turn shorts are in the coils nearest the pole (the small coils); this condition will lead to thermal sensitivity – a thermal vibration vector. Thermal vectors >6 mils are not uncommon and such a thermal vector will force repairs to become necessary. See Section 2.2.3.10, below.

2.2.3.9 Field Insulation Mechanical Duties

Mechanical duty of field insulation is high and is a common source of field failure. Duty results both from centrifugal forces and from axial differential expansions. Components are exposed to both low and high cycle fatigue. Low cycle fatigue results from startup and load cycling. High cycle fatigue results from load cycling and at-speed rotation.

The various combinations of low and high cycle fatigue can cause migration of slot liners, creepage blocks and turn insulation. Cyclic duty can also cause copper and insulation cracks and wear, as well as causing small foreign bodies to penetrate turn insulation.

Low-rpm turning gear operation, less than about 50 rpm, can cause fretting of the copper turns against each other and the insulating components. This fretting is the source of the copper dust phenomenon which has caused turn shorts and field grounds due to the contamination with copper particles. Figure 2-39.

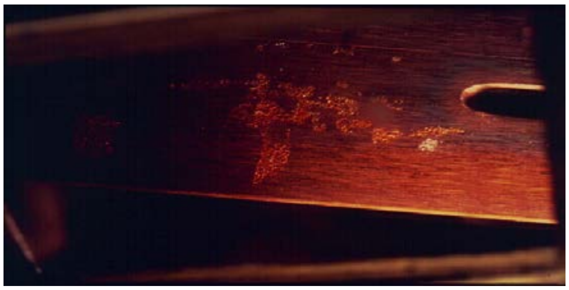


Figure 2-39. Site of Abrasion of Copper Conductor Resulting in "Copper Dust"

2.2.3.10 Field Thermal Sensitivity

Field vibration often is caused by thermal sensitivity. No matter how carefully the field is mechanically balanced, both static and dynamic, operation may be jeopardized by a thermally-generated vibration vector.

There are numerous possible design, operation and/or service related causes for these vectors, which may be linear or non-linear in nature. Linear vectors are directly related to field current, both increase and decrease together. Non-linear vectors increase with field current, but lock-in and tend not to decrease with field current reduction. Many of the known or suspected causes are listed below under the two categories, linear and non-linear. (Some causes may result in either linear or non-linear vibration.)

<u>*Linear Vibration*</u>

- Field copper bonded to slot liners
- Uneven end turn blocking
- Turn shorts
- Cracked field forging
- Uneven ventilation in slot region or under retaining rings
- Forging thermal sensitivity due to ingot deficiency or residual machining stresses
- Uneven paint coverage thickness
- Displaced slot liners or turn insulation
- Operation close to vibration critical

<u>*Non-linear Vibration*</u>

- Uneven coefficients of friction: copper surfaces, turn insulation, slot liners, retaining ring insulation, creepage block surfaces, discontinuities between creepage blocks
- Wedges fitted too tightly
- Wedges shifting radially upward in dovetails
- Wedge yield
- Overlapping turn insulation
- Overlapping retaining ring insulation
- Turns bonded to slot liners
- Uneven bonding of turns to turn separators
- Cocking/shifting retaining rings
- Cocking/shifting of fan rings
- Cracked shaft forging
- Shifting end turn blocks
- Broken turns

The lists are long, susceptibilities vary between designs, characteristics may be subtle, and analysis is often difficult. No attempt will be made here to elaborate, beyond indicating that identifying the root cause(s) of a thermal vector can be quite difficult. Resolution of the complexities of thermal vectors may be expedited by obtaining the assistance of the OEM engineers who are familiar with the details of the particular design.

2.2.3.11 Miscellaneous Mechanical Duties on Fields

Other mechanical duties seen by fields include torque and resonances. Torques associated with incorrect synchronizing or sudden short circuit are large and can damage turbine/field couplings or break interconnecting shafts. Rare cases of torsional resonances have broken the field forging under collector rings on fields with shaft-driven exciters.

Although field mechanical unbalance is a dominant source of generator vibration, ironically, vibrational forces acting on the field itself are negligible.

2.2.4 Core Design Failure Mechanisms

2.2.4.1 General

Core operating problems normally are not related to design, but rather are service related, e.g., foreign objects, cuts and impact, over fluxing. However, there are several design and assembly considerations relating to the high mechanical and thermal duties placed on cores.

2.2.4.2 Lamination Insulation

Two common approaches are taken to core design, Figure 2-40 & Figure 2-41. The design in Figure 2-40 uses a belleville-washer shape on the large core clamping flange, and thus compressive force can be applied using only bolts (keybars) at the outside diameter of the core. The Figure 2-41 design uses keybars and also through-bolts to apply compressive force near the geometric center of the core structure.

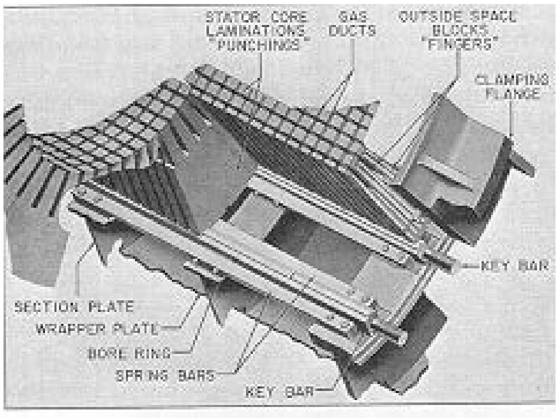


Figure 2-40. Typical Non-Through-Bolt Core Design (General Electric Company)

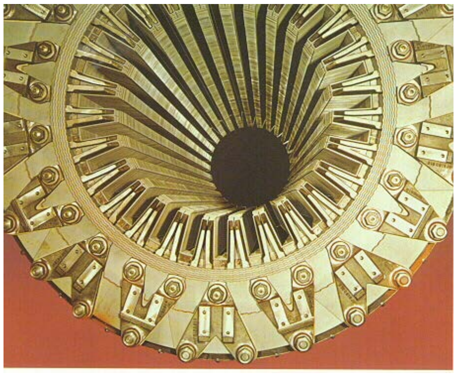


Figure 2-41. Through-bolt Core Design (Westinghouse)

In both these designs, direct iron contact will occur to the keybars at the core outside diameter, i.e., the laminations will become shorted to ground at these keybars. This is permissible since so long as only a single connection is made between each lamination and ground, no current can flow. But in the Figure 2-41 design, there can be no contact permitted between the laminations and the through bolts; the bolts must be insulated and the insulation must maintain integrity. (On some designs, the OEM may insulate the laminations from the keybars.)

Lamination insulation materials, which typically are only 0.1 to 0.3 mils total build on the two sides of a lamination, must be thermally stable and must retain electrical properties under overheating conditions. Otherwise, the inevitable minor, localized damage will progressively increase to run-away over-heating and core failure. To address this concern some manufacturers use inert fillers in the lamination enamel; these fillers will retain a high level of insulation even when the enamel is completely burned away. In addition, lamination insulation must be mechanically stable against overall and localized compressive forces. Otherwise, creep may allow excessive core loosening and perhaps direct iron contact between punchings.

Some manufacturers use only the inorganic “mill coat” for lamination insulation. This coating is very thin and may be susceptible to core failure in the event of relatively minor foreign particle or mechanical damage. There are also indications that this type insulation may be susceptible to wear-out.

In order to further reduce the possibilities of core failure due to current flow, some manufacturers design the lamination/keybar arrangement such that each lamination contacts only one keybar. In a well-designed machine, voltage between keybars will normally be very low; in this arrangement, any current which attempts to flow between adjacent keybars must pass through at least two layers of lamination insulation, further attenuating possible heating effects of circulating current.

2.2.4.3 Magnetic Mechanical Vibration

The magnetic attraction between the field and core is huge. On a 2-pole design, which in effect applies a high force at opposite sides of a thick hoop, the core is relatively easily deformed into a simple oval shape. The deformation may be in the order of 3 to 5 mils. As the field rotates, this deformation translates into a heavy vibrational force. In order to avoid destructive vibration to the frame and power plant structure, the core deformation is isolated from the frame by various spring systems, one of which is shown in Figure 2-40.

On 4-pole designs, the magnetic force is applied at four locations. Because a hoop is much more rigid to a four-point load, magnetic deformation is far less, perhaps 1/6th that of a 2-pole core. As a result, core/frame isolation generally is not required on 4-pole generators.

2.2.4.4 Core Compressive Loading

Ideally, core compression force would be distributed uniformly over the entire core cross-section, the back iron and the teeth, and would be stable with operating time. However, because of inherent taper and/or crown in the raw lamination iron, and possible non-uniform application of lamination insulation, distribution of force will not be perfectly uniform. In particular, there is likely to be concentration of force near the radial center of the punchings, thus leaving relative looseness of the teeth. Manufacturers control this problem by periodically adding thin tapered compensating fill shims to the tooth location of the punchings around the full circumference of the core inside diameter. Typically these circumferential rings of shims will be located at 2 or 3 axial positions at each end of the core.

Because of the inherent creep of lamination insulation materials over a period of time, on larger generators designers generally allow for retightening of the core. If the travel required to tighten a core is high, perhaps >1/8”, on some designs the axial location of the end winding support system may become a concern.

In the event that a core becomes rather loose, individual laminations may move and wear the insulation. In severe cases of looseness, electrical etching of the punching iron may occur and corners may fatigue and break off the lamination teeth; these small pieces of iron have a tendency to stay in place and wear through the stator bar groundwall insulation. An additional concern from a very loose core is that of radially inward migration of punchings or space block assemblies. This can be a serious condition, since experience has shown that keyways will not necessarily hold the core assembly fixed, particularly at the core ends, in the presence of looseness and axial temperature gradients.

2.2.5 Frame Design Failure Mechanisms

2.2.5.1 General

The generator frame serves several purposes: structural support of internal components, vibration isolation and control, gas flow direction, exclusion of foreign materials, gas pressure containment. In addition, the frame acts to interconnect the generator to the plant foundation during normal operation, as well as during short circuit incidents or the enormous possible forces associated with the rare field burst.

Accomplishing these multiple purposes for normal operation of a large, complex machine is a challenge at which designers are generally successful. Designers do not attempt to design for the rare worst case condition of field component fracture. Frames are designed to contain a major gas explosion, but internal baffle damage may occur.

2.2.5.2 Failure Causes and Modes

The most common cause of frame difficulty is probably related to normal vibration. Because core isolation is not perfect, frames experience vibration. To avoid frame fatigue fracture, designers avoid resonances and use generous radii in stress concentration areas.

On hydrogen cooled generators, leakage prevention has been a historic challenge. Frame fabrication leaks are no longer common, but can be difficult to find and correct.

In the event of extensive contamination due to heavy oil leakage or serious armature winding burning, cleanup of the frame is difficult. Manufacturers provide limited numbers on cleaning ports, and access can be made through cooler locations. Special openings can be cut at strategic locations in the wrapper, Figure 2-42, but cleaning access to all locations cannot be provided.

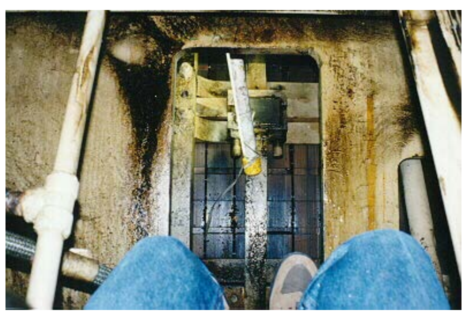


Figure 2-42. Opening Cut in Frame Wrapper Plate for Access

2.2.6 Internal Cooling System Design Failure Mechanisms

Cooling systems vary widely between manufacturers, with the most major difference being use of simple fans and multi-stage compressors. Fans may use axial or radial flow, integral or separate hubs, forgings or weldments, removable blading or fixed. Compressors are used only with generators originally built with direct gas cooled stator windings. Problems are not common with these devices, but when serious concerns arise, assistance of the OEM may generally be necessary.

Coolers also differ widely in design detail. All are subject to leaks, possible vibration of components, and unavoidable contamination.

Most generators have multiple coolers, and in some machines designers allow for mixing the flow of cooling gas between ends of the generator in order to maintain a limited capacity to operate with one cooler out of service.

2.2.7 Excitation Systems

2.2.7.1 General

Excitations systems come in numerous forms. Detail varies widely between manufacturers, although many of the basic features are similar. Discussion of the many varieties of excitation sources will not be attempted in this text. However, all non-rotating rectifier systems use collectors, and because these devices tend to be a significant maintenance item, the subject of collectors and brush holder rigging design and function will be discussed in some detail below.

2.2.7.2 Collectors and Brush Holder Rigging

Carbon-brush collectors have successfully performed the function of transferred current from excitation power sources to the rotating fields of synchronous generators for over 100 years – since the infancy of the electrical industry. The basic principles of current transfer have remained the same, although numerous improvements have been made in carbon-brush materials, collector ring materials, brush holder designs, and ventilation arrangements. Still carbon-brush collectors do require on-going attention of operation/maintenance personnel. Fortunately this work is of a relatively minor nature. But unfortunately, the collector operates at 100 to 700 volts DC, in a very noisy and windy atmosphere. Thus there is an understandable reluctance on the part of operations and maintenance personnel to perform the needed inspections and on-line service of the brushes and collector. As a result, collectors are sometime overlooked, and failures occur. These failures can be severe and the resulting forced outage may be long and very costly.

Collector performance is not directly monitored at all by control-room instrumentation. As a result, the condition of the collector must be monitored by looking directly at the collectors and brushes themselves. Primarily because of brush wear, collectors require continual minor attention. Fortunately, collectors almost never fail without ample warning, thus regular (daily) observation of the collector allows plant personnel to find and correct potential trouble long before a failure can occur.

Dependable brush-to-collector current transfer relies on the following three conditions, which must be satisfied simultaneously:

Collector surface film: Correct balance is needed between the film-forming and the polishing actions of the brush on the collector ring. This balance depends on the brush material, which commonly is natural graphite with a small amount of abrasive material and suitable binder, and on the ring material – typically hardened steel on large generators. Contaminants in the cooling air can adversely influence this balance, as can low humidity, since water molecules are a necessary ingredient of a good film.

Brush contact pressure: Satisfactory transfer of current between the brush and the ring demands that contact pressure be maintained within limits established by the manufacturer. This means that the brushes must not hang-up in the holder and that the spring pressure must be correct. Early machines were supplied with a helical-coil-spring brush holder, which required periodic manual readjustment of the spring force to compensate for brush wear. Brush holders with a constant-pressure spring are now common, and this has virtually eliminated problems caused by improper contact pressure on those machines with the constant-pressure spring.

***Continuous brush-to-ring contact**:* When a collector ring and its brushes are not in continuous contact, arcing results. Once arcing becomes visible, operating performance deteriorates rapidly. Thus arcing should be recognized immediately as a warning of impending serious trouble. Loss of continuous contact is caused by excessive brush vibration, which can be cured only by re-conditioning the collector-ring surface – assuming, of course, that the excursion of the shaft itself, due to unbalance, is acceptable.

Collector outages are usually caused by one of two reasons:

1. Planned outage to resurface the collector, or
2. Forced outage due to collector flashover.

The term flashover describes the opening of the highly inductive generator field circuit at either one or both collector polarities. Typical consequence of a flashover is shown in Figure 2-43.

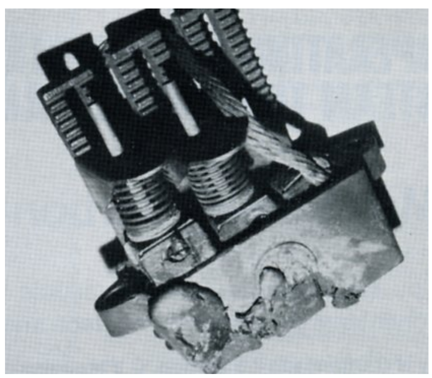


Figure 2-43. Burned brush holders due to flashover. Note short brushes and extended pigtail.

Breakdown of the insulation separating the two polarities, which are at different but low electrical potentials, is a rare occurrence. The open circuit is the result of a progressive loss of contact between the ring and brushes, which causes the current to be transferred by arcing across the gap until the gap becomes too large for the arc to be sustained. This action is similar to very slowly opening a knife switch in an inductive circuit.

To compensate for the energy lost during the heavy arcing prior to flashover, the automatic voltage regulator simply calls for higher exciter output to keep the generator terminal voltage constant. This action can be identified indirectly by the presence of erratic and generally higher-than-normal temperature indications on the generator field temperature recorder. Thus, erratic behavior of the generator-field temperature recorder is an indicator of possible collector malfunction, and plant operating personnel should immediately check for brush arcing.

Malfunction of the collector, and possible impending failure, is affected by several conditions:

***Surface-film contamination**:* Contaminants in the cooling air – such as oil vapor, ammonia, hydrogen sulfide, abrasive dust, insects, vapors from silicone rubber, etc. – have a detrimental effect on the formation of a good, stable film on the collector rings. The film, which consists of layers of metal oxide, graphite, and adsorbed water vapor, lubricates the contact surface. Without this lubrication, brush friction increases drastically, resulting in excessive wear, chatter, and brush breakage. Figure 2-44.

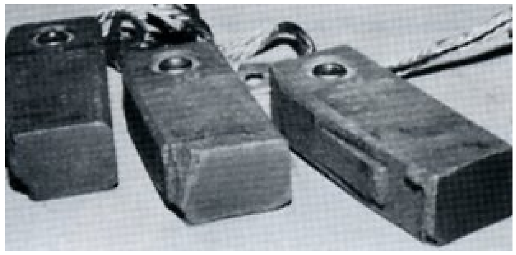


Figure 2-44. Chipped and ridged brushes

Contamination problems are often hard to pin down. Film quality is not easily discernible by looking at a collector ring, and there is often more than one possible cause of any observable symptom.

Particle contaminants usually can be removed by proper filtration, or by sealing air intake leaks around pipes and bus work. To avoid blockage of air flow as the filters become loaded, impingement filters may be specified. This type of filter will pass dirt along with the air as the filter becomes saturated with particulate matter; it does not plug and cause overheating. Regardless of the type of filter, care must be focused on the filters to assure that proper cleanliness is accomplished.

The importance of good filter maintenance is obvious from Figure 2-45, which shows two adjustable-pressure brush holders that have been damaged by oil and dirt contamination.

Figure 2-45. Burned brush holders caused by heavy contamination with oil and dirt.

Gaseous contaminants – such as oil vapor from bearings and pipe joints – should be eliminated at their source. However, gaseous contaminants from sources external to the power plant – such as a nearby chemical plant – generally cannot be eliminated, and thus more careful maintenance practices may be required. Residue of common cleaning solvents left on the rings is itself a serious contaminant.

Ventilation: High-capacity collectors are cooled by forced convection, typically with ventilating air pumped by shaft-mounted fans. Proper ventilation is important for preventing overheating, which can result from blocked passages in intake or exit ducts, from plugged ventilation holes in the collector rings themselves, or from plugged filters. The initial effect of overheating usually is increased brush wear, but high wear rates can lead to other, more-serious problems.

Incorrect current loading: Brushes tend to perform poorly if current in each brush is not within an acceptable range. Experience has shown optimum performance is generally obtained with current density in the range of 40 to 60 amperes per square inch of brush cross-section. (Brush manufacturers tend to have different recommendations relating to amperes per square inch.)

Mixing or misuse of brush grades: The performance of an individual brush on a collector depends heavily on brush properties. Tight quality control is maintained by the brush manufacturers to keep properties of each brush grade within a very narrow band. Despite such efforts, even brushes of the same grade will not necessarily share current equally, that is, they may exhibit some selectivity. Mixing of brush grades on the same ring can lead to intolerable selectivity, which may burn off a brush pigtail and make that brush inactive. The remaining active brushes, therefore, will overload, and a runaway condition may start. This condition can lead to collector flashover.

The original brush grades recommended by the turbine-generator manufacturer normally will be satisfactory. If difficulties are experienced, however, the OEM should he contacted before switching brush grades. When a new grade is installed, it is important to clean the ring surface down to the bare metal in order to let the new brush grade form its own characteristic film.

Brush contact pressure*:* Failure to maintain correct spring pressure has been a frequent cause of collector flashover. Proper pressure is required not only to keep the brushes in contact with the ring, but also to keep all brushes carrying a near-equal share of the current.

Brush hang-up: Brushes can hang up (see Figure 2-43 & Figure 2-46) in the holders for various reasons, including:

- A mixture of contaminants and carbon may build up, restricting free motion of the brush.
- Brushes may have worn too short, so the pigtail rubs against the box.
- Brush holders and brushes may not match.
- “Brush chatter”.

Figure 2-46. Carbon build-up inside brush box. (Cutsworth Products/Services)

The most common of the causes of brush hang-up is brush chatter, a term that describes tangential brush vibration. Brush chatter is caused by high or non-uniform friction around the ring periphery – which, in turn, is usually caused by ring contamination. If the brush does not ride smoothly on the ring, and chatter results, the top edge of the holder can wear a ridge in the side of the brush.

The brush may then sit on the ridge and not respond to spring pressure. Thus, the brush becomes unloaded electrically. If enough brushes hang up, arcing will start, and may eventually result in flashover. Short brushes are another major cause of flashovers. When brushes reach the end of their useful wear length, they must he replaced.

Continuous brush-to-ring contact: Excessive collector vibration can result in brush bounce, arcing, and ultimately on several specific brushes. Assuming unchanged generator balance, brush vibration can be expected to increase slowly over a long period of time, due to collector-ring wear. Generally, a series of peaks and valleys are formed around the periphery of the ring, Figure 2-47 also ring contour may vary from brush track to brush track.

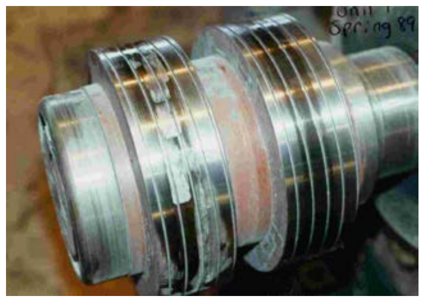


Figure 2-47. Patterning of brush wear on collector.

If brush vibration is allowed to increase to high levels, at some point the brushes will no longer be able to maintain contact with the ring around the entire periphery, and brushes will start bouncing and arcing. Under such conditions, arc erosion of the ring surface quickly deepens existing valleys. From this point, brush vibration will increase much more rapidly with time, which will result in brush chipping and breaking, and ultimately, a flashover if it is not corrected. (See Figure 2-43.)

There is no characteristic level of brush vibration that signals the start of brush bounce, because the outward radial *force* on the brush depends on brush mass and acceleration, not displacement. Fairly high radial displacements – that is, those due to shaft unbalance – can be tolerated on 50/60-Hz equipment. But if peaks and valleys have developed in the ring periphery, higher vibration frequencies will result and consequently higher forces on the brush. Since acceleration is proportional to the square of the frequency, these forces may become quite high.

It is generally accepted that, for 3000/3600-rpm generator collectors, brush-vibration magnitudes of less than 6 mils will give acceptable operating conditions. Severe problems usually begin to occur soon after vibration-caused displacements increase beyond about 10 to 15 mils.

2.2.8 Auxiliary and Excitation Systems Design Failure Mechanisms

Depending on generator design, several auxiliary systems accompany generators: lubrication oil, hydrogen seal, hydrogen or air cooling water, and stator winding cooling water.

The variety and specialty of components and systems preclude discussion of design detail in a text on general generator maintenance principles.

3. Chapter 3 - Operation

3.1 General

Ideally a generator would operate with few load cycles and always within the parameters recommended by the equipment designers. Since these ideal conditions are neither possible nor practical, it is worthwhile to consider the effects on generator reliability and length of life of common operating practices, i.e., load cycling, start-stops, temperature control, over-loading, off-line turning gear, off-line stationary, cleanliness and contamination, unbalanced armature load current.

In addition, mis-operation and malfunction will have a determining influence, e.g., cooling water leaks, oil entry, loss of cooling, synchronizing errors, sudden short circuit events, loss of lubrication, over-speed, loss of excitation, over-fluxing incidents, auxiliary system failures, alarm failure or mis-interpretation.

These effects on reliability and length of life from normal operation, mis-operation and malfunction will be considered below.

3.2 Operating Problems and Concerns

3.2.1 Load Cycling

All generator components are adversely affected in various ways by cyclic loading. Increased maintenance and shortening of life will lead to:

- Armature bar groundwall and internal insulation mechanical deterioration and migration
- Core looseness and punching migration
- Stator wedging systems loosening
- Stator bar end winding support system degradation
- Field copper cracking, foreshortening, lengthening
- Field turn insulation and slot liner mechanical deterioration and migration.

3.2.2 Loss of Cooling

This is a potentially serious condition. Partial loss of cooling may cause no damage, if load is appropriately reduced. However, the extreme of total cooling loss can destroy the stator and field insulation systems, if allowed to persist. This condition may also cause internal paints to blister, therefore requiring removal. (On water cooled stator windings, insufficient water flow to an armature bar can quickly boil the water in that bar and thereby stop water flow; the immediate result will be gross overheating of the bar. Destructive fracture of the bar insulation will occur on both ends of the bar at the first radius outside the slot.)

3.2.3 Temperature Control

Adverse effect of operation above recommended temperature values will primarily influence life of the insulation systems, although field copper mechanical properties will fall off rapidly with elevated temperature. Operating substantially below recommended temperatures can adversely affect critical properties of the metallic components.

3.2.4 Over-loading

Because over-loading even by modest amounts substantially influences reliability and life, designers continue to emphasize the importance of operating within specified design limits. In particular, the reactive capability curve limits should be maintained (Figure 3-1). Differential expansions of armature bars and field copper will increase, with accompanying increased mechanical deterioration rates. Also, over-temperature conditions will tend to exist and will impact life of insulating materials.

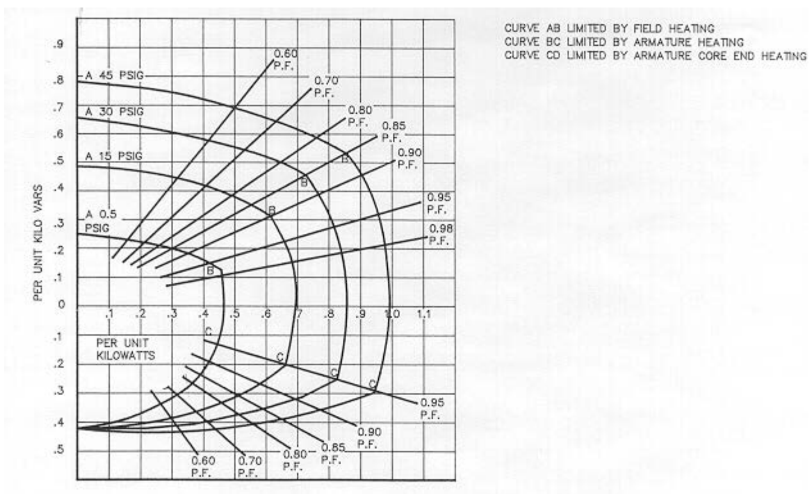


Figure 3-1. Typical Capability Curve

3.2.5 Start/Stops

In addition to temperature cycling, start/stop operation mechanically cycles all components of the field. This includes wedges, collectors, retaining rings, fan rings, and field forging. Shrink fit locations are also cycled. Non-body mounted retaining rings go through a heavy flexing of the field copper at the inboard end of the rings. Generally speaking, generators do not like shutdowns.

3.2.6 Turning Gear Operation

On those units with rotation speed sufficiently high for centrifugal force to overcome gravity, above about 50 rpm, impact of turning gear rotation should be minor if proper bearing lubrication is maintained.

Low-speed turning gear operation allows field coils and blocking to continually shift with rotation. This is the root cause of the “copper dust” phenomenon. Otherwise, low speed turning gear should not affect reliability if bearing lubrication is maintained properly.

3.2.7 Off-line Stationary

Provided that internal humidity is properly controlled so as to avoid insulation troubles and metallic component corrosion, deterioration should be negligible. On outdoor units, water-containing components (including water-cooled stator bars) must be kept above freezing temperatures.

3.2.8 Cleanliness and Contamination

Buildup of contaminants is a serious deterioration mechanism. Contamination can be fatal to insulation systems, particularly field insulation, but also stator windings, if severe. Conductive contaminates are a major problem to both fields and stators. Contamination is a particular concern in the event of oil leaks. Figure 3-2 shows a severely contaminated field forging after removal of the field winding.

Figure 3-2. Contamination Build-up in Ventilation Circuit of Air-Cooled Generator with Inadequately Maintained Filtered Open Ventilation System

3.2.9 Unbalanced Armature Load Current & Asynchronous Operation

Unbalanced armature current produces what is called “negative sequence current”. These currents cause field body current at an apparent frequency of 100/120 Hz at rated speed. Asynchronous operation, including closure of the generator load breaker with field at stand-still, also causes field body current which can be very high. If sufficiently high, effect will be damaging to the field in a very short time, Figure 3-3, and can cause destructive field component failure, Figure 2-32.

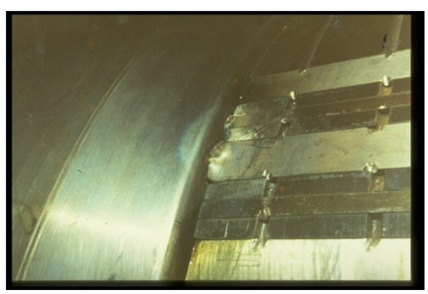


Figure 3-3. Field Heating Resulting From Asynchronous Operation

If a generator at standstill is placed across the line single phase, there is no rotating torque, but induced body currents will be huge and will tend to destroy the field, probably in a few seconds. If placed across line three phase, body currents are again huge, but also there is huge rotational torque. On large generators, by the time roughly one-third of rated speed is reached the field may have shed parts, e.g., aluminum slot wedges .The abrupt stop will destroy the complete rotating chain, turbine and generator, and there will be exposure to severe plant damage and the likelihood of personnel injury and death. Smaller generators may reach slip-frequency speed without shedding parts but damage from body currents is likely to be severe.

3.2.10 Sudden Short Circuit Events

These events can be among the most destructive to a generator, particularly larger generators. If the fault is within the generator, or close to the generator on the low side of the transformer, conditions are particularly severe. Armature current can break armature bars, deform bars in the end windings, throw bars out of the stator slot (Figure 2-13), crush gas cooled bar ventilation tubes (Figure 2-14), and generally harm a generator.

System faults and synchronizing errors are accompanied by high torque on the field, which is transferred into the turbine. In the process, the couplings may slip, bolts may be deformed, shafts broken, and the turbine severely damaged.

Fortunately because of the high reliability of isolated phase buss, close-in faults are uncommon on large machines. Also short circuit is most likely to occur due to flashover near peak armature voltage; this will limit current to about one-half the theoretical maximum obtained if a short circuit were to occur at the instant of zero armature voltage on the AC voltage cycle. Because force is a function of the square of current, force would be limited to one-fourth of theoretical maximum. But even so, the forces can be very high, on the order of 100 times normal operational force.

3.2.11 Synchronizing Errors

Mis-synchronizing has similar impact to sudden short-circuit fault. If the angle of error is small, a few degrees, damage is unlikely. If the error is high, approaching 180 degrees, the effect on the armature winding is that of a severe sudden short circuit. Since closure can occur at the instant of zero voltage on the AC voltage wave, maximum possible forces can be applied. The result would probably cause damage to the armature winding with any type of end winding support structure. Synchronizing near 120 degrees error places the maximum possible torque on the turbine-generator shafts, and can be expected to slip couplings and cause damage to rotating components.

3.2.12 Loss of Excitation

Excitation loss while carrying load will result in asynchronous operation; unit speed will increase a few percent to a point where current will automatically flow in the field forging sufficient to cause the generator to operate as an asynchronous machine. The generator will continue to deliver to the power grid whatever power the turbine is producing. If allowed to persist, severe and destructive damage may occur to the field in a matter of moments.

Reclosure of the field will cause the generator to pull back in step as the field builds back up over a period of a few seconds. This will place some additional duty of the armature winding; however, this may be preferable to a continuation of asynchronous operation if the steam valves cannot be closed and the machine shut down.

3.2.13 Over-fluxing Incidents

This condition is most likely to occur while disconnected from the system. (If the stator is connected to a grid, excess field will result in high vars output, i.e., high lag power factor.)

Under non-synchronized conditions, excess field current will cause magnetic circuit saturation. Exciters are capable of output of more than 3 times the necessary field current for rated no-load stator voltage. A field current value of 1.5 times no-load field current will typically give about 1.20 times rated armature voltage. On an unsynchronized generator, this field current will cause significant stator magnetic circuit saturation. This, in turn, will drive significant flux beyond the outside diameter of the core, and will also increase duty from core end leakage flux. If the condition is prolonged, core iron damage can be expected. Values of field current for varying load conditions are provided by manufacturers on the “V-curve”, Figure 3-4.

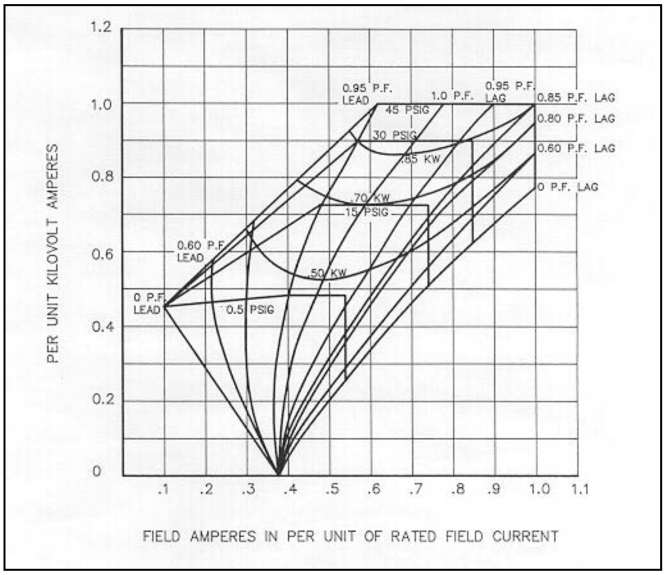


Figure 3-4. Typical Generator V-Curve

The condition of maximum exciter current output to an unsynchronized generator can be expected to destroy the stator core, probably in a matter of several seconds, Figure 3-5. Core iron burning will be particularly severe at the core ends and at the keybars. Tooth burning is likely to cause stator-winding failure, with additional core burning and contamination damage.

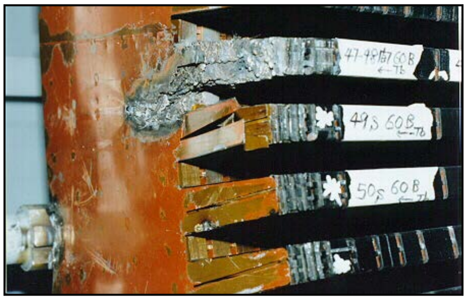


Figure 3-5. Core Damage Resulting from Over-fluxing

3.2.14 Cooling Water Leaks

Serious water leaks can cause insulation failure. Slow cooler leaks may result in deposit of residue on the stator winding. This water, in conjunction with cooler tube soldering lead, can result in formation of lead carbonate, a hazardous material. The deposit in Figure 3-6 has the appearance of lead carbonate.

Figure 3-6. Foreign Material on Stator Winding from Cooler Leak

If the field uses 18/5 retaining ring material, a slow persistent leak can cause stress-corrosion catastrophic fracture of a ring in a period of only a few months.

3.2.15 Loss of Lubrication

This is one of the most serious of turbine-generator malfunctions. If loss is partial and is immediately corrected, little or no damage may result. However, if the machine comes down without oil, severe bearing and turbine rotating component damage will occur. Oil fire is likely, Figure 3-7, and if the machine is hydrogen cooled, hydrogen fire (detonation) can be expected.

Several redundancies are incorporated into lubrication oil systems, but failures of this type still periodically occur. Furthermore, the severe vibration is likely to fracture bearing oil supply lines. Due to the several back-ups provided to assure lubricating oil supply to the bearings under all conditions, the system will tend to pump the oil tank dry into the resulting fire.

Extensive equipment and plant damage can be expected in the event of complete loss of lubrication oil.

3.2.16 Oil Entry

Oil ingress, if allowed to persist, can adversely affect stator wedging systems, deteriorate some insulation materials, and increase collection of other contaminants in unwanted locations. In large amounts, oil can plug gas ventilation passages in gas cooled high voltage bushings and elsewhere. However, oil ingress in modest amounts is ordinarily not significantly damaging to most generators.

3.2.17 Overspeed

Excessive overspeed can destroy a turbine-generator, Figure 3-7. Even if fracture does not occur, components may yield and stretch to a point where replacement is required.

Figure 3-7. Broken Turbine Control Standard after Severe Vibration and Fire

3.2.18 Collector and Brush Holder Rigging

Carbon-brush collectors have historically been an operations/maintenance concern on turbine-generators. This is understandable in that this relatively small generator component is one of the most frequent causes of generator forced outages. The primary root cause of collector service problems is the failure to perform the on-going daily inspection recommended by the OEMs. While this inspection and the associated maintenance effort are relatively minor, it is sometimes overlooked or done inadequately. Performance of the daily inspection and the needed maintenance should result in identifying and correcting collector operating conditions before any serious problems can develop. This in turn will greatly reduce or eliminate exposure to carbon-brush collector service problems.

One of the primary reasons for inadequate attention to the collector and brushes is the concern for safety issues associated with handing energized components – brushes typically operate at 125 to 500 Vdc. There is the legitimate concern with possible hazards to personnel and equipment due to need to adjust and replace brushes while the generator is operating. Even with field voltage removed, the brushes may still be energized to about 125 Vdc by the field ground detection circuit. Larger machines usually have insulated magazine brush holders that allow brush maintenance without contact with the collector voltage; smaller machines usually do not. Fortunately retrofit removable brush holder retrofits are available to replace individual fixed brush holders. At least one design is available which is essentially a drop-in replacement, and the retrofit can be accomplished at modest cost during a one-day outage.

The preventative maintenance check list, below, can be used as a guide in reviewing plant collector inspection/maintenance practices to assure that optimum collector maintenance is being accomplished.

Daily Inspections:

- Inspect for sparking between brush and rings.
- Listen for brush chatter.
- On brush holders without constant pressure springs, check that pressure is still within acceptable range.
- Look for loose, frayed, or blue pigtails.
- Check for dust or oil.
- Look for short brushes.
- Check for any instability or increase in indicated field temperature recorder readings.
- Watch for any changes from previous conditions.

- *Any abnormalities should be immediately reported to responsible plant maintenance and/or management personnel.*

Weekly Inspections:

- On brush holders without constant pressure springs, adjust brush-spring pressures so they are all within proper range.
- Remove a brush at random, and examine its wear face for evidence of pitting, edge chipping, grooving, or threading.
- Check all brushes for hang-up in the brush holder.
- Examine brush springs and pigtail connections.
- Spot-check for vibration, and record and plot the levels on long-term chart.
- Observe brushes and pig-tails with infrared scope.
- Observe collector rings with stroboscope.
- Replace worn and/or deficient brushes, removing one brush (or magazine) at a time.
- Note the appearance of collector ring surfaces and of the brush films on the rings for any change from normal.
- Inspect air filters. Replace or clean as necessary.
- *Conditions should be recorded and timely correction of deficiencies should be accomplished.*

3.2.19 Auxiliaries

The pumping units, valves, and piping associated with the auxiliaries tend to be a source of constant minor maintenance. However, the auxiliaries generally are not a major problem if given proper on-going maintenance.

Alarm conditions, such as high levels and low pressures, should be immediately addressed since if left unattended may lead to a serious forced outage. Conditions of particular concern include low oil pressures, high gas flow from the stator cooling water or hydrogen seal systems, and liquid accumulation in the detectors.

3.2.20 Alarms

Instrumentation monitoring the status of the generator from the control room is limited in quantity, with few backups, sometimes ambiguous information, and infrequent alarm conditions. As a result, mis-interpretation, misunderstanding or procrastination in response to alarm conditions occasionally occurs, with serious consequences.

For example, failure to respond to one or two RTDs or TCs reading high temperature on a liquid cooled stator winding can result in winding double-failure to ground with extensive arc damage. Core monitor alarm may be false or indicative of beginning stages of fatal burning of insulation. Sudden increase in vibration may be minor or the beginning stages of catastrophic failure. High cooling gas temperature may be a bad sensor or a generator in the process of severe overheating. A field ground alarm may be of little consequence or preliminary stages of forging burning or a double ground problem.

Most power plants now incorporate a Distributed Control System (DCS). Correct response(s) to each of the various generator alarms should be programmed into the DCS.

4. Chapter 4 – Generator Failures and Root Cause Diagnostics

4.1 General

Generators can fail in a remarkable number of different ways. Section 4.2 will discuss many of the more common failure modes and summarize the mechanisms behind these failures.

But in order to perform an efficient and correct repair, the root cause of the failure must be known. Root-cause diagnostics is an order of magnitude more complex than performing the actual repair of the component, and identifying a correct root-cause has become a major problem in the industry, particularly during the last 30 years. Generator maintenance specialists from OEMs and from the independent generator repair companies are trained to be proficient in a specific assignment – *inspecting, testing and repairing* of generators. Typically these specialists do not have the technical background or experience to perform diagnosis of the root cause of a failure where the cause is not common or well known. Nor have they been educated for such diagnostics. As a result, mis-diagnosis has often occurred and these errors in diagnosis have resulted in major (and sometime unnecessary) expenditures for incorrect, insufficient and unsuccessful repairs.

The information in Section 4.3, below, will illustrate many typical failures, and will discuss the difficulties in root-cause analysis of each specific failure. Suggestions will be provided for obtaining necessary technical assistance to better assure accurate assessment of root cause. Better understanding of the difficulties of obtaining accurate generator diagnostics, and approaches for overcoming these difficulties, can greatly reduce maintenance costs and improve generator reliability.

4.2 Specific Problem Areas

4.2.1 Stator windings

4.2.1.1 Foreign Material and Unconfined or Loose Components

Foreign material and unconfined or loose components have been a major cause of forced outages. Sources are numerous: over-looked repair tools, objects lost from pockets, inadequately locked bolts, magnetic materials picked up by the rotor's residual magnetic field, loose field and stator end winding blocking, small pieces of broken core laminations.

If trapped in one location, even small magnetic steel chips and pieces of core lamination may wear deeply into and fail groundwall insulation.

4.2.1.2 Stator Bar Slot Vibration

Vibration of stator bars in the slot has been a serious concern throughout the history of the power generation industry and remains so today. It continues to cause forced outages and large repair costs. On some generators with wedging systems not properly assembled, bar vibration has developed into vibration sparking (Section 4.2.1.5) and insulation mechanical impact damage. Both of these mechanisms can result in service failure in only a few months of operation. Larger, high force generators tend to use more sophisticated wedging systems, but vibration may still occur from loosening wedges and clearance under stator bars. If vibration damping systems are used, i.e., side ripple springs, damage is likely to be from insulation wear rather than impact, Figure 2-10.

Bar vibration is a particular concern since it is an accelerating problem and will get progressively worse on a generator if not identified and corrected.

4.2.1.3 End Winding Bar Vibration

End winding vibration is also a ubiquitous problem that has been a major concern. Early, string-tied end winding support systems were not capable of supporting end windings of large stators, either against normal load or sudden short circuits. Reliability of the newer support systems is greatly improved, but periodic retying, re-tightening and re-bonding may still be required. Again, if not identified and corrected, the problem will get progressively worse, Figure 4-1.

Figure 4-1. Stator End Winding Vibration

4.2.1.4 Electrical Damage

Partial discharge (PD) is a widespread phenomenon. On hydrogen cooled windings, PD activity in the end windings is likely to result only in superficial surface deposits. On air-cooled generators, some penetration of the insulation groundwall has been reported, but probably only if there are conditions that distort the voltage field, such as an RTD cable laying on or near a bar at some distance from the core.

In general, PD problems in the slot will result from inadequate slot grounding paints, e.g., original resistance too high, unstable paint subject to loss of properties at operating temperatures, degradation of a deficient paint with time and temperature, insertion of a non-conductive layer of material between the grounding paint and the mica insulation. The paint may also be severely degraded by wear or by vibration sparking. PD will correlate with the location of the bar in the phase belt, with attack occurring only on the bars in the higher voltage locations, about the top one-half of the phase – never on low voltage bars.

If deterioration is observed with the appearance of PD damage, but is occurring randomly and on the neutral and other low voltage bars, *it is not partial discharge*. If in the slot, it is likely to be vibration sparking (see below). If random discoloration is observed in the endwindings, it is likely to be tape layer delamination, or some other anomaly in appearance which is not necessarily a concern. Again, if the phenomenon is occurring on the neutral and other low voltage bars, *it is not partial discharge.*

Both PD and vibration sparking damage are a concern, but damage from vibration sparking, while not common, tends to be *much more* aggressive.

The conditions leading to PD activity have been studied for 50+ years on power generation equipment, and are well understood. But two other deterioration mechanisms are not well understood: *vibration sparking* and *slot discharge*. Theories have been postulated for each of these phenomenon, and both require that the bar be sufficient loose in the slot to allow the bar to vibrate a few mils in relation to the core iron:

1. *Vibration Sparking* (Spark Erosion). Current flowing in slot grounding paint collects into a significant magnitude due to: a) low resistance of the slot grounding paint, b) inadequate occurrence of bar-to-core contact, and c) vertical and/or side vibration of the bar against the core iron. (Voltage generated on the bar copper – *and* in the grounding paint – is roughly 50 volts per foot of core length on higher rated generators.) Because of the bar vibration, a make-break condition exists at twice power frequency rate. The energy of the associated sparking erodes the groundwall insulation. This erosion can be widespread and deep, can grow rather rapidly, and is random around the winding (unrelated to the voltage on the bar copper).
2. *Slot Discharge.* Capacitive electrical energy is delivered across the stator bar ground insulation to the grounding paint, where the associated current collects and is delivered across a vibrating contact to the core. This condition focuses on the higher voltage bars.

Neither of these explanations is intuitively completely satisfying. But the problems exist nevertheless, and vibration sparking can be much more destructive to stator bar insulation than is partial discharge.

4.2.1.5 Shorted Turns

When shorts occur between turns on a multi-turn coil, the shorted turn begins to circulate current within the shorted turn. The amount of current will be high if the short resistance becomes low; this condition will rapidly overheat the coil. Fortunately turn shorts are infrequent as winding failure is likely to result in a very short time, Figure 4-2.

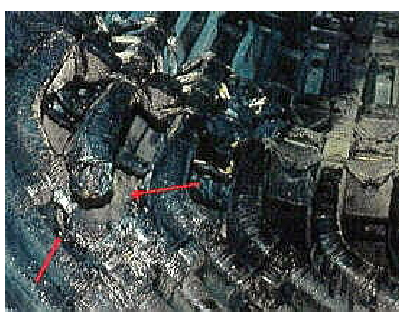


Figure 4-2. Typical Failure from a Shorted Turn – Immediately Outside the Core in the First Radius.

It is not a practical possibility to test a finished winding for turn shorts.

4.2.1.6 Broken Connections

Some large direct-cooled generators are designed with multi-group bars where individual groups of strands carry the current in parallel with the remaining groups. For parasitic loss reasons, these individual groups are continuous (and isolated from each other) through the entire phase belt. Typically there will be 6, 7 or 8 coils in the phase belt, i.e., 36, 42 or 48 slots in the stator core of a 2-pole generator. On a double-tube stack winding (a 4-wire wide bar) with 42 slots, there may be (4 x 42/6 = 28) groups. If the strands in one of these groups crack and the group becomes open-circuited, the remaining 27 groups will carry the current, and the increase of heating will be low, i.e., about 4%, Figure 4-3a. (When a parallel group breaks, an arc will continue to carry the current until extinguished. Once extinguished the arc will not re-strike, as the voltage across the open circuit is not the turn voltage (perhaps 1500 volts) but only the voltage resulting from the reactance of the turn - in the order of 15 volts).

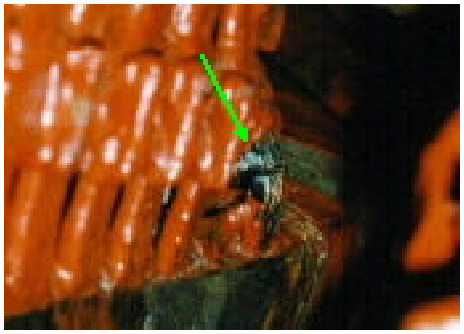


Figure 4-3a. Broken Group in Series Connection of 4-Wire Double Tube Stack Winding.

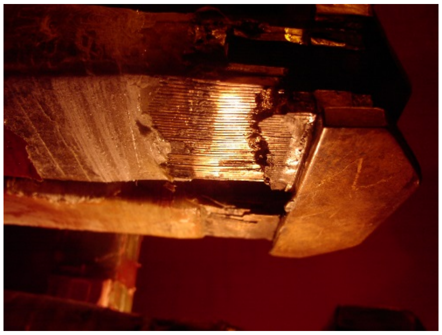


Figure 4-3b. Broken Side of a Series Connection in a 2-Parallel Circuit Winding.

Some smaller direct gas-cooled generators are designed with 2 parallel circuits within the ground insulation; in these designs the 2 circuits are isolated from each other through the entire phase belt. In the event one of the 2 circuits fails and burns open, all the current will be carried by the remaining circuit, Figure 4-3b. This condition is easily identified as the temperature rise will double in that circuit.

4.2.1.7 Water Leaks

Water leaks are a frequent cause of outages and winding maintenance. Broken or cracked piping and fittings periodically occur, sometimes with serious consequences. Cooler tube leaks are not infrequent.

Stator bar strand header leaks on liquid cooled stator windings have been a significant concern. The industry has generally closely followed the OEM recommendations for inspection and test of these windings. As a result, while hipot failure of these windings has occasionally occurred, in-service failure has been rare. However, this problem continues to be a major maintenance item on the classes of machines involved.

4.2.1.8 Contamination

Stator windings will always be subject to surface contamination problems, particularly air-cooled units, Figure 4-4. But hydrogen cooled units are also subject to contamination from vibration wear products, oil, and ambient dust. Particularly on fields, the contamination can result in low megger readings, failure of electrical creepage paths, blocked ventilation flow passages, and field rewind. Stators are more likely to just need cleaning to remove the contamination.

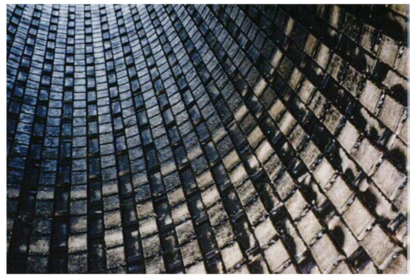


Figure 4-4. Air Cooled Stator Heavily Contaminated with Dirt, Oil and Water

On water-cooled windings, failures have occurred due to internal contamination of the liquid circuit. For example, on one unit, a small piece of gasket material cut off flow to a top and bottom bar, causing the 2 bars to grossly overheat and expand axially about one-half inch; both bars fractured at each end of the core. The resultant burning and arcing severely contaminated the entire stator winding, field and frame.

On early direct oil-cooled stators, magnetic “termites” in the oil drilled holes completely through the copper strands and also insulation. (These “termites” were pin-head sized magnetic steel chips, which passed within the armature bar strands to the oil exit end of the core. At this point, the termite was captured by the magnetic field, and remained in place in the oil to spin, cut, and wear through the copper and insulation. This phenomenon has not been reported on water-cooled windings, probably because the extremely small size permits oxidation and destruction of the termite before serious damage can be done.)

4.2.1.9 Tape Migration

Tape migration has been confined to asphalt stator insulation systems. Figure 4-5a is a 1940s-1950s vintage 40+MW unit and Figure 4-5b is a 1980s vintage 16 MW generator – with a coil winding. Many of the older vulnerable stators have been rewound or retired; problems on remaining older machines is becoming small since migration decelerates with time, and the remaining vulnerable units are becoming rather old, 55+ years in age. Only a few of the coil windings were made, but these appear to be quite susceptible to severe migration and insulation failure.

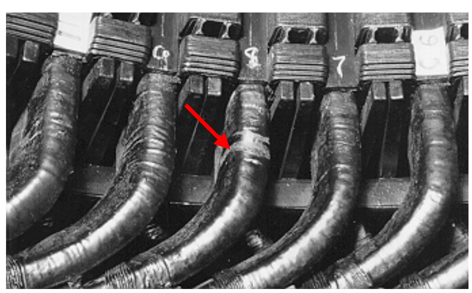


Figure 4-5a. Tape Migration Girth Crack on Long-Service Asphalt Stator Winding

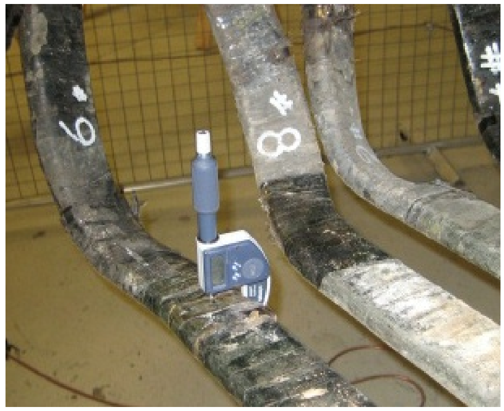


Figure 4-5b. Tape migration on a newer smaller generator.

4.2.2 Stator Core

4.2.2.1 Foreign Material

As with stator windings, foreign objects are a major concern. Metallic materials in the air gap, particularly those that are larger and magnetic, can cause damage sufficient to require extensive repair, or re-stacking the core and replacing of the stator winding. Even relatively small objects can result in core damage, Figure 4-6.

Figure 4-6. Core Damage from Small Object Impact

4.2.2.2 Damage to Core During Winding Repair

Damage to the core often occurs during winding repairs, particularly during winding removal. This type of damage is usually minor in nature and in the form of small chisel cuts or tool impact. When damage is properly repaired, it is unlikely to cause operating problems.

4.2.2.3 Core Looseness

Looseness is not a frequent cause of forced outage, but routine re-tightening is common on large generators. If local or general looseness is allowed to persist, significant damage can and does occur to the core and the stator winding.

4.2.2.4 Lamination Insulation Breakdown

Spontaneous lamination insulation breakdown is an uncommon occurrence. However, a core with a weak or deficient lamination insulation system is vulnerable to complete failure in the event of relatively minor damage from a foreign material or core looseness incident, Figure 4-7. Also, a retightened core may be more likely to fail due to lamination insulation wear that occurred while the core was operated in a loose condition.

Figure 4-7. Complete Core Melt-down due to Lamination Insulation Failure.

4.2.2.5 Assembly/Disassembly of Field

Occasionally a field is lifted into the top bore of the stator core, or allowed to settle directly onto the bottom bore. The protruding retaining rings are the most likely location of contact to the stator winding. Resulting damage to the core can be serious and armature bars have been fractured during such an incident. Figure 4-8.

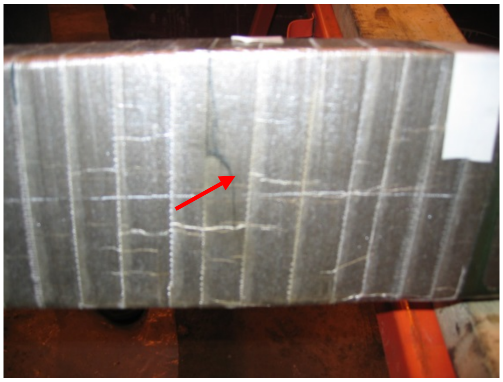


Figure 4-8 Fractured bar due to contact of bar by the rotor retaining rings just beyond end of core.

4.2.2.6 Over-fluxing

Fortunately, over-fluxing is an uncommon failure, because damage can occur quickly, can be extensive and severe, and may require a new core and stator winding, Figure 4-9.

Figure 4-9. Severe Core Burning from Over-flux Incident

4.2.2.7 Component Failure

Structural failures have occasionally occurred, for example keybar fracture or breaking of welds between keybars and frame. The former will allow the core to loosen and may cause a forced outage. The latter is likely to result in increased noise level.

On older 2-pole generators, looseness often developed between keybars and core-iron dovetails. The resultant vibration noise caused great concern, and “belly bands” were added to clamp the keybars tightly against the core, Figure 2-42. These bands are relatively light in cross-section, perhaps ½” by 3”, and may loosen with time and require re-tightening. On newer generators, heavy bands may be added to detune cores which are experiencing resonance at near operating frequency.

4.2.3 Stator Frames and Mechanical

4.2.3.1 Vibration

Noise levels of some frames have been high due to vibrating contact between components, and/or other causes. Outages have resulted for the purpose of identifying the problem(s) and taking any necessary corrective actions, which may be very difficult establish and perform.

4.2.3.2 Component Failure

Extensive breaking of the internal structure has occurred on a few generators where the core vibration was not sufficiently isolated from the frame, and/or where the frame components did not contain sufficiently generous radii. Also frame failure may result on a frame that is tuned to near resonant conditions.

4.2.3.3 Ventilation

Occasionally machines have been designed with stagnant cooling gas locations or other ventilation deficiencies. This condition can result in severe overheating and failure of a generator winding, Figure 4-10.

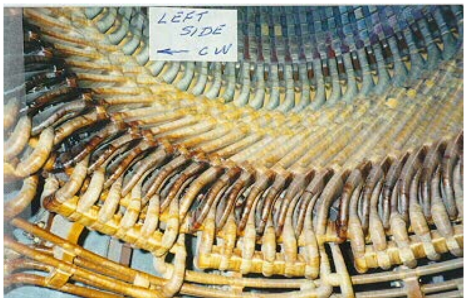


Figure 4-10. Stator Winding Failure from Inadequate Ventilation Design

4.2.4 Fields

4.2.4.1 Retaining Rings

Retaining rings have failed in service several times in recent history. Destruction has been extensive: oil and hydrogen fire damage, new stator winding, partial or complete core re-stacking, new field, and often major plant damage, Figure 4-11. Fortunately loss of life has been rare.

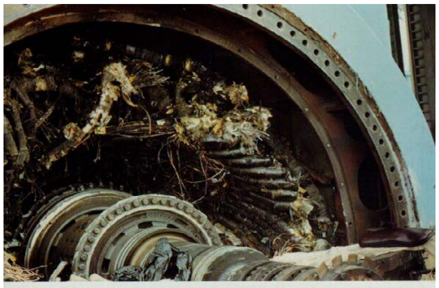


Figure 4-11. Generator Damage from Failure of Retaining Ring

4.2.4.2 Field Winding Turn Insulation

Perhaps the most common failure mode on field windings is turn shorts. These shorts can cause thermal and/or magnetic field unbalance, with accompanying mechanical vibration. Also, excessive field current may be required.

Shifting turn or creepage block insulation has also disturbed ventilation gas flow symmetry and has resulted in thermally induced mechanical vibration. This condition can cause sufficiently high vibration that the generator must be shut down for repair.

4.2.4.3 Ground Insulation

Field grounds are a common cause of outages. Ground insulation can fail due to contamination of creepage surfaces, fractures, migration, burn damage from coil-to-coil shorts, and from broken field turns, Figure 4-12. Failures under the retaining rings are the more common location, but grounds may also occur in the slot.

Figure 4-12. Broken Field Slot Top Creepage Block

4.2.4.4 Turn Breaks

When a turn breaks, the current is not immediately interrupted. An arc will develop to allow the current to connect to the next adjacent turn or to flow between the broken halves, Figure 4-13. In either case, current will continue to flow through the arc; the conditions are similar to an electrical welder arc. Intense heat will be generated, the slot or retaining ring insulation will be destroyed, and the winding will go to ground. If field current is not removed, arcing will continue, and has been known to burn deep into a retaining ring or along the inside of a slot for as far as 5’, Figure 4-14.

Figure 4-13. Arc Damage to Copper Conductors from Broken Top Turn

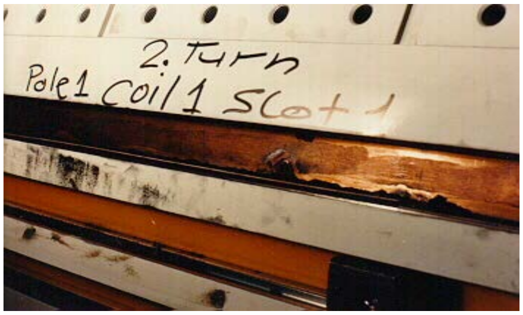


Figure 4-14. Ground Current Damage to Copper Turn and Field Forging from Broken Top Turn

Breaks are most likely to occur at coil inter-connections or at changes of copper cross-section, and some manufactures will change copper cross-section several times in each single turn.

Retaining rings that are not body mounted are also a common cause of turn breaks, Figure 4-14. Manufacturers have had standard procedures in place for many years to alleviate, but not eliminate this condition.

4.2.4.5 Turn/Coil Distortion

Because copper has a relatively low yield strength, and the mechanical stresses can be high, turn and coil distortion may occur, Figure 4-15. Minor cases may result only in turn shorts. Major coil distortion may short out entire coils, and can result in serious magnetic and electrical problems, including arcing to ground. Also coil distortion can cause high mechanical unbalance due to a lower portion of the coil foreshortening sufficiently to throw turns out from under the upper portion of the coil.

Figure 4-15. Field Winding Turn Distortion

A few machines have used aluminum alloy conductors. These windings have given reasonably good service, but are difficult to repair because of the specialized welding processes required.

4.2.4.6 Thermal Sensitivity

Thermal sensitivity is a common problem, which often results in load curtailment or early shutdown for correction. If the vibration levels are not unreasonably high, it may be possible through careful balancing to compensate the vector to where the machine can operate without restriction. This will require thorough knowledge of the behavior of the thermal vector. In order to know the vector behavior pattern, measurements must be made of vibration *magnitude and angle* as a function of field current magnitude. Field current is changed by making selected load and power factor swings.

Finally, before shutting down to attempt repair, it is essential that the thermal vibration vector magnitude and angle be clearly understood, as this information may assist in locating the source of the thermal vector. Refer to Chapter 2, Section 2.2.3.10.

4.2.4.7 Copper Dust

Copper dust (small copper particles) has been generated by field copper inter-turn abrasion during turning gear operation. The problem apparently has largely been confined to a few classes of large machines, and most have been corrected.

4.2.4.8 Collector Connections

Because the components are difficult to examine, and because mechanical duty on the copper can be high, failure of collector connections is fairly common, Figure 4-16. Failure tends to occur without warning and when failure does occur, repair tends to be difficult and time-consuming.

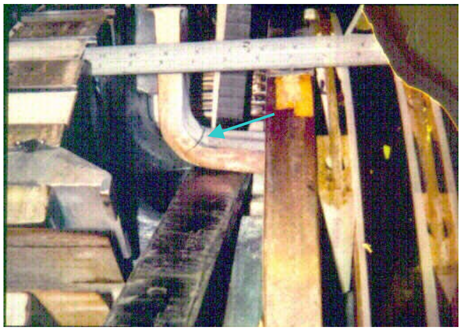


Figure 4-16. Cracked Collector Connections Main Lead (Green Arrow.)

4.2.4.9 Collectors and Brush Holder Rigging

Collectors and brush holder rigging can have a long reliable life, but require routine inspection and maintenance, Figure 4-17 . Fortunately this effort is generally of a minor nature. But if not properly maintained, collectors are a major cause of forced outage. Minor sparking may be tolerable for a short time, but significant sparking will require shut-down, if other corrective actions are not effective. If proper attention is not given these components, flashover will occur and the result will be an immediate forced outage.

Figure 4-17. Contaminated and Rusted Collector

4.2.4.10 Rotating Rectifiers

If properly maintained, rotating rectifiers tend to be reliable. Excess failure of diodes may require an outage. There have been cases of thrown components, but support ring bursts have been rare.

4.2.5 Other

4.2.5.1 Gas Leaks

The hydrogen shaft seals can be difficult to assemble and maintain. As a result, seal problems are probably the most common cause of outage due to gas leakage. But occasionally frame or piping leaks may also require shut-down and repair. Failure of the end shield joint seals, either by hydrogen leakage out of the generator or seal oil leakage into the generator, is also a cause of outage.

Air cooled generators are a lesser problem, but if a closed system design is not maintained adequately tight to air leakage, heavy induction of contaminants may cause a costly outage for internal cleaning and correction of leakage, Figure 4-4. Also, oil leakage into the generator has occurred on some air-cooled designs, particularly if not well maintained.

4.2.5.2 Bearing Failures

All generators, excepting the very small, use journal bearings, and these bearings are remarkably rugged and reliable if not seriously abused. Foreign material induction or loss/restriction of oil flow will result in damage that may force the unit from service. Figure 4-18.

Figure 4-18. Heavily Scored Bearing

Minor conditions may result only in vibration problems or early shut-down. The worst case scenario is that of total loss of oil flow, and the result will be catastrophic, Figure 3-7.

4.2.5.3 Coolers

Cooler leaks are not an uncommon cause of outages. Also, if cooling water quality is poor, plugging of tubes may progress to where shut-down is required, although on some designs, coolers can be cleaned with the generator on-line. Minor leaks, if not corrected, may simply deposit foreign material on the winding, Figure 4-19. Stator or field windings may develop low resistance to ground, with resulting forced outage. Catastrophic retaining ring failure may also occur, Figure 4-20.

Figure 4-19. Foreign Material Deposit on End Winding from Cooler Leak

Figure 4-20. Section of Retaining Ring which Failed in Service Due to Stress Corrosion Cracking

4.2.5.4 Shaft Current

Bearing damage due to shaft currents is common, but it is unusual for shaft current to cause an outage.

4.2.5.5 Asynchronous Operation

Asynchronous operation, if allowed to persist, will require a forced outage for possibly major repairs to the field. Also there is the danger of forging failure with catastrophic results.

4.2.5.6 Mis-operation

Numerous forms of mis-operation have caused immediate and major forced outages.

4.2.6 Trends

4.2.6.1 Existing Problems

Most of the problems discussed previously have existed for many years, some from the infancy of power generation. These problems can be expected to persist, although some are resolved with time as machines wear out and are retired, or as the problem is corrected on the affected machines.

But since the fleet is aging, outage problems can be expected to become worse with time.

4.2.6.2 Newer Problems

A few problems are of more recent vintage: stator bar end-of-slot vibration, water leaks in liquid cooled generator stator bar strand headers, frame vibration. Others no doubt exist or will develop.

Further, as equipment variety increases and the demands on operators increase, operations errors can be expected to persist. But the problem of operator error will be considerably alleviated by the effective application of the enormous capability of the Distributed Control Systems.

4.2.7 OEM Support

It can be hoped that the adverse trends for OEM support beginning about 1980 have stabilized and are reversing. But the cost pressures placed on the OEMs by the industry will make it difficult for the OEM situation to significantly improve. Growing strength of independent service providers may partially compensate, but these service providers will continue to have only a very limited number of engineers capable of root cause diagnostics. Users may be left more dependent upon their own resources (and good judgment) at a time when users are also experiencing heavy budgetary constraints.

4.3 Root Cause Diagnostics

4.3.1 Root Cause Analysis Challenges

Historically diagnosis of new and complex generator failures was done by original equipment manufacturer (OEM) factory engineers. This was the case because accurate diagnosis can be significantly assisted by a technical education background and by generator engineering design experience. With the contractions in number of highly qualified OEM engineers, there are now available few OEM engineers with good diagnostics capability. Because personnel of this caliber are vital to other OEM efforts, obtaining their services at a power plant may be a challenge. Thus it has become increasingly difficult to obtain personnel that are capable of performing diagnostics.

But root-cause diagnosis of generator failures is a particularly challenging task. Specifically:

- Generators are complicated mechanically, and more particularly, the theory of the function of a generator is complex and understood by few people.
- While design and operation of most mechanical components of a power plant are somewhat “intuitively obvious” to a knowledgeable, intelligent person, there is little about a generator that is obvious to even the best of intuition.
- Generators can fail in many failure modes. OEM engineers sometime say: “We haven’t had this kind of failure before”. And you are rightfully skeptical. But in fact because there are so many ways a generator can fail, this comment may be quite accurate.
- Typically no one in a power plant knows much about the function of the generator. In a power plant there will be several operating and maintenance personnel that quite clearly understand the turbine (and most other plant mechanical components). These personnel often can assist greatly in determining why a component has failed. This is unlikely to be true of plant personnel with respect to the generator. Lack of knowledgeable plant personnel makes the difficulties faced by generator diagnostics personnel even more difficult.
- Finally, even with the best generator monitoring instrumentation, often the plant records will shed little light on the failure root cause. This problem is sometimes compounded by lack of retention of plant records which may have existed.

There are no easy answers to this dilemma. Pressure can be put on OEM management to make their indispensable engineers available to the plant. But for obvious reasons, this pressure may not always be successful. There are several independent maintenance companies, and some may have one or two individuals with the skill level the diagnostics requires. There are many independent generator consultants, and again, some will have the skill level required for a specific failure root cause investigation.

Guidance to generator owner personnel can perhaps be summarized as follows:

1. Be certain that the generator monitoring equipment is state-of-the-art and kept in good operating condition.

2. Record and retain monitoring equipment information.
3. Use your own good judgment to assess that the diagnostics information you are receiving from an individual who has come on-site appears to be plausible.
4. Bring in additional support *early* if you are not completely comfortable with the diagnostics information you are receiving.

Mis-diagnosis of the root cause of generator failures can be exceptionally costly. Five typical diagnosis errors observed in recent years are summarized below. The direct repair cost associated with these incidents ranged from a few hundred-thousand dollars to many millions of dollars.

- "Ring-of-fire" stator winding failure on a 900 MW water-cooled winding was initially incorrectly charged to the piping arrangements within the connection ring cooling circuits. Whereas the actual problem was associated with a cost reduction that placed high voltage bushing cooling water flow in series with connection ring piping. Had the correct root-cause not been identified by further consultation, repeat of the massive stator winding failure would have been inevitable on this and its duplicate generator. Figure 4-21.

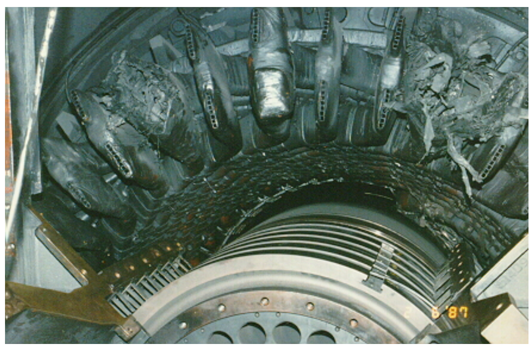


Figure 4-21. Similar failure on a direct hydrogen-cooled winding.

- Stator winding failure on a 200 MW stator incorrectly charged to "lightening". Corrective action taken was based on this wrong diagnosis, i.e., line-to-line phase connection with very small clearance was reinsulated with non-mica insulation. The unit failed again several months later at the same location for the same cause – partial discharge. (Remember: "Lightening never strikes twice in the same place".) Figure 4-22.

Figure 4-22. Failed non-mica connection insulation.

- On a 250 MW generator, contamination of a core end-package was judged to be from minor stator bar vibration and no corrective action was taken. The root problem was actually local core looseness, and the stator winding failed to ground a few weeks after return to service. Figure 4-23.

Figure 4-23. Similar loose core laminations.

- Core discoloration over-looked at location of stator winding failure, combined with deficient ElCid test-this 80 MW stator was rewound without correcting the core-iron condition. New replacement winding failed in service a few hours after return to service. Photos Figure 4-24a&b.

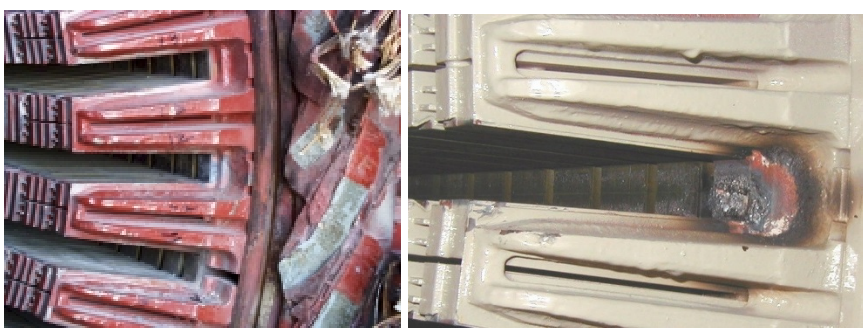


Figure 4-24a&b. Before and after condition of the same location on core.

- Asphalt stator winding incorrectly diagnosed as having rapid migration of the groundwall. The recommendation of an OEM generator specialist and an independent non-engineer generator specialist was to perform an immediate stator rewind on this 200 MW machine. Both said in their reports: rewind or "be exposed to catastrophic service failure". A 3rd consultant was old enough to intimately know this insulation system, and pointed out that in fact migration had long-ago ceased. The stator passed recommended 1.5E hipot and was returned to service of 60 hours/year. Rewind would require field removal in a laboratory situation of extremely dangerous conditions. Figure 4-25.

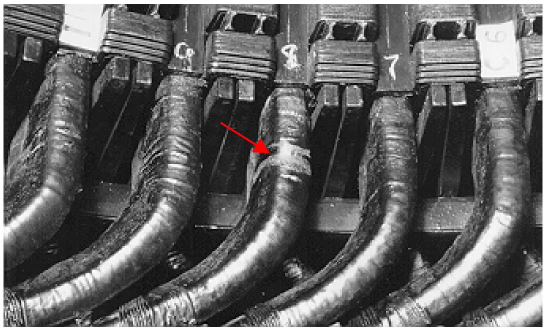


Figure 4-25. Inconsequential tape migration indication.

These 5 root cause diagnostic errors are not untypical of root cause investigations and illustrate the challenge to owners of obtaining reliable root cause diagnostics.

4.3.2 Root Cause Analysis - Stators

4.3.2.1 Stator Winding Failures – Endwindings and Connections

Stator winding failures are one of the most frequent causes of generator forced outages. Windings fail in numerous ways, and some are considered below.

Endwinding Looseness: Local or general vibration distress is often seen on large generators. Vibration problems occasionally are associated with the whole endwinding, Figure 4-26, but more commonly involve only a local area, Figure 4-27. In either case, it is important to understand and correct the root cause. This may not necessarily be simple, as there are several possibilities, e.g., lack of bonding, insufficient ties and blocks, resonances, loosening due to short circuit forces. Incorrect or inadequate repairs have often been made due to lack of understanding the root cause, or for cost-saving reasons.

Figure 4-26. White dust generation due to general endwinding looseness

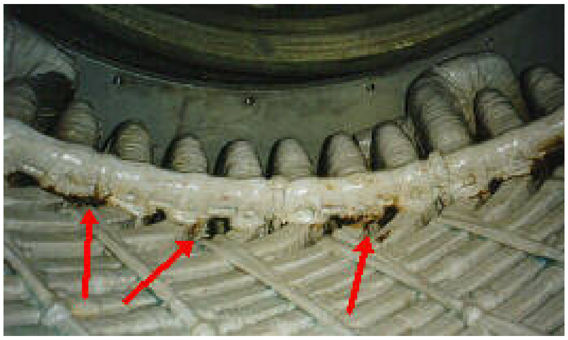


Figure 4-27. Local "greasing" due to debonding of high mechanical duty components

Electrical Connection Failure: Because there are so many connections in a stator winding, exposure to connection failure is significant. Several examples of failures are shown below. The failure in Figure 4-28 probably resulted from local resonance, and due to the extent of burning, confirming a root cause may not be possible. But after repair of the connection ring, natural frequency must be confirmed to not be near operating frequencies. A "ring-of-fire" failure is shown in Figure 4-29. This type failure may result from several causes, e.g., inadequate electrical connection, local resonance, phase-to-phase electrical failure. The electrical burning will have hidden much if not all of the evidence of root cause.

Figure 4-28. Burned connection ring. Note missing 10" of burned away lead.

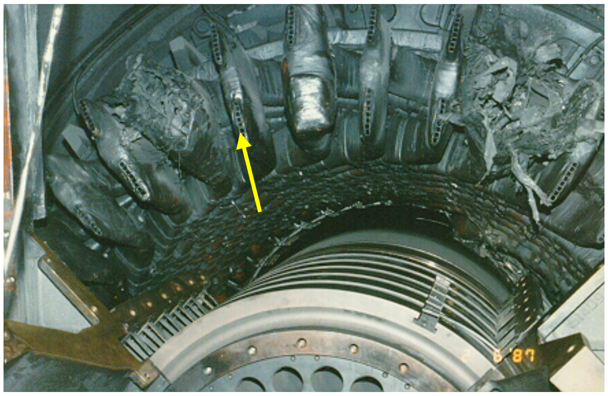


Figure 4-29. Failed electrical joint. Missing several inches of conductor

Figure 4-30 shows one section broken on a seven-parallel-circuit series connection. Because the current in the interrupted circuit is readily carried by the remaining 27 circuits, arc damage is minor. Root cause is well known – vibration of the joint. Corrective options are not all equally reliable. Figure 4-31 shows the broken half of a series connection. When this type connection breaks, current is transferred to the other half of the bar, doubling the temperature rise of the bar, but not causing significant arc damage. Again, the evidence of root cause remains, and is well identified – vibration resulting from omitted series connection blocking.

Figure 4-30. Broken braze on one seventh of a top-to-bottom bar connection

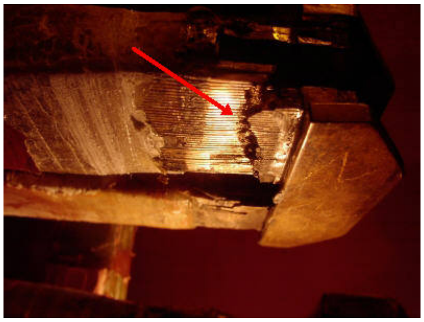


Figure 4-31. Broken series connection

The most common root cause of these types of connection failure is local resonances, although general endwinding resonance may also occur. Root cause analysis can be aided by testing the failed winding for natural frequencies; the overall natural frequencies may not have been significantly affected by the failure. Running frequency resonances tend to be associated with insufficient blocking and tying, and occasionally from OEM omission of blocks and ties for cost reduction reasons. Bump testing of the winding should be able to identify resonant frequencies, keeping in mind that natural frequencies will be lower when the winding is hot from operation. Also review of operating experience on duplicate generators or generators of similar design may be instructive.

Foreign Object Damage: Most commonly if there is foreign object damage, the evidence will be visible. Figure 4-32 is typical of what might be seen in the event of a foreign object lodged between the layers of bars in an endwinding. (However, in this particular case, the root cause was a chisel cut through the insulation of each of two adjacent top bars.) Locating an actual foreign object may be difficult as the object may be small and hidden in the endwinding. Also the object may have been burned up in the arc of the failure, or otherwise not able to be located.

Figure 4-32. Arc damage from a short circuit between adjacent bars in an endwinding

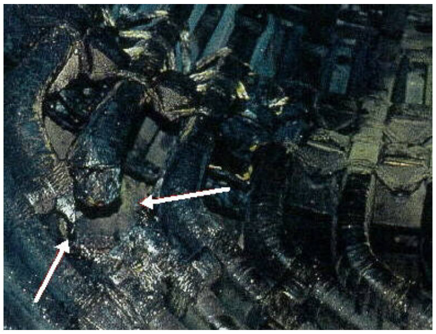


Figure 4-33. Severe short arc damage in an endwinding

Arc damage in the winding just outside the core in the first radius, as seen in Figure 4-33, may completely eliminate all possibility of determining root cause. Three most probable root causes are (in descending order of likelihood): 1) strand or turn shorts in one of the involved armature bars, 2) fractured strands in a bar, and 3), a foreign object. But in all probability, the root cause may not be identifiable.

Foreign object damage may also result from generator components becoming loose, and lodging in vulnerable locations. In Figure 4-34 a loose stator winding component has worn completely through the insulation on a connection ring during only a few weeks of operation; fortunately the ring was at neutral voltage and winding failure did not occur.

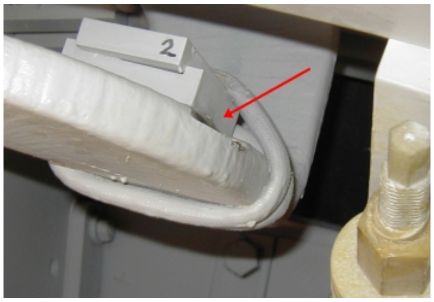


Figure 4-34. Bare copper exposed on a connection ring

4.3.2.2 Stator Winding Failures – Slot Portion

Slot Bar Vibration: This is a common phenomenon on older machines with inadequate wedging, and on large direct-cooled generators. The primary diagnostic questions are: 1) assessment of severity of the vibration, and 2), establishing the root cause of the vibration. Unfortunately, the root cause may not be obvious. Widespread indications throughout the entire core are likely related to general winding looseness. If indications are only at the ends of the core, root cause is almost certainly not inadequate wedging, but rather bars held off the slot bottom by the endwinding support. See Figure 4-35.

Figure 4-35. Severe bar vibration only at the ends of the core

Figure 4-36. Wedge vibration on hydrogen-cooled generator

If the condition is red oxide on the wedges and iron, the most likely root cause of the indications is simply individual wedges vibrating, not bar vibration. See Figure 4-36. It is important to distinguish whether the bars are vibrating or just the wedges are vibrating. Correct diagnosis is critical, since bar vibration is always a serious concern, whereas wedge vibration is not.

Vibration Sparking (VS): It can be difficult to distinguish between the damage appearance of partial discharge (PD) and vibration sparking. But it is vital that the actual root cause be identified. PD is a slow deterioration mechanism; vibration sparking is a fast mechanism. If vibration sparking is occurring, indications of sparking may be seen at the ends of the slots, and through the ducts on machines with radial ventilation ducts, Figure 4-37 & Figure 4-38.

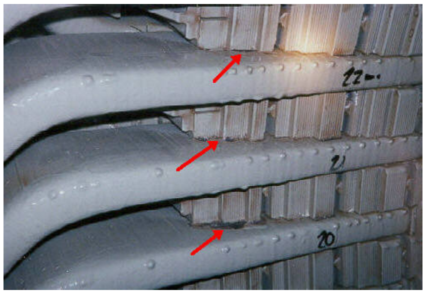


Figure 4-37. Indications of vibration sparking on the edges of bars of global VPI winding

Figure 4-38. Vibration sparking viewed by borescope on non-VPI winding

The sparking damage indications may be similar in appearance to PD indications, but will be different in pattern from the indications of PD, shown in the following section. (PD will ***always*** correlate with location of the bar in the phase belt, i.e., always on only those bars in the top perhaps 1/3rd of the phase belt voltages. VS can be anywhere in the phase belt, high- or low-voltage bars.) Assessment of the extent of damage from this relatively fast-acting phenomenon cannot be made short of hipot test. But even though a winding has passed a significant over-voltage test, assurance for an extended period of operation cannot be assured. Basically, OEM recommendations should be followed with respect to frequency of test, inspection and repair.

4.3.2.3 Partial Discharge (PD)

Partial Discharge – Endwindings: PD indications may be widespread in the slot and endwindings. Figure 4-39. Windings of the type shown in these four photographs, (Y-connected, 2-circuit, 2-pole) have 3 locations of phase-to-phase voltage break in the endwinding. Figure 4-40.

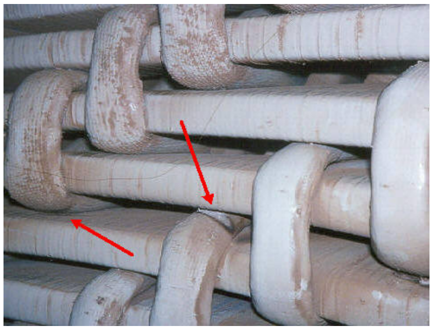


Figure 4-39. PD at the close proximity of a bar tie at a line-to-line phase break

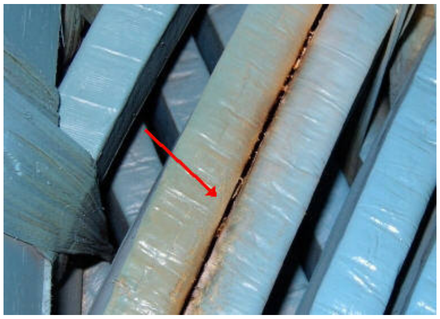


Figure 4-40. Heavy PD indications at a line-to-line phase break

Figure 4-41 & Figure 4-42 are at two of the three line-to-line phase breaks on the same generator. In this winding failure, the initial assessment by an independent "expert" was that the root cause was a lightning strike. This, of course, was incorrect. The root cause was clearly PD in the presence of non-mica insulation.

Figure 4-41. Failed connection after removing insulation

Figure 4-42. PD at a non-failed phase connection location

However, root causes of endwinding PD will more generally be:

1) inadequate endwinding grading paint/tape application,
2) inadequate physical spacing, and/or
3) inadequate connection of the endwinding grading paint to the slot grounding paint. Unless service failure has actually occurred, which is unlikely, assessment of extent of groundwall insulation damage will be difficult, short of hipot test.

Partial Discharge – Slots: Manifestation of PD in the slot portion of the winding is somewhat different from the endwindings. Two examples are shown in Figure 4-43 & Figure 4-44.

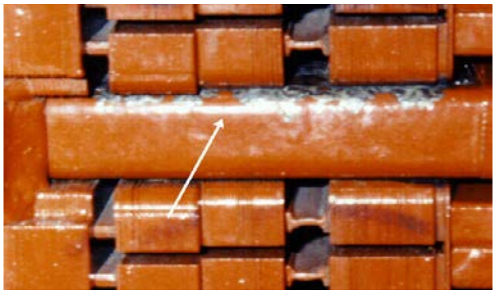


Figure 4-43. PD damage activity on a bar surface

Figure 4-44. Wedges burned away by severe PD on a stator bar

In Figure 4-43, the PD activity can be seen beyond the wedging, and in Figure 4-44, PD is destroying the wedges. In neither case can an accurate assessment of root cause be made, although most certainly the semi-conducting paints/tapes are inadequate in both cases.

4.3.2.4 Strand Header Leaks

This problem on water-cooled stator windings has been an ongoing concern. Diagnostic tests are available to assess for water contamination of the insulation, i.e., capacitance test and wet insulation detector. If the insulation is confirmed to be wet (which should be done with utmost care and with field removed), almost certainly the root cause will be leaking in the braze between the strands in the electrical clip, Figure 4-45.

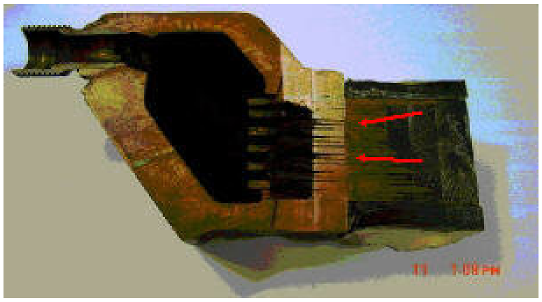


Figure 4-45. Strand header leaks on a bar clip

4.3.2.5 Tape Migration

This is an old (and poorly understood) problem, currently associated only with asphalt insulation systems, See Figure 4-5a. The problem is confined to very old generators from a single OEM.

There is little that can or needs to be done with respect to controlling future migration, as the nature of the insulation system is for the winding to become much less prone to migration as the unit ages. Many of these units are still in service, and with the technical expertise currently available, obtaining an accurate assessment of winding condition by inspection alone is virtually impossible. Hipot is probably the only assessment tool now available to the industry.

4.3.2.6 Contamination

General contamination can be seen at a glance, thus locating the contamination presents no diagnostics challenge, Figure 4-46.

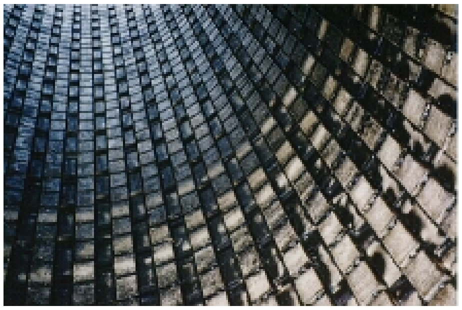


Figure 4-46. Heavily contaminated stator

Common contaminants are water, oil, outside ambient dirt (even on non-air-cooled generators), internal dust from inadequate cleaning or from wearing parts. The actual source and impact of contamination may be difficult to ascertain, and thus may involve a diagnostics challenge. But if the generator has failed due to contamination, and the source of the contamination can be identified, the corrective options will usually be apparent.

4.3.2.7 Stator Core Failures

Cores can fail in numerous ways, and often the root cause is difficult if not impossible to establish. Because repairs resulting from core failure can be so extensive and costly, understanding and correcting of the root cause is particularly important. Thus in the event of core damage or failure, priority should be given to obtaining qualified, skilled assistance in attempting root-cause analysis. Some examples of core failure follow.

Core Looseness: If a core is loose, it *should* be readily apparent. On a loose core, normally there will be dust generation at area(s) of looseness. The simple effort of carefully inserting a knife into the core at a suspect location will confirm local or general looseness of a core, Figure 4-47. But if the inspector simply assumes that the dust on the core seen in Figure 4-48 is resulting from bar and/or wedge vibration, the looseness may be overlooked. Such a case recently occurred, and the mis-diagnostics resulted in winding failure a few weeks after the unit was returned to service.

Figure 4-47. Knife check of local core looseness

Figure 4-48. Grease generation from either bar vibration or core looseness

Local Core Over-Heating: Manifestations of core overheating come in various ways, e.g., local hot spot, bands of discoloration, local burned spots, and massive melt-down. The example shown in Figure 4-49 appears relatively minor, and appears to have been caused by physical damage to the punchings. The damage seen in Figure 4-50 appears to have resulted in lamination insulation failure, and would be a much greater concern.

Figure 4-49. Local core lamination burning, probably due to minor core damage

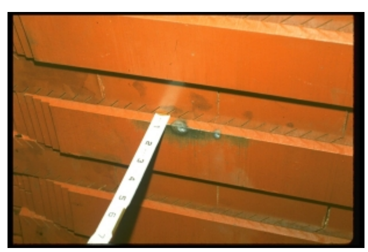


Figure 4-50. Broad heating pattern, probably from lamination insulation failure

Small damage locations of these two photographs can be easily overlooked unless the core inspection is thorough. Often it will not be possible to determine the cause of such damage, although the two most likely causes are: 1) a minor nick due to workman error or small foreign object, or 2), core lamination insulation breakdown. The former is normally inconsequential, but the latter raises a serious concern as to core integrity. Determining root cause, therefore, is vital, and yet may be difficult if not impossible, even with the best of expert assistance.

General Core Melting: Occasionally there will be massive core melt-down with large amounts of molten metal deposited in the endwinding and/or elsewhere. See Figure 4-51.

Figure 4-51. Melted core iron deposited in the stator endwinding

In this event root cause may be impossible to establish, i.e., the extent of melting damage may be so great that the evidence of the root cause has been destroyed. Possible root causes that may be speculated include: core looseness, sparse (unusually thin) lamination insulation, through-bolt insulation failure, major foreign object damage. The susceptibility to general, "spontaneous" core failure appears to be OEM selective.

Over-Flux Damage: This is an uncommon failure mode, but when it does occur, damage may not be obvious to the casual observer until the stator winding is removed. See Figure 4-52. However, damage may be extensive, and repair costs high, i.e., a new stator core and stator winding, and possibly extensive field and frame cleaning. The root cause is operation with excessively high field current while the generator is ***off-line***. In the particular case of these two photographs, the unit ran several months after the incident before extensive core melting caused the stator winding to fail. See Figure 4-53.

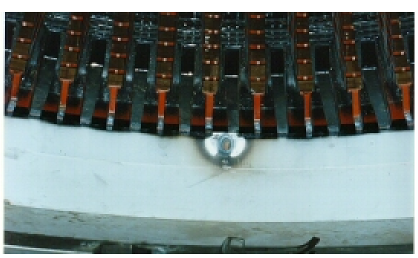


Figure 4-52. Evidence of core melting seen only by careful examination prior to winding removal

Figure 4-53. Extensive damage seen after partial disassembly of core

The rate of damage during an over-flux incident would normally be so great that failure would be expected concurrent with the over-flux incident. This type failure may not be recognized by a non-expert as resulting from an over-flux incident.

4.3.3 Root Cause Diagnostics – Fields

4.3.3.1 Windings

Grounds*:* Field windings may have low or zero resistance to ground from several causes. e.g., general contamination, localized contamination, broken turns, arcing between coils. Usually the actual ground location is easily found. But determining the root cause of the problem initiating the ground can be very difficult. Several examples are shown in the subsequent photographs, with likely root cause indicated. See Figure 4-54 through Figure 4-55.

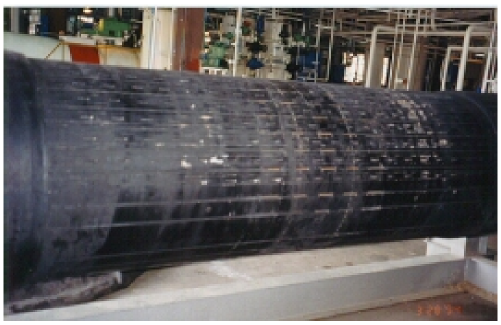


Figure 4-54. General contamination. Root cause: Defective shaft oil seals and inadequate filter maintenance

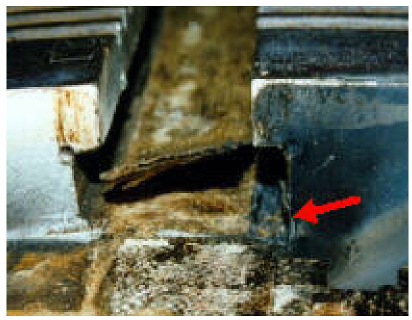


Figure 4-55. Forging burn due to double field winding ground. Root cause: old, worn-out insulation

Open Circuit: Open circuited windings are not common, and distinguishing between the possible root causes may be difficult. Typical contributors include: start-stop operation, cyclic loading, inadequate blocking, incorrect copper hardness, and improper friction planes. Examples are shown in the subsequent photographs, with likely root causes. See Figure 4-56 through **Figure 4-58.** (In **Figure 4-58**, the open circuit is the least of the problem.)

Figure 4-56.Fractured turn. Root cause: Braze location, reduced copper area, stress risers.

Figure 4-57. Cracked top turn. Root cause: Non-body-mounted retaining ring.

Figure 4-58. Open-circuited field. Root cause: 18/5 retaining ring fracture.

4.3.3.2 Mechanical

Vibration: Diagnosis of vibration root cause is often difficult on generators. There are at least a dozen possible contributors, e.g., field copper bonded to slot liners, uneven end turn blocking, turn shorts, broken turns, cracked field forging, uneven ventilation in slot region or under retaining rings, displaced slot liners or turn insulation, uneven coefficients of friction, wedges fitted incorrectly, overlapping retaining ring insulation, turns bonded to slot liners, cocking/shifting retaining rings, shifting end turn blocks.

As a result of the numerous possible causes, and complexity of obtaining analytical information, establishing the root cause of field vibration is sometimes difficult or not possible. Thus, unfortunately, the root cause is sometimes mis-diagnosed, and incorrect actions are taken to alleviate the conditions.

Local Overheating: Root cause of localized hot areas on the field forging is flow of body current. The cause of this current flow is from one of two conditions: 1) excessively unbalanced armature currents, or 2), asynchronous operation. The latter can result from a broad spectrum of conditions ranging from across-the-line connection at stand-still, to minor mis-synchronizing errors, to loss of field current while continuing to carry light or heavy load. If plant records are of good quality, it should always be possible to identify root cause of forging burns. Figure 4-60 through Figure 4-62 show three increasingly severe examples of burning due to body current resulting from asynchronous currents.

Figure 4-59. Local wedge burns

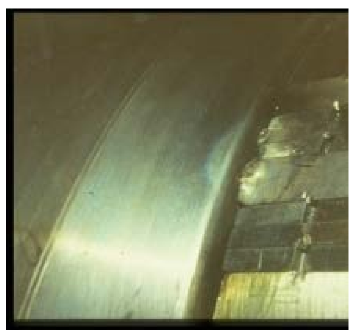


Figure 4-60. Severe wedge and retaining ring burning

Figure 4-61. Melted field and retaining ring forgings

Field Forging Cracking: There are four identified locations for cracks to appear on field forgings: 1) under the retaining ring shrink fit, 2) at the edges of the pole faces near the body centerline, 3) at ends of slot wedges near body centerline, and 4) at the inboard end of the journal. Root cause of these types of cracks seems generally well understood by the OEMs. Since field forging cracks involve serious personnel hazard and plant reliability concerns, it is important that vulnerable field designs be checked for cracks in accordance with OEM recommendations.

Retaining Rings: Cracking (and failure) of retaining rings bring the potential for forging failure, catastrophic plant damage, and safety hazard to personnel. It is important to follow OEM recommendations for care and inspection of retaining rings. The predominant issue of today continues to be the 18/5 retaining ring material. These rings can fail in a very short time (months or very few years) if exposed to significant moisture. Keep in mind that one of these 18/5 rings failed catastrophically only 18 months after both rings on the field were removed and passed full NDE tests. See Figure 4-20 and Figure 4-63.

Figure 4-62. Stator winding after retaining ring burst.
Note that the bars are still in the slots.
(The stator winding has not been removed.)

4.3.4 Conclusions – Root Cause Diagnostics

Restating the challenge to generator owners:

1. If possible, monitor the generator with state-of-the-art equipment.
2. Keep the monitoring equipment in good operating condition.
3. Be certain to record and retain all monitoring equipment information.
4. Try to assure yourself that the failure investigation is thorough, and that the diagnostics information you are receiving from on-site individuals is plausible and reasonable.
5. In the event that you are not completely comfortable with the diagnostics information you are receiving, bring in additional technical support, and do this *early*, before critical information is lost.
6. If you are unable to obtain *qualified* OEM diagnostics personnel, use other available sources to obtain necessary technical support.

5. Chapter 5 - On-Line Monitoring

5.1 General

5.1.1 Background

Generator stators and fields have historically been monitored by relatively unsophisticated instrumentation, reading various currents, voltages, temperatures, pressures, flows and vibration. In addition, instrumentation is included to monitor the external systems. In order to increase the likelihood of detecting developing deterioration, more advanced instrumentation has been added to some machines: core monitors, various partial discharge measurement systems, field turn short detectors, end winding vibration monitoring devices, and gas discharge rate monitors on liquid cooled stator windings.

Paralleling attempts to develop better instrumentation has been efforts to place the available information in a format that is more user-friendly to the plant operators. An early attempt in this direction is the relatively primitive computer "expert" systems, Figure 5-1.

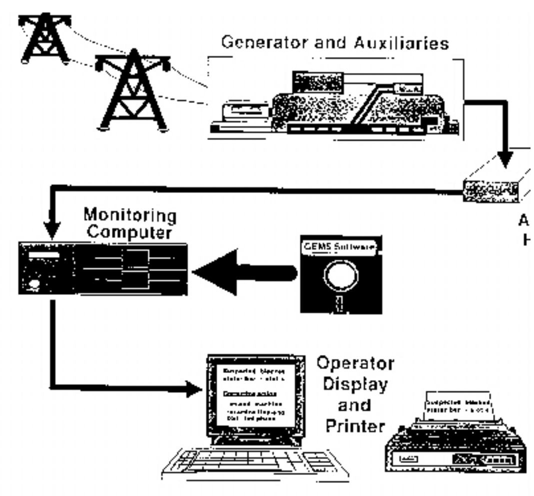


Figure 5-1. Schematic of a Very Early Generator Expert Monitoring System (General Electric)

Far more powerful are the more recently developed and installed Distributed Control Systems (DCS), Figure 5-2 & Figure 5-3. Most power plants now incorporate a DCS as the interface between the control room operator and the plant equipment. Correct response(s) to each of the various generator alarms should be programmed into the DCS. The DCS can be configured to display a checklist of appropriate actions in either a textual or flow-chart format in order to assist the operator in making a timely and logical response to the alarm. This can be particularly helpful on generator alarms since typically generator alarm situations occur infrequently. Furthermore, operators must rely on the less-than-perfect generator monitoring equipment and information, which makes the operator challenge even more difficult.

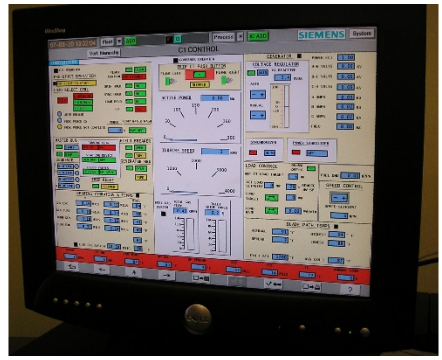


Figure 5-2 & Figure 5-3. Modern DCS Control System, Overall View on Left and Individual Panel on Right.

The necessity for better monitoring capability has also been accelerated by the trends toward Condition-Based Maintenance and Outage Interval Extension.

But regardless of the need for and efforts focused on developing better monitoring of generator condition, major monitoring problems remain. Even with most complete of available generator monitoring devices and systems, several of the more common and important modes of failure are not detected.

5.1.2 Monitoring Capabilities

The historic monitoring systems will commonly detect over-current, under-current, general over-temperature conditions, abnormal vibration, incorrect pressures, field ground, and phase unbalance, stator single ground, stator line-to-line fault.

With the better monitoring systems, additional protection may be gained against the presence of more subtle failure mechanisms. For example, slot discharge, some forms of stator bar vibration, field turn shorts, some forms of localized overheating, stator insulation delamination or cracks, stator over-flux, and some forms of series/phase joint deterioration.

5.1.3 Monitoring Limitations

Even the best of the monitoring devices and systems, however, remain with little or no detection capability for some of the more common and serious deterioration mechanisms, e.g., stator bar vibration without partial discharge or vibration sparking, stator bar clip water leaks, developing stator bar connection cracking, developing field turn cracks, retaining ring corrosion and cracking, and forging cracks. Unfortunately, equipment with the capability of detecting these problems does not appear to be forthcoming.

The most flexible of the newer monitoring capabilities is that of partial discharge measurement on stator windings. The various partial discharge systems can detect the presence of partial discharge, but have several individual and/or collective weaknesses: look primarily at the end portions of the winding, difficult to isolate real PD signals from noise, and may require laboratory-type equipment. The most important of the challenges in using PD measurement is the accurate interpretation of readings. Nevertheless, these systems can be valuable, and it is possible that ultimately on-line partial discharge will reach the capability of accurately and conveniently measuring and interpreting many forms of significant discharge within any portion of the stator winding.

5.1.4 Retrofit Practicality

The non-standard or newer devices can be added to the generator without undue cost, particularly during a major outage with field removed: field turn short detector, end winding vibration pick-ups, partial discharge detectors, liquid system hydrogen leakage monitor, and Generator Condition (Core) Monitor. Also, if the plant incorporates a DCS, and the system has not yet been programmed for maximum power in monitoring the available generator instrumentation, this should be done at the first opportunity.

5.2 Monitoring Equipment

5.2.1 General

Manufacturers have published standing recommendations on generator monitoring and protection against normal mis-operation conditions. These should have been reviewed in the initial design stages for the plant. It may be worthwhile to periodically review these recommendations to be certain they are applicable to present operating and maintenance requirements, and are compatible with present financial goals. See ANSI Standards C50.10 and C50.13.

These Standards and manufacturer documents may apply to the generator itself, or to the auxiliaries. Recommendations may be to either alarm or trip, depending on the likely consequences of the incident. Electrical devices include: stator overcurrent, stator ground fault, stator phase-to-phase fault, unbalanced armature currents, overvoltage, over-volts per hertz, voltage surges, field ground, and loss of excitation. Other devices include: bearing vibration, synchronizing errors, motoring, loss of synchronism, field overheating, low seal oil pressure, low stator winding cooling water flow, and high water conductivity.

Some of the measurement devices are considered in more detail below.

5.2.2 Mechanical

5.2.2.1 Field Vibration

Because fields are heavy, they must be finely balanced; otherwise acceptable levels of vibration cannot be maintained on the stationary components. In order to properly balance a field, levels of vibration associated with field rotation must be accurately measurable, both magnitude and angle of vibration. Experience has shown that this is more effectively accomplished by measurement of vibration directly on the field journals. Most larger generators incorporate shaft-riding or proximity vibration detectors. Retrofit of modern equipment can be accomplished on generator using the inertial devices.

5.2.2.2 Stator End Winding Vibration

Stator endwinding vibration has been a major deterioration concern on large turbine-generator windings for 50 years. The ongoing endwinding problems relate in part to the lack of a safe, convenient and reliable method for measuring vibration in the high voltages which exist everywhere in the endwindings

Only recently has there been instrumentation available to safely and accurately measure and transmit actual vibration magnitudes throughout the range of frequencies that are of interest in endwindings.

On larger generators, which are known to be subject to excessive stator end winding vibration, detectors can be installed. These devices can be readily added during a short outage.

Fiber optics accelerometers consist of an optical head and conditioning electronics connected by a fiber-optic cable. This cable provides immunity and safety from the high level of voltages that exist in an endwinding, i.e., line-to-neutral stator winding voltage rating. Figure 5-4.

Figure 5-4. Typical vibration pickup partially mounted on a stator winding connection. (Pickup courtesy of VibroSystM, Canada)

Because of the high costs associated with ongoing problems being experienced with endwinding vibration, the availability of these devices to the industry is extremely important. This equipment should be of great assistance to generator designers but also to personnel responsible for operating and maintaining large turbine generators. Because of the vital need for such capability, application of such devices should become wide-spread.

It is unlikely that application of endwinding vibration measuring equipment will become as universal as, for example, resistance temperature detectors. However, it can be expected that these devices will eventually become standard monitoring instrumentation on all large generators, as well as common on smaller generators.

5.2.2.3 Rotor Torsional Sub-synchronous Resonance

When connected to a power grid that has series capacitor compensation or high-voltage DC transmission, a turbine-generator may develop a torsional resonance condition. A fairly costly sensor and compensation system has been developed and may be required on some machines for reliable operation.

5.2.3 Electrical

5.2.3.1 Stator winding ground

All generators incorporate stator winding ground detection.

5.2.3.2 Shaft voltage

Because shaft voltages can be destructive, it may be desirable to add sensors to detect their presence. However, if a reliable insulation system has been applied to the proper bearings, and if good shaft grounding is maintained, the probability of damaging current-flow damage should be small.

5.2.3.3 Field ground

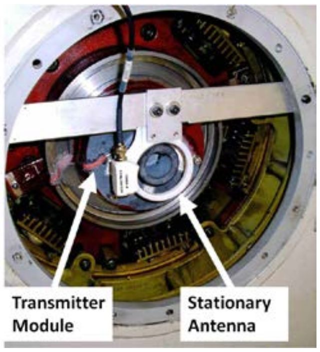
Because either single or double field ground conditions can be hazardous to equipment and personnel, manufacturers recommend that the unit be brought off-line in the event of field ground alarm. On a field known to be in poor condition, immediate trip may be advisable.

Because field grounds can result in such serious consequences, it is important to continuously monitor the field winding for ground faults. This is easily and uniformly done on brush/collector fields by simply applying a bias voltage on the field excitation circuit (which is designed to operate ungrounded); the resulting current flow into the field is monitored and initiates an alarm immediately if a ground appears. But on brushless excitation systems, there is no accessible connection point on the winding to attach such a monitoring system. Some brushless generators are designed with a small separate slip ring which is electrically connected to the winding. Periodically (daily or each shift) the associated brush is dropped down on the ring to detect whether or not a ground has developed. (Continuous brush-ring contact is not common because of problems associated with brush wear and contact resistance to an inactive ring.)

Non-continuous monitoring carries a hazard, since a ground which results from arcing between winding and forging can be immediately dangerous. This delay problem, as well as reliability problems with the monitoring ring, can now be easily overcome with wireless technology that has been developed in recent years. Wireless technology eliminates the contact problem and allows continuous monitoring for instantaneous detection of a field ground.

Wireless telemetry has advanced to the stage where robust, sophisticated systems are available for rotating rectifier rotors. Typically, these systems employ closely coupled rotating and stationary antenna structures to transmit data off the rotor and also pass sufficient radio frequency energy to the rotor to power the rotating electronics. Small electronic modules fabricated in a manner to withstand the high centrifugal forces are mounted on the rotor. These modules combine sensor and measurement signals and digitize them into high speed digital data streams for wireless transmission off the rotor.

Examples of such equipment are shown in Figure 5-5 & Figure 5-6.



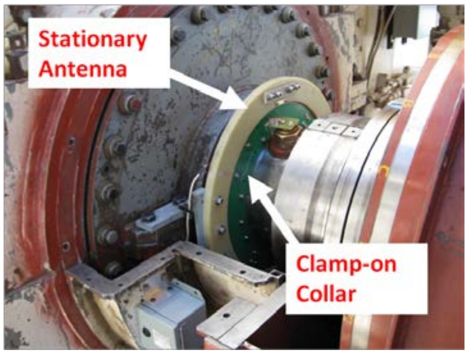


Figure 5-5 & Figure 5-6 End of shaft and mid shaft mounted antenna structure systems.

See Section 5.3.2 for additional discussion of rotor winding ground detection concerns.

5.2.4 Generator Condition (Core) Monitor

5.2.4.1 Principle of Operation

One group of the inadequately monitored failure mechanisms on generators has been stator core lamination insulation failure, cracks developing in electrical conductors, and shorts and grounds developing due to field coil/turn distortion. This limitation has been troubling, since these failures may be associated with expensive repairs and outage time. The Core Monitor (later called “Generator Condition Monitor”) was developed in the 1960s in an attempt to address this concern. This device detects very early stages of localized overheating. Unfortunately, the technology associated with the monitor was so sensitive and sophisticated that the monitor was subject to alarm due to causes not related to component overheating. It took many years of intensive effort from several organizations to refine the design to a point where by about 1990 the equipment could be considered reliable.

The operation of the Generator Condition Monitor is based on the fact that thermal decomposition of organic materials, such as epoxy and polyester resins, enamel paint and core laminate enamel, results in the production of large quantities of very small submicron particulates (pyrolysate products) that range in the size from .001 to .01 microns. Under normal operating conditions, there are no particulates of this size in the cooling gas. The presence of these small particulates can only take place as a result of thermal decomposition of organic materials.

The thermal monitor consists basically of an ion chamber detector, an auto sampling system and the system electronics. The ion chamber contains a weak alpha source that produces negative ions. The negative ions produced by the alpha source are carried into a collector assembly via piping across the generator ventilation fan. The negative ions are attracted to a positive electrode in the ion chamber detector which then produces a very small current flow. This current is electronically amplified to produce an output that is typically set at 80% of full scale on a monitoring device.

When there is no overheating taking place within the generator, the output will remain stable at this 80% base. However, if overheating is occurring anywhere within the generator, thermal decomposition will take place and produce a large quantity of submicron particles. These particles are carried to the thermal monitor via the generator cooling gas system. When these submicron particles enter the ion chamber detector, the negative ions attach themselves to these particles. Since the submicron particles are relatively heavy compared to the negative ions, the attached pair is more likely to flow past the positive electrode of the collector assembly, thus decreasing the current and lowering the output below the preset 50% alarm level.

Overheating is verified by the insertion of a confirmation filter at the input to the ion chamber. The confirmation filter will remove the submicron particles, which will allow the ion chamber detector current to increase, causing the output to return to 80%, and thereby confirming the presence of thermally generated submicron particles, i.e., overheating somewhere within the generator.

In order for the monitor to function reliably, the gas flow rate must remain constant and the ion chamber detector and electronics must be operating properly. Since the gas flow is created by the generator cooling gas fan, gas flow will remain constant unless restriction occurs in the piping or the speed of the rotor changes.

5.2.4.2 Monitor Alarm Conditions

There are four conditions that can cause the monitor output to drop: 1) decrease in gas flow, 2) a faulty ion chamber detector, 3) faulty system electronics and 4), actual overheating within the generator. The first three conditions will provide an invalid alarm; mis-interpretation of these erroneous signals has been essentially eliminated by the evolution of modifications described above.

The 4th condition, actual overheating, is responsive to high temperatures associated with component failure anywhere within the generator. Typical failure modes which will result in monitor alarm are: core iron lamination insulation break-down, cracking stator winding electrical connections, and field winding shorts/grounds or broken turns.

An additional overheating mechanism which may result in a monitor alarm is high local temperatures on the core clamping flanges or on the copper flux shields which are used at the ends of the core by some generator manufacturers. As load conditions move toward leading power factor, starting around .98 lag the components at the ends of the core begin to generate additional eddy current losses and may become rather hot. In general, this condition is not harmful to the generator. But paint or contaminates such as oil on these components may overheat and form submicron particles that can alarm the monitor. Since alarms from this operating condition will only occur at higher power-factor loading, it is possible to screen out this type of false-positive alarm.

5.2.4.3 Operating Experience

A year 2007 Electric Power Research Institute (EPRI) industry survey of monitors produced after 1990 is summarized below:

- Quality of the maintenance of the monitors: Excellent – 6, Adequate – 21, Poor – 0
- Quality of operator training: Excellent – 2, Adequate – 18, Poor – 9
- Experiencing of invalid alarms: Yes – 2, No – 19.

Overall, it appeared that plant personnel were providing sufficient maintenance to the monitors. But it was clear that better attention to training was needed. Training is particularly important because of the infrequency with which operating personnel will be experiencing alarm of the monitor, and because of the fundamental relationship between training and correct operator response to monitor alarm. The two invalid alarms reported were general comments that did not address lack of reliability of the post-1990 monitors.

5.2.4.4 Training and Maintenance Requirements

Operator Training

Recommended steps for responding to an alarm can be found in the Installation and Operation Manual provided with the monitor. The individual checks are not complicated, but alarm of the Generator Condition Monitor is likely to occur so infrequently that a control-room operator may not recall appropriate action to take upon receipt of an alarm. Most power plants now incorporate a Distributed Control System (DCS). Basic information relating to configuring the Generator Condition Monitor into the DCS can be obtained from the Installation and Operation Manual or directly from the manufacturer of the monitor. The DCS can be configured to display a checklist of appropriate actions in either a textual or flow-chart format in order to assist the operator in making a timely and logical response to the alarm.

Monitor Maintenance

Reliable operation of the Generator Condition Monitor requires relatively simple periodic checks described in the monitor Installation & Operation Manual, specifically:

Daily. Observe gas flow rate and adjust if necessary. Verify that monitor output is at the 80% set point; recalibrate if necessary.

Weekly. Push the "Verification Filter Button" to confirm proper operation of the filter system.

Monthly. Perform Relay Test, Contact Test, Keypad Test, Output Test and Power Test.

Yearly. Check for hydrogen leaks on tubing, fittings, joints and valve packing. Activate Auto Sampling System to confirm proper operation.

5.2.4.5 Operating Performance of Generator Condition Monitors

By December 2006, there had been 17 reported incident where a valid alarm has resulted from generator component over-heating. A brief description of each of these incidents is listed below, along with estimated repairs avoided:

Blockage of Liquid Hose. An alarm gave indications of slowly developing overheating. The unit was tripped and it was found that a stator winding Teflon cooling water hose was becoming blocked causing overheating of two stator bars. Had failure occurred, a double ground fault would have resulted in massive arcing and burning. Repairs avoided: Full stator rewind, probable field rewind, extensive cleaning of core, frame and coolers.

Arcing of Rotor Winding. Alarm resulted in shutdown where a winding fault was found. Repairs avoided: Possible arc damage to forgings with major impact on overall repairs.

Burning from Rotor Shorted Turns. Alarm resulted in shutdown where arcing was found between shorted turns. Repairs avoided: Possibly full rewind.

Phase Connection Failure. Alarm at full load automatically verified. Reduced load by about 20% and alarm cleared. Returned to full load and alarm returned. Inspection revealed burning of a failing phase connection. Repairs avoided: Full stator rewind, field rewind, extensive machine cleaning.

Baffle Rub. Alarm received during initial commissioning of turbine-generator. Inspected generator and found that the temporary shipping baffles that had not been removed. Repairs avoided: Minor.

Intermittent Alarm on High Loads. Poor contact between several tube-to-copper connection resistors on gas-cooled stator bars, resulting in a hole burned in a cooling duct. Repairs avoided: Probably minor, but possibly stator winding failure.

Stator Winding Water Flow Blockage. GCM alarmed on load increase. Inspection revealed blocked water flow, thereby preventing winding failure. Repairs avoided: Probable stator rewind.

Stator Core Failure. GCM was in constant alarm for 30 minutes prior to stator core meltdown failure. Intermittent alarms were occurring during the prior several months. Potential for avoided repairs: Restack of core and stator rewind.

Field Winding Arcing to Ground. GCM alarmed and the generator was manually tripped. Tests revealed two shorted coils under retaining ring. Repairs avoided: Possibly fracture of a retaining ring, with total destruction of the generator.

Operation Without Cooling Water. GCM alarmed at 150 MW on a 650 MW generator while unit was being ramped up to full load. Alarm was temporarily disregarded, but unit was manually tripped at 250 megawatts. Inspection revealed that the hydrogen coolers were inoperative. Repairs avoided: Possibly extensive damage to the generator.

Generator Field Ground. GCM alarmed about 40 minutes before manual trip of the generator. Inspection and test revealed that several rotor coils had elongated and caused multiple grounds to the retaining ring. The associated arcing had resulted in the GCM alarm. Repairs avoided: Possibly fracture of a retaining ring, with total destruction of the generator.

OEM Test Protection. Use of a GCM as protection against over-temperature during acceptance test detected a stator cooling water blockage early and prevented serious damage. Prior tests without a GCM had resulted in over-temperature that destroyed an entire field. Repairs avoided: Severe over-heating damage to a field.

Core Burning. GCM alarmed due to a core lamination hot spot approximately two square inches in size which developed during normal operation. Repairs avoided: Possibly eventual core meltdown.

Water Cooler Valved Out. GCM detected overheating in a 550 megawatt generator while it was ramping up to full load, following a generator rewind. The GCM was the first indicator that one of the water coolers was valved out. Repairs avoided: Possibly overheating of generator.

Baffle Rub. During restart after stator replacement, GCM alarmed. Inspection of the generator revealed a rub between the field and a gas flow restriction baffle. The GCM correctly identified the particulate as a valid alarm condition. Repairs avoided: Minor.

Breaking of Stator Winding Connection. GCM alarmed on fracturing of a connection, allowing unit to be shut down without experiencing the extensive contamination normally associated with such a failure. Repairs avoided: Severe contamination of generator, possible stator rewind.

Field Turn Shorts. Existence of turn shorts was confirmed by monitor alarm, allowing shutdown without collateral damage. Repairs avoided: Probably small impact in overall repairs required.

5.2.4.6 Summary – Generator Condition Monitor

The Generator Condition Monitor is an exceptionally sensitive device. Many years of development and design evolution were required before reaching a state of high reliability against mis-interpreted alarms. That point appears to have been reached in about 1989. The device monitors the generator for several adverse conditions that can initiate a valid alarm. These conditions range from the benign to core melt-down – a spectrum from minor rub to complete generator internal destruction. Unfortunately, there will normally be at least some uncertainty as to the exact source and urgency of the condition initiating the monitor alarm. But since the risks associated with non-response to an alarm can be exceedingly high, it will always be prudent to regard an alarm as valid unless known information confirms otherwise.

Because of the inherent nature of the failure modes being monitored, expeditious response may be very important. Thus, it would be advisable to configure the plant Distributed Control System (DCS) to assist the operator in making a timely and correct response to an alarm.

If properly maintained and operated, the Generator Condition Monitor can be a valuable device that could mean the difference between a brief shut down for minor repairs or a major overhaul involving weeks or months of costly downtime.

5.2.5 Stator Winding RTDs and TCs

On conventionally cooled stators, these devices embedded in the slot read a temperature average of surrounding media: copper (through a thermal insulation blanket), tooth iron, and cooling gas. Also, the devices are generally located near the end of the slot where the temperature is typically lower than the axial center of the slot. These devices tend to read about 20 to 30C lower than actual winding copper temperature. The accuracy is improved on thin insulation builds (newer machines and low voltage windings).

On gas cooled armature bars, some manufacturers locate sensors to read the outlet gas temperature from individual armature bars. On smaller direct gas cooled stators, one RTD may be located in each of the six phase belts, i.e., 6 RTDs. On larger generators where an RTD is located in the gas discharge from each slot, slot RTDs may be omitted.

On water-cooled windings, in-slot detectors (usually RTDs) read an average of top and bottom bar outer surface temperatures, and surrounding media. If one bar in the slot is starved of cooling water, the condition may not be apparent based on the reading of the device. Water-cooled generators also have TCs reading the outlet water from the bars. In many designs, a common outlet is used for a top and a bottom bar, thus if only one of the bars is starved, or if no flow exists, the device may not be at all sensitive to the condition. Furthermore, on some designs the connection rings are cooled in series with selected armature bars. These circuits (usually in multiples of 6) will read higher than the remaining devices, by several degrees. It is important, then, to separate the TCs into the two comparable groups when evaluating TC readings. The net result of the complexity of these instruments is that it is difficult to determine if malfunction is occurring without careful analysis of the data. Timely performance of this analysis is probably beyond the scope of most operators, but can be programmed into a Distributed Control System.

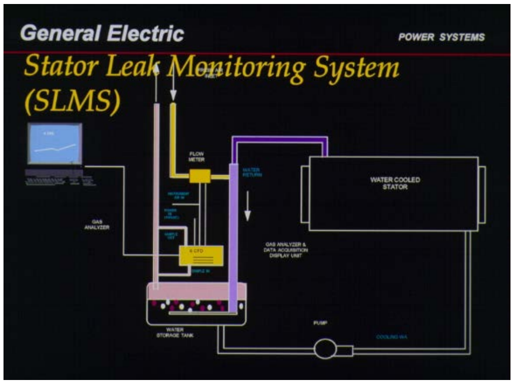
5.2.6 Auxiliary Systems

5.2.6.1 Precautions

Generally the external units are well instrumented. Since several of the modes of failure or malfunction of the pumping units can cause forced outage, some very serious, the condition of these equipments should be carefully monitored. Of particular concern are loss of bearing lubrication, hydrogen seal oil pressure, hydrogen/air cooling water, and stator winding water flow.

5.2.6.2 Stator Winding Cooling Water System

Monitor flows, pressures, temperatures, water purity, tank level. Addition of equipment to measure hydrogen gas vent flow is advisable, Figure 5-7 & Figure 5-8. The Stator Leak Monitoring System (SLMS) equipment is particularly valuable on high-oxygen systems, such as the GE system, as SLMS will tend to assure that the system retains the intended high oxygen content in the atmosphere over the cooling water.



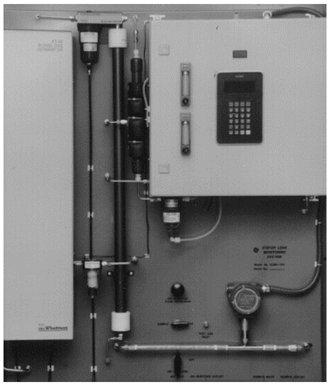


Figure 5-7 & Figure 5-8. Equipment for Monitoring Gas Flow from Stator-Cooling Water System (General Electric)

5.2.6.3 Hydrogen Gas System

Monitor temperatures, pressures, hydrogen purity, liquid detector, high dew point, hydrogen consumption. If problems are occurring in maintaining a low dew point on the hydrogen gas, a drier system would be advisable. The latter would be particularly important on any generator with 18/5 retaining ring material.

5.2.6.4 Seal Oil System

Monitor filter pressure, vacuum, seal oil pressures, motor overloads and overheating, drain enlargement liquid overflow detector.

5.2.6.5 Lubrication Oil System

Monitor oil pressures, bearing and oil temperatures, bearing oil flows.

5.2.6.6 Excitation System

Brush Holder Rigging: Monitor air flow, filter condition and differential pressure, noise levels, brush sparking, brush wear, dust buildup.

Rotating Rectifiers: Monitor fuses and cleanliness.

Exciter (transformers, DC generator, AC generator, controls): Monitor temperatures, pressures, cleanliness, brush wear and sparking, filters, alarm conditions, evidence of overheating.

5.2.6.7 Iso-phase, Current Transformers, High Voltage Bushings

Monitor temperatures, air flows, evidence of local or general overheating, leaking compound, cleanliness.

5.2.7 Field Inter-turn Short-circuit Detection (Flux Probe)

5.2.7.1 General

Field inter-turn short-circuit detection equipment has been available for many years, but only in recent years has this device come into extensive use. Application increased rapidly when technology (hardware and software) and procedures were developed that allowed data to be accurately and conveniently taken on-line, without interruption of service and without modifying armature connections, Figure 5-9.

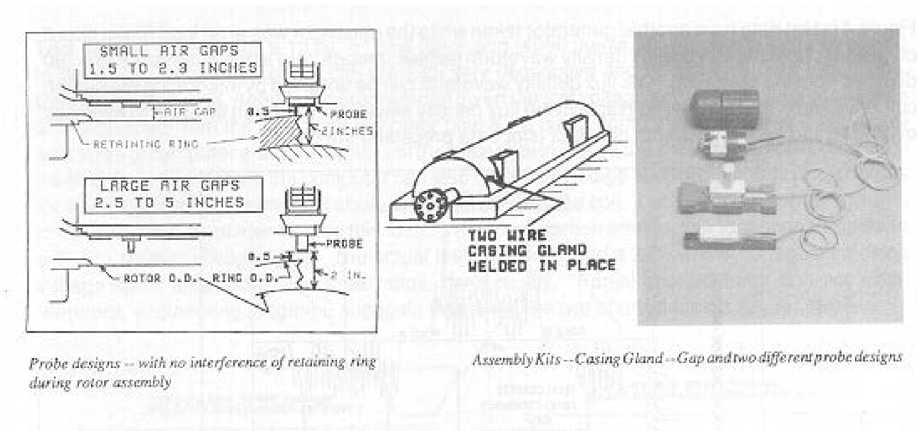


Figure 5-9. Components of Field Shorted Turn Monitoring System (Generatortech)

Initially a temporary probe was assembled by a somewhat complicated and risky process. But present-design permanent probes are inexpensive and simple to install and do not interfere with operation or maintenance, Figure 5-10 & Figure 5-11. However, the field must be removed to install a permanent probe, and the field slot wedges under the probe region must be non-magnetic in order to obtain a reading on the slot. Ordinarily this is not a problem. (Temporary probes are still available and can be used without field removal.)

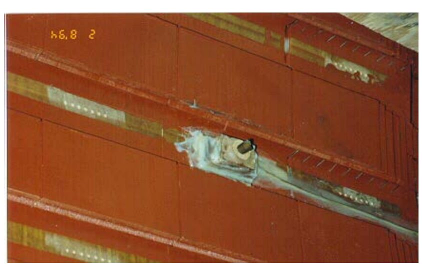


Figure 5-10 & Figure 5-11. Two Applications of Field Air Gap Flux Probes

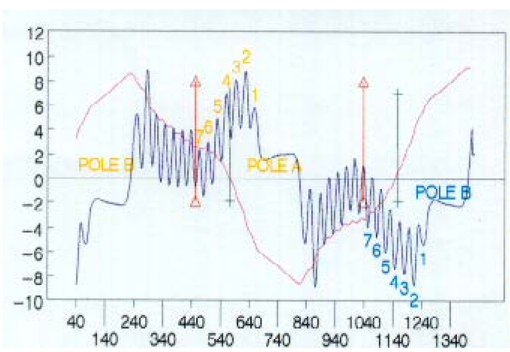
Although isolated shorted field turns are undesirable, their existence is not necessarily a serious concern. Many fields, even those that are relatively new, may contain one or more turn shorts. But if operation is satisfactory, the complicated and expensive repair may not be warranted.

Data should be taken periodically, with frequency depending on known condition of the field winding insulation, operation to which the unit is subjected, and suspected problems. Field turn-short problems may be suspected if the field is showing indications of thermal sensitivity in relation to field current, or if higher field current is required than previously experienced at a specific load.

5.2.7.2 Technical Background

The current in the turns in each slot of a generator contributes to the total magnetic flux of the field. However, in the process, the current in each slot generates a leakage flux surrounding the turns in that slot. This leakage flux can be measured by placing a search coil in the air gap at the top of the slot. The leakage flux generates a voltage that is directly proportional to the number of current-carrying turns in the slot. If shorted (inactive) turns exist in a slot, the leakage flux voltage of that slot will be lower in direct proportion to the number of shorted turns.

Measuring this leakage flux is complicated by the existence of the strong main flux field. However, the varying of stator load and power factor will shift the angular relation between main flux and the field circumferential physical axis. By this process, the main flux field can be reduced to near zero in the vicinity of each coil of each pole. This is accomplished by taking roughly 5 sets of test data as stator load is varied from zero to full load at differing power factors. The theoretical analysis is somewhat complicated, but in practice computer programs have been prepared which make analysis simple and straight-forward. Sensitivity is good, making possible the detection of a single turn short in a 20-turn coil, Figure 5-12 & Figure 5-13.



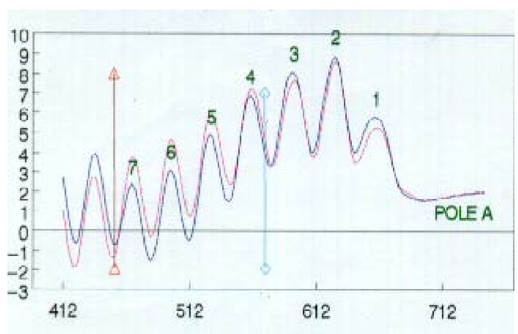


Figure 5-12 & Figure 5-13. Data from Field with Shorted Turns in Coil #6 (Generatortech)

5.2.7.3 Equipment and Hardware

Performance of the shorted-turn test requires custom installation of a single flux probe, typically on a stator wedge near the end of the slot. See Figure 5-10 & Figure 5-11. The field should contain non-magnetic wedges at this axial position. If a slot contains magnetic wedges in the probe position, leakage flux will be too small to allow a reading to be obtained for that slot.

Originally data was read and analyzed by oscilloscope. But analysis is now conveniently possible by use of an analog-to-digital board and a laptop computer with software specifically designed for this purpose.

5.2.8 Monitoring of Partial Discharge

5.2.8.1 General

Since partial discharge is directly and/or indirectly associated with important stator winding failure mechanisms, efforts toward the use of PD monitoring, and the better understanding of PD output signals, has for 35 years been high. Most of this effort has focused on the ***time-domain*** test (PD testing), and this equipment has proven to be a valuable asset in monitoring for potential problems with stator windings. Much less effort has focused on the ***frequency-domain*** (EMI test). This is unfortunate in that EMI (Electromagnetic Interference) test can provide significant information on winding condition (as well as the condition of other power plant equipment). Furthermore, the combination of PD testing and EMI testing can provide a better assessment than either system alone.

5.2.8.2 Capabilities and limitations of partial discharge testing

It cannot be doubted that there are certain limitations to PD and EMI testing for the condition of a stator winding and other electrical equipment. For example:

- The tests provide only a rough approximate magnitude and extent of PD.
- There is not 100% certainty that a specific spectrum of signal is associated with a specific PD site or magnitude.
- The tests provide little information on location of PD throughout a winding.
- Neither PD nor EMI provide direct knowledge of the extent of damage (if any) which may be occurring to electrical equipment.
- There are numerous “noise” signals in the frequency spectrum that must be identified and eliminated from association with the condition of the equipment.
- Interpretation of results can be a challenge and can require knowledge of a trained and experienced test engineer.

Comparing the capability of the two test methods in establishing the location of the PD source(s) in a stator winding:

- PD testing can suggest the most likely PD location in stator bar groundwall insulation, i.e., against the copper, within the groundwall, on the outside surface.
- One of the EMI testing methods can provide guidance as to location within the stator winding, i.e., slot, endwinding and connection rings. A second method can also locate partial discharge generating sites anywhere within the power plant.
- (These comparisons will be discussed in some detail below.)

As with all monitoring devices on generators, both approaches to monitoring partial discharge are imperfect. But each has considerable strength. Furthermore, because of the fundamentally different nature of the two tests, use of both PD and EMI monitoring systems together can provide a better assessment of the condition of a stator winding than either system used alone.

It is important that good sensors and monitoring instruments be available before attempting to obtain partial discharge data by either method. In the case of PD testing, elimination of the effects of noise (stray signals) and interpretation of results is the most uncertain aspect of the test. Absolute readings may not be as helpful as trend-line evaluation on a given machine, or comparison of results on similar units using the same test equipment.

5.2.8.3 PD Testing

5.2.8.3.1 Machine Conditions

Many types of discharge are influenced by machine operating conditions: stator current and voltage, winding temperatures, humidity and gas pressure. Comparative tests will be more meaningful if conducted under the same machine conditions.

A few general statements can be made with respect to variation of discharge level as operating conditions change:

- Bar vibration may be suspected, if amount of discharge is related to armature current.
- Voids in the insulation may be suspected, if partial discharge decreases with increasing winding temperature.
- Contamination may be suspected, if discharge increases with decreasing humidity.

Prior to taking data, machine conditions should be stable, which may require holding steady load for an hour or more. For each test, records should be made of load, stator voltage, stator current, power-factor, gas pressure, humidity, temperatures (stator winding, field winding, hot gas, cold gas), field current, machine vibration levels, and noise emission from generator.
Records should also be made of operating history: hours of service, amount of load cycling, start/stops, duty (peaking or base load).

5.2.8.3.2 Equipment

Sensors for the different test approaches differ in design, assembled location and signal output. Sensors may be located permanently in the ends of selected stator slots, Figure 5-14 & Figure 5-15.

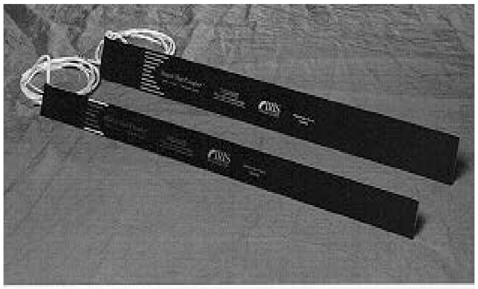
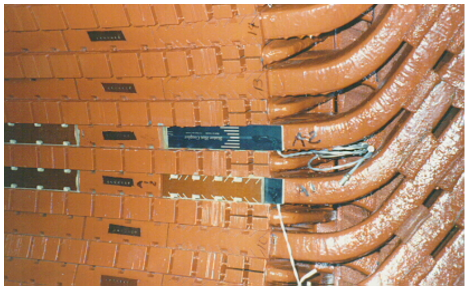



Figure 5-14 & Figure 5-15. Permanently Located Stator Slot Couplers (Iris Power Engineering)

The most common location, however, is on the high voltage line leads or iso-phase connections near the terminals of the stator. Figure 5-16.

Figure 5-16. Line Pickup, 80 pF, with Cable not yet Connected (Iris Power Engineering)

Signal may be taken from the line sensor by a small current transformer, Figure 5-17.

Figure 5-17. Radio Frequency Current Transformer on Lead from Adwel 1000 pF Line Pickup (ABB)

Sensors are not yet standardized between testing companies, or within a single testing company. The instrumentation which measures the sensor outputs is also quite different. Thus it is not possible at this stage of development to make a definitive, concise statement relative to sensors and instrumentation.

5.2.8.3.3 Test Procedures

Because the tests are complicated and require specialized equipment, tests will ordinarily be done by experts experienced in this type testing.

It is important to keep in mind that the sensors are commonly located proximate to high voltage leads, and all test systems are susceptible to high stray over-voltage. Necessary safety precautions must be taken.

The specific test procedures will be defined by the testing company and personnel. In general, the machine will be tested at very light load and at high load (high stator current). Other condition parameters may also be varied. Load will need to be held at each condition until temperature conditions stabilize.

5.2.8.3.4 Analysis of Data

Output can be in the form of 2 dimensional plot of pulse count rate vs. pulse magnitude, Figure 5-18, left, or 3 dimensional plot of pulse count rate vs. pulse magnitude vs. phase angle, Figure 5-18 right.

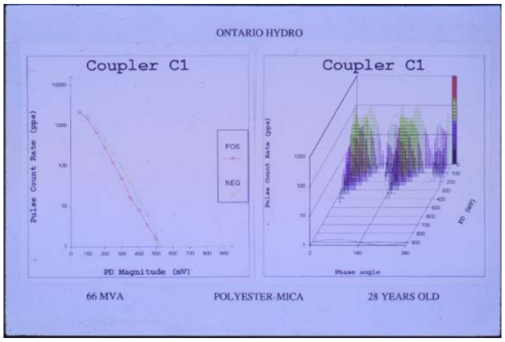


Figure 5-18. Stator Slot Coupler Signal Output (Iris)

Comparison can be made between end winding and slot readings to assess location of signals, Figure 5-19.

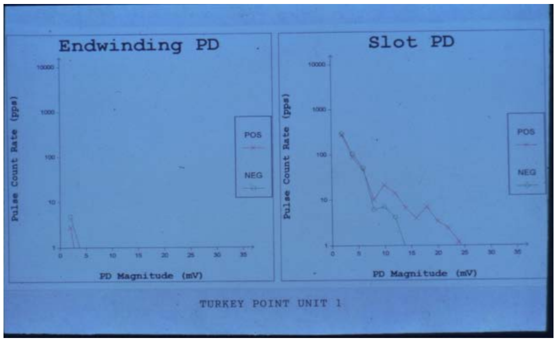
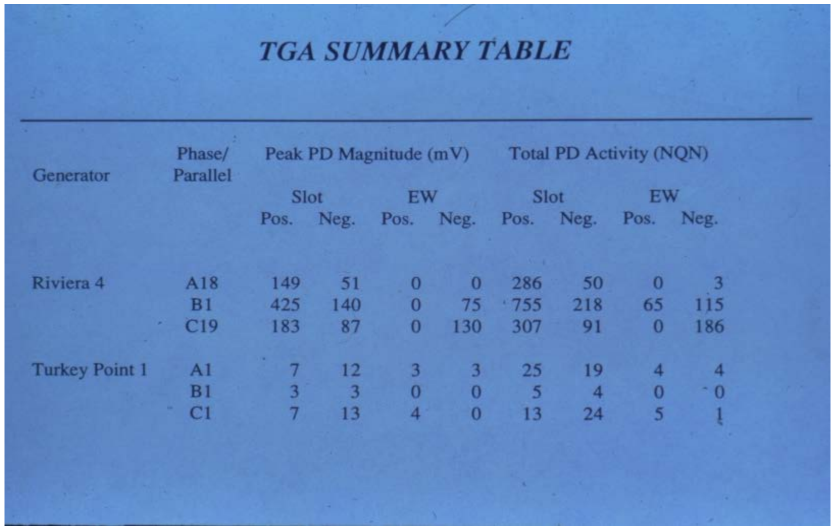


Figure 5-19. Data From End Winding and Slot Pickups Indicating High Activity in Slot Portion of Winding

Comparison between similar machines can be read and tabulated. Figure 5-20.



TGA SUMMARY TABLE

Generator	Phase/ Parallel	Peak PD Magnitude (mV) Slot Pos.	Slot Neg.	EW Pos.	EW Neg.	Total PD Activity (NQN) Slot Pos.	Slot Neg.	EW Pos.	EW Neg.
Riviera 4	A18	149	51	0	0	286	50	0	3
	B1	425	140	0	75	755	218	65	115
	C19	183	87	0	130	307	91	0	186
Turkey Point 1	A1	7	12	3	3	25	19	4	4
	B1	3	3	0	0	5	4	0	0
	C1	7	13	4	0	13	24	5	1

Figure 5-20. Comparison of Two Similar Windings with Very Different Sets of Partial Discharge Data

Testing company approaches to analysis of data is not standardized. One major PD vendor has relatively simple procedures and instrumentation, and very large data banks. This allows generator owner engineering personnel with modest training to collect and analyze their own data. The owner can then make general comparisons of a specific generator with a significant population of similar generators. If the generator in question has values exceeding 90% of all similar units in the data bank, the owner is cautioned to investigate the source of the high readings.

Other testing vendors prefer to take all data with their own personnel and instrumentation, and then forward the results to a central engineering staff for analysis. One testing company has reached sufficient sophistication that their equipment provides a set of 3 colored lights to indicate the condition of the generator from satisfactory to a high level of concern.

The differing approaches used by the various testing companies have given good results in monitoring generator performance. In several cases units have been brought off-line for investigation of high readings, and significant problems have been found and corrected before major damage occurred.

Some judgment of winding quality is made based on absolute readings, and all vendors also rely on trending of readings over time on a given generator. A winding that is trending greatly upward is monitored closely and depending on readings, may be disassembled for inspection.

While PD testing is perhaps still in its infancy, PD testing is being found very useful in monitoring stator windings for some critical deterioration mechanisms. Development and evolution of PD testing is moving at a high rate, and it can be expected that PD testing will become even more valuable in the future.

5.2.8.3.5 Capability of On-Line Partial Discharge Testing

Stator winding deterioration is not monitored by any of the standard instrumentation. Because stator winding failure has been a major generator failure mechanism, a high effort has been focused on the goal of better monitoring the condition of these windings. On-line partial discharge (PD) measurement was developed in an effort to address these issues.

Partial discharge measurement has been used as a stator winding evaluation tool for over 55 years. During this period, many technical papers have been written discussing the capabilities of partial discharge monitoring; these papers have cited numerous anecdotal cases have illustrated successful prediction of individual winding problems based on high PD readings. Still, users of PD monitoring have been left with uncertainty as to just how valuable PD measurement might be in assessing the condition of the stator winding of a specific generator.

In an attempt to address this concern, the “success rate” of the Iris Engineering data base was analyzed in 2005. Iris was chosen because their system has been installed on a large number of generators and motors. Results have been received from about 3600 of these machines.

In 216 cases, investigation of high PD readings has been conducted and the owner has provided the PD equipment vendor with the results of the investigations. The following paragraphs summarize the results of analysis of this 216-unit data base.

5.2.8.3.6 Analysis of data base

Table I summarizes the 216 incidents where the on-line PD test indicated suspected generator problems. A few cases involved connected equipment, rather than the stator winding. Visual inspection has been made on most of these 216 incidents; these inspections confirmed that there were stator winding problems on the suspect machines.

Since 216 incidents came from a population of 3600 machines, about 6% of machines were identified by PD as having stator winding insulation issues. Similar problem-identification rates appear to have been found by other testing companies, including Adwel, Alstom and American Electric Power.

The incidents are categorized by machine type. For the most part, the identification was based on Qm levels that are higher than 90% of the readings from similar machines. In a few cases, incidents were identified based on a high rate of increase in PD from a previous moderate PD level.

An Observation. Clearly, there is considerable uncertainty in the analysis provided below, and necessarily several suppositions were made. As data continue to be accumulated by the several PD testing companies on PD monitoring, a more definitive analysis will be possible.

TABLE I. Categories of Failure Root-Causes and Insulation Systems

	Root Cause						Insulation System		
Equipment Type/(Number of Units)	Contam-ination	Vibra-tion	Design/ Manu	Operation/ Maint.	Non-Gener-ator	Root-Cause Total	Asphalt Mica	Poly-ester Mica	Epoxy Mica
Turbo, H2 (17)	2	7	8			17	7	2	9
Turbo, air (29)	1	4	14	8	2	29	2	1	26
Hydro (121)	3	31	85	2		121	28	33	42
Motor (40)	3	12	20	2	3	40			39
Switch Gear (9)	1				8	9			
Totals	10	54	127	12	13	216	37	36	116

5.2.8.3.7 Root-Causes by Categories

Considering the several categories the root-cause selected in Table I:

Contamination. There were few incidents in this category. Perhaps this is to be expected, since most contamination materials, e.g., ambient dust, wear products and oil, tend to suppress partial discharge rather than cause partial discharge. Unexpected is that the hydrogen-cooled generators, which should be relatively free of ambient dirt, were relatively high in the assigned contamination category.

***Vibration*.** The percentage of hydrogen-cooled generators with vibration identified as root cause is relatively high, reflecting the higher electromagnetic forces in the higher-duty hydrogen-cooled generators. The relatively high percent of hydro generators would reflect the inadequate wedging and tying systems used on many of these units in the 1960-1970 time-period.

In addition, included in this category may be cases of “vibration sparking” (also called “Type 1 slot discharge”). While this phenomenon is not true PD, the severely- degrading sparking may be picked up on the PD sensors.

***Design/Manufacturing*.** This category was assigned a large amount of input from the data base. Many of the incidents were not described in detail, but were described in the reports as general PD in the endwindings, with no reported vibration. It was assumed that` most of these cases resulted from close physical proximity of bars of different phases, although there may also be cases of failure of the connection between the end-arm grading and the slot grounding paint.

Operations/Maintenance. Few cases seemed to fit into this category; largely these were associated with thermal cycling and with poor connections in the electrical circuits.

Non-Generator. Generator PD detection instrumentation is also sensitive to PD sources not originating in the stator winding. These incidents were classified in the reports as outside the generator, and might more properly not have been labeled in the generator category.

***Insulation Systems*.** Of the 189 cases where the type of insulation system was recorded, about 40% were asphalt-mica or polyester-mica, indicating that many of these machines are old. Common use of asphalt was discontinued in about 1960 and the transition from polyester-mica to epoxy mica on new windings occurred in 1970’s.

5.2.8.3.8 Failure Consequences

Stator winding failure from PD alone has been uncommon, because mica insulation systems are used to contain most high electrical voltages in generators. More usually, PD has been an indicator of other problems within the generator, e.g., stator bar vibration, failing electrical connections, inadequate voltage grading/grounding systems.

The explanations provided in the 216 incident summaries were not of sufficient detail to allow more than a rough estimate of avoided costs. But because of the large number of incidents, clearly there would have been a major negative impact on the utilities involved were not the PD data acquisition systems installed. Permitting the owner to take a maintenance outage, rather than a forced outage, would itself result in a major positive impact.

Of the 216 incidents in the data bank, most would not be expected to cause in-service failure. Only those listed in the "*vibration*" category are probable candidates for service failure. But the 54 units tabulated are not an insignificant number of generators. If as many as half were to fail in service, these would represent forced outage costs associated with 27 incidents, and *unscheduled* repair costs of many millions of dollars.

Of the remaining incidents, it is unlikely that any of the "*contamination*" incidents would result in forced outages, and only a few of the "*design/manufacturing*" and "*operations/maintenance*" would force an outage. Still, in each case, necessary work was permitted to be accomplished during a planned, rather than forced outage.

5.2.8.3.9 Summary – PD Testing as a Stator Winding Evaluation Tool

While many electric power generators have PD detection systems installed (perhaps in the order of 5,000 in the industrial countries), this is probably less than 10% of the large generators in these countries. PD monitoring systems appear to be finding conditions of concern on about 6% of generators where the equipment is installed. While this may seem low, probably no other generator monitoring system exceeds this rate of problem detection.

Partial discharge monitoring has identified many pending service problems, prevented a significant number of generator service failures, and has resulted in a major cost saving to the power generation industry. Because of the significant stator winding monitoring capabilities of PD equipment, installation of PD monitoring devices may be advisable on all generators that are important to the power generation system.

5.2.8.4 EMI testing

5.2.8.4.1 Background

Electromagnetic Interference (EMI) testing has also been used for about 35 years, but application has been limited in scope. There are two basically different approaches to EMI testing. The first uses a radio frequency current transformer (RFCT) to obtain PD signals from the entire winding of a generator or motor. The basic principles of this test approach are not well understood and interpretation of the signal output can be difficult and perhaps controversial. The second approach to EMI testing uses a small hand-held instrument to picks up "stray" PD signals emanating from an electrical device, e.g., generator, motor, transformer, switchgear, controls. This EMI test approach is easily understood, powerful, simple to perform, and easily interpreted.

5.2.8.4.2 EMI condition assessment of stator windings

EMI condition assessment can be accomplished by 2 different approaches:

1. Installation of a radio frequency current transformer (RFCT) on the neutral grounding cable of a stator winding. This RFCT will pick up high frequency signals coming from anywhere in the stator. It will also pick up "noise", e.g., AM and FM broadcasts, carrier frequencies, brush sparking. As with time-domain testing, these noise signals can cause difficulties in segregating out the signals of interest generated within the stator winding, although to some degree the noise signals are easier to identify with EMI testing.

2. Use of a hand-held device to search for EMI signals coming off any piece of equipment in a power plant, e.g., generator, motor, isophase buss, leads, switchgear.

Interpreting the results from the RFCT approach is rather subjective and difficult. But the hand-held device is simple and straight forward. Both will be discussed in the sections below.

5.2.8.4.3 Identifying EMI sources

RFCT Instrumentation

This test involves use of a radio frequency current transformer (RFCT) to obtain radio frequency signals generated by partial discharges in a stator winding.

Initial use of the principles of Electromagnetic Interference (EMI) testing on stator windings began in the 1950s. At that time a modified AM radio was found useful in detecting the sparking generated by failing connections. Far broader application of the EMI principles began in the late 1970s when it was realized that EMI pulses from PD or other sources within the stator winding could be detected by an RFCT located at the stator winding neutral. Figure 5-21.

Figure 5-21. Two Radio Frequency Current Transformers Assembled on Lead to Neutral Grounding Transformer

It was known that several types of insulation deterioration common to large rotating electrical machines produce EMI at discrete frequencies or within bands of frequencies. By use of standing wave theory, it was possible to predict by calculation the natural resonant frequencies of various locations within the winding, i.e., endwindings, slots, connections.

It became apparent that certain types of EMI were only found at discrete frequencies or within bands of frequencies corresponding to the certain locations within the winding. Insulation defects generate electrical impulses that excite various parts of the winding into oscillation. These damped sinusoidal waveforms are in effect impulses filtered by the electrical (physical) networks adjacent to each source of electrical discharge.

It was noted that EMI signals occurred predominantly at these resonant points on a machine's impedance curve. Electrical noise from external sources such as the conduction of exciter thyristors usually occurred broadband, over several of these resonant points.

Based on these fundamental principles, and many tests of stator windings (with supporting inspections of the windings), it was possible to establish basic EMI frequency-dependent curve patterns associated with PD within specific locations within the winding.

Development of an understanding of these properties of stator windings required a background in transmission line theory (and associated short-wave radio principles). These technologies are outside the knowledge base of most engineers associated with power plant machinery maintenance today, and as a result, may seem somewhat obscure and perhaps doubtful, but nevertheless they are valid.

<u>Hand-Held Instrumentation</u>

Use of simple hand-held instrumentation for detecting EMI radiation in power systems dates back 50+ years. This approach has been used for assessing condition of power line insulators and other purposes

The technology is basic and easy-to-understand, e.g., any poor electrical connection produces arcing. The arc will produce radio frequency (RF) radiation of some magnitude, depending on magnitude of the arc. A small, hand-held device can measure the strength of the radiation at any selected distance from the arc source. Since arcing is a very common deterioration mechanism where electric current is flowing, this type of monitoring is a potentially powerful tool for assessing power plant condition.

Radio frequency radiation is also produced by PD, although generally of much lower magnitude than RF radiation produced by an arc. Nevertheless, the hand-held device can be successfully used in search for PD. Particularly, the device can be helpful in locating the source of known PD activity.

Monitoring for PD with either the time-domain or frequency-domain approaches involves some uncertainties and requires significant technical training and skill to perform and interpret the results. Also specialized instrumentation is required for both approaches. The hand-held approach is relatively simple to understand and the use of the device relatively simple and straight-forward.

A hand-held device, such as shown in Figure 5-22, can measure the strength of the radiation at any selected distance from the arc source.

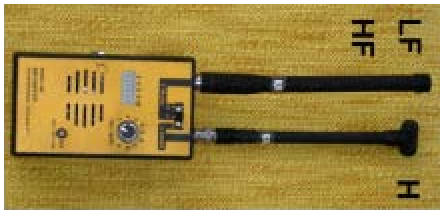


Figure 5-22. Hand-held PD search instrument.

There are two probes to assess different intensity levels of signals. In Figure 5-22, the LF/HF probe detects electrical energy (EMI) emission signals, and the H probe detects magnetic emissions. The two probes allow detecting and locating emission signals ranging from very low to very high levels of emission.

5.2.8.4.4 Growth and use of EMI testing

<u>Use of RFCT Instrumentation</u>

Based on the technology described in the previous Section, many stator windings were tested using the RFCT equipment. From these tests (and associated inspections) came confirmation of the validity of the

EMI approach to stator winding condition assessment, as well as an understanding of the frequency spectrums generally associated with various types and locations of PD.

While an RFCT has been used for EMI testing of stator windings for over 35 years, this test procedure has not become widespread in the industry. There are perhaps several reasons for this situation:

- The basic physical principles on which EMI testing functions are not easily or commonly understood, and thus the test has been perceived to be something of a "black magic" approach. Furthermore, the test output is not crisp and unambiguous. Thus clearly, there is a rational basis for concern relative to validity. But as mentioned earlier, on generators this property of ambiguity and uncertainty is not unique to EMI testing, and probably is not a solid basis for non-use of the test.
- The EMI test is perceived to be rather complex and output data difficult to interpret. While true, again this situation on generator condition assessment is not unique to EMI testing. There is no intrinsic weakness in performing the test and interpreting the more common results. Several operating companies are successfully using the EMI approach as a tool for generator condition assessment.
- Resource limitations are also an issue. However, standard equipment is available and cost is nominal. Training costs are also a concern. But again, performance of the test is relatively simple, and the capability to interpret the more common outputs is within the scope of most engineers.

Many stator winding problems, some very serious, have been found with this instrumentation system.

<u>RFCT Frequency Spectrum</u>

A typical frequency spectrum from a generator test is shown in Figure 5-23. Inspection of these curves will indicate why EMI testing has raised concerns among those engineers involved in generator maintenance. Clearly there is no readily obvious interpretation of the shapes observed in these plots.

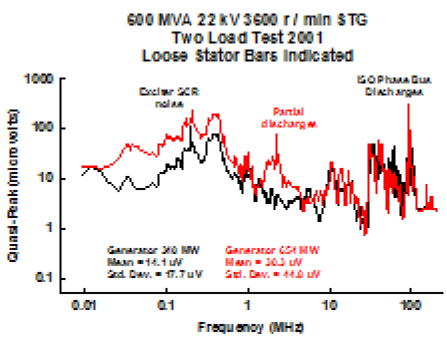


Figure 5-23. Typical curve spectrum – suggesting loose wedges and bar vibration.

<u>Use of Hand-Held Instrumentation</u>

Searching for EMI emissions with the hand-held device involves walking around the plant equipment in question and listening for the level of signal coming from the instrument. This is a simple operation and a typical motor can be scanned in moments. Historical experience suggests that roughly 75% of typical motor failure modes emit detectable radiation energy.

With modest training and experience, an operator can perform the necessary tests throughout the power plant. Photos below. By observing the location and magnitude of detected signals it is possible to make valid judgments relative to the nature of suspected deficiencies in plant equipment. Based on this information, necessary inspection and test can be planned to reduce the likelihood of further damage and/or forced outage on the specific piece of plant equipment.



5.2.8.4.5 PD testing, in summary

The RFCT instrumentation can identify several common deterioration mechanisms in stator windings, including partial discharge and vibration sparking; the RFCT can also detect collector, excitation equipment and isophase problems.

The hand-held device can quickly and easily locate sources of EMI associated with, for example, failing connections, contamination, switch gear deterioration, and bearing distress.

EMI testing is an important addition to the monitoring capability of power plant electrical equipment. The RFCT approach and the hand-held device have complimentary capability, making use of both tests highly valuable. Furthermore, EMI testing is complimentary to the classic frequency-domain PD testing. PD and EMI testing used together can provide power plant service personnel a powerful additional source for monitoring electrical performance of the plant equipment.

5.3 Generator Rotor and Stator Winding Ground Protection Equipment

5.3.1 General

On turbine-generator rotor windings, experience has shown that single grounds resulting from fracture of a rotor winding electrical conductor can cause dangerous burning of rotor forgings. But IEEE Standard C37.102-2012 implies that a single ground in a rotor winding may not be a major concern except for exposure to a double ground.

On stator windings, the electromechanical ground relay 59GN commonly used in generator protection does not respond to grounds in the bottom ~5% of the winding. Four recent failures in this portion of the winding each caused massive damage to the generator and collectively had a total cost, including repair and loss of generation, close to $500,000,000. But IEEE Standards, C37.101-2006 and 102-2012 imply that this detection deficiency may not be a major concern.

The common thread between these two conditions is the overlooking of the unfortunately common winding failure mode of fracture of a rotor or stator conductor. This paper describes these types of generator winding failures, discusses associated negative impacts of such failures, and provides recommended corrective actions.

5.3.2 Serious rotor winding ground protection deficiency

5.3.2.1 IEEE Standards

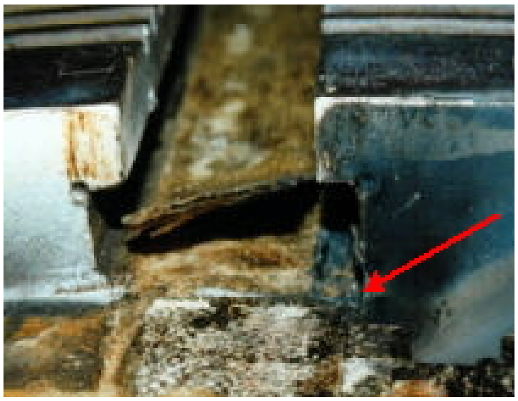
Recommended rotor (field) winding relay protection systems for generators are spelled out by IEEE Standard C37.102-2012, *Guide for AC Generator Protection*. Relative to rotor windings, on page 46 this recently re-issued guide states:

The field circuit of a generator is an ungrounded system. As such, a single ground fault will not generally affect the operation of a generator. However, if a second ground fault occurs, a portion of the field winding will be short-circuited, thereby producing unbalanced air gap fluxes in the machine. These unbalanced fluxes may cause rotor vibration that may quickly damage the machine; also, unbalanced rotor winding and rotor body temperatures caused by uneven rotor winding currents may cause similar damaging vibrations.

This statement is not completely accurate relative to single ground. Excepting only turn shorts, rotor ground insulation failure is probably the most common failure mode of rotor windings. Ground fault detection of rotor windings is provided by a relay system that injects a low voltage onto the (ungrounded) rotor winding. If a ground develops, this relay is activated. Based on industry guides and experience, this relay is normally set to alarm rather than trip. This is probably a rational approach – but with a caution: Beyond the exposure to a double ground, a single ground can be a serious condition if the ground results from a broken conductor (or shorted coils) rather than a simple failure of the ground insulation. Since conductor fracture is a somewhat common rotor winding failure mode, a single ground should not be taken casually.

5.3.2.2 Examples of rotor grounds

During a short period of time, the author was involved in five rotor ground failures. One of these failures was a double ground and it resulted in minor forging burning in two locations. Figure 5-24 is one of those locations. The forging burn damage was in a low mechanical stress area and easily corrected by minor iron removal similar to Figure 25.



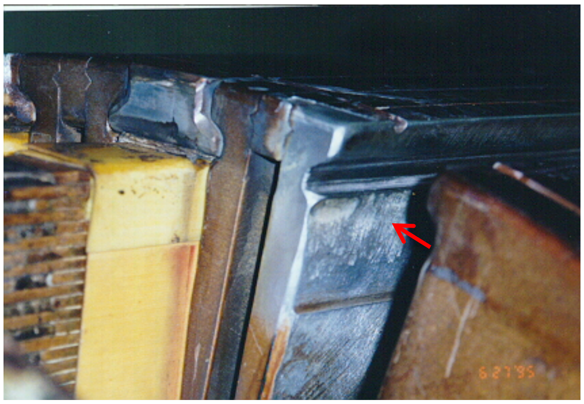


Figure 5-24 & Figure 5-25. Local minor burning of rotor forging and removal of forging burn by minor grinding of material.

The other four failures were single grounds resulting from broken conductor or shorted coils. Each of these four failures involved forging burning of a serious nature. When the turn in Figure 5-26 broke, current continued to flow through conduction involving the retaining ring and rotor body, Figure 5-27.

Figure 5-26 & Figure 5-27. Broken top turn and forging arc damage resulting from the break.

The conditions shown in Figure 5-28 and Figure 29 resulted from shorting between the two largest coils in a large rotor. (Because the ground detection circuit was incorrectly connected, the ground persisted for a significant period of time.)

This condition would constitute a single ground, but the damage to the retaining ring seen in Figure 5-29 was extremely serious and dangerous.

Figure 5-28 & Figure 5-29. Arc damage from shorting between 2 coils and resulting near-fatal burn damage to the retaining ring inside diameter.

5.3.2.3 Rotor winding ground relay systems

Rotor windings operate at low voltage, and an ungrounded design is normally used. This permits easy identification of a ground in the rotor winding. Furthermore, the rotor winding relay system itself is also inherently relatively simple. If the relay system is set up correctly the relay will perform reliably.

On brush/collector excitation systems the relay is connected to the rotor winding via the collector rings. On rotating rectifier rotors, however, ground detection involves complicating factors since there is no direct method of connecting the relay system to the rotor winding. But because ground detection is vital to reliability and safety, connection for ground detection is often provided to the winding via a separate instrumentation slip ring or via wireless transmittal of signal.

5.3.3 Serious stator winding ground protection deficiency

5.3.3.1 General

Recommended standard stator winding relay protection systems for generators are spelled out by IEEE Standards C37.101-2006, *Guide for Generator Ground Protection,* and C37.102-2012, *Guide for AC Generator Protection*.

One of the recommended protection devices is ground detection of the stator winding. Relative to this relay, C37.101-2006 states on page 29:

> *"The importance of detecting ground faults close to the neutral point of the generator is not dependent on the need to trip because of fault current magnitude, since it may be negligible and will not, in general, cause immediate damage. If a second ground fault occurs, severe damage may be sustained by the machine because this may result in a short-circuit current not limited by the grounding impedance."*

This statement is not completely accurate.

The historically common ground relay is an electromechanical relay that is powered by the voltage of the stator winding itself. Thus, if a ground occurs low enough in stator winding, there is insufficient stator winding voltage to cause the relay to activate. This inactive voltage range covers about the bottom 5% of the winding. As a result, any time a ground occurs in the bottom ~5% of the stator winding the electromechanical relay does not respond and there is no stator winding ground relay protection at all. Generator trip must await sufficient damage to cause other relay protection to become involved, generally the differential relay.

If the stator winding ground is resulting from failure of the groundwall insulation itself (for example, foreign object damage or badly cracked groundwall), this condition may not be particularly hazardous. There will be a current flow to ground, but the path of this circulating current returning to the winding is through the high impedance stator neutral grounding system – typically a resistor-loaded distribution transformer.

This ground circuit impedance is set to limit current to a small value, about 3-10 amperes. This amount of current can not result in burn damage to the winding or core iron. So while the condition of a ground at any location of the winding is undesirable, consequential damage to the generator will not occur. Thus from this narrow viewpoint, omission by the Standards of recognizing the condition of low-end ground in the stator winding may be understandable.

5.3.3.2 Examples of stator grounds

However, the condition of failure-to-ground due to a stator conductor fracture is not rare. Particularly if the failure location is in the bottom 5% of the winding, this failure mode is far from benign. The author has been personally intensely involved in four such incidents in a recent 2-year period. All four of these incidents occurred on a neutral bar or neutral connection ring. All four resulted in massive damage to the generator. Examples of these failures are shown in Figure 5-30 & Figure 5-31.

Figure 5-30 & Figure 5-31. Typical core and winding damage resulting from broken stator winding conductor.

5.3.3.3 Stator winding ground faults

In-service stator winding failure to ground is a relatively common failure mode on generators. There are many possible causes. Some relate to mechanical damage of the ground insulation – Category #1. Examples include: ground insulation wear-through from a foreign object or loose component, fracture of the groundwall due to a sudden short circuit, deficient groundwall insulation system, partial discharge combined with vibration, vibration sparking, inadvertent damage during maintenance, wet insulation due to strand header water leak, bar vibration in the slot.

Other failures relate to fracture of the conductor with the resulting burning away of the groundwall insulation – Category #2. Examples include: fracture of bar copper due to high cycle fatigue associated with vibration, fracture of bar copper due to gross overheating of the copper, core iron melting, failure of a bolted connection, failure of a brazed or welded joint, failure of a series or phase connection.

Category #1 failures should generally be benign. Unless a second ground occurs, the current flow to ground is limited to the 3-10 ampere range and no peripheral damage is likely to result from this ground current itself. (However, there is always the possibility that a second ground may simultaneously occur. This probability is increased due to the situation that a first ground is likely to be on a higher-voltage bar, thus elevating the voltage on the high-voltage bars of the other two phases. Two such simultaneous grounds guarantee that massive arcing will occur at each of the ground locations.)

A Category #2 failure almost certainly will be highly destructive to the generator in all situations. These failures involve fracture of the current-carrying copper. When a conductor breaks, current will temporarily continue to flow uninterrupted within the stator bar groundwall insulation as in a welding arc; the heat generation will be extremely intense. This current will flow inside the insulation until the insulation is mechanically destroyed. Experience has shown that the copper will be vaporized for perhaps 8 to 12" before the internal arcing breaks through the insulation wall and becomes an exposed and wide-spread arc – and involves ground. Figure 5-32, and also Figure 5-30 and 5-31.

Figure 5-32. Burned away copper of a fractured connection ring.

If the failure occurs in the slot, and is in a low voltage portion of the winding, relay trip will still not occur! (If the failure is in a higher voltage location, immediate trip will occur but there may still be significant arc damage as there will still be several seconds of continuing arc while rotor current decays.)

If the failure is in a low voltage portion of the winding, generator trip will not occur until some other relay system recognizes there is a problem, e.g., core melting damage progresses to where bars at higher voltage become involved, arc current bypasses a current transformer and differential relay trip occurs, arcing becomes so wide spread that other portions of the winding become involved.

A comment on failure root cause investigation. Root cause investigation of failure of stator windings that have failed due to a broken conductor is usually very difficult. This is because there is always massive burning and arc damage, and usually the actual cause of failure will be burned up in the resulting arcing. In virtually all cases the root cause can only be deduced from circumferential inference, e.g., condition on similar components within the winding, conditions of similar generators, conditions of nearby portions of the failed components, engineering judgment, engineering intuition. Obviously each of these "inference" tools contains inherent uncertainty.

But regardless of root cause, the resulting damage is likely to be widespread and hugely costly in terms of repairs and loss of generation.

5.3.3.4 Costs associated with recent stator winding failures

Obviously it would be of interest to calibrate on the direct loss associated with non-functioning ground relay systems. Looking only at the four largest, and based on input from the plant personnel, the following values result:

- *Actual* costs of the 4 incidents:
  - Repair costs - $104 million
  - Realistic loss of generation costs estimate - $378 million
  - Total - $482 million
- *Estimated* costs with functioning ground relay system may have been in the order of:
  - Repair costs - $30 million
  - Loss of generation costs - $128 million
  - Total - $158 million
- Net savings with a functioning ground relay system would have been in the order of:
  - Repair costs - $74 million
  - Loss of generation costs - $250 million
  - Total - $324 million

The $324 million is an incredibly large number. For comparison purposes, there have been numerous stator winding failures in the higher-voltage portions of windings where the ground relay trip was correct. Two such failures are shown in Figure 5-33 and Figure 5-34. In each incident repairs were relatively minor – in both cases stator repair was accomplished without rewind and in only one of these failures was contamination sufficient to require field rewind. Outage time was in the order of one month for each failure.


Figure 5-33 & Figure 5-34. Failed phase and series connection.

Obviously it is not possible to accurately estimate the saving from a functioning ground relay system. But $324,000,000 is a huge sum. A saving of an order of magnitude less would still be $32,000,000 – a non-trivial amount of money.

5.3.3.5 Stator winding ground relay systems

The stator windings of power station generators are typically Y-connected and high-impedance grounded through a distribution transformer. The impedance is controlled by the magnitude of the resistor connected across the transformer. This impedance is selected to allow a maximum of 3-10 amperes in the event of a ground at the high voltage end of the stator winding. Figure 5-35.

High-Impedance Grounding

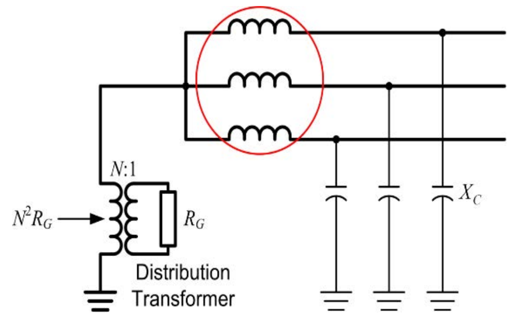


Figure 5-35. Simplified circuit for the grounding of a large generator. (Courtesy Schweitzer Engineering Laboratories – SEL)

Historically across the resistor is placed an electromechanical relay, 59GN. This relay is powered by the voltage of the stator winding. The characteristics of this electrical circuit and relay are such that the relay does not respond to the voltage of the bottom ~5% of the stator winding.

This weakness of the electromechanical relay has been recognized for many years. By the early 1970s, in Europe most generators larger than 100 MW were also protected by a 3rd harmonic relay 59THD, and in 1980, 3rd harmonic relay protection was applied in North America. This combined relay system protects 100% of the winding. Figure 5-36.

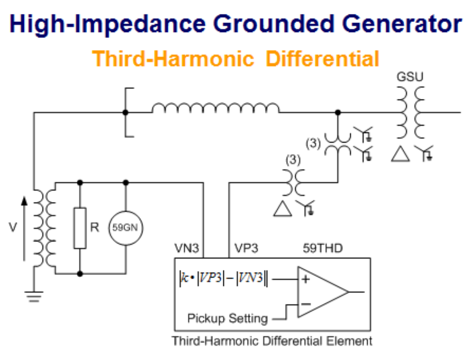


Figure 5-36. Circuit for the combined electromechanical 59GN and third harmonic 59THD relays. (Courtesy SEL.)

However, the 3rd harmonic relay system requires initial calibration with the generator operating off-line and on-line in order to properly set the relay responses: this calibration work can involve significant cost and inconvenience to the plant. Furthermore, some generator designs may not produce sufficient third-harmonic voltages to allow reliable ground fault protection schemes based on 3rd harmonic signals. Finally, the 3rd harmonic relay system has been found to occasionally cause false-positive trip due to subtle changes over time in the power system 3rd harmonic voltages.

Because of these 3rd harmonic concerns, there is a trend toward developing and installing voltage injection relay systems 64S. Figure 5-37.

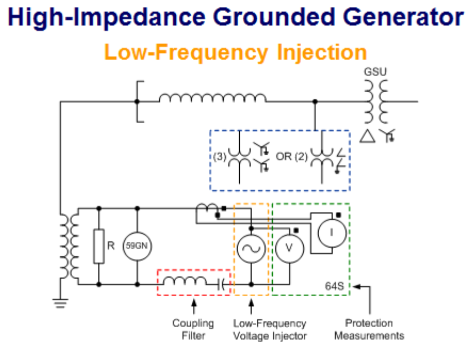


Figure 5-37. Voltage injection ground protection. (Courtesy SEL.)

With the injection relay system, ground fault protection can be functional when the generator is shut down at standstill or turning gear, during startup, and at-speed off-line or on-line. A sub-harmonic sinusoidal voltage is injected continuously, typically at 15 or 20 Hz (on 60 Hz systems). The resultant sub-harmonic current is measured via the 64S relay and if a ground fault occurs anywhere in the three phases of the stator winding, the current in the relay increases and causes the relay to operate.

The injection relay system is self-monitoring and the sensitivity is independent of power system voltage, load current, or frequency. This system has improved sensitivity compared to the 59GN or 59THD relay systems because of the higher impedance path of the generator capacitances at these lower frequencies. Also, because the 64S relay system integrates over a half cycle of the sub-harmonic frequency, there is no contribution from the signals of system base frequency and harmonics, e.g., 60 Hz, 120 Hz, 180 Hz. Thus these frequencies do not influence the 64S relay performance.

The cost associated with providing and maintaining a reliable injection source is a disadvantage. But this disadvantage may be small compared to the costs associated with calibration efforts required on the 3rd harmonic relay system.

The coverage of the stator winding provided by the three relay systems in shown graphically in Figure 5-38.

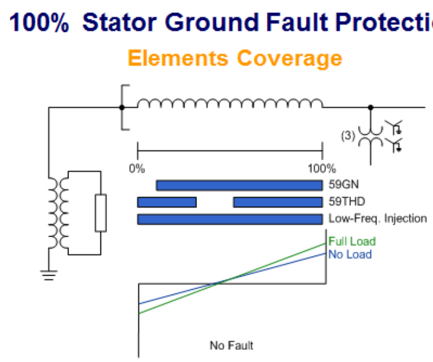


Figure 5-38. Ground fault stator winding protection.
(Courtesy SEL.)

In summary, the 59GN relay gives reliable protection, but only on the top ~95% of the winding. The bottom ~5% remains completely unprotected. In some cases, this has proven to be a near-fatal deficiency based on the experience reported earlier in this document.

The 59THD relay does not protect the mid-portion of the winding and must be used in conjunction with an additional relay system. Thus even if fully reliable, the 3rd harmonic system could not be considered as adequate protection by itself.

The injection relay system 64S has the disadvantage of the cost of the signal generator, but can alone reliably protect the entire winding. It has the further advantages in that it can detect open circuits in the grounding transformer primary or secondary and is self-protecting for a grounding relay system problem or loss of injection voltage source.

5.3.4 Ground detection corrective actions

Because of the hazard associated with either rotor or stator winding grounds, the power plant ground protection systems for both components should be reviewed and any deficiencies found and corrected.

The ground protection systems for rotors are relatively uncomplicated, but the alarm/trip decision may not be uncomplicated. If a rotor is known to have marginal or suspect ground insulation, and if the generator is important to the power system, a ground should not be allowed to exist for more than a brief period, e.g., minutes, hours or a few days at most.

On stators, the historic stator winding ground protection relay 59GN should not remain as the sole protection system on any generator of importance to the power system. Based on the industry experience reported in this paper, it would be advisable to upgrade to incorporate 100% stator winding ground protection.

The third harmonic relay 59THD unfortunately has proven to occasionally perform unreliably due to insufficient or changing 3rd harmonic voltages, and more particularly to cause a false positive trip (thus incorrectly removing a turbine-generator from power production). These concerns would seem to make the 3rd harmonic relay unattractive unless the reliability issues can be resolved.

Based on operating experience and the present state of the art for relay systems, it appears an injection stator winding relay system 64S should be installed on any generator where high reliability and low cost exposure are considered important.

Finally, IEEE Standards C37.101-2006 and 102-2012 relative to ground protection of rotor and stator windings need to be revised to reflect the broken conductor failure mechanism. Plans are in place to make these corrections, although this may require 2 or 3 years to complete.

6. Chapter 6 - Visual Inspection

6.1 General

6.1.1 Scope

Evaluation of the actual condition of a generator is an exceptionally challenging task. Inspection has several limitations: necessary to disassemble components, many areas cannot be seen even with the best tools including robots, results are qualitative and highly operator dependent, time consuming. Each of the many tests also has one or more of several limitations: cannot find local discrete weak areas without risk of insulation breakdown, gives averaging results only, insensitive to vital deterioration mechanisms, requires specialized equipment, personnel hazard.

Fortunately, however, the two approaches to generator assessment – inspection and test – are quite complimentary. The combination of a good testing program and thorough inspection by a skilled and trained individual can give a good assessment of almost all common forms of generator deterioration.

On generators that are important to system reliability, it is important that both test and inspection be performed, and that neither be neglected nor superficially done.

6.1.2 Special Inspection Cautions

Many problems will be immediately obvious to initial glance, and can be seen without entering the generator, e.g., stator winding double failure to ground. Some locations are not easily accessed, e.g., under retaining rings. Some forms of deterioration are very difficult to locate, e.g., stator winding single failure to ground. Some problems are difficult to assess, e.g., stator bar vibration.

It is vital, then, that the inspection is thorough, that proper tools are used, and that conclusions as to winding condition not be lightly or quickly reached.

6.1.3 Check-lists

Because of the complicated nature of the task, a comprehensive check-list is essential to assuring that important components and areas are not overlooked. Also an organized, consistent approach will make comparison of results of various inspections more meaningful, particularly if subsequent inspections are not performed by the same individual.

Good check-lists are available in the literature, or can be custom developed by a qualified individual.

6.1.4 Common Evidences of Deterioration

Fortunately many of the prevalent deterioration mechanisms leave tell-tail signs of trouble: dust, dirt, grease, fretting, discoloration, displacement, cracks, foreign objects, deformation, distortion. All of these signs should be kept in mind as an inspection is performed.

However, it must also be kept in mind that the evidence may be subtle and limited, particularly in the early states. Such evidence may be extremely important and may easily be overlooked if proper care is not exercised. Figure 6-1 is burning in an end winding, visible only by careful inspection with a mirror; the bar failed hipot at a low value. Figure 6-2 appears to be a small amount of “greasing” from minor bar vibration, but more likely is associated with side ripple spring wear deep into the bar insulation.

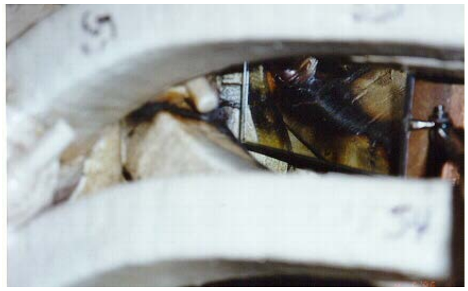


Figure 6-1. Arcing Damage from Hipot Test

Figure 6-2. Dust Deposit on Stator Core Bore from Bar Vibration

6.1.5 Training/Experience

Because inspection is inherently difficult and often judgment must be made as to the significance of evidence, it is essential that the inspection be performed by a qualified individual. Training and experience are important, and on failure root-cause analysis or a new and complicated phenomenon, basic generator design understanding will be needed. Experience has shown that diagnostics of generator failures can be exceptionally difficult. Unfortunately, most OEM and maintenance company field service personnel have little training and background for correctly diagnosing new and/or unusual generator failures – they are trained to repair generators.

Mis-diagnosis is common and can be exceptionally costly. Chapter 4, Section 4.3.

6.1.6 Equipment/Tools

A cursory inspection can be made with little more than a flashlight. However, when the complete inspection is performed, other hand tools are needed: borescopes (flexible and rigid), background lights, large and small flashlights, various shapes of mirrors, magnifying glass, small hammer, knife, magnet, and print and video cameras and adapters, Figure 6-3.

Figure 6-3. Typical Hand Tools for Generator Inspection, Courtesy Enoch Silva, ES Consulting

Some inspection operations require equipment in order to be quantitatively and expeditiously performed: wedge tapping, top ripple spring checks, borescope. A digital camera and many photos will always be helpful.

Robot equipment is available for inspection with the field in place. Generally these inspections will not be as good as direct inspection, but still can be valuable and are much less costly and time consuming compared to removing the field. Also, risks of disassembly/reassembly damage are greatly reduced. Figure 6-4 is typical of damage done by field contact with the stator core during generator assembly. But unfortunately, if a problem is found, and this often is the case, the field may require removal for correction of the defect, thus nulling the benefit of the robot inspection.

Figure 6-4. Damage from Contact Between Field and Stator Core

6.1.7 Time Intervals

Accessible components should be inspected at every convenient opportunity, but particularly during minor and major outages. Frequency of inspection should also vary based on known problems and on importance of the machine to the system.

In addition, OEM recommendations should be considered in planning of outage schedules, both machine-specific recommendations and general recommendations. In general, OEMs have recommended major inspection with field removed every 5 years. However, the intervals may logically be extended for several reasons, e.g., satisfactory inspection through use of robots, unit base loaded, particularly reliable performance, little operating time, cost constraints, unit not of high priority. There are several corresponding reasons for shortening the interval, e.g., cyclic loading, known weakness in a component, operating incident, mis-operation, information of concern from the monitoring devices.

6.2 Equipment/Component Accessibility Considerations

6.2.1 With Field in Place

Fully assembled generators allow little access for inspection. Examination of Figure 6-5 indicates the restricted access even with partial disassembly.

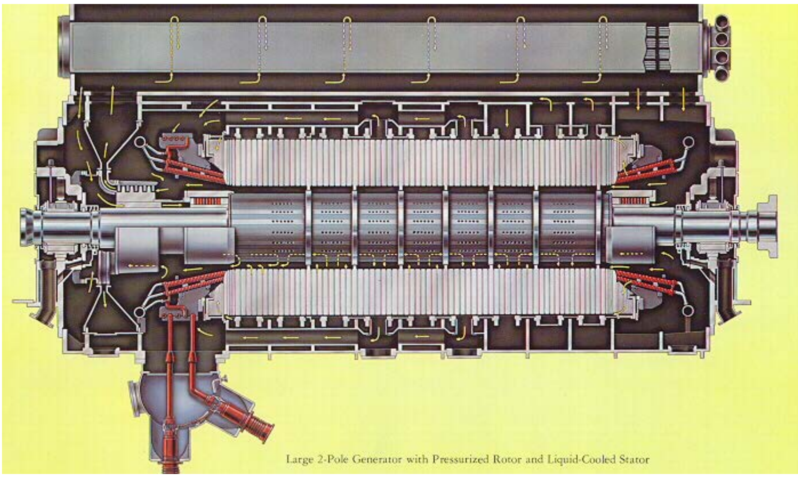


Figure 6-5. Cross Section of a Large Generator (Westinghouse)

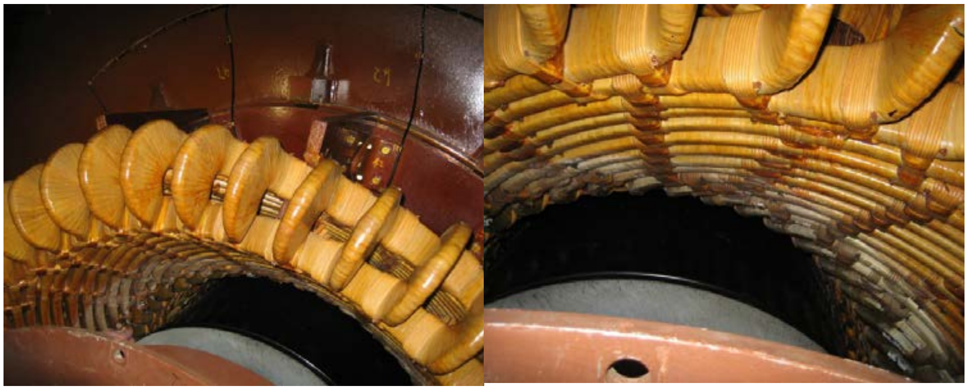
6.2.1.1 Inspection Ports

Manufacturers provide a limited number of ports, primarily for assembly and balance purposes, although on some designs important access is available through man-way covers or perhaps by removal of a cooler. Generally, little can be observed, although if severe burning or other major damage has occurred this may be readily evident. Removal of covers located behind the core will gain very limited access to the back of the core. Removal of a cooler may allow a small agile person to inspect substantial areas of the core outside diameter and the frame, and perhaps the stator endwindings. On air-cooled generators with man-way access at the ends of the frame, it is possible to have good access behind the stator windings, Figures 6-6a&b.

Figures 6-6a&b. Inspection Man-way in Frame Behind Stator Endwinding. Access to Winding through Man-way.

6.2.1.2 End Shields Off

Removal of the inner and outer top-half end shields will allow important portions of the generator to be inspected, Figures 6-7a&b. The right tools, e.g., mirrors, flexible borescope, and miniature video cameras placed on an extension pole, may give access to the retaining rings, field end wedges, core end iron, and stator end wedges.



Figures 6-7a&b. Views of Stator Endwinding with End Shields Removed.

Robotic equipment that is available can traverse the entire length and circumference of the airgap, even those machines with air gap baffles. With these robot devices, many additional vital generator parts can be inspected: field wedges, stator bar vibration, Figure 6-8 & 6-9, stator and field wedges, stator wedge vibration, stator core, air gap baffles, Figure 6-10, core ventilation ducts. Figure 6-11, radial spring ripple height. These inspections are made with miniature video camera, wedge tapper, and ripple height measuring attachments.

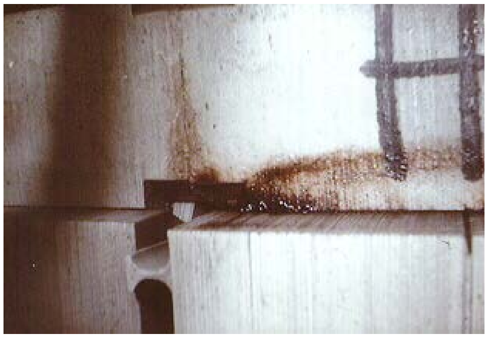


Figure 6-8 & Figure 6-9. Robot Camera View of Stator Bar Vibration and Core

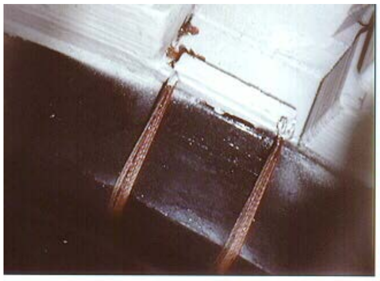


Figure 6-10. Air Gap Baffle

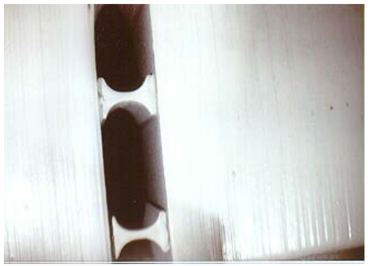


Figure 6-11. Core Ventilation Ducts

6.2.2 Field Removed

A “complete” stator and field inspection requires removal of the field. Good access is provided to visible surfaces such as stator end windings, vent ducts via borescope or very small flashlight, and under retaining rings with flexible borescope and mirrors, Figure 6-12 and Figure 6-13. Also on most direct-cooled fields, ventilation circuits can be checked through the radial gas discharge holes in the wedges.

Figure 6-12. & Figure 6-13. Field Winding Inspection with Mirror and Direct View

Examination of stator bars is greatly improved, and this will allow better determination for the critical conditions of slot discharge and insulation mechanical wear due to vibration. Disassembly of stator wedges is also facilitated.

Even with the field removed, however, there remain inaccessible locations: most internal components of the field, most of the core, stator bars below wedges.

Removal of retaining rings, and some field coil blocking, will allow the entire field end winding to be inspected for distortion, cracks, and ventilation problems. Examination of the full surface of the retaining rings is also permitted.

6.3 Duties on Components (Special Considerations)

6.3.1 Mechanical

Because most failure mechanisms are mechanical in nature, increased attention should be given components on which mechanical duties are particularly high. Important components on stators would include: stator bars, wedges, bar connections, end winding support, core laminations. On fields: field copper turns, coil and collector connections, forging, retaining rings, wedges, collectors and brush holder riggings, journals. On the frame: core key bars, coolers, welds and other attachments, bearings, hydrogen seals.

6.3.2 Electrical

Electrical stresses are a concern on both stator and field windings. In stator slots, electrical discharge can eat away the bar insulation in areas very hard to inspect. In the stator end winding, partial discharge deposits may be found where bars and connections in different phases are in close proximity, partial discharge may have attacked the grading materials and ground insulation.

Most fields manufactured in the last 40 years contain extensive creepage surfaces which can become contaminated. Field turn and ground insulation can crack and/or migrate, e.g., slot liners, turn separators, top-of-slot creepage blocks. Collectors and brushes operate in a contaminated atmosphere (carbon dust) which will deteriorate the creepage paths.

6.3.3 Liquid Leaks

Three common sources of leaks are found on large generators: bearing oil, water from coolers, and water from stator bars on direct cooled windings. Unfortunately, leaks from these sources are common. In broadly differing ways, leaks of any type can have serious negative impact on generator reliability and durability.

Lubrication oil can degrade some types of insulating materials, reduce friction coefficients on stator bar slot restraint systems, and combine with dusts to form heavy deposits which can restrict or plug ventilation circuits and fill ventilation passages. Water leaks from coolers can facilitate stress corrosion cracking of retaining rings, degrade electrical creepage paths, deposit contaminants on stator end windings. Minute stator bar strand header water leaks can irreversibly damage stator bar groundwall insulation, and can lead to stator winding hipot or service failure. Large stator winding water leaks can be associated with loss of water flow to stator bars (with differential expansion fracture of bars), and interruption of stator winding current flow (with severe arc damage).

Each of these problems can result in long forced outage due to required major repairs.

6.4 Inspection Procedures

6.4.1 Stator

6.4.1.1 Slot Portion of Winding

Slot electromagnetic forces are high and deterioration is common and can be severe. The slot portion of the stator winding is probably the most critical and difficult area of a generator to properly inspect. Most of the important areas of interest are enclosed behind the wedges and the core iron. Proper inspection becomes tedious, but if proper tools are on hand and if the operator is patient, persistent and perceptive, a good inspection can be accomplished. In particular, a borescope is a powerful tool for inspecting the slot portion of the winding on those machines with core radial ventilation ducts. Considering various deterioration mechanisms and locations:

6.4.1.1.1 Slot Wedges & Bar Vibration

Partial or complete looseness of individual wedges can be detected by tapping either manually with a small hammer or by mechanized tools. Also, commonly there will be dust or "grease" generated by the fretting actions, and these deposits will be easily seen, although not necessarily easily assessed. Where dust and/or grease are present, it is important to try to distinguish between simple wedge vibration**,** which may not be a serious concern, and bar vibration, which is always a deep concern. Loose wedges may simply vibrate small amounts and generate significant amounts of dust without causing measurable damage to the wedge or the iron, Figure 6-14.

Figure 6-14. Dust Generated by Vibrating Wedges

But loose wedges may also allow bar vibration, may wear into the core iron, and may allow filler migration. The degree of winding deterioration cannot easily be assessed my observing the amount of dust or grease. If deposits are widespread and heavy, it is certain that bar vibration is occurring. However, local and relatively small deposits of dust or grease may also be associated with severe bar vibration damage, Figure 6-15.

Figure 6-15. Severe "Greasing" Due to Bar Vibration at Ends of Core

Bar vibration occurring only at the ends of the core, without bar vibration occurring towards the center of the core, is almost certainly due to the bars being held off the bottom of the slot by the endwinding support. Figure 6-15. Wear can occur with very small clearance, perhaps less than 3 mils, Figure 2-12. Clearance less than about 30 mils cannot be seen directly or with a borescope, nor measured by feeler gauge. However, these small clearances can be detected by bar jacking at the end of the slot. **Error! Reference source not found.** shows this process using a standard bar jack and a core-mounted dial indicator. Note that vibration of this type can occur with tight-sounding wedges.

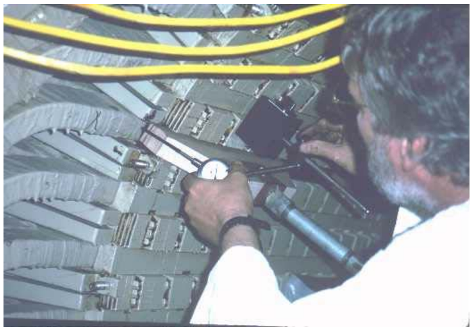


Figure 6-16. Bar Jacking Process for Assessing Slot Clearance

To stator bars is limited and only available at the core ends and on most designs, through ventilation ducts. In the ducts, side packing and ripple springs will limit access to the bars. Care should be taken to examine both sides of each bar as it exits the slot, where access for inspection is good. In the core area, a borescope sufficiently small in diameter to enter radial ventilation ducts may help in evaluating: groundwall insulation partial discharge activity and mechanical wear, vibration sparking damage, quantity of dust or grease buildup, puffing or bulging of insulation, severe insulation cracks or migration, filler migration, large radial clearances. Figure 6-17 & 6-18.

Figure 6-17 & Figure 6-18. Inspection for Stator Bar Slot Vibration by Borescope and Flashlight

It should be noted that observations through a borescope are magnified and distorted; the operator must clearly recognize and allow for this distortion. In some cores with wider (>3/16”) ventilation ducts, a very small flashlight will also allow direct, undistorted observations near the top of the slot, Figure 6-18. Removal of wedges and top fillers may also assist in assessing suspected deterioration.

6.4.2 End Windings and Connections

The stator end windings are more accessible than the slots. The forces are lower, but the restraining systems are also less effective. In addition, vulnerability to foreign object entrapment and wear is high. Thus inspection of end windings and connections also requires that the operator be patient, persistent and perceptive in examining all areas. Considering various deterioration mechanisms and locations:

6.4.2.1 Vibration

May be observed on all components and all locations, and usually will be evidenced by dust or grease deposits, Figure 6-19 and Figure 6-20. Unless trivial, indications of vibration are always a cause for concern. Blocks, rings and ties should, therefore, be inspected carefully and checked for looseness by tapping or small mechanical force.

Figure 6-19. Dust Generation from Connection Ring Vibration

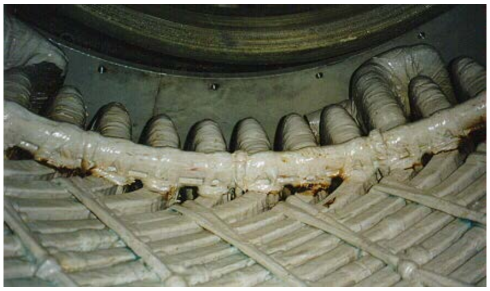


Figure 6-20. Stator Bar End Winding Vibration

6.4.2.2 Partial Discharge Activity

Partial discharge can result in several conditions that are detectable by thorough inspection. (Partial discharge indications tend to be much greater on air-cooled generators than on hydrogen-cooled units.) The most serious of the operating conditions is the whitish deposit shown in Figure 6-21a & Figure 6-21b. This damage results from intense partial discharge and may cut into the insulation. (Cases have been reported on air-cooled generators where the depth of damage may exceed 20% of the insulation wall, although commonly the discharge cutting will not proceed beyond the surface of the first layer of mica tape and even "severe" PD may not penetrate mica insulation in the life of the generator.) In hydrogen cooled generators, partial discharge may deposit a brown-sugar appearing solid.

Figure 6-21a. Partial discharge at Line-to-Line Phase Break in Stator End Winding

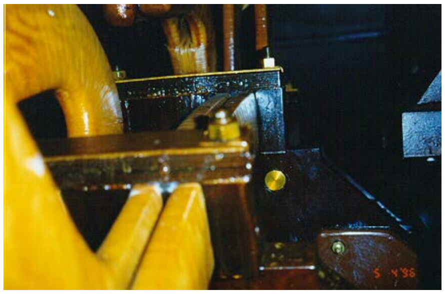


Figure 6-21b. Partial discharge Between Two Line Voltage Connection Rings

Both air-cooled and hydrogen-cooled generators have formed brown or black semi-liquid deposits. Figure 6-22. These materials are suspected of being a product formed from bearing oil vapor in the presence of a high voltage field. If the partial discharge activity is not cutting into the insulation, careful cleaning may be the only action required.

Figure 6-22. Deposit Resulting from Partial discharge Field Acting on Lubrication Oil Vapor

High voltage test may also damage insulation through severe arcing. Figure 6-23 shows damage probably resulting from factory hipot.

Figure 6-23. Arc Damage from Stator Hipot

All indications of partial discharge activity should be carefully examined for determination of necessary corrective action.

6.4.2.3 Short Circuit Damage

If the generator has been subjected to a short circuit or mis-synchronizing incident, the winding will have experienced mechanical forces which can be very high, in the order of 100 times maximum normal operational forces. Check for broken ties and bar displacements, Figure 6-24, bar insulation hair-line cracks, Figure 6-25, and cracks in the blocking (beyond the normal hair-line cracks associated with differential expansions). If the generator is suspected of having experienced a short circuit event, examine the bars just outside the core in the first radius region for hair-line cracks in the insulation surface; even tiny cracks, Figure 6-25, are likely to be indications of insulation broken completely through.

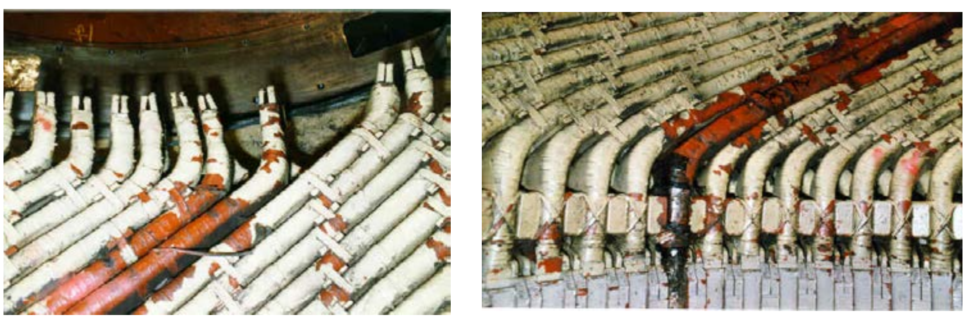


Figure 6-24. Broken Ties and Bar Displacement Due to Short Circuit Forces

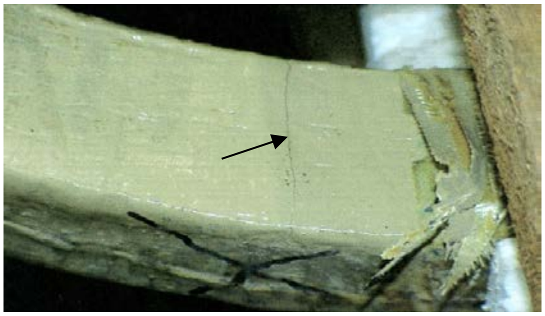


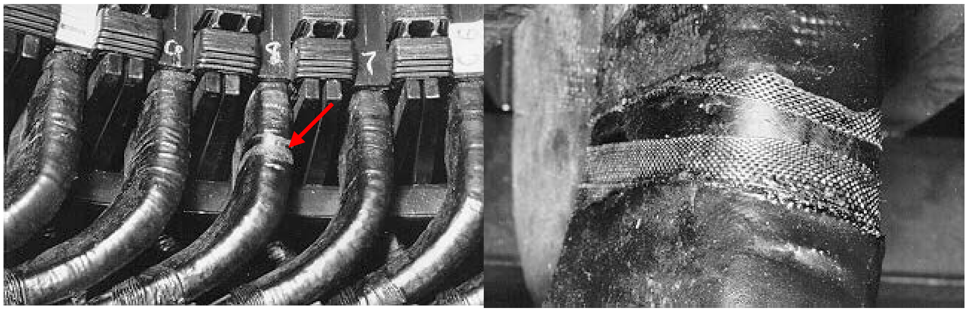
Figure 6-25. Severe Crack from Short Circuit Forces

6.4.2.4 Foreign Objects

Foreign objects may be located anywhere in the matrices of the end winding and connections. Often an object may be very difficult to detect, unless generating tell-tail dust. If foreign object intrusion is suspected, inspection should be particularly thorough.

6.4.2.5 Tape Migration

Many large asphalt windings and a few early thermoset windings have experienced this problem, usually on the top bars and at the collector end of the winding. The classic manifestation of tape migration is the "girth crack", or separation of the surface layer of tape at the end of the slot. Figures 6-26 and Figure and 6-27 show the results of a 3/4" tape migration.



Figures 6-26 and Figure 6-27. Armature Bar Girth Crack (Center of Photo) Resulting from Tape Migration

Two inspection information sources relate to amount of damage done to a specific bar:

1) total amount of tape migration, and

2) physical appearance of the bar in the area of the separation.

Assessing the total amount of migration is difficult. The separations occur in the area from about 4" inside the core to 12" beyond the end of the core, but most commonly in the 6" area of the bar just outside the core. If the girth crack appears in the end winding and the winding has not ever been painted, the width of the surface separation is the amount of the migration. If the winding has been painted, one must sum the amounts of migration observed between each application of paint. Since such records are rarely kept, determination of total amount of migration generally is not possible. This is unfortunate because amount of deterioration closely correlates with total amount of migration on an individual bar. Significant deterioration usually has not occurred with migration of less than ½", and may not be serious with total migration of 1".

Evaluating the physical appearance of the bar is often equally difficult. If a deep crack exists, the bar can be regarded as unusable. More commonly the bar may appear to be normal except for the surface separation. Any bar showing evidence of insulation migration should be examined by hand pressure for signs of sponginess or indications of voids. (Asphalt insulation is rigid at room temperature; if the surface of a suspect bar is raised to about 40C by heat lamp, examination for sponginess will be easier.)

There are few active service engineers who are at all familiar with this old insulation system. (Few large asphalt insulated winding were built after the early1960s.) But many asphalt windings are still in service. Because of limited access to technical information and the uncertainties of inspection for tape migration, hipot is probably the only reliable tool for assessing the condition of an asphalt winding. It should be kept in mind, however, that if the winding is clean and dry, a defective bar may fail without warning and require that the bar be replaced. Fortunately, tape migration is predominately in top bars, thus allowing relatively easy replacement.

6.4.3 Core

Most core deficiencies can be observed from the core surfaces, and a careful inspection (combined where appropriate with core flux test) will generally give a good assessment of core condition. Considering the various deterioration mechanisms and locations:

6.4.3.1 Contamination

Contamination may be heavy on the core inside diameter and in ventilation ducts. Sources include ambient dirt, rain, bar vibration wear, wedge vibration, bearing oil leaks, core lamination vibration. Figure 6-28. Examination should determine source and nature of the contamination in order to facilitate corrective actions.

Figure 6-28. Heavily Contaminated Stator Core

6.4.3.2 Minor Mechanical Damage

Minor mechanical damage may range from a small knife or chisel cut to punchings bent during rewedging or field removal. The problems generally are confined to the accessible inside diameter areas of the core, but may not be detected unless inspection is thorough.

6.4.3.3 Minor Overheating or Burning

Mechanical damage may result in shorting of only a few adjacent punchings. The fault may appear as a small, localized solid-metal surface, or alternatively, small areas of scorched lamination paint. Figure 6-29 & Figure 6-30. These conditions can be serious, and may be overlooked if inspection is not thorough.

Figure 6-29 & Figure 6-30. Minor Core Burning Probably only Requiring Small Amounts of Grinding and/or Etching to Correct

6.4.3.4 Severe Mechanical Damage

Severe mechanical damage can be caused, for example, by foreign objects in the airgap, by careless w edging, or field removal. It usually will be wide-spread, easily observed and very serious. All damaged spots must be located and identified for corrective actions.

6.4.3.5 Looseness

Core looseness usually will occur at the inside diameter near the ends of the core. However, it is possible for looseness to be general and/or exist on the core outside diameter. If looseness is suspected, degree of looseness can be evaluated by carefully inserting a knife blade between punchings, Figure 6-31. Looseness may be accompanied by dust/grease generation, punching and spacer movement, or small pieces of punchings flaking or cracking off.

Figure 6-31. Use of Knife to Evaluate Core Looseness

6.4.3.6 Cracked Laminations

Cracking of laminations usually occurs at the ends of the core. Pieces will be missing and may have worn into stator bar insulation. May be accompanied by general and/or local core looseness.

6.4.3.7 Displacements

Individual punchings, groups of punchings, or outside or inside space block assemblies may move tangentially or radially. Care must be taken to distinguish between original stacking errors, which may be up to about 15 mils, and actual migration. Since punching displacement can result in armature winding failure, inspection should be carefully performed.

6.4.3.8 Damage from Lamination Insulation Failure

Lamination insulation failure damage may be evidenced by general or localized surface overheating or burning of paint, and in extreme case, melted iron, Figure 6-32. It may also involve the core outside diameter and/or support structure. This is always a serious condition which must be identified and corrected (probably by re-stacking core). Lamination insulation can also be degraded by relative movement between punching on a loose core; if a loose core is retightened, the improved contact between punchings may result in core failure on restart.

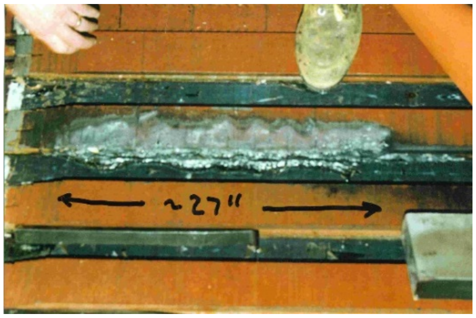


Figure 6-32. Severe Core Overheating Requiring Re-stacking

6.4.3.9 Core Damage Due to Over-fluxing

Burning will focus on the ends of the core and on the keybars behind the core iron. Assessment of extent of damage may be difficult, particularly since burning may occur within the core back-iron. An incident may appear to involve only small amounts of burning and look as if minor. However, more significant damage may have occurred deep in the core and on the keybars, Figure 6-33. In the worst case, burning will be severe at core ends (with holes melted in the teeth), and with large burn areas behind the core between core and keybars, Figure 6-34. The latter condition will usually be accompanied by stator winding failure. In all cases, whether appearing minor or severe, core over-fluxing damage is a serious concern and must be thoroughly investigated by qualified personnel.

Figure 6-33. Keybar Burning Due to Over-flux Incident

Figure 6-34. Melted Keybar and Tooth Areas Due to Over-flux Incident

6.4.4 Frame and Coolers

Frames ordinarily are not the cause of generator problems. However, there are issues which should be kept in mind and the frame inspected accordingly.

6.4.4.1 Dirt and Foreign Material

Because of the inherent complexity of frame structure, there are many areas for accumulation of contaminants, Figure 6-35. Because these materials can be carried by the high velocity ventilation gases, all accessible portions of the frame should be examined.

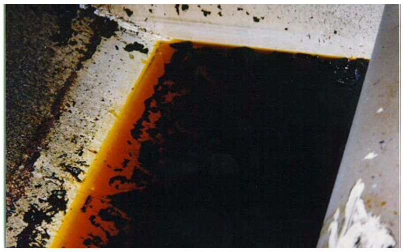


Figure 6-35. Oil Accumulation in Stator Frame

6.4.4.2 Vibration

Accessible attachment points should be checked for evidence of fretting, such as dust generation. Vulnerable locations include keybars, section plates, and cooler supports, Figure 6-36.

Figure 6-36. Wear Products from Vibration of Cooler Components

6.4.4.3 Cracks and Distortion

In the event of malfunction of the generator, or known weakness of design, complete examination should be made of the wrapper, core attachment points, and other components of the frame. This inspection is particularly important on hydrogen cooled generators, Figure 6-37.

Figure 6-37. Inspection for Cracks in Generator Frame Structure

6.4.5 Fits & Hardware

Throughout the entire generator, all locks, bolts and other attachments should be examined for looseness, displacement, or fretting, Figure 6-38 & 6-39.

Figure 6-38 & Figure 6-39. Fretting Winding Support and Field Balance Weight Locks

6.4.6 High Voltage Bushings and Stand-off Insulators

There are numerous deterioration mechanisms and locations which must be evaluated:

Contamination - Standoff insulator and high voltage bushing gas passages must be open and free of blockage. If a large quantity of lubrication oil has entered the machine, check that gas cooled bushings do not contain oil internally which could block flow of cooling gas.

Fretting - Check the bond between the porcelain and metallic flange of standoff insulators and high voltage bushings for evidence of cracking, looseness or fretting, Figure 6-40. Also check that all bolted connections are tight and properly locked.

Figure 6-40. Standoff Insulator with Unbonded Flange

Figure 6-41 shows a high voltage bushing where the bond between the insulating porcelain and the support flange has broken on a hydrogen cooled generator. The sealing compound that was used to prevent hydrogen leakage has flowed through the defect and down the surface of the porcelain.

Figure 6-41. Flow of Sealing Compound through Failed High Voltage Bushing Flange

Mechanical Damage - Inspect for chipped or cracked porcelain on bushings and standoff insulators.

Electrical - Check for tracking or other indications of electrical distress.

Overheating – Many of the electrical connections are brazed and should not be subject to failure. Some are bolted and accessible, Figure 6-42. Some are covered with several layers of insulation and are thus difficult or impossible to inspect, Figure 6-43. However, surface conditions should be checked for signs of over-temperature which may suggest a failing electrical connection.

Figure 6-42 & Figure 6-43. Bolted Accessible Isophase Electrical Connection and Bolted Insulated High Voltage Bushing Connection

6.4.7 Bearings and Seals

Primary areas of concern are mechanical deterioration of the journal contact surfaces and loss of insulation integrity. Considering these areas:

Bearings - Usually will have some deterioration due to normal wear and minor amounts of foreign material passage, but damage may occasionally be serious, Figure 6-44 & 6-45.

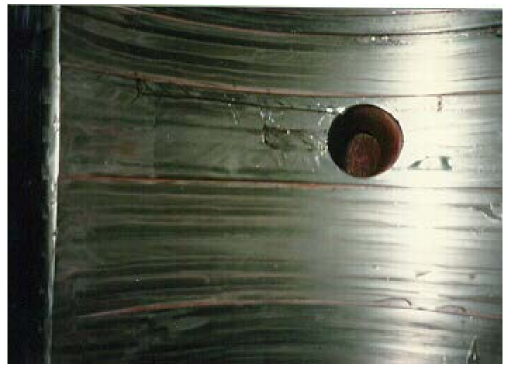


Figure 6-44 & Figure 6-45. Bearing Scored by Foreign Material

If insulation is defective and current has been flowing, surfaces will tend to appear etched. Babbitt bond to the forging may also be broken, and this condition must be evaluated. Assessment of extend of damage to the babbitt is usually apparent, but determining corrective actions may be judgmental.

Seal Rings - Check for weak springs, seal ring friction or hang-up, damage to all contact surfaces.

Insulation - Check face and bolt insulation for missing pieces, cracks, contamination build-up, debonding, loose or missing screws, Figure 6-46.

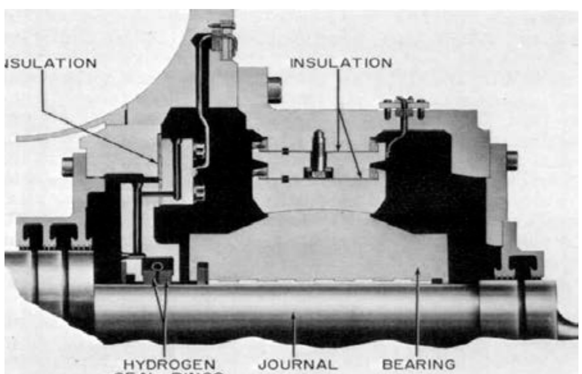


Figure 6-46. Hydrogen Seal/Bearing Assembly with Insulation Components

6.4.8 Instrumentation

Temperature sensors and leads are vulnerable to mechanical damage by personnel entering and working in generator, Figure 6-47. All components should be checked accordingly. Also, mechanical attachments should be checked for loose or inadequately locked hardware.

Figure 6-47. RTD Damaged by Careless Personnel

6.4.9 Brush Holder Rigging

Carbon-brush collectors have historically been an operations concern on turbine-generators. Figure 6-48. This is understandable in that this relatively small component is one of the most frequent causes of generator forced outages. The primary root cause of collector service problems is failure to perform the necessary on-going inspections and associated maintenance. Because of their intrinsic nature, carbon-brush collectors require regular daily observation, as well as periodic maintenance.

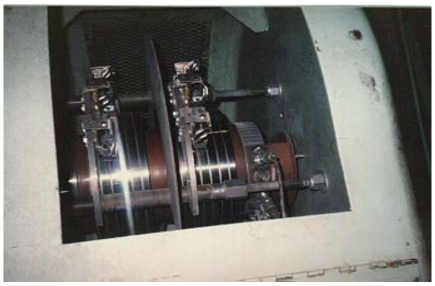


Figure 6-48. Collected Opened for Inspection

6.5 Field

6.5.1 Winding

Check field winding so far as accessible for coil displacements or deformation, turn displacements, contamination build-up, turn and slot insulation displacement and cracks, shifted or missing blocking and baffling, and arcing or burning between conductors (coils, turns, leads) and ground.

If retaining rings are not removed, inspection of end portion of the winding is difficult. On some designs, limited access can be obtained directly, Figure 6-13 & Figure 6-49, or by use of mirrors, Figure 6-12.

Figure 6-49. Inspection of Underside of Coils of Assembled Field

Most designs will give some access to borescope inspection. This inspection is tedious and time-consuming. Interpreting the borescope views is challenging because of distortion, uncertainties of location, and limitations of perspective. With retaining rings and insulation removed, access is good and inspection can be quite complete, Figure 6-50.

Figure 6-50. Field Winding Turn Distortion Accessible After Retaining Ring Removal

On direct ventilated fields, inspection can be made through the ventilation holes in the wedges on the body portion of the field, Figure 6-51.

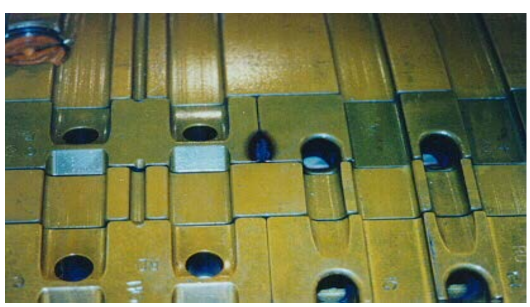


Figure 6-51. Field Ventilation Holes, Direct Cooled

Valuable information may be found relative to copper dust generation, Figure 6-52, foreign material contamination build-up, and ventilation blockage due to displacement of insulation and/or copper.

Figure 6-52. Copper Dust Generation Site on Field Turn

6.5.2 Collector

Most areas of interest are accessible. The collectors should be carefully inspected for depth and uniformity of surface wear, surface etching and burning, insulation contamination and cracks, arcing or burning of insulation and metallic parts, mechanical damage. Figure 6-53. See also 0, above.

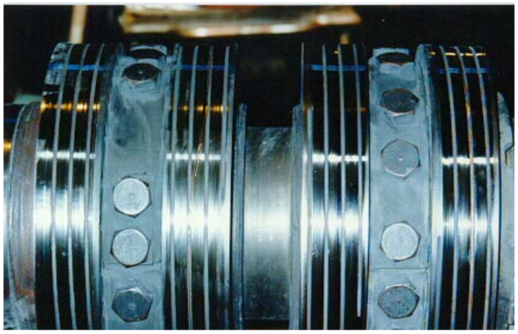


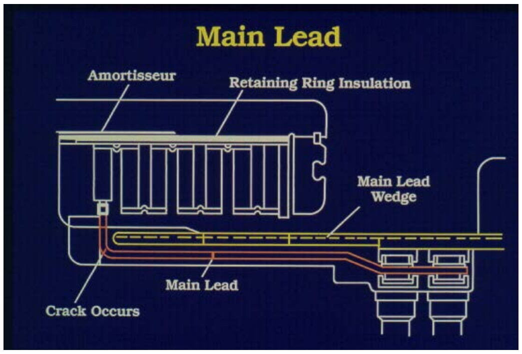
Figure 6-53. Collector in Good Condition Except for Heavy and Deep Wear

6.5.3 Collector Connections

Access to the connections is limited, but visible component should be checked for cracks, deformation, overheating or burning, and mechanical damage. Particular care should be focused on borescope check of accessible connections under the retaining ring, Figure 6-54.

Figure 6-54. Distorted Borescope View of Crack in Main Lead Under Retaining Ring

With retaining ring removed, access is improved, Figure 6-55 & 6-56.



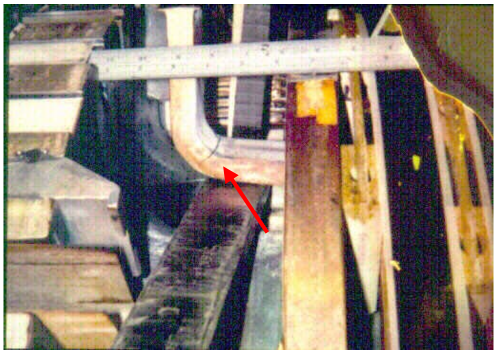


Figure 6-55 & Figure 6-56. Schematic of Main Lead and View of Cracked Main Lead

6.5.4 Forging

Many portions of the field forging are accessible, and inspection should be thorough. General concerns are: local or general overheating, cracking, rust, fretting, contamination, mechanical damage. Specifically:

Local Overheating - Most commonly is caused by negative sequence currents associated with asynchronous conditions or significant unbalance of armature phase currents. Evidence will be seen at the ends of the winding slots and at the ends of pole-face cross-slots. May range from slight discoloration to actual burn, arc damage and local cracking. Figure 6-57.

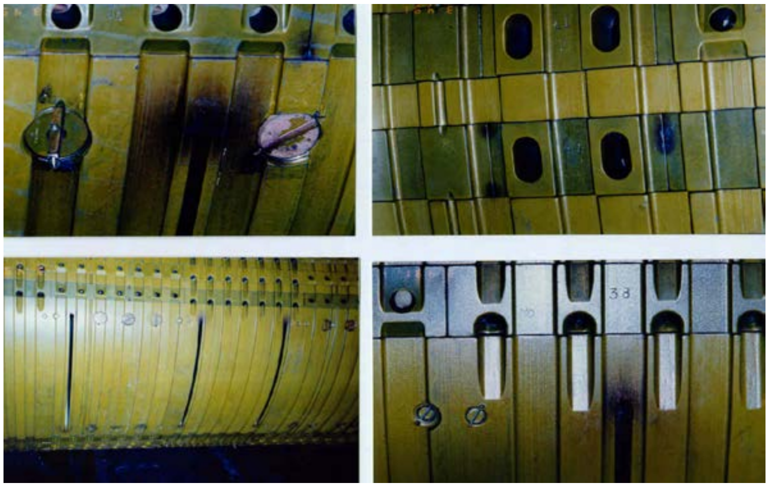


Figure 6-57. Various Forms of Evidence of Forging and Wedge Overheating

General Overheating - Usually will be accompanied by stator overheating, Figure 6-58 & 6-59. Paint may be blistered and pealing.

Figure 6-58 & Figure 6-59. Blistered Paint and Extended Armature Bars from Severe Over-temperature Incident

Forging Cracks - May be visible to the naked eye. Most likely to occur on teeth at the ends of the slots under the retaining ring shrink fit; retaining rings will require removal in order to access these surfaces. Circumferential cracks have been found on the pole face at the top of the slot at the body centerline, and shaft cracks have been found on the inboard end of a journal. Visual inspection must be accompanied by NDE.

Contamination and Rust - Cursory inspection will ordinarily assess these problems, but rust may be found in localized, less accessible areas. Figure 3-2. If machine is heavily contaminated, large build-up of contaminants may be centrifuged onto entrapment surfaces, Figure 6-60 and Figure 6-61.

Figure 6-60. Heavily Contaminated and Rusted Field

Figure 6-61. Rust Accumulation on Centering Ring and Retaining Ring

Mechanical Damage - Should be easily observed. Because of the high surface rotational speed, 300 to 400 mph, any substantial object can cause significant impact damage to the forging and other rotating components.

Fretting - Likely only to occur between components where shrink fit to the forging is low or has been lost: fans, centering and retaining rings, balance rings, Figure 6-39.

6.5.5 Wedges

Wedges are subject to several important problems:

Cracking and Deformation - May be visible to naked eye if severe, although cracks more commonly will be on the dovetails and not accessible without wedge disassembly. Deformation may occur, particularly on non-ferrous materials, i.e., aluminum. Any radially outward displacement needs to be found and may be detectable only by measurement.

Axial Displacement - Easily detected by examining lock area and gap between wedges and retaining rings. This is a fairly common phenomenon on certain field designs, particularly if wedges are not locked securely, Figure 6-62.

Figure 6-62. Field Wedge with Poor Lock and Axial Movement

Burning and Arcing - Negative sequence currents will cause current flow that may burn the wedges. Burning will normally be found at the ends of wedges, particularly near the end of the rotor body, Figures 4-55 & Figure 6-63. Burning may also be in the dovetail area, and also between the end wedges and retaining rings, if wedges have contacted non-body-mounted retaining rings.

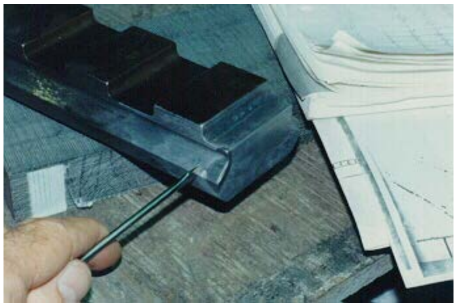


Figure 6-63. Burning of Removed Field Slot Wedge

6.5.6 Retaining Rings

NDE testing will be the primary assessment of retaining ring condition. However, careful visual inspection is essential to record gross evidence of concerns: visible cracks, fretting, movement on shirk fit, etching, burning, rust (on magnetic rings), and mechanical damage, Figure 6-64.

Figure 6-64. Retaining Ring with Minor Pitting Detected

Visual inspection should be thorough, using good lighting and magnifying glass as necessary.

6.5.7 Fans/Compressors

Design variations are extensive, and inspection procedures will vary with design. In general, during inspection search for: cracks, contamination, rust, mechanical damage, missing parts, deficient component locks, fretting, displacements, bent components, and deformation.

As in the case of retaining rings, NDE is necessary to reliably validate condition of these rotating components.

6.6 Excitation Equipment and Auxiliaries

6.6.1 Excitation Systems

Brushless exciters should be inspected for contamination, mechanical damage and other forms of deterioration, Figure 6-65 and 6-66.

Figure 6-65 & Figure 6-66. Contaminated Shaft Driven Brushless Exciter Rotor and Stator

Static excitation components should also be inspected for mechanical deterioration and contamination, Figure 6-67 and 6-68.

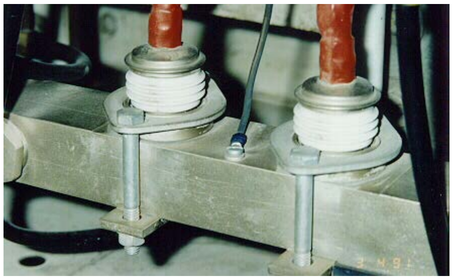


Figure 6-67 & Figure 6-68. Contaminated Static Excitation Components

The early-design DC exciters are particularly subject to contamination, component wear and mechanical damage; these components should be inspected accordingly, Figure 6-69 & 6-70.

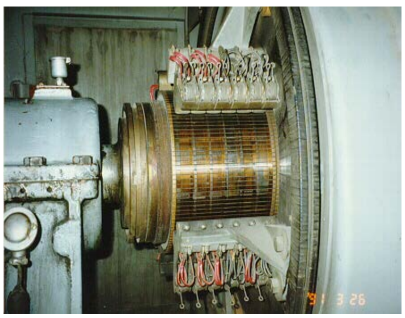


Figure 6-69 & Figure 6-70. Contaminated DC Exciter Armature and Field

6.6.2 Stator Cooling Water (and Oil) External System

Numerous varied components make up the stator cooling water system external to the generator: cooling water piping, flanges, electrical controls, valves and regulators, pressure sensor lines, coolers, pumps, motors, and storage tank, Figure 6-71.

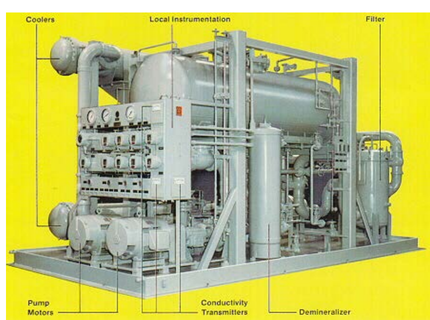


Figure 6-71. Typical Large External Pumping Unit for Liquid Cooled Generator (Westinghouse)

Deterioration mechanisms vary widely between components, and a proper inspection will require use of several skills. Listing some of the numerous deterioration mechanisms and locations which must be evaluated on the individual component:

Piping and Flanges - Leaks, contamination, loose supports, mechanical damage.

Electrical Controls - Malfunction, overheating components, mechanical damage, poor connections.

Valves, Lines and Regulators - Smooth operation, air or hydraulic leaks, wear, mechanical damage.

Coolers - Internal and external leaks, internal contamination, thin or plugging tubes.

Pumps and Motors - Flexible coupling wear and alignment, water leaks, overheating, mechanical damage, output pressure, vibration.

Storage Tank - Internal contamination, leaks, sight glass visibility, spray lines clear.

6.6.3 Hydrogen Seal Oil External System

Problems and wear mechanisms are similar to the Stator Water system, excepting typically there will be no cooler, Figure 6-72. Guideline in Section 4.3.2. can be followed.

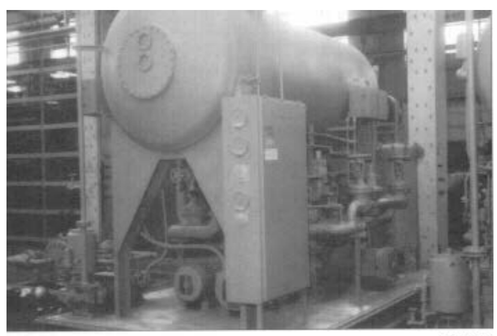


Figure 6-72. Typical Hydrogen Seal Oil Pumping Unit (General Electric)

6.6.4 Hydrogen/Air Coolers

Should be inspected for evidence of tube, tube-sheet leaks (discoloration, chemical deposits, rust), tube plugging, Figure 6-73. If tube vibration is occurring, fretting products should be visible. Fins should be checked for spalling, breakage, and bends.

Figure 6-73. Cooler Tube Sheet with Cover Removed

6.6.5 Lubrication oil

Generally lubrication oil will be supplied from the turbine system. Inspection items would be similar to 0. In addition to the condition of the mechanical and electrical equipment, the lubrication oil itself should be checked for particle count, neut number, and other properties.

6.7 Iso-phase

All internal & external accessible components should be inspected for: local and general overheating, local burning or overheating of electrical connection joints (between isophase sections and on ground straps), failed insulators , Figure 6-74 & 6-75, cracking of ground straps or other components and connections, contamination, loose or fretting connections, Figure 6-42, mechanical damage. If forced cooling is used, the blower/cooler system should be checked for malfunction or incipient difficulties.

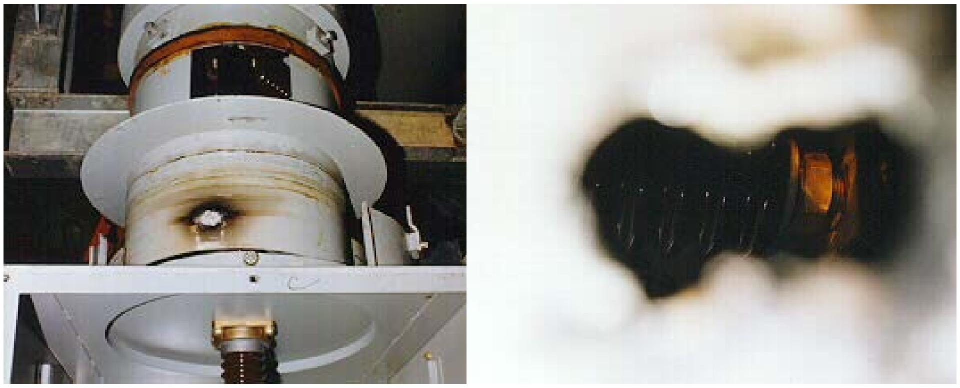


Figure 6-74 & Figure 6-75. Hole Burned in Isophase by Standoff Insulator Failure, External View and View of Insulator Through Hole in Cover.

Figure 6-76 provides and isometric view of an isophase system and indicates the complexity and large number of components.

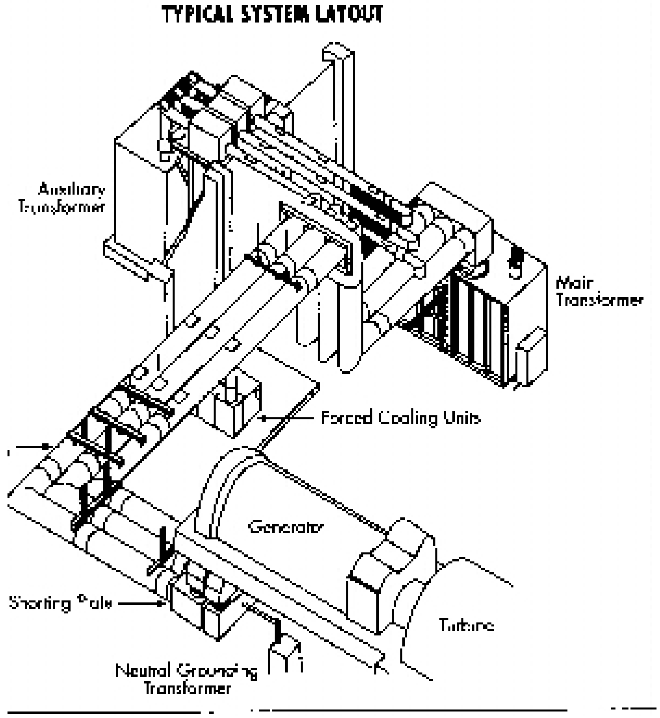


Figure 6-76. Isometric View of Isophase System

7. Chapter 7 - Testing

7.1 General

7.1.1 Scope of Tests

Several different tests are used in evaluating generators. Most are common to all types of machines, e.g., high potential test, insulation resistance, conductor resistance. Some are used on specific classes of machines, e.g., leak testing of water-cooled stator windings. Most have been used since the infancy of power generation, but a few are of more recent development, e.g., partial discharge, field shorted turn flux probe.

Most of the tests are benign and will not harm the component under test. The primary exception is that of over-voltage testing, and this topic is considered in some detail in this Chapter.

Since even under the best of conditions precise evaluation of the condition of a generator is difficult, it is generally better to use the full battery of tests when performing generator inspection and test. Each of these tests will be considered in the sections below.

7.2 Over-voltage Tests

7.2.1 High Potential Test, General

7.2.1.1 Special personnel safety precautions

Because over-voltage tests are performed at lethal voltages, it is absolutely essential that test equipment operators be fully trained and certified before attempting to perform these tests. If the tests are not properly performed, both test equipment operators and plant personnel are at risk of death. This is not a theoretical concern; there are recent recorded incidents of death during performance of such tests.

While megohmmeters operate at relatively low voltage, typically 500 to 2500 Vdc, this voltage must still be considered very dangerous. Although megohmmeters are designed for low output current, the voltage is sufficient to cause personnel injury due to reflex actions. Also discharge current of the capacitance of the winding under test may not be low. Thus for all field and stator megohmmeter tests, appropriate protective actions must be taken.

7.2.1.2 Special equipment safety consideration

It is important to recognize that during every type of over-voltage test, on stator or field insulation systems, there is the possibility of failure to ground.

On stator windings, because of the nature of the systems and the high inherent safety margins, failure almost certainly will not occur during a properly conducted over-voltage test unless *severe* winding degradation has already taken place. Nor will good stator winding insulation be measurably degraded during the brief application of over-voltage.

7.2.1.3 High potential testing of field windings

Field windings operate at relatively low voltages, less than 750Vdc, and are generally designed with extensive creepage paths, which are subject to contamination. As a result, a good evaluation of field insulation can be performed with a megohmmeter test. Routine high potential testing of field windings is generally not recommended. However under specific circumstances, failure investigation for example, field high potential test may be appropriate.

7.2.1.4 Merits of performance of stator over-voltage tests

The great importance of high potential testing results from the fact that stator insulation systems normally deteriorate at a modest rate. Unless subjected to mis-operation or other localized distress, in-service failure of a well-designed and properly manufactured system would not be expected for 30 to 40 years or more. Deterioration rates for different assumed conditions are shown pictorially in Figure 7-1.

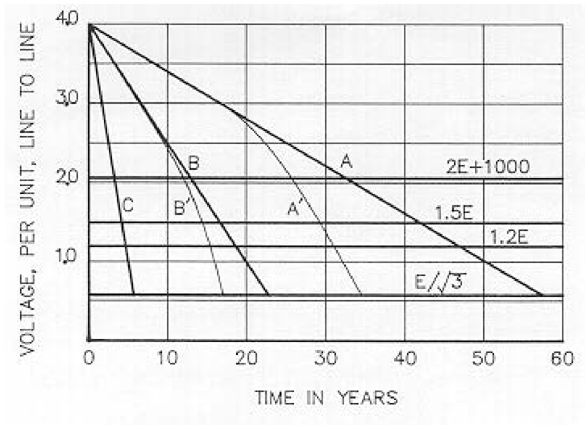


Figure 7-1. Stator Winding Deterioration Rates

Deterioration is shown as linear; this will be a reasonable approximation if machine operating conditions do not change. Linearity will be lost, however, if an accelerating phenomenon develops, e.g., bar vibration, vibration sparking, foreign material wear, core loosening.

Three curves of insulation system deterioration are shown:

Curve A -	Well designed system with no mis-operation or localized distress.
Curve B -	System of marginal design with no mis-operation or localized distress.
Curve C -	System of deficient design, with built-in deterioration mechanism, e.g., bar vibration in slots, poor partial discharge grading, endwinding resonances.

Curves A' and B' show the impact of changing conditions due to a developing problem, e.g., foreign object, bar vibration, partial discharge degradation.

Figure 7-1 also shows:

- Machine rated line-to-line voltage (E)
- Line-to-neutral voltage, E/1.732 = E/√3
- IEEE Standard new machine high potential test value (2E + 1000)
- Commonly recommended high potential test values for in-service machines (1.5E and 1.2E)

Referring to Curve A, where failure at line-to-line voltage is assumed at 50 years, a 1.5E high potential test would give assurance against line-to-neutral failure of approximately 15 years minimum. A 1.2E high potential test would project no failure for at least another 11 years of operation.

Curve B indicates that even with an insulation system of marginal design quality, with an assumed line-to-line failure after 20 years, the assurance period is still about 6 years with a 1.5E high potential test.

With a poor insulation system or non-linear and/or rapid deterioration, Curves C, A’ and B’, protection periods against service failure without system disturbance would be much shorter. It would be important to use a full 1.5E high potential test and limited time between tests, i.e., less than 1 year.

Of course, deterioration of a specific insulation system will not be purely linear, and most good stator windings may be expected to operate much longer than 57 years without line-to-neutral service failure due to general deterioration. But the central point remains: Excepting under unusual circumstances, a program of regular scheduled high potential testing will give very high assurance against in-service generator stator winding failure.

7.2.1.5 Stator High Potential Test Considerations and Concerns

There are several important technical and business considerations and concerns relative to high potential testing:

1) Manufacturers often recommend an in-service test value of 1.5E (although some recommend no hipot at all). This recommendation to hipot is based on the knowledge that bars which have failed in-service high potential test invariably show severe insulation degradation. Thus it is believed that a voltage less than 1.5E is unnecessarily conservative. However, at the owner’s discretion a lower test voltage may be appropriate. As indicated in Figure 7-1, even a test at 1.1E will give some protection against service failure, although the margin may be small in the event of system disturbance. Generally speaking, a test level of at least 1.2E is preferable.

2) There is always the possibility of winding failure during over-voltage test. When this occurs, it will usually not be possible to make a local repair of the failed location. Thus, unless previous preparations have been made (outage time scheduled, spare parts, repair personnel), outage extension may occur.

3) Full test voltage is applied to the entire winding, whereas in normal operation the voltage within the winding scales from zero at the neutral end to line-to-neutral voltage at the line end.

4) A winding may contain a weak area which is located near the neutral end of the winding. Such an area may continue to operate for a long period of time without service failure. However, it should be kept in mind that a system disturbance may result in elevating of the voltage at the neutral and thus cause service failure at this location.

5) High potential testing becomes particularly important on a machine with general, serious deterioration, since the first failure is likely to be at a location near line voltage. With high impedance neutral grounding (common on generators), neutral voltage will become elevated. This will place the line end of the other two phases near line-to-line voltage and thus overstress weak bars in these locations. (Keep in mind that a bar has just failed at line-to-neutral voltage.) Should a second failure occur on the winding, extremely high current will flow through the faults, e.g., 10,000 amperes. The resultant burning will be severe, and the current cannot be interrupted until the field voltage has decayed. The open-circuit time constant of a typical field is about 5 seconds. Thus, it will take about 5 seconds for the field current to decay to roughly 30% of initial field current on open circuit. If the machine were operating at rated load conditions, after 5 to 10 seconds there will still be sufficient field current to develop near rated open circuit stator voltage; this voltage will continue to feed the arc and increase the winding damage and machine contamination. Statistical experience on tape-migration stators was that double winding failure occurred on about 30% of single ground failures. But for a widespread deterioration mechanism, e.g., vibration sparking, general wear-out, double winding failure may be expected to occur on 80 to 90% of single-

ground failures. Double-ground failures have occurred on many stators, and each case resulted in a full stator rewind and full field rewind, and often partial core restacking.

7.2.1.6 The high potential test decision

In reaching the basic decision relative to performance of stator high potential tests, the owner is faced with divergent and conflicting alternatives: 1) perform a suitability-for-service high potential test and risk high potential test failure, or 2) omit high potential test altogether and accept increased risk of service failure, forced outage, and possible severe machine damage. In the final analysis, depending on the importance of a particular machine to the system and other business and economic factors, judgment must be made among the options to high potential test at a selected voltage, perform a DC leakage current or step voltage test, or omit over-voltage test altogether.

But the basic principles remain. A properly conducted high potential test:

1) Will not damage a winding that is not already severely deteriorated.

2) Will give good assurance against service failure for a stator winding that is not experiencing aggressive local or general deterioration.

7.2.1.7 Comparison of Megohmmeter to High Potential Test (AC vs. DC vs. 0.1 Hz)

7.2.1.7.1 Components of Measured Direct Current

When voltage is applied to an insulation system by a megohmmeter or other DC test device, 3 components of current are measured. These components vary considerably in properties:

Capacitive Charging Current - This component is caused by the charging of the geometric capacitance of the winding being tested. On generator stators and fields, the capacitance is relatively small and this component reduces to zero rather quickly, in seconds, and will not ordinarily be observed by the megohmmeter operator.

Leakage Current - This is a resistive current, the quotient of applied megohmmeter voltage divided by insulation resistance. As such, this component of current rises and becomes stable immediately. This current results from groundwall insulation flaws and surface leakage paths. If significant groundwall and/or surface contamination is present, the current flow will be high, and the megohmmeter resistance reading will be low. Conversely, if the insulation is dry and clean, leakage current will be low and megohmmeter reading high.

Absorption Current - This component results from molecular changes within the insulation material. It is a complicated physical phenomenon having to do with the molecular “dipoles” which make up the components of the groundwall insulation. These dipoles are randomly oriented unless placed in a DC electric field. When DC voltage is applied to the insulation, the dipoles tend to rotate slowly within the groundwall, so as to align with the applied voltage direction. Absorption current is the flow of current associated with the rotation of the dipoles, and decreases asymptotically toward zero over a period of several minutes.

7.2.1.7.2 Megohmmeter

Megohmmeter testing is the safest of the electrical tests performed on insulation systems. If properly done, this test presents no risk of damage to the insulation and virtually no risk of winding failure. This is a valuable test, and should be performed at each convenient opportunity.

Megohmmeter voltage ranges of 500 to 2500V are commonly used on stators. Because fields are designed to operate typically at less than 750Vdc, field windings can be satisfactorily tested with a 500Vdc megohmmeter. It generally is not recommended to use of a higher voltage megohmmeter, as this will place an unrealistically high voltage on the field winding insulation.

The insulation resistance value will give an indication of overall insulation integrity, and may identify a fault that responds to relatively low voltage. Contamination, particularly with a conductive material or in the presence of moisture, will result in low megohmmeter insulation resistance readings.

Polarization index (PI), the ratio of the 10 minute megohmmeter reading to the one minute reading, will give an indication of surface and internal moisture. The mechanism of “polarization” is described in 7.2.1.7.1, above. Specifically, the rate at which the 3 components of DC current stabilize establishes the value defined as “polarization”.

If the insulation is dry, the predominant flow of current is consumed in reorienting the dipoles, and the current flow will asymptotically decrease to near zero. The corresponding resistance reading will then slowly steady out at a high level over a period of several minutes. The PI will also tend to be high, in the range of 1.5 to 4.0.

If the insulation is damp internally and/or externally, the current flow will be high and predominately resistive. A PI reading of 1.5 to as low as 1.0 may be expected.

One note of caution. A megohmmeter with a low-value full-scale reading (perhaps 1000 megohms or less) usually will not give a valid PI on a clean, dry winding. This results because the megohmmeter may read almost maximum on the instrument scale after only 1 minute, and thus the reading will not properly increase between 1 and 10 minutes. The result will be an artificially low PI value.

Megohmmeter readings will vary over a wide range from machine to machine, or on a given machine over a period of time. Judgment is required to interpret the megohmmeter resistance and PI values. For example, a low PI may be perfectly satisfactory if the absolute reading is high, as is often the case on good, dry field insulation. However, if both values are low, action generally is required before it would be considered safe to either high potential test or place the machine back is service. See Section 7.2.2.1.2, below, for suggested test values.

7.2.1.7.3 General high potential considerations

The single most effective electrical test evaluation tool for the quality of a stator winding is the high potential test. The choice of test voltage source is of secondary concern; all three commonly used systems are effective: power frequency AC, 0.1Hz AC, and DC.

In the slot portion of the winding, the 3 types of tests are roughly equally searching. But in the end winding, performance is quite different because the 0.1Hz and DC voltages stress the end winding insulation relatively more severely than operation voltage or 60Hz AC high potential test. Thus use of DC or 0.1Hz AC will tend to increase the risk of inadvertent winding failure in the end arm regions.

Figure 7-2 shows the approximate voltage stress distribution across the groundwall insulation for the various test equipments: Curve 1 = 60Hz, Curve 2 = 0.1Hz AC, and Curve 4 = DC.

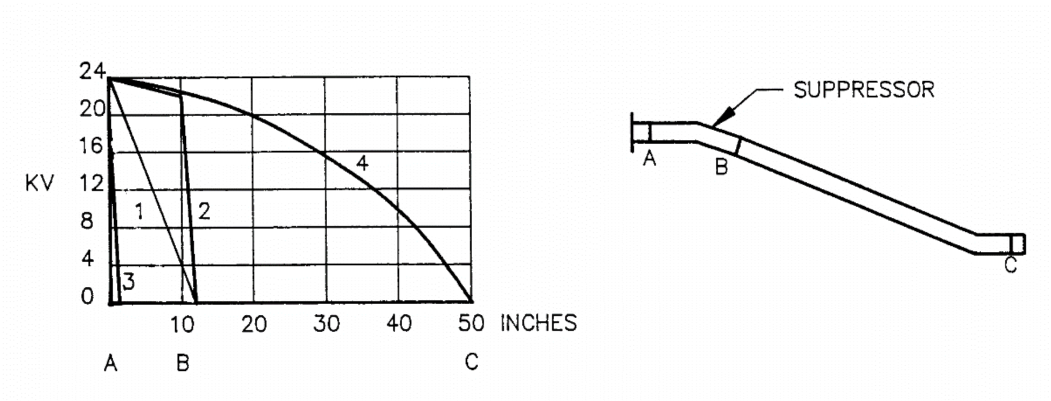


Figure 7-2. Approximate Voltage Distribution Across Groundwall Insulation in Stator Bar End Region

With 60Hz AC the voltage falls off quickly and will apply voltage across the groundwall for only a few inches beyond the slot grounding material, Curve 1. (The full length of the end winding grading material is not active on the relatively low voltages of maintenance high potential tests.) With DC, high voltage stress is applied across most of the end arm insulation, Curve 4. With 0.1Hz, nearly full test voltage is applied across the ground insulation to the end of the end arm grading, Curve 2.

On low voltage machines, this grading system will be applied perhaps 4-8" beyond the end of the slot grading material. On high voltage machines, the grading may extend up to 15" beyond slot grading. Note also that on some designs, the slot grounding paint may extend to near the mid-point of the end arm.

7.2.1.7.4 Characteristics of the alternative test equipments

Power-frequency (60Hz) Alternating Current – Most closely duplicates actual voltage stresses in the winding. Traditional test equipment was heavy and required a substantial power source. In recent years various types of "resonant" 60Hz high potential test sets have been produced and are readily available; while still heavy, these test sets are not bulky and do not require high power for operation. Figure 7-3. In addition, the resonant sets are lower power devices and tend to store lower energy during test, and thus may cause less burning should a failure occur.

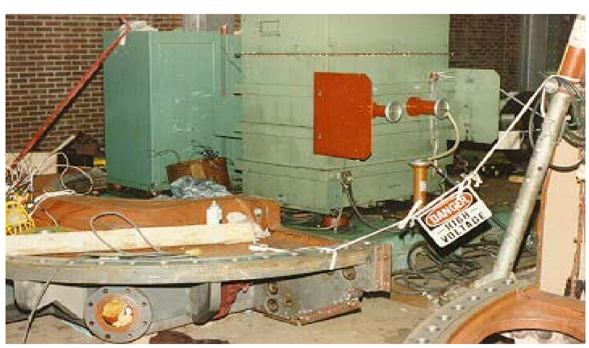


Figure 7-3. 60Hz High potential Transformer

0.1Hz Equipment - This test equipment was originally developed in the 1960s to combine the advantages of DC and 60Hz AC. While light and requiring low power supply, the sets are bulky and subject to maintenance difficulties. Figure 7-4. This type equipment is currently in only very limited use in testing generator windings.

Figure 7-4. Van Mounted 0.1Hz High Potential Test Equipment

Direct Current - The test equipment is portable, light, inexpensive, easy to use, and low maintenance. Figure 7-5. If the winding under test is damp and otherwise contaminated, it *may be* possible to interrupt the test before an actual flashover occurs.

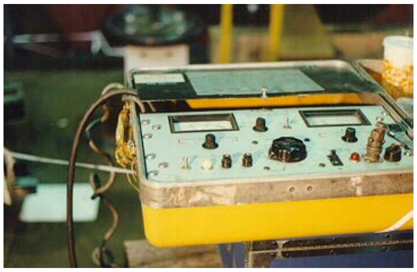


Figure 7-5. DC High potential Equipment

7.2.1.7.5 Controlled-voltage DC Tests

High potential tests are basically qualitative in nature, the winding either passes or fails. In order to develop quantitative information relative to insulation condition, 3 types of controlled voltage DC tests have been used: Fixed Incremental Steps, Time Graded, and Ramped Voltage. These tests are outlined in IEEE Std. 95-1977. Each method limits the maximum voltage to about machine rated line-to-line voltage, thus minimizing the likelihood of insulation failure. Using these procedures, the relationship of test current to test voltage is observed as voltage is built up to a predetermined value. If significant nonlinearity is observed, the voltage is immediately reduced.

Results of the test can be compared to earlier data on the same machine, as well as data from other similar machines. Thus it may be possible to reach general quantitative conclusions as to the overall condition of the winding.

On wet or contaminated insulation, impending failure of the insulation system at a point of weakness may be detected before failure. This would allow the operator to abort the test and may avoid puncturing and/or tracking the insulation, although the insulation may still have been damaged. On the other hand, the protracted time of voltage application may cause insulation to fail that might have passed the relatively short hipot test, for example a marginally wet armature bar.

7.2.2 Over-potential Test Procedures

7.2.2.1 Procedures and background common to all methods of testing

7.2.2.1.1 Operator qualification and training

The individuals performing the pre-test inspections and operating the test equipment must be thoroughly trained and qualified. Personnel safety procedures are paramount, but equipment safety is also important. See paragraphs 7.2.1.1 & 7.2.1.2, above.

7.2.2.1.2 Inspection and megohmmeter checks

Prior to performing any over-voltage tests, the winding should be carefully inspected for overall condition and for possible localized damage. In addition, satisfactory megohmmeter readings should be obtained, both resistance and polarization index, before any over-voltage testing is done.

Typical values of polarization index on good windings are:

Stators	1.5 to 4.0*
Fields	1.0 to 2.5**

* Water cooled windings will be near 1.0 until fully dried internally. Air cooled generators, if contaminated, will often be near or at 1.0 until cleaned and dried.

** Acceptable values for over-potential test:

Megohms	25 to 100	>	100 to 200	>	200
Minimum PI	1.25		1.10		1.00

It may be found necessary to clean and dry the stator winding before conducting over-voltage tests. The classic insulation drying curve for a very wet winding is shown in Figure 7-6. Typically the insulation resistance value (and polarization index) will fall for the first few hours after heat is applied. If the insulation integrity is basically good, the values will then slowly increase over a longer period of time until satisfactory values are reached.

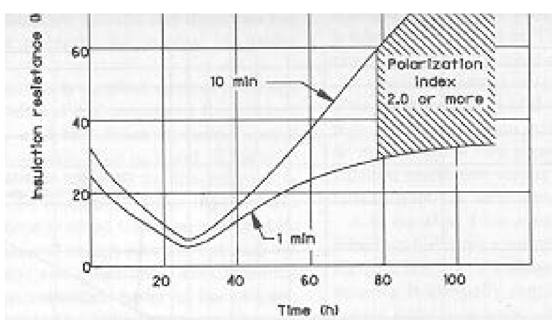


Figure 7-6. Dryout Curves for a Wet Stator Winding

7.2.2.1.3 Safety

Good safety practice should be followed in every step of the procedure. See paragraphs 7.2.1.1 & 7.2.1.2, above. Personnel should be protected from electrical hazard as well as risk of fall or other injury. The winding to be tested must be absolutely isolated electrically from the power system. Phases, windings, and instrumentation not under test should be solidly grounded, as should be the test apparatus. Preferably, both ends of each winding should be shorted together. Sphere gaps should be used to check the calibration of the test equipment. Sphere gaps will also protect against excessive voltage over-shoot if set 5 to 10% above test voltage. Figure 7-7.

Before voltage is applied, the area around the machine to be tested should be isolated by recognized safety tape and signs, and with flashing lights(s) easily visible from all approach directions. If the machine is not small and compact, foot switches should be available as well as electronic communication equipment for use of individuals acting as protective guards. These individuals should be located at strategic positions around (and below) the machine. High voltage cable should be used between the test apparatus and the winding. Electrical conducting materials, such as disassembled components of the turbine-generator, should not extend from within the high potential test enclosure to beyond the protective tape.

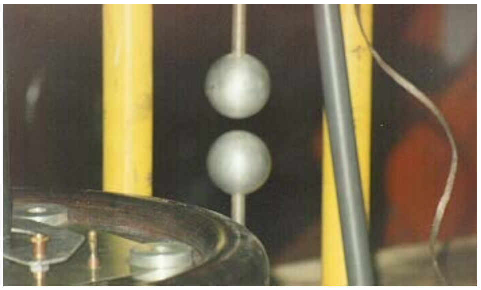


Figure 7-7. Sphere Gaps in Use During High potential

Figure 7-8 shows a typical, less-than-acceptable high potential test setup: protective tape too close to high voltage, metallic parts protruding under tape, no flashing lights. This setup does include sphere gaps and an appropriate sign, however.

Figure 7-8. Inadequate High Potential Test Safety Preparation

Use of DC in any form of test requires special cautions. First, DC can charge nearby ungrounded electrically insulated objects, such as replacement armature bars. Thus any such components should be grounded if located within several feet of the test equipment. Second, after the test is concluded and the winding solidly grounded, the insulation of the tested winding will still retain a charge. The charge may not be fully dissipated for a considerable period of time, many minutes to an hour or so, depending on test voltage and conditions of the winding. (The charge results from the slow return of the "dipoles" back to random orientation condition. Paragraph 7.2.1.7.1. above.) At the conclusion of the test, the winding under test must be short circuited to ground for a period of at least 4 times as long as the test voltage was applied, and in no case less than 1 hour. Before bare hand contact is made, absence of voltage must be confirmed.

During high potential testing, there is the possibility of localized arcing or flashover to ground. These events may ignite insulating materials or combustible materials on the surface of the winding, for example, lubrication oil. For this reason, testing should never be performed on a closed generator with an air (oxygen containing) atmosphere. On a closed machine, the operators may not become aware of the fire, or if aware, may not be able to access the winding for extinction of the fire. Figure 7-9.

Figure 7-9. Stator Winding Support and RTD Cable After Internal Fire Ignited by High Potential Test

A closed machine may be high potential tested in a carbon dioxide atmosphere. Also high potential test can be done in a hydrogen atmosphere at elevated pressure, but test personnel must be certain that hydrogen purity is above the acceptable level, typically 95% or greater.

Test procedures should be in compliance with regulations and rules of the owner company, testing company, and government.

7.2.2.1.4 Test equipment condition

The test equipment must be in good working order and carry a valid calibration record. Over-voltage test should not be conducted without use of sphere gaps to verify calibration and protect against significant over-voltage.

7.2.2.1.5 Owner approval and voltage limits

No testing should be conducted without prior owner approval.

The test equipment operator must be certain to know the selected test value and control the voltage rise so as not to overshoot this value.

7.2.2.2 Performance of AC high potential test (Power Frequency and 0.1 Hz)

Test voltage should be raised to the selected value at a steady, controlled rate. Care must be taken to be absolutely certain that voltage over-shoot does not occur. At the end of one minute at the selected test voltage, voltage is reduced, again at a steady rate.

In the event of any personnel safety concern, or observed abnormality on the test winding, voltage should be immediately reduced to zero. (Preferably the test set should not be tripped, as this can set up transient over-voltages on the winding.)

The **peak** 0.1 Hz value approved by the industry is 1.63 times the 60 Hz **rms** value. (The 1.63 multiplier is derived based on a somewhat arbitrary 1.15 intensity increase for the 0.1 test, i.e., 1.15 x 1.414 = 1.63.)

7.2.2.3 Performance of DC high potential test

Test voltage should be raised to the selected value at a steady, controlled rate not exceeding the output current capacity of the test set. Care must be taken to be absolutely certain that voltage over-shoot does not occur. At the end of one minute at the selected test voltage, voltage is reduced, again at a steady rate within the capability of the test set to discharge the winding.

In the event of any personnel safety concern, or observed abnormality on the test winding, voltage should be immediately reduced to zero. (Preferably the test set should not be tripped, as this can set up transient over-voltages on the winding.) The special DC safety considerations discussed earlier must be carefully followed.

The DC value accepted by the industry is 1.7 times the 60 Hz **rms.** value. (In actual fact, there is not a simple direct relationship between the 2 types of voltage. Laboratory comparison tests have shown values as low as 1.414 and as high as 4.0. But the 1.7 multiplier is an acceptable compromise.)

7.2.2.4 Step voltage test

Procedures for conducting these three specialized DC tests are covered in IEEE Std. 95-1977. This document may be referenced for background information. Conducting of these tests should only be done by an operator trained and experienced in performing such tests.

The selected test voltage will be determined from known conditions of the winding, previous test results, and equipment history.

Briefly summarizing each of the tests:

Fixed Increment Steps - Voltage application is started at about 30% of the maximum intended test voltage (at which point insulation resistance and polarization index are usually obtained). Voltage is then raised in succeeding steps of about 3%, with each step held for one minute before proceeding to the next step. Current readings are taken at the end of each one minute interval. Unless abnormality is observed, steps are made in succession until the final level is reached. Data are plotted on log scale and should be a near linear curve. Any significant deviation from linearity is cause for concern and termination of test.

Time Graded Method - This test is more complicated than the Fixed Increment test. It is designed to reduce charging and absorption currents to negligible levels so that measured current flow after a prescribed elapsed time actually represents leakage current. The initial reading is again at about 30% of the maximum intended test voltage. During the initial 10 minute PI reading, the relationship between voltage and current is plotted on a log scale. From this plot, voltage steps are calculated from a formula contained in IEEE 95. The remainder of the test is conducted similar to the Fixed Increment test.

Ramped Voltage Method - This somewhat complicated test requires automated test equipment. Again the test is started at about 30% of intended maximum voltage, with a 10 minute reading to obtain polarization index. Voltage is ramped at a selected rate, typically 1 kV/min. The aim is to eliminate effects of dielectric absorption current, leaving only leakage current to be read, plotted and analyzed.

7.3 Off-line Corona Tests (Partial Discharge)

7.3.1 General

7.3.1.1 Equipment

Several off-line tests are available for evaluating partial discharge of generator windings. (On-line tests are covered in Chapter 5.) Two general approaches are used: 1) test of the entire winding by individual phases or as a unit, and 2) search of local areas by use of a probe or wand. Both methods have significant strengths and weaknesses. Both require a discharge-free AC power source for energizing the winding to the required voltage, typically about line-to-line voltage (1.732 times line-to-neutral voltage). Discharge-free resonant high potential sets are available, and these are smaller, lighter and less expensive than the standard high potential set.

7.3.1.2 Test Sensitivity

In both types of tests, all portions of the winding are at test voltage, in contrast to normal operation where bar voltage scales up from zero at the neutral end to line-to-neutral voltage at the line end. In both tests, the machine must be off line, and for the probe tests access must be available to the stator winding at the ends of the core. The whole-winding test does not allow for discrimination of actual partial discharge sites. Also since readings may be taken only at the ends of the winding, signals from sites distant from the sensing instrument will be attenuated. (This is not wholly bad, since these sites will operate at lower voltages in actual service.)

Because the machine is off-line, there will be no electromagnetic forces on the bars. Thus a bar which might be generating partial discharge because of bar vibration will not vibrate and will not generate partial discharge during the off-line test.

7.3.1.3 Interpretation

As is the case with on-line monitoring, Chapter 5, interpretation of results is difficult and uncertain. Trend review and comparison to duplicate windings may be more valuable than analysis of absolute readings. Also as with on-line monitoring, maintenance decisions cannot be alone based on partial discharge data, as data may be indeterminate or actually misleading. Efforts are underway within the industry to converge the several test methods and gain a more definitive interpretation capability for all systems. This work may not be completed for many years yet.

7.3.2 Partial Discharge Testing

7.3.2.1 Technical Background

On-line and off-line testing operates on the same basic principles. This subject is discussed in Chapter 5, On-line Monitoring and Diagnostics.

7.3.2.2 Test Setup

Preferably each phase will be read individually. The sensor, a discharge-free coupling capacitor, is located on the input voltage line. Signal is read through a high pass filter into an oscilloscope or other recording/display instrument.

Both narrow- and wide-band measuring systems are in current use. Neither is ideal and there is as yet no standardization of band areas to be considered most significant.

7.3.2.3 Procedure

Voltage is raised until discharge pulses are first observed (discharge inception voltage - DIV), and readings taken. Voltage is then raised to selected maximum, and readings again taken. Voltage is then lower until discharge pulses extinguish (discharge extinction voltage - DEV), and a final set of data taken.

7.3.2.4 Interpretation

The 3 sets of data are then reviewed for trends and absolute values. No standardization yet exists on analysis of data, but some general principles apply: readings above 5000 pC may be indicative of winding deterioration, equal distribution of positive and negative pulses may indicate voids are within the stator bar groundwall insulation, preponderance of positive pulses may suggest voids on the insulation surface, and predominance of negative pulses may indicate voids at or near the copper.

7.3.3 Radio Frequency (RF) Probe

7.3.3.1 Technical Background

Partial discharge (PD) radiates radio frequency energy from the PD site. The RF probe is simply a modified AM radio loop-stick antenna which picks up this signal. The larger the discharge, the greater the AM signal. This signal is fed into an RF amplifier for measurement. The reading is not absolute, and is greater the closer the probe is held to a given PD site. However, an experienced operator can make a qualitative estimate of the intensity of the partial discharge.

7.3.3.2 Test Setup

Access requires that the field be removed from the stator. The probe is located on the end of an insulated pole, but a wire leads from the probe. Thus safety considerations are great, and extreme care must be exercised. (This test is more commonly applied to hydro generators.)

7.3.3.3 Procedure

Voltage is raised on the stator winding to the selected value. The individual bars are then probed with the antenna, including end winding and the portion of the slot that can be safely reached. Readings are taken of any active site.

7.3.3.4 Interpretation

High readings tend to be associated with PD sites, although resonances within the stator winding circuit can give false readings. Thus interpretation is subject to judgment and highly operator dependent. However, a skilled and experience operator can often obtain useful data with this test.

7.3.4 Ultrasonic Probe

7.3.4.1 Technical Background

Locations of serious surface degradation are likely to have high partial discharge activity. This surface activity will generate an acoustic noise, similar to that of a high voltage transmission line on a foggy day. The noise is primarily in the high tonal range, around 40kHz. A directional microphone may pick up this noise and identify the location of a severe discharge. Discharges within the ground wall are unlikely to generate a noise that can be heard, thus this test is sensitive only to surface discharge.

7.3.4.2 Test Setup

Access requires that the field be removed from the stator. The probe is located on the end of an insulated pole, but a wire leads from the probe. Thus safety considerations are great, and extreme care must be exercised.

7.3.4.3 Procedure

Voltage is raised on the stator winding to the selected value. The individual bars are then probed with the microphone, including end winding and the portion of the slot that can be safely reached. Readings are taken of any active site.

7.3.4.4 Interpretation

High readings will tend to be associated with sites of high surface PD activity. Interpretation is subject to judgment and highly operator dependent. However, a skilled and experience operator may obtain useful data with this test.

7.3.5 Power Factor and PF Tip-up (Dissipation Factor, Tan δ)

7.3.5.1 Technical Background

Power factor is the term commonly used to describe the measure of losses in a stator insulation system. For practical purposes, Cos ϕ, dissipation factor, loss factor and tan δ are identical, since the angle between total current and capacitive current is small. (Cos ϕ approximately equals tan δ at small angles.) Figure 7-10.

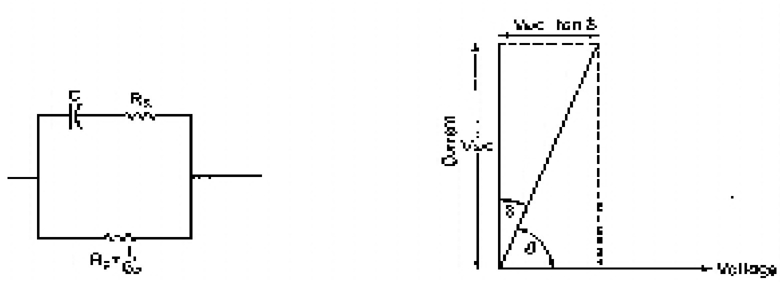


Figure 7-10. Capacitor Current

The stator insulation system is, in effect, a capacitor – an insulation system bounded by two electrodes: the copper conductor and the surface grounding paint. If it were a perfect capacitor, the losses in the insulation would be zero and the power factor zero. However, inherent voids and losses in the resin materials result in power factors of good insulation systems typically in the 0.2 to 1.5% range. Deteriorating systems may have power factors as poor as 5 to 10%, but a high power factor does not alone confirm that the insulation system is in poor condition.

In a perfect capacitor, losses would increase linearly with increase of applied voltage. However, in stator insulation systems losses tend to deviate upward from linearity as voltage is increased. This increasing loss rate results primarily from losses associated with partial discharges occurring in voids. The term "tip-up" is applied to this deviation, Figure 7-11. A stator insulation system in good condition typically will have a tip-up of 0.5 to 1.0, but values in excess of 1.0 do not necessarily indicate that the winding is in difficulty.

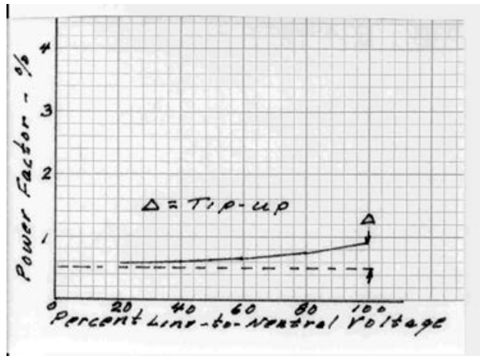


Figure 7-11. Insulation Power Factor Vs Applied Voltage

7.3.5.2 Test Setup

Required equipment includes a power frequency high potential transformer capable of reaching at least generator line-to-neutral voltage and a suitable capacitive-bridge measuring instrument. Preferably each phase should be measured separately.

7.3.5.3 Procedure

Test voltage is increased to about 20% of nominal line-to-neutral voltage, and readings taken. (At this voltage, partial discharge is unlikely to be present.) Voltage is then increased to the selected test value and the readings repeated.

7.3.5.4 Interpretation

Power factor testing is perhaps the most common elevated voltage test performed, often under the name "Doble testing", and while the test itself is quite straight forward, interpretation is not. It is popularly believed that power factor and tip-up relate closely to winding condition, and this often is not the case. More likely surface contamination and moisture will be responsible for higher tip-up values, and perhaps high power factor values. On the other hand, very low values may not be indicative of good insulation system quality.

Power factor and tip-up tests are a useful test medium, and are worthwhile to perform. But the test results should be used only as a guide and not as an absolute measure of system condition. High, low, and "optimum" readings can be associated with insulation systems in good and in bad condition.

A note of caution: Power factor (Doble) testing is considered to be "non-destructive", and it is. But there have been rare cases of severely deteriorated stator windings failing on line-to-neutral voltage.

7.4 General Field and Stator Tests

7.4.1 Mechanical Tests

7.4.1.1 Stator Wedge Tightness

Historically, tightness has been checked with a small (2 oz.) ball peen hammer. This is inherently subjective, but nevertheless, with some experience and training, a competent operator can make a good judgment of wedge tightness.

More recently, acoustic and mechanical test devices have been developed. This type equipment removes much of the operator variability and gives a permanent, quantified record. Figure 7-12**.** The field must be removed for the manual hammer test and hand-held tapper, but robotic equipment can perform the mechanized test with the field in place.

Figure 7-12. Hand-held Stator Wedge Mechanical Wedge Tapper

For designs which apply springs under the wedge, manufactures have developed procedures to measure ripple height through a series of small holes drilled in strategic locations along the top of the wedge. Robotic equipment is available for taking these readings with the field in place.

7.4.1.2 Stator End Winding Bump Tests

These tests are used to assess resonant frequencies and looseness of end windings and connections. Use of OEM or testing company personnel will generally be required to do this type testing. Particular skill and training will be required to interpret the results.

On new, modern windings, the primary operational concern is that of resonances, local and/or model (complete winding involved). In order to assure that there are no resonance conditions within a new stator winding, "bump" tests are normally conducted on the newly assembled windings. These relatively well understood tests are conducted by exciting individual locations, or the entire winding, with the impact of a calibrated hammer, while reading and recording the resulting resonance frequencies. Figure 7-13 & Figure 7-14.

Figure 7-13 & Figure 7-14. Calibrated mallet for "bumping" test piece and pickup for receiving signal.

In general, it is desirable and practical to bump test every individual series and phase connection on the winding, as well as every connection ring. This test sequence will identify potentially dangerous local resonance locations, as well as overall endwinding resonance.

There is not a consensus as to allowable resonant frequency margins. Different manufacturers accept (on 60 cycle units) resonance limits as low as 130 Hz and as high as 140+ Hz. Natural resonant frequencies will reduce immediately when the component is heated, and become progressively lower over time due to wear associated with operating duties. Thus it is probably advisable not to accept upper-limit test resonance values with a margin less than perhaps 20 Hz, i.e., 140 Hz (on 60 cycle units).

7.4.1.3 NDE of Mechanical Components

Non-destructive evaluations (NDE) are performed on retaining rings, wedges, forging, collector, fans, centering rings, couplings and bolts. Figure 7-15 & 7-16. Personnel with specialized training are required to perform the tests, and input from the OEM will be needed in the event of observing questionable results.

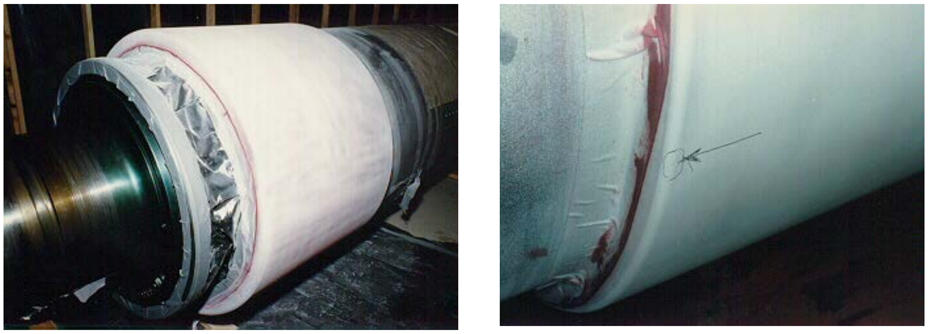


Figure 7-15 & Figure 7-16. NDT Evaluation of Field Retaining Ring

7.4.2 Electrical Tests

7.4.2.1 Testing for field turn shorts

Several approaches are taken to assess turn insulation. These tests will not be described in detail here, since they are well documented in the literature. But in summary:

Rotor Impedance Test - Can be performed at stand-still (or at speed on fields with collector rings). A variable AC voltage is applied across the field winding. Changes in impedance are observed as a function of voltage and/or speed. Steps in impedance are an indication of speed or voltage sensitive shorts. Absolute impedance is also checked against earlier data, including as-shipped values. Figure 7-17.

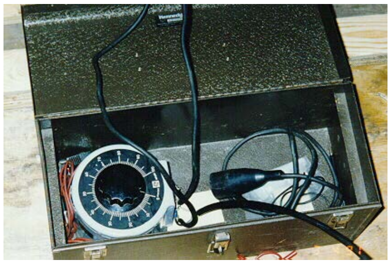


Figure 7-17. Power Supply for Measuring Field AC Impedance

Pole/Coil Drop Test - Performed off-line, preferably with retaining rings removed. DC voltage is applied across the winding, and voltage is read on each accessible coil and pole connection, Figure 7-17. Readings are compared between coils of same location, and with as-new condition. Voltage can also be applied using an excitation coil coupled magnetically to the field winding coil, Figure 7-18.

Figure 7-18. Checking Pole/Coil Voltages with Retaining Ring Removed

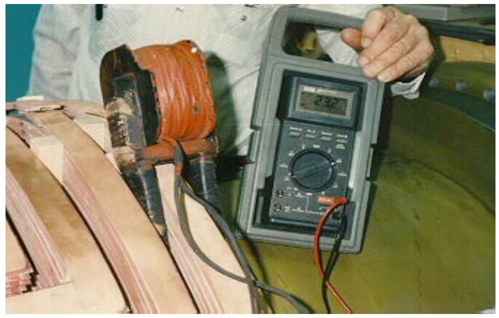


Figure 7-19. Turn Short Excitation Coil

Turn Drop Test - Similar to the Pole/Coil Drop test. Generally the retaining rings must be removed, Figure 7-20. However, on some direct cooled field designs, there may be sufficient access through the wedge ventilation holes to permit fully assembled testing. Data are examined for turns which show no voltage drop (change).

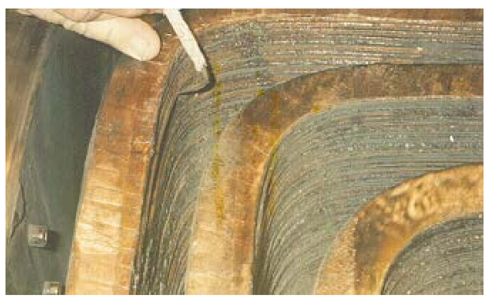


Figure 7-20. Field Turn Voltage Drop Test

Flux Probe Test - This on-line test requires installation of an air gap flux probe, Figure 7-21. This test, which is very effective and not difficult to perform, is covered in Chapter 5, On-line Monitoring and Diagnostics.

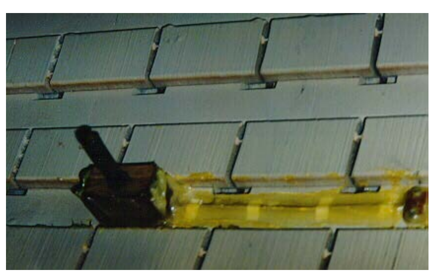


Figure 7-21. Assembled Field Turn Short Flux Probe

7.4.2.2 Brush Holder Rigging Insulation

Brush rigging components are easily accessible. Unless mechanical or electrical arc damage has occurred, insulation integrity generally can be restored with proper cleaning. Satisfactory condition can be confirmed with a 500 megohmmeter, reading >1 megohm. Test should be made separately on each pole, with the brushes lifted and all cables and leads disconnected.

7.4.2.3 Bearing and Hydrogen Seal Insulation

Designs vary between manufacturers, and many machines have been built with single insulation. On single insulated components, some disassembly is required and conducting of the test can be difficult. The OEM operating manual should be reviewed in preparation for testing insulation condition.

On double insulated components, the test can be easily conducted simply by connecting the test voltage source to the test lead; this can be accomplished on-line and without disassembly.

With either type of insulation arrangement, follow OEM recommendations relative to test voltage and satisfactory values. Test voltages will be low and resistance values of >1 megohm are likely to be fully satisfactory.

7.4.2.4 High Voltage Bushing Loss Test

This is a specialized test which should be done by qualified test personnel and performed in accordance with OEM recommendations.

7.4.2.5 Winding Copper Resistance (Field and Stator)

Because the resistance values are very low, readings must be accurate within about 3 significant digits, using a double bridge or equivalent digital low ohm meter. Figure 7-22 (The “double bridge” simply means that the test instrument current is applied to the winding under test through one set of leads and voltage drop is measured by a second set of leads.)

Figure 7-22. Digital Low Resistance Ohmmeter (DLRO) on the Left, and Megohmmeter to the Right.

Typical values for field winding range between 0.012 and 0.32 ohms. Stator values are even lower, typically between 0.0008 and 0.013 ohms.

Values must be corrected for actual winding temperature. In order to obtain meaningful data, temperatures must be allowed to stabilize and temperature readings should be taken at several locations.

Results should be compared to new winding and previous service values. An out-of-range high reading on the stator may indicate failing connections, always a serious condition which must be corrected. The same would be true on fields, although the likelihood is lower and the damage potentially less severe. Low readings on fields are usually associated with turn shorts. On a field with about 100 turns, a single shorted turn would give a 1% low reading. Smaller fields usually have more than 200 turns, but individual turns shorts can still be detected. On a field with advanced deterioration, several turns may be shorted, and the condition easily detected.

7.4.3 Other Tests

7.4.3.1 Insulation of Generator Monitoring Instrumentation

Electrical insulation used on instrumentation is low voltage, and any integrity checks should be in accordance with OEM recommendations. The devices may be harmed if excessive voltage is applied. Figure 7-23.

Figure 7-23. Instrumentation Measuring RTD Insulation Resistance

Procedures for checking accuracy will vary between devices, and these checks should also be in accordance with OEM recommendations. However, a rough check of accuracy of TCs and RTDs can be obtained simply by comparing the readings of the devices, since there are generally many devices reading near-identical conditions. Of course, machine temperature must be stabilized before this can be done, and there will be a fairly uniform small variation between the lower and higher portions of the machine (or from side-to-side on a sunny day for an outdoor unit).

7.4.3.2 Stator Bar Turn, Group and Vent Tube Insulation

Turn and group insulation integrity of multi-turn coils is difficult to assess on an assembled winding. (It is not easy to do even on a single unconnected coil.) This test is therefore uncommon, since disconnecting of coils will be required to obtain meaningful data. The OEM should be contacted if turn insulation integrity is questioned.

Direct hydrogen cooled stator windings use insulated ventilation tubes. Tubes are insulated from each other and from the winding copper. Test procedures vary between OEMs, and OEM recommendations should be followed as defined.

7.4.3.3 Gas Cooled Bar Flow Tests

Reliable operation requires that the ventilation tubes be able to pass design gas flow. These tubes on generators from certain OEMs tend to be thin and weak, and may also be vulnerable to blockage by foreign material. OEM recommended tests for evaluating gas flow should be followed as specified.

7.5 Stator Core Tests

7.5.1 General

Confirmation of the condition of the core insulation can be essential, particularly in the event of known problems or questionable inherent quality. Also, testing may be advisable before and after maintenance work that directly or indirectly involves the core, e.g., stator slot rewedging. These tests, however, may tend to be difficult, complex, expensive, and/or hard to interpret. In some cases, OEM input may be necessary. Tests should be performed by experienced, qualified personnel.

7.5.2 Low-power Lamination Insulation Test

A few types of low-power test equipment have been developed. The most common is the ElCid test. This test is conducted at about 4% rated flux density, a very low value. Meaningful results require good equipment properly operated. The test setup is shown in Figure 7-24.

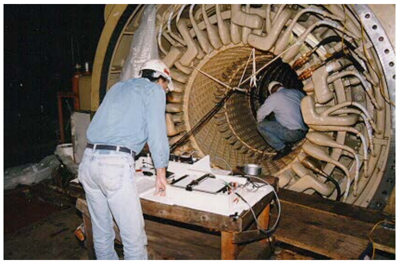


Figure 7-24. Low-power Lamination Test Instrumentation and Excitation Coil

There are several advantages of this type test: setup is short and simple, costs are low, quantitative results are obtained, and data are repeatable. In addition, there is no hazard to the equipment and little personnel safety risk. There are corresponding disadvantages: insensitive to damage that is not near the top of the tooth, difficult to read accurately on the step iron at the ends of the core, may not detect damage in the core back-iron, the 4% flux level (which is associated with 4% inter-lamination voltage) will not cause current to flow unless the electrical connection at the defect is solid. (This is true also of full-flux test, i.e., the voltage between laminations is so low that the connection must be solid.)

Overall, this is a valuable test. It is recommended this test be performed before and after any maintenance work is done which might affect the integrity of the core, e.g., stator rewedging, retightening core, partial or full rewind. Also the test can be useful for evaluating known or suspected damage or weakness of the core lamination insulation.

Because specialized equipment and training are required, it is important that this test be performed by qualified and experienced personnel. In particular, obtaining reliable readings in the critical core iron step region at the ends of the core can be difficult and requires use of a special pick-up coil. Also, input from the OEM may be useful, as core design, quality and reliability varies between manufacturers.

In no case should a core be restacked based on ElCid readings alone without further evaluations, including high-power tests.

7.5.3 High-power Lamination Insulation Test

Variously call “ring test” or “loop test”, setup is time-consuming, requires a long length of high amperage cable, large power source, and necessary breakers and controls. Figure 7-25b&c. This test also tends to carry inherent personnel safety risks. However, the test is often performed because it closely reproduces the conditions of actual service.

Figure 7-25b&c. Ring test excitation coils.

High-power variable voltage sources generally are not available. Since few turns are used in the coil, and turns must be adjusted in increments, exact selection of flux level is not possible. Also, current and power increase exponentially as rated flux density is approached. Therefore, in initial selecting of number of turns in the excitation coil, be certain to error on the side of too many turns.

Satisfactory test can be conducted at flux densities between 85 and 100% of rated flux; testing above 100% flux level should be avoided due to the hazard of experiencing gross test coil over-current.

Input from the OEM will be helpful in designing the excitation coil: core dimensions, rated flux level, magnetic properties of the core back-iron.

7.5.4 Through Bolts

Some manufacturers use a through-bolt design to apply pressure to the core iron. Because these bolts are cut by the excitation flux, they also generate a significant voltage, in the order of 200 to 800 Vac from end-to-end. Current flow cannot be permitted in these bolts, thus they must be fully insulated from ground and from the core punchings.

The OEM should be contacted relative to test frequency and parameters. Since failure of this insulation can be thoroughly damaging to the equipment, manufacturer insulation test and retightening recommendations should be closely followed. Otherwise major damage to the generator may result.

7.5.5 End Shunt Insulation Resistance

Some manufacturers use an insulated end-flux shunt, Figure 7-26. Manufacturer recommendations should be followed to assure satisfactory operation.

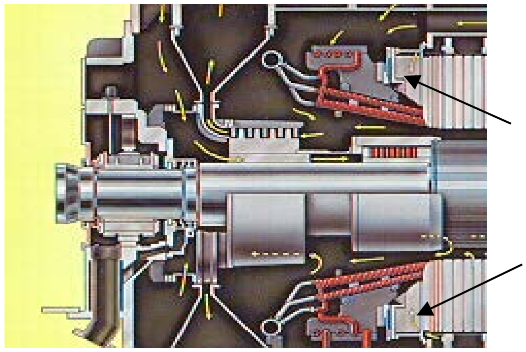


Figure 7-26. Flux Shunt Location at End of Core (Westinghouse)

7.5.6 Core Tightness

Core tightness can be checked simply by assessing the amount of force required to insert a knife between laminations. A tight core will resist knife entry from light tapping on the knife with a small hammer, Figure 7-27. This is a crude test, but effective. It can be done without harming the insulation, and is not inherently dangerous if performed by a skilled workman, since loss of insulation integrity between two adjacent punchings is not measurably harmful to a sound core.

Figure 7-27. Knife Test of Core Tightness

A more scientific test can be performed by measuring the force required to locally expand a core tooth. This test requires customized tooling, is difficult to interpret and is not commonly done.

Typically, cores are simply retightened if looseness is suspected because of inherent design weakness, unit history, core inspection, low nut torque or other considerations. However, increased core pressure may tend to increase the duty on the lamination insulation. Also if the core were rather loose, the lamination insulation may be degraded from local vibration. Cores should not be retightened without input from the OEM.

7.6 Liquid Cooled Stator

7.6.1 General

Liquid cooled stator windings contain thousands of joints with the potential for permitting leaks to develop. There are three general categories of joints that can become a source of hydrogen or water leak: 1) numerous flanged and clamped hydraulic joints and fittings, 2) many brazed pipes and fittings, and 3) the complex brazed hydraulic/electrical connections between the stator bar strands and the individual bar water supply header, Figure 7-28. In addition there is the possibility of cracking or other mechanical failure of pipes, hoses and fittings.

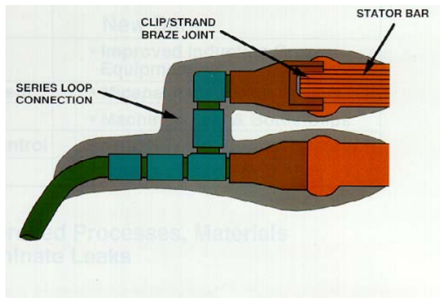


Figure 7-28. Stator Bar Strand Header Design

Leaks associated with loosening flanges, deteriorating clamp fittings or cracked piping may be benign or serious, depending on size and location. Small leaks typically will not result in winding damage so long as hydrogen gas pressure is always maintained above the stator cooling water pressure. Escaping hydrogen will simply be vented to atmosphere through piping provided for that purpose. But large leaks associated with piping, flanges, and fittings may cause major winding failure.

If hydrogen flows into a stator bar hydraulic circuit and displaces water flow, or if water flow is interrupted to individual bar circuits by local obstruction, the involved bars(s) will overheat and may fracture due to differential expansion between the hot bar(s) and the remaining winding. (Differential expansion in the order of .400" may be expected on long stators.) On the other hand, if water leaks from a winding hydraulic circuit, electrical creepage surfaces may be contaminated, causing flashover and severe winding damage.

Experience has shown that the third category of leak, that of the individual bar strand headers, is much more troublesome. Leaks in these areas generally are very small, and water leakage rates in the order of 2 or 3 cm^3/week can cause irreparable damage and eventual failure of stator bar groundwall insulation. Leaks of this type are difficult to detect, both due to size and location. On-line tests, as well as the vacuum and pressure decay tests, are unlikely to detect a strand/header leak.

Methods of monitoring and detecting large leaks that occur while machine is operating, as well as maintenance procedures for locating all leaks including small strand-header leaks, will be described later.

Knowledge of the operating and maintenance history of the specific generator is important to assessing present conditions and progress of any deterioration which may be found. In addition, participation of the OEM may be necessary in order to assure understanding of design details of the generator which impact the decision making process.

7.6.2 Personnel and equipment requirements

7.6.2.1 Personnel

Numerous, broad-ranging technical procedures are described in this portion of the guide. Personnel assigned to do this work should be familiar with operation of the sophisticated equipment used in the various tests and should understand the purpose, nature, and interpretation of the inspections and tests performed.

7.6.2.2 Equipment

These tests are inherently complicated. In order to perform the leak tests expeditiously and accurately, several pieces of specialized equipment are necessary.

a) Flanges and other accessories to seal of the disconnected piping.

b) Skid capable of removing the bulk water from the winding, and to dry the remaining moisture from the system, Figure 7-29.

Figure 7-29. Test Skid for Removing and Drying Water from Stator Windings (General Electric)

c) High accuracy vacuum measuring instruments.

d) Accurate pressure decay instruments and thermometers, Figure 7-30.

Figure 7-30. High Accuracy Pressure Gauge

e) Supply of tracer gases and corresponding instruments. If helium is used, the instrument is particularly specialized, Figure 7-31.

Figure 7-31. Gas Test Leak Sniffer and Instrument

f) Simple capacitance meter and special electrodes for making contact to stator bar insulation. Figure 7-32. Alternatively, GE has been developing a "wet bar" detector that in the present state of evolution seems to be quite accurate in distinguishing bars with wet insulation. Section 7.6.7.6.

Figure 7-32. Bar Insulation Capacitance Testing

7.6.3 Information Sources

Because these tests tend to be intricate to perform, input from the OEM may be helpful in planning and conducting of the tests. Interpretation is somewhat judgmental, and should be based on fleet experience, history of the unit under test, and input from the OEM.

7.6.4 Time Intervals

On a normally operating unit with no known special concerns, checks and inspections should be performed on the following schedule:

Weekly - Check flow from the water cooling system ventilation line.

Minor Inspection (2-3 year cycles) - Vacuum and pressure decay tests. Tracer gas test (rotor removal optional).

Major Inspection (5-7 year cycles) - Vacuum and pressure decay tests. Tracer gas test (rotor removed).

7.6.5 Precautions

The described tests and inspections are generally non-destructive in nature and are not inherently hazardous to personnel if performed with care.

Because there is the potential for severe winding failure associated with the various undetected failure mechanisms, it is important that the recommended tests and inspections be performed accurately and on a regular basis.

7.6.6 On-line Test Procedures

Three common methods of in-service leak detection are available on the liquid cooled stator winding: a) hydrogen gas dew point, b) the liquid detector alarm, and c) excess hydrogen gas flow from the liquid system vent line. Commenting on each:

a) A high dew point level alone may not be cause for concern, but if dew point is high, particularly close attention should be given the other methods of leak detection.

b) If water is found in the leak detector, the gas flow from the liquid system vent should be immediately checked. If gas flow is normal, the water leak source is probably the hydrogen coolers, although small amounts of water may be inducted from a contaminated hydrogen gas supply.

c) Historically, checking flow from the liquid system vent line has been done by various manual methods, which are cumbersome but fairly effective. However, there is now available instrumentation that will continuously monitor, display, and alarm vent line gas flow, SLMS – Figure 7-33. If flow from the vent line is found to be excessive, damage to the generator may be imminent. Corrective actions should be taken in accordance with OEM recommendations. A secondary but important feature of the SLMS equipment is that it continually feeds air into the storage tank, thus assuring that the atmosphere over the tank water will always be oxygen rich, as intended. Presence of incorrect water ph or accumulation of "green slime" in the cooling water filters may indicate that excessive hydrogen is getting into the water circuit.

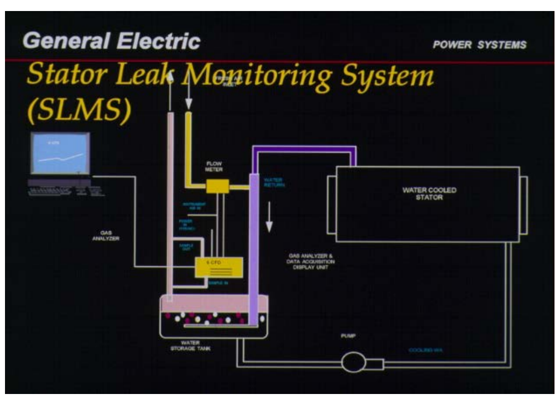


Figure 7-33. Gas Leak Monitoring Equipment for Stator Windings

7.6.7 Off-line Test and Evaluation Procedures

7.6.7.1 Water Flow Verification

Two methods are available for verifying that water flow through the individual stator bar liquid circuits is correct: a) flow continuity test, and 2) more recently developed acoustic flow measurement equipment.

Flow continuity test is a major effort and is performed off-line by establishing a temperature transient across the winding. This test requires: a) large heat source, 125-175kw, to heat the stator cooling water to near 90C, b) instrumentation to rapidly read the stator winding RTDs and TC' during the temperature transient, and c) cooling water supply to establish the temperature transient.

Acoustic equipment with the proper sonic pick-up can read individual hose flow magnitudes.

7.6.7.2 Water Removal and Internal Drying of the Liquid System

It is essential that the stator liquid system be thoroughly dried internally before performing stator water leak testing (not including capacitance testing). Even small amounts of moisture within the winding can conceal a small leak and make the leak undetectable. Also, it is not practical to perform a vacuum decay test with moisture in the winding.

The most efficient method of removing the bulk of the water from the liquid system is through blow-down with dry air from a large pressurized holding tank. The last remaining moisture can then be removed in about 24 hours using a large pump to pull a high vacuum. (Application of heat to the winding can shorten this process.) Manufacturers have equipment available specifically to efficiently dry liquid systems, Figure 7-29.

7.6.7.3 Vacuum Decay Testing

The primary advantage of vacuum decay testing is the sensitivity of the test. Decay measurements are made in units of microns, 10^{-6} torr. (One micron is equivalent to 0.00002psi, which is undetectable on a typical pressure gage, yet easily measured with common vacuum gages.)

Vacuum decay test measures the leak rate of the entire winding without requiring internal access to the generator. The test is relatively insensitive to changes in temperature and barometric pressure, and accurate results can be obtained in as little as one hour.

However, because of the extreme accuracy of the test, it is essential that all external connections be tight and all test components be in good condition. In addition, it must be recognized that the electrical isolating hoses may out-gas at a sufficiently high rate to simulate a very small leak. Windings that fail vacuum decay test and show indications of out-gassing must be further vacuum dried and retested.

7.6.7.4 Pressure Decay Test

Pressure decay test has three advantages over vacuum decay test: a) provides up to five times the pressure differential, b) applies the pressure in the normal direction of water leak flow, and c) allows use of bubble solutions, Figure 7-34. These factors make it easier to find some leaks undetectable with vacuum.

Figure 7-34. Testing for Water Leak using Bubble Solution

Drawbacks to pressure decay testing are its insensitivity to small leaks, sensitivity to changes in environment (temperature and barometric pressure), and time required to obtain a significant increment of test values. On a typical test, 1.0 ft^3 must leak out of the system to register a change of 1 psi. Thus patience and extremely accurate instrumentation are required.

The liquid system must be completely dried before beginning pressure decay, since the high pressure may force moisture into insulation through a yet undetected leak. Therefore, it is preferable to conduct vacuum decay test before pressure decay test, and dry air or nitrogen should be used for pressurization.

Experience has shown vacuum and pressure decay tests to be quite complimentary and neither should be omitted.

7.6.7.5 Tracer Gas Testing

There are a number of tracer gases and tracer gas detectors on the market. Helium is the preferred tracer gas for testing water-cooled windings because of several properties: small molecule, inert, nontoxic, and non-hazardous. Figure 7-35. SF6 has also been used, because of its inherent sensitivity and low cost of detection equipment; however, there is some concern because SF6 is not inert and under certain conditions may combine with water to form an aggressive compound.

Figure 7-35. Checking for Stator Winding Leak using Halogen Gas Detector

Sensitivity of tracer gas can be greatly increased by bagging the individual series and phase connections, Figure 7-36. In numerous cases, tracer gas has found small leaks (as small as 10^{-4} std cc/sec) buried under the insulation that otherwise were not found with vacuum and pressure decay.

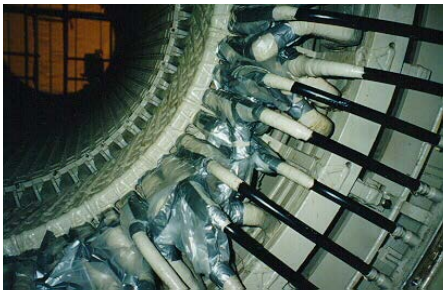


Figure 7-36. Bagging of Series Loops for Stator Winding Leak Test

Where bagging can not be applied, the sniffer must be brought within 2 or 3" to detect small leaks. Without bagging, tracer gas evaluation of an entire winding is probably impractical.

7.6.7.6 Testing for Wet Insulation

Capacitance testing is used to detect moisture within the groundwall insulation. The test is performed with an inexpensive, readily available battery-powered capacitance meter. The test is nondestructive to the insulation. Figure 7-37a,b&c. The reading is taken in the end winding region, usually within a few inches of the end of the core. The capacitance test must be done well or uncertain results will be obtained.

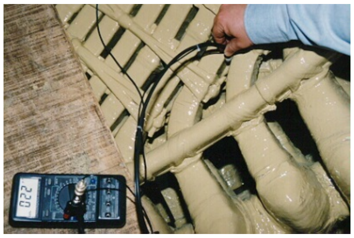


Figure 7-37a,b&c. Capacitance and Wet Insulation Testing (WID) Testing for Wet Insulation

The GE "wet bar" detector seems to be somewhat more accurate than the capacitance test in distinguishing bars with wet insulation. Both instruments can obtain readings with the field in place. But because it is difficult to access the bottom bars for good readings without removing the field, a decision to perform maintenance on a winding should not be made without obtaining field-removed data. Any bar that shows a high capacitance and/or wet-bar reading should be carefully examined in the area of high reading for any signs of bar surface anomaly before concluding that the bar should be removed from the winding.

The intent of these test is to locate bars that are at high risk of in-service and/or high potential test failure. If a bar fails the test, water has penetrated under the groundwall insulation the full length of the bar arm from the strand header. Under these conditions, insulation deterioration will be significant, and the bar is not considered suitable for long-term service, even though it may pass high potential test.

Water within the stator bar groundwall will degrade the mechanical bonds and reduce the inter-layer electrical creepage properties. In addition, hot water will dissolve the resin systems used on Thermalastic and Micapal, and other polyester-like insulation systems. Thermalastic-Epoxy and Micapal II resins, and other epoxy systems, are not dissolved by water, but the mechanical and electrical properties will be irreversibly degraded by the presence of water in the groundwall.

The capacitance test is based on the large difference between the dielectric constant of water and that of typical dry groundwall insulation, a ratio of about 4:1. Readings are taken for each top and bottom bar at both ends of the core. When plotted, unaffected bars will form a fairly tight "normal" distribution with a standard deviation value of about 2 to 3 units. Wet bars typically will fall significantly outside a smooth normal distribution curve. A bar which reads +3 standard deviations or greater is considered suspect and should be retested and further evaluated. A bar with a reading in the range of +5 standard deviations from average is almost certainly seriously damaged.

Judgment is required in evaluating the data. For example, data taken by a skilled operator using good equipment will tend to have a smaller standard deviation value. Thus these higher quality tests are likely to reject a bar with a lower deviation value than data taken with less care.

Bars which are confirmed to fall significantly outside the normal distribution curve should be further investigated by stripping the series/phase insulation. Visual examination for signs of moisture should be made of the joint and groundwall tapes, along with further pressure decay, tracer gas and bubble solution checks. Furthermore, even if wet insulation or indications of a leak are not detected in the series/phase joint insulating materials, the bar ground insulation should be investigated for degradation.

7.6.8 Interpretation

The broad scope and complexity of the various tests associated with assuring hydraulic integrity will require that personnel be fully qualified. Most bigger leaks will be easily found and required corrective action will be obvious. But assessment of small leaks, particularly those under the groundwall insulation, may be difficult and involve a high level of judgment.

Because decisions must be made based on the specific design of the unit, participation of OEM engineers will generally be essential.

8. Chapter 8 - Maintenance

8.1 Practices

8.1.1 Maintenance Programs

8.1.1.1 Basic Importance

Although generators typically deteriorate slowly, deterioration occurs in all generators, and may be rapid on units of marginal design or built-in deficiency. Essential maintenance must be done if plant reliability and maintenance costs are to be controlled. Industry-wide, maintenance programs are becoming fundamentally more important for several broad reasons:

- Desire for longer cycles between major inspections
- General aging of the fleet
- Developing of new, serious problems on larger generators
- Higher duty design stresses on newer machines.
- Increasing in number of design/manufacturing deficiencies in new generators due to limited OEM resources, rapid design evolution and reduction in built-in design margins. (This situation has resulted from purchasing policies of users looking for the lowest price generator, often without focusing sufficiently on quality.)

8.1.1.2 Basic Approaches

Industry-wide income pressures on power producers have led to increased management concern with the cost of basic maintenance programs. As a result there has been a strong industry trend toward longer cycles between maintenance outages, and minimizing the amount of work done during an outage. Unfortunately, generator condition-monitoring capability has not kept up with this need. Furthermore, users are finding it increasingly difficulty to obtain reliable technical information from OEMs. Thus owners are left with limited technical information on which to make a rational cost judgment of optimum cycle period and repair. The net result of these pressures and constraints is increased exposure to service failure being accepted by some equipment owners.

8.1.1.3 Technical Personnel Needs

Generators are a complicated machine with many inaccessible wear parts. Figure 8-1. Adequate and safe inspection and test of a generator requires that inspection personnel be well trained and experienced. Furthermore, once all applicable information is assembled, determination of optimum corrective maintenance can be difficult.

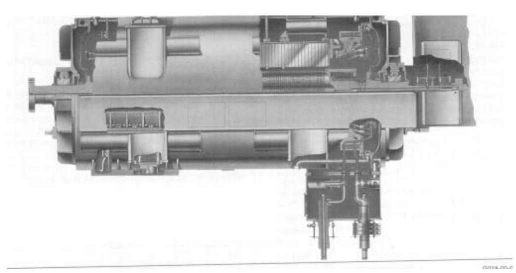


Figure 8-1. Cross-section of Generator (General Electric)

Some larger utilities have in-house capability to inspect and test a generator, and in many cases make appropriate judgments and recommendations. But because generator work is relatively infrequent and skill needs are high, of necessity many owners must rely on outside sources for assistance. This is particularly true in the event that the root cause of a failure incident is not clearly obvious.

Traditionally, the primary source of outside technical assistance was the OEM generator specialists and factory engineers. But cost pressures on the OEMs caused a reduction in OEMs capability which has only partially been compensated by an increase in independent service providers. Thus, there remains a challenge to equipment owner personnel in obtaining reliable information on which to base maintenance decisions. Hopefully this text will assist equipment owners in better understanding the generator, and also allow more effective communications with OEM and independent maintenance personnel who arrive on site to perform generator test, inspect and maintenance.

8.1.1.4 Inspection Periods and Priorities

Generally OEMs have recommended first inspection of a generator at the end of one year, and periodic major inspections every 5 years thereafter. However, these recommendations are modified by owners to accommodate specific conditions and requirements, based on several considerations:

- Available maintenance funds
- Acceptable financial risks and trade-offs
- Known problems with individual units
- Importance of a specific machine to the system
- Operating hours of the generator
- Machine-specific recommendations from OEMs
- OEM fleet information
- Owner fleet information
- Quality of monitoring equipment on a particular unit

On units with known existing problems or concerns, inspection periods of 1 to 2-1/2 years may be preferable. On the other hand, inspection cycles of 7 or more years may be appropriate for particular classes of machines or system requirements.

8.1.1.5 Maintenance Program Dangers

Several obvious concerns and priorities apply to planning and executing maintenance programs:

- More frequent inspection should be considered on equipment known to have a defect with high and/or accelerating deterioration rate.
- More frequent inspections should be considered if failure may cause serious damage to the generator or disruption to the system.
- Some suspected or known problems are of a nature that no advance warning of failure can be expected.
- Condition monitoring equipment is not capable of giving advance warning on several important known generator failure mechanisms.
- Inexperienced inspection and test personnel can call for unnecessary repairs or miss or misunderstand important problems.
- On machines, which are in marginal operating condition, errors of judgment can result in forced outage and much greater damage.

- Forced outage is likely to result in a substantial outage extension in relation to time required to perform planned corrective maintenance.

8.1.2 Upgrade/Uprate Programs

8.1.2.1 General

Upgrading of power plant equipment, including the turbine-generators, has become commonplace in the industry. Two concurrent existing forces are contributing to this decision:

1. The opportunity to uprate old equipment, and
2. The need to continue operating increasingly old equipment.

These two factors are related to pressures to reduce cost of power production combined with difficulties in obtaining permits for construction of new power plants.

Considering the first of these 2 factors, *uprate* of older turbines is made possible by modern design capabilities that allow higher efficiency of the turbine, for example by restaging the high-pressure turbine blading. This design modification allows “free” energy, i.e., more power from the same steam flow, but requires the generator to also handle increased power. Typically the increased output from a fully modernized turbine may range up to 10-15%. An older generator cannot be expected to safely handle the increased duty without considerable upgrading.

The second factor contributing to generator upgrade relates to the fact that many 30+ year old generators are still regarded as prime power producers.

8.1.2.2 Turbine uprate/upgrade

In a power plant, the turbine itself is relatively well understood – the function of a turbine is relatively intuitive. Furthermore, the turbine contains many wear parts that require on-going maintenance, thus giving plant personnel an opportunity to become familiar with the turbine components. Because of these two factors – the intrinsic intuitive nature of the turbine and the relatively frequent maintenance required on the turbine – there are generally several personnel within a power plant that are comfortable in their understanding what needs to be done to a turbine to keep it operating reliably and at high efficiency. From this knowledge base, plant personnel tend to be comfortable with the parameters for both *uprating* and *upgrading* of the turbine.

None of this is true for the generator. There is almost nothing about the generator that is “intuitively obvious”, and aside from the bearings and shaft seals, there are essentially no obvious “wear parts”. As a result, the generator is infrequently opened for maintenance, and when opened, there usually is no one in the plant comfortable with assessing the condition of the generator. From this very limited knowledge base, there is likely to be no one involved in the turbine-generator upgrade decision that is comfortable in deciding what *upgrading*, if anything, needs to be done before *uprating* the generator.

Thus the focus of a plant uprate may concentrate on the turbine, and on larger units costs for these modifications to the turbine alone may exceed $40 million. The generator is often considered only as an after-thought and no plans incorporated to correspondingly upgrade the generator. Late in the planning cycle, generator expertise may be brought into the uprate decision process. But the money is all committed to the turbine, and the generator may be left with no upgrade commitment at all.

8.1.2.3 Generator uprate/upgrade

But a decision to upgrade the generator to correspond with an upgrade of the turbine on a large turbine-generator set will impact heavily on the cost of plant uprating. A stator rewind combined with a field rewind can add 50% to the cost of the uprate. But obviously, if the generator is not correspondingly upgraded, at the end of the uprate the plant reliability may have experienced a significant negative impact.

This is unfortunate because mechanical and electrical duties on the generator tend to be a square function of the uprate. For example, consider the case of a 15% uprate:

- Stator current will increase linearly with amount of uprate, but electromechanical forces on the stator bars will increase by the square of current increase. Many of the older slot and endwinding support systems were marginal at best. Increasing the forces by 32% (1.15^2) raises important reliability questions.
- Likewise, temperature rises increase with the square of current. Since the stator windings of most large generators are water cooled, and the windings are typically designed without large margin to the boiling point of water, there is the risk of encroaching on 100C. If the water in a single bar reaches boiling point, destruction of the stator winding is almost instantaneous – steam will not cool the stator bar.
- In the rotating field, the copper winding temperatures will increase significantly. This additional temperature rise will result in higher thermal and mechanical duties on a material (copper) that has low intrinsic mechanical properties. Field winding failure due to distortion of coils and fracture of turns may be the result.

8.1.2.4 Generator Upgrade Options

Upgrade options for the generator stator include:

1. Thorough inspection and test of the stator to assess as well as is possible the condition of the components in an attempt to predict remaining life. A precise assessment, however, is not possible due to the complexities of the generator, and thus uncertainties will remain.
2. Installation of an upgraded slot wedging system may be advisable to incorporate radial and side pressure springs. But there may be insufficient space in the slot to allow for either of these spring systems.
3. Replace the stator winding with a design that operates at lower temperature rises and incorporates:
    a. modern slot wedging systems, and
    b. upgraded endwinding support system.

On a large generator with a 30-year-old stator winding, the preferred quality option would certainly be a rewind, i.e., the winding is already old and cannot be expected to operate reliably for 50 years. Thus the logically option, assuming available resources, would be the stator rewind.

Upgrade options for the rotating field include:

1. Inspection and test of the field winding. But inspection is limited in quality due to limited access, and over-voltage test is generally not recommended on field windings. With poor access and tests of marginal capability, this assessment will be incomplete regarding rotor winding quality.
2. Full non-destructive evaluation of all forging components.

3. Rewind of the field with all new insulating materials, and with new copper if significant copper distortion has been occurring.
4. Replacement of the retaining rings if there are indications of distress or the rings are the old 18/5 material.
5. Replace the collectors if worn.

There may be limited options for a field winding redesign to operate at lower thermal or mechanical duties.

In addition to deterioration due to wear of components, generators that are more than perhaps 20 years old may have components that warrant consideration for replacement. Some specific obsolete designs and components include:

- Large generator fields with retaining rings not shrunk onto the field body. The copper conductors, particularly the top turns, are vulnerable to breakage and as a group, these fields have required significant amounts of repair in the form of partial or complete rewinds.
- All retaining rings manufactured with the 18/5 stainless steel material.
- Large generator stators with string-tie endwinding support systems. These machines can be kept running only by repetitive minor and sometimes major on-going maintenance repairs, with the accompanying risk of forced outage.
- Many varied designs of stator wedging systems have been used over the years. Some were remarkably ineffective and troublesome, e.g., the “camel back” wedge. On generators subject to wedging problems, rewedging with a modern system should eliminate need for repetitive rewedging.
- Instrumentation systems have evolved over the years. More particularly, these systems provided very little diagnostic information in the event of failure. Modern DCS monitoring may easily be justified to replace a still functioning primitive system.

8.1.3 Predictive Maintenance

Identifying what and when maintenance should be done is an essential part of a good maintenance program. There are a number of tools, which can be used in this process. These tools will be discussed in the paragraphs, which follow.

8.1.3.1 Unit-specific History

Good records of generator operation and maintenance history should be kept and made available for periodic review. These records should be held over the life of the machine, and the entire history should be factored into maintenance decisions on specific units.

Maintenance records, including extensive photographs, are an invaluable analytical tool, which unfortunately sometimes are not available. At the end of every outage, the condition of all components should be carefully recorded, and all work done should be thoroughly documented. When work is done by contract, this requirement should be specified and met. Of course, the requirement is equally important if the work is done by in-house personnel.

Another important evaluation tool is the review of day-to-day operation of the machine. Wear rates for many of the more common deterioration mechanisms are affected by the way the unit is operated. Also, records of system disturbance, mis-operation, or malfunction are vital to understanding the impacts of certain short-term failure mechanisms.

Failure to keep good operation and maintenance records can result in unnecessary work being done, or in omission of performance of critical maintenance tasks. Lack of good records can substantially increase direct maintenance costs and could result in an otherwise avoidable long and expensive forced outage or outage extension. Figure 8-2 & 8-3.

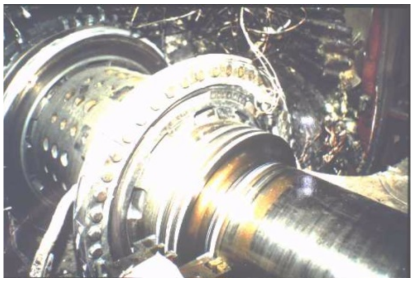


Figure 8-2 & Figure 8-3. Results of Retaining Ring Burst: Extensive Generator Damage and Replacement Field

8.1.3.2 Fleet Experience

Owners with duplicate or similar units should maintain long-term, fleet-wide records of operation and maintenance. In order to be useful, these records need to be available to those involved in making the maintenance decisions, including where applicable, OEM and other vendor personnel.

8.1.3.3 OEM Recommendations

The OEM should be a key source of maintenance planning information. While OEMs have perhaps deservedly gained a reputation of recommending conservative maintenance programs, often these recommendations will be found to be accurate and should always be seriously considered.

OEM planning recommendations can come in the form of general technical information letters, or communications specific to the affected unit. But more particularly, at the end of an outage, the OEM recommendations for future actions should be obtained and well documented.

8.1.3.4 On-line Monitoring Information

As will be discussed below in Section 8.1.3, Interval Extension, review of normal operation of the unit as well as any mis-operation incidents is essential to prediction of future maintenance requirements.

8.1.3.5 New and Specialized Tests and Evaluations

Industry cost pressures have led to recent improvement in inspection capability without removal of the field; robots are available for carrying miniature cameras, wedge tappers and spring height measurement equipment. Figure 8-4. Also, recent improvements in partial discharge capability have resulted in increased capability to assess those conditions of the generator that result in partial discharge activity.

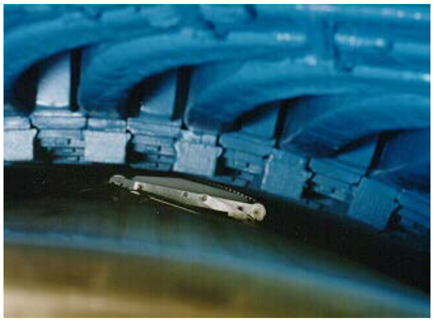


Figure 8-4. Generator Inspection Using Air-gap Robot

8.1.3.6 Old and Standard Tests

These tests are covered in detail in Chapter 7, Testing. The majority has been available for 75 years or more. Even so, the capabilities and limitations of these tests are not fully understood. However, these tests are extremely important, and the results and trends should be carefully evaluated for information relating to prediction of necessary maintenance.

8.1.4 Interval Extension/Condition Based Maintenance

Closely related to any discussion of Predictive Maintenance are the subjects of Interval Extension and Condition Based Maintenance.

8.1.4.1 Risks Associated with Performing Maintenance

Designing of an optimum maintenance program is not an easy task. There are numerous identifiable direct costs involved in performance of maintenance work, e.g., parts, materials, labor, equipment, supervision. There are also indirect costs such as loss of generating capacity. And there are risk costs. For example, handling of the field can result in damage to the core, stator winding and field itself, Figure 6-4. Residual magnetism of the field can carry magnetic foreign objects into the stator.

Performance of repairs themselves also carry risks, including damage to a component not scheduled for replacement, removal of a component that may yet be in good condition, and installation of a component with an “infant mortality” deficiency.

8.1.4.2 Interval Extension Risks

There is obvious economic advantage in successful deviation from historic inspection schedules. There are also good technical reasons for extending outage periods on specific units: base load operation, extended shut-down periods, known reliable design, machine not critical to system reliability.

But condition-based outage extension may be based more on immediate cost pressures, and hope, than on available generator condition information, since generator condition monitoring capability is still somewhat inadequate.

On balance, a conservative approach perhaps is preferable for all but expendable machines.

8.1.4.3 Analysis of Existing Maintenance and On-line Monitoring Information

Information on day-to-day generator condition in most plants is limited to data on vibration levels and to temperature readings for armature winding, cooling gas, field winding, and bearings. Many units will also have core monitors, field shorted turn detectors, partial discharge detectors, and end winding vibration monitors. In addition, manufacturers have available direct-factory assistance through telecommunications systems, although these systems have not as yet become popular with users. Figure 8-5 & 8-6.

Control room equipment will also record plant and system disturbance and failure conditions. But often this information is not adequately recorded for subsequent evaluation and analysis, particularly on units with older instrumentation and recording equipment. Nor can the quantity and quality of information be readily increased. Nevertheless, the information that is available should be given close attention.

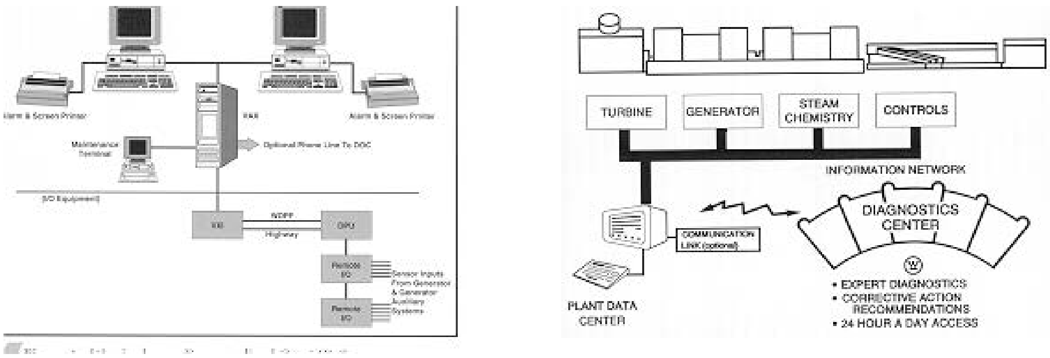


Figure 8-5 & 8-6. Manufacturer Telecommunication Monitoring System (Westinghouse)

The records of malfunction and mis-operation, plus review of day-to-day load conditions, can likewise provide guidance as to generator condition.

Some assessment of condition can be made by careful review and analysis of previous inspection, test, and repair history of the specific unit. Also, useful information may often be obtained by reference to performance of similar generators, or classes of generators with similar components.

8.1.4.4 OEM Maintenance and Upgrade Recommendations

Since all OEMs have some amount of information on specific machines, classes of machines and performance of particular components, care should be taken to assure that all available information is obtained from the manufacturer. General information on extent of normal repairs, service failures, and trends should be available from the OEM with some degree of accuracy. Obtaining this information from an OEM, however, may take some diligence and follow-up.

In addition, manufacturer recommendations with respect to upgrade and uprate possibilities may assist in understanding the basic capability, quality and life expectancy of a specific unit.

8.1.4.5 Additional Monitoring Devices

Outage extension risks can be minimized by application of state-of-the-art monitoring equipment. Retrofit application of some of these devices to existing machines is not particularly costly and should be considered. Chapter 5, Monitoring and Diagnostics, can be referenced for further information on monitoring devices.

8.1.4.6 Risk Assessment

In the final analysis, judgment must be made of risk vs. cost saved, based on a number of variables some of which cannot be accurately defined. Uncertainties can be minimized, however, by application of top quality monitoring equipment and careful analysis by competent personnel of all operation and maintenance data from all available sources.

8.1.5 Parts Replacement and Storage

8.1.5.1 Spare Parts Procurement

8.1.5.1.1 OEM Recommendations

Recommendations from the OEM can be invaluable, since the OEM should have fundamental understanding of service problems not only on the specific generator but also fleet-wide information. Of course, the OEM may also have certain profit motives, or may simply recommend parts based on superficial, general-practice considerations. Nevertheless, consideration of these recommendations should be an important part of the owner decision process.

This decision process for purchase of spare parts has always been difficult for many owners. In conflict with OEM recommendations, several factors bring strong incentives to avoid purchase:

1) historic high generator reliability
2) significant initial purchase costs
3) storage costs
4) possible shelf-life limits
5) possibility that purchased parts may never be used, and
6) concern that needed parts are not on the recommendation list.

There is no simple, single answer to these issues, and each owner must make the decisions based on difficult cost analysis and on judgment of specific conditions and needs, some of which are discussed below.

8.1.5.1.2 Individual Machine Assessment

Fundamental to the decision process are several machine-specific issues:

- results of latest inspections and tests
- machine overall operating history
- importance of the machine to the system
- costs of an outage on the machine
- number of duplicate machines on the system
- possibilities of borrowing parts from other operating companies
- probable procurement time
- cost penalties for priority delivery
- retirement plans on the specific unit and sister units.

Beyond all of the above consideration is a broader question: What is the likelihood that a complete field or stator, or even an entire generator, should be replaced? While these major components are costly, this path is increasingly being used, and may be the most cost-effective overall solution in difficult situations.

8.1.5.1.3 Parts Procurement Source

Historically parts were procured from OEMs, unless sufficiently simple as to be made in-house. Outside sources are now available for several of the more common wear parts. In addition, manufacturers are increasingly willing to produce minor and major parts for other OEM machines.

This change of situation often has obvious cost and delivery advantages to the owner. But there are negatives to non-OEM vendor purchase, and while not necessarily over-riding, they should be kept in mind:

- warranty conflict situations may develop

- vendor capitalization may be marginal
- vendor quality consistency may be inadequate or erratic
- vendor technical staff capability may be very limited
- further negative impact will occur on OEM capability to support the industry.

8.1.5.2 Storage of Spare Parts and Components During Overhaul

8.1.5.2.1 General

OEMs have issued specific recommendations for storage of parts, Figure 8-7. There are minor procedure differences between short-term and long-term storage, but if components are preserved under proper conditions, and if preservation materials are maintained at regular intervals, most parts (excepting short shelf life items) can be stored indefinitely without deterioration. Those parts with limited shelf life usually have short procurement cycles and do not present an availability problem.

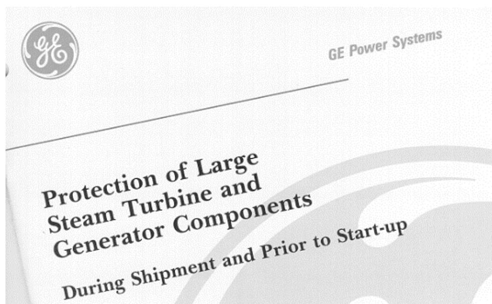


Figure 8-7. Storage Recommendations Book (General Electric - GEZ-5691)

8.1.5.2.2 Special field storage considerations

Generator fields are the most sensitive major component from a storage standpoint. Because both metallic and insulation components are susceptible to moisture damage, it is important that fields be stored in a low humidity atmosphere, either by use of heat or dehumidifiers. Heat lamps are often used, but must be located so as not to ignite combustible materials covering or supporting the field.

Manufacturers recommend that if fields are supported in the body area, support should be located on a pole face (not tooth areas). Load must be kept off retaining rings.

8.2 Cleaning and Painting

8.2.1 Cleaning

8.2.1.1 General

Because contamination is such a major maintenance problem, cleaning is the focus of abundant attention. Methods vary, and all are a compromise. Components are difficult to access and some contaminants are difficult to remove. In addition, solvents that are effective in removing contaminants often will also attack the resins in insulation systems. Finally, most (all?) of the better cleaning agents have been banned by government.

As a result, cleaning remains a problem that is both time-consuming and only partially effective. Usually a combination of materials, procedures and agents will be employed to accomplish cleaning. Input from the OEM should be obtained to assure that the materials and process used will not damage sensitive components.

8.2.1.2 Cleaning Methods

8.2.1.2.1 Initial Cleaning

Removal of some of the light dusts and other non-bonded materials can be accomplished by use of vacuum cleaners. Clean, dry compressed air, at moderate pressure, can be used in combination with vacuum cleaners to remove additional contaminants.

8.2.1.2.2 Solvents

Acceptable solvents have continually changed over time. Perhaps the only universally acceptable solvents are water and alcohol, and both are weak and can be damaging.

OEM recommended materials and procedures should be considered in selection and use of solvents. Materials should only be used as approved by local and federal government regulations. Proper personnel safety equipment should be correctly utilized. Since there are flammability considerations on many solvents, necessary fire protection will be needed.

Solvents should be used sparingly and should be removed as quickly as convenient in order to minimize side effects to generator components.

8.2.1.2.3 Aggressive Cleaning Methods

Severe contamination has been successfully removed through use of abrasive cleaning. Care must be taken that insulation surfaces are not attacked in the process, and capture and removal of cleaning materials must be accomplished. This latter problem is eliminated if CO_2 can be utilized, but solid materials such as corn cob and walnut shells will find their way into the smallest, most inaccessible cavities.

In cleaning field copper, care is required to avoid changing the surface conditions and modifying coefficients of friction. Also on twin-turn coils, solid particles may not be removable from the twin-turn junctions.

Steam cleaning may also be effective on selected components, although moisture tends to be hostile to most materials.

8.2.1.2.4 Stator Winding and Core

Cleaning the slot portion of stator windings is difficult and time-consuming if contamination is extensive. The ventilation ducts will trap and hold materials. Dry materials may be removed with vacuum, bottle brushes and compressed air. But in the latter case, the materials will simply relocate and remain within the generator, unless removal access is available. If materials are solid or grease-like, solvent washing, bottle brushing and air will remove much of the accessible material. But again, if care is not used, the contaminants may simply redeposit in other unwanted areas.

Access to the end windings, connections and supports is better, but the configurations allow for deep entrapment and difficult cleaning.

Because these areas are difficult to clean, and residual solvents and contaminant accumulations can be troublesome, recommendations of the OEM should be solicited where appropriate.

8.2.1.2.5 Field

Some cleaning can be accomplished through ventilation ducts and other openings. But overall access to the field winding and collector connections is poor, even with retaining rings off. In the event of severe contamination, major stator winding burning for example, complete rewind of the field will be required. Often the winding copper is reusable. Although the costs of cleaning and straightening the copper are high, both in time and money, reuse of the copper generally will allow rewind without need for rebalance, providing adequate care is taken.

Access to collectors and rotating rectifiers is good, and these components generally can be cleaned of most any contaminant that does not penetrate into the insulating materials.

8.2.1.2.6 Frame

Frames may be contaminated from several sources and materials: oil, dust, oil/dust mixture, vibration products, and combustion products. Cleaning requirements will vary depending on conditions. For example, if a large oil spill has caused filling of ventilation passages of high voltage bushings, siphoning or draining may be required. If an armature winding burn-up or core failure has occurred, the frame is likely to be heavily contaminated throughout with conductive materials.

Oil contamination is common and oil alone is relatively easy to clean. Since oil is ubiquitous in many designs of generators, cleaning the last quantity of oil may not be worthwhile. But oil can contaminate the entire frame, and can be troublesome when combined with dust. Also, oil can adversely affect stator-wedging systems and degrade some insulating materials including asphalt.

Contaminants remaining in the frame after cleaning can re-contaminate the windings after restart, thus extensive cleaning may be needed and this can be difficult to accomplish. If cleaning through existing access holes is insufficient, additional permanent or temporary access holes may be needed, Figure 8-8. Cutting and closing these holes bring opportunity for contamination with metallic particles.

Figure 8-8. Inspection Port for Stator Frame Internal Inspection

8.2.1.3 Painting

Painting of generator components is a common, routine practice during maintenance. Often the result is simply cosmetic. Machine performance is not necessarily improved by painting, and may be harmed due to increased heat transfer resistance or covering of evidence of previous deterioration. General guidelines are indicated below, but OEM recommendations should be considered in application of any paint.

8.2.2

8.2.2.1 General

8.2.2.2 Structural Components

Metallic structural parts (frame, end shields) may need repainting to prevent rust, but care must be exercised to assure that the surfaces are sufficiently clean to form a good bond and prevent spalling.

8.2.2.3 Armature Winding

These components are built with heavy resin (paint) content, thus they do not inherently require painting. When painting is done on indirect cooled windings, a thin coat is advisable to reduce heat transfer impact.

On asphalt windings, the common practice of application of black paint will hide existing evidence of tape migration that has occurred since last paint application. Paint should not be applied until the evidence of any tape migration is carefully catalogued.

Paints are sometimes applied directly to stator wedge dovetails to reduce wedge vibration. This is an acceptable practice, since minor wedge vibration can normally be stopped by application of paint to the dovetail. (This is in marked contrast to stator bar vibration.)

8.2.2.4 Field and Retaining Rings

Application of paints to the field components is a particular concern, especially the painting of body and retaining rings. OEM recommendations should be followed closely in any paint application to fields. Figure 8-3 clearly shows unpainted non-magnetic retaining rings on a new field.

8.3 Component Repairs

8.3.1 Armature Winding

8.3.1.1 General

Bar vibration, loose parts, foreign object damage, partial discharge attack, and mechanical damage combine to make armature windings a relatively high maintenance component. Length of life varies between manufacturers and among classes of machines made by a given manufacturer. End-of-life can be reached in only a few years. But most windings will function well for 30 years, and many windings are still operating reliably after 50+ years.

Many of the required repairs are common to all manufacturers, but procedure details vary. In addition, installing a stator winding, as well as most other generator repairs, tends to be more an art than a science. As a result, safe and expeditious completion of all of the described operations requires use of fully equipped and trained personnel who are skilled in the particular operations. In addition, because of the inherent complexities, capable technical support and supervision should be on-site.

Finally, because the materials, tools and equipment are specialized, costly and critical, close attention must be placed on each these items.

8.3.1.2 Drying Winding

All windings are susceptible to surface moisture, and some windings absorb moisture within the ground wall. If a winding is exposed to humidity, as is the usual case for air cooled machines, drying may be needed before a unit is over-voltage tested and may be necessary before placing on line.

Procedures are described by OEMs, and involve application of heat to the winding over a period of time. Figure 7-6. Heat can be applied internally by passing current (or water) through the armature bars, or externally with electric heaters. In both cases heat application rate should be controlled so as to remove moisture slowly. Drying of a damp machine may take 24 hours or much longer, 3 to 5 days, if moisture has penetrated the insulation.

A word of caution in drying stator windings with winding current. Since the resistance of an armature winding is very low, large current flow will be required to supply significant heat. This large current may generate damaging local heating at any marginal winding connections which may exist, e.g., marginal series loop connections.

8.3.1.3 Rewedging

Rewedging is one of the most common stator repairs. Several different wedge systems are used by manufacturers: flat with low side interference, flat with high side interference, double end taper “camel-back”, flat with radial springs, single tapered slide “piggy-back”, double tapered slide, herring bone. Assembly techniques vary between systems and among manufacturers.

Rewedging is a relatively complicated task with a number of inherent risks: damage to core iron, cuts in armature bars, excess radial pressure, irregular or inadequate radial pressure, improper materials. OEM recommended procedures should be referenced. Figure 8-9.

Figure 8-9. Stator Rewedging Equipment

If only the wedges are loose, Figure 8-10, correction may be accomplished by simply painting the wedge dovetails. If general bar vibration is occurring, full rewedge with OEM procedures may be required. If bar vibration is occurring only in the end regions of the slots, Figure 2-12, likely cause will be clearance under the bars, and modified rewedge procedures will be necessary. If correct rewedge procedures are used, in all probability the bar vibration can be stopped indefinitely.

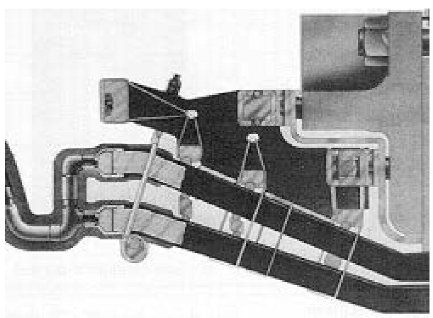
Figure 8-10. Red Dust Generation Resulting from Wedge Vibration in the Stator Slot Dovetail

Bar vibration is highly unlikely on asphalt windings (low forces, puffing, low rebound and high natural friction). In general, rewedging of asphalt winding should not be required or done. If rewedging is performed, however, care should be taken to assure that high radially downward pressure is not applied, as tight wedging of asphalt windings can increase insulation migration rates.

8.3.1.4 Tightening End Winding

If there are any signs the end winding is not tight (resonance, dust or grease, worn ties, loose blocking), corrective actions should be taken based on OEM recommendations and specific unit experience.

Procedures differ with end winding support design. Some systems allow for correction by retightening clamping and tensioning bolts. Figure 8-11, 8-12 & Figure 8-13.



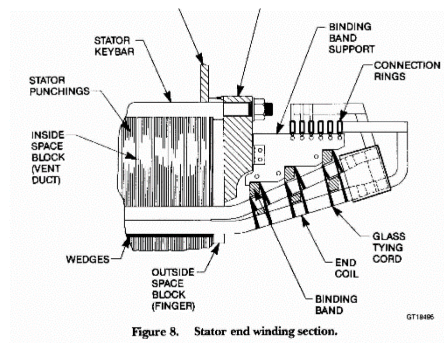


Figure 8-11 & Figure 8-12. High and Low Force Stator End Winding Support Systems (General Electric)

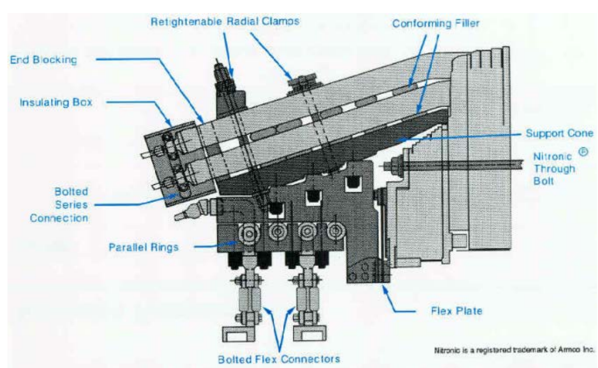


Figure 8-13. High Force Stator End Winding Support System (Westinghouse)

Other systems may require reflooding and rebonding. All systems may require replacing or adding of ties and blocks. (Components must be cleaned of oil and other contaminates before adding ties.) Figure 8-14 & Figure 8-15.

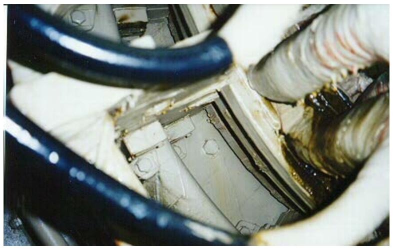


Figure 8-14. Individual Stator Bar Vibration

Figure 8-15. Replacing Individual Tie on Stator End Winding

In every case, symptoms should be adequately addressed, including assessment for possible resonances. Correction of looseness is particularly important since deterioration due to vibration is an accelerating problem.

8.3.1.5 Bar Replacement

Individual bar replacement, particularly that of a bottom bar, is perhaps the most complex of stator winding repairs. In all cases the work must be skillfully executed. Otherwise peripheral damage may be done which can extend the outage and/or shorten the life of the winding.

Removing of the first bar from the layer requires that all bonded blocks be debonded or removed, and this is tedious and precise work. If lifting the bar arm from the nested position is done with high force, i.e., come-alongs, the bar will be broken in the end-arm region. If subsequent bars are broken loose in the end winding by use of wedges to apply side-forces, the bar will be broken unless the forces are applied uniformly along the length of the bar arm. This force is difficult to control.

Removal or reassembly of the first bar from a layer is further complicated by the significant interference with remaining bars due to the geometry of the bars in the end winding. Figure 8-16.

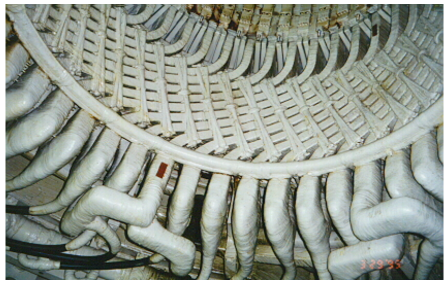


Figure 8-16. Stator Bar End Winding Geometry

As a result of this interference, the rigid bar must be heavily strained. Even if several bars are removed, the last bar to be reassembled must still be subjected to this strain. (The interference is much greater on 2-pole windings than on 4-pole.) There is no physical way this interference can be eliminated. It can be alleviated only by a bar step-up process for removing and assembling the last bar of a layer, but this requires that the entire layer of bars be removed, or cutting loose and lifting of several bars that otherwise would not be involved in the repair. It also requires sliding bars endwise in the slot and lifting of the bars sufficiently to allow the final bar being assembled to slip under the last step-up bar at initial insertion end of final bar. This process is complicated and often incorrectly performed.

Bar removal in the slot portion can also be difficult, particularly on larger machines with specialized vibration restraining systems. Figure 8-17. Tight side packing, or side pressure springs, will cause high friction against bar removal. The filler or side pressure springs should be removed, if possible, before attempting to remove the bar from the slot.

Some armature winding designs may have curable conforming agents within the slot which may bond the bar to the core iron. Also, a few manufacturers cure the bar groundwall insulation resin after bar assembly; stator bars in these windings may be fully bonded and probably impossible to remove without destroying the bars.

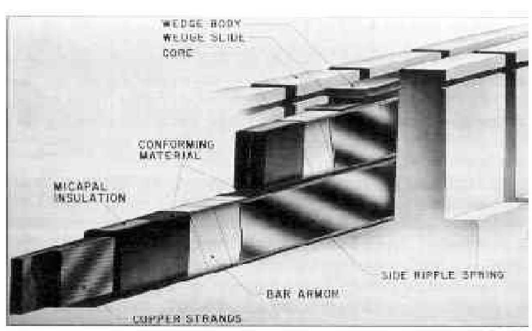


Figure 8-17. Stator Bar Slot Restraint System

Associated damage may preclude reuse of bars. Tight side filler or side ripple springs and/or bonding of bars in the slot may require high mechanical forces to be placed on the bar during removal. The resultant bend is likely to damage the bar groundwall. This bend may not be observed since a bar can be bent and restraightened during the removal process. A proper high potential test will detect the fractured groundwall, but reinsulation may not be a viable option. A bend that will break the groundwall insulation may also damage the bar internal insulation (in particular the vertical separator between strand tiers), and this cannot be found nor can it be corrected. Basically, if a bar is kinked in the process of removal and/or fails high potential test after removal from the slot, it probably should not be restraightened and it should not be reused.

Caution: If the bars are intended for reuse, the entire bar should be given a pre-assembly hipot with foil extending down the bar arm to within about 8" of the bare copper.

Finally, there is the challenge of curing the assembly and blocking materials. Heat cannot be applied to the full length of individual bars on long machines, as they will grow in length with respect to the remainder of the winding. (On a 260" core, the relative length change for a 60C difference in temperature is more than .270", and this will fracture the bar at the first radius at both ends of the core.)

Manufacturers, and service companies, have developed standard procedures for accomplishing individual bar replacements. Because all these processes are complicated and difficult to execute, even on small machines, a review of the entire operation should be conducted before the work is begun.

8.3.1.6 Full Stator Rewind

Manufacturers of stator rewind materials have developed standardized procedures for performing a full rewind. In all cases the process is lengthy and involves many high-skill operations. Also tooling, equipment and material inventory needs are substantial. (The length of the rewind process is highly dependent on the capability of the rewind provider.)

The list of all necessary parts and materials is long and specialized. A missing item can cause major delay and disruption to progress, and can adversely affect finished quality. Thus it is preferable that drawings be carefully reviewed and all parts pre-inventoried before work begins. During rewind, good accessibility and control of materials should be maintained. Figure 8-18 & 8-19.

Figure 8-18 & Figure 8-19. Material Storage Access During Stator Rewind

A realistic and accurate schedule is essential if there are time and cost constraints. The necessary winders and support personnel should be pre-identified to execute this schedule. Also necessary station support should be available: heat, electricity, air, lay-down space, safety arrangements, and crane availability.

A detailed review of rewind steps is beyond the scope of a single document, particularly since on-site rewind processes vary widely by manufacturer and machine class. Also the processes are all somewhat elaborate and challenging, with many critical steps. But neither winding removal nor reassembly can be neglected.

Winding removal is a major operation and suitable procedures are important, otherwise progress may be slow and damage may be done to peripheral components, e.g., the stator core. If winding reassembly is properly executed, progress will be rapid, component failure rare, and results satisfactory. But if not correctly done, delays will occur and quality may suffer.

Prior to selection of rewind vendor, a full and detailed review should be conducted of the vendor capability, including:

- specific procedures to be used for all processes

- schedules, number of similar rewinds
- number of similar new-machine windings
- problems experienced during the rewinds, and
- operating history of the particular winding materials and techniques on both new machines and rewinds.

There are a number of particularly critical steps to review:

Winding Removal:

- Initial inspection, photographs, records of dimensions and connections
- Initial integrity of core lamination insulation
- Hazardous material (asbestos) control
- Cleanliness of operations, including copper filings generated during severing of bars
- Internal cleanliness of liquid cooling systems
- Wedge removal without core damage
- Cutting of end winding ties
- Bar removal without damage to core
- Disposition of materials, including suspected hazardous
- Core tightness

Winding Assembly

- Core condition before winding assembly
- Radial/axial locations of end winding support components
- End winding support hardware condition, tightness, float and locking
- Bar fit-up and end blocking and tying pattern
- Slot cleanliness before assembly of each bottom and top bar
- Details of bar assembly: fillers, side ripple springs, conforming materials, temporary wedging
- Elimination of possible clearance under bar(*)
- Temporary blocking and tying of slot and end winding
- Permanent end winding blocking and ties
- Close-up procedures for last bar in bottom and top layer
- Bar inter-layer supports
- Series and phase bar electrical connections
- Series and phase bar liquid connections
- Series and phase bar insulation
- Connection ring ties and blocking
- High voltage bushing connections and insulation
- Wedging procedures: tooling, core damage, under-tightening, over-tightening, radial spring assembly, gauging
- Details of baking procedures
- Final winding inspections
- Final core condition: tests, inspections
- Cleanup and painting

- Final report

* Experience has shown that on some designs, bar vibration may result if a bar is not fully seated in the ends of the slots without strain on the copper. This assurance may require placing a thin temporary non-metallic shim under the bar before seating bar in slot using only end winding downward clamping pressure.

8.3.1.7 Water Leaks

Liquid cooled generator designs differ in important detail between manufacturers. Before corrective actions are taken, OEM input should be obtained.

8.3.1.7.1 Cracked Pipes and Fittings

Necessary repairs will normally be quite apparent and will involve replacement of the affected parts. If a crack is on series or phase bar locations, insulation will require removal and replacement. Figure 8-20. Over-temperature and flexing of hot copper must be avoided in the processes. (Red-hot copper has the mechanical properties of swiss cheese.)

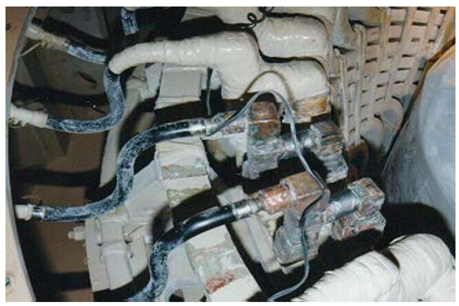


Figure 8-20. Insulation Stripped from Piping to Liquid Cooled Series Loop

If resonant vibration is suspected as the root cause of the problem, the condition must be corrected, and may require adding of blocks and ties.

8.3.1.7.2 Correction of Strand Leaks

Leaking strands are not only a serious problem, but correction can be very difficult. Figure 8-21.

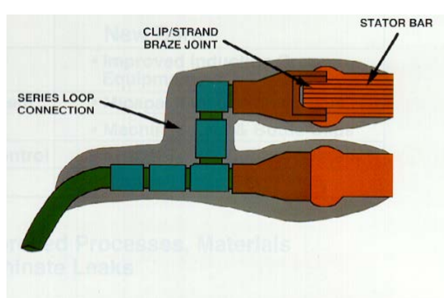


Figure 8-21. Liquid Cooled Stator Bar Strand Header

Prior to correcting a known leak on a bar, the condition of the insulation of that bar should be assessed, as discussed in Chapter 7. If the insulation was become wet from the water leak, the insulation quality will be permanently degraded, and bar repair is unlikely to be a viable solution. The affected bar should be replaced.

Various suppliers have developed corrective procedures for clip-to-strand leaks. Two general approaches are used: sealing leaks with a carefully selected resin system, and clip replacement. Each approach has important advantages and disadvantages.

The resin approach is relatively fast, but is difficult to perform, very costly, and may not be a permanent fix.

Procedures for replacing of clips have been developed by several vendors. These processes are thought to be permanent, but are difficult to execute and may be risky and time-consuming. The old clip must be removed without debonding the individual strands from each other, a procedure that requires precise temperature, time and force control. (Alternatively, each individual strand must be cleaned, polished, sized and otherwise restored. This is a huge and difficult task.) Successful rebrazing of the new clip components requires explicit procedures with narrow temperature control, careful addition of braze materials, and accurate dimensional control. In addition, no matter how carefully the work is performed, the existing copper will be degraded by braze material penetration due to repeated heating.

The alternative of installing a new winding is costly and time-consuming, but should be evaluated if leaks are believed to involve several bars, particularly if one or more bottom bars are involved. If the unit has been operating for 20 or more years, and is expected to be operated for perhaps another 15 years, a properly performed rewind would be the best option.

8.3.1.8 Water System Contamination

8.3.1.8.1 Correction of Atmosphere over Water

Manufacturers use two types of systems: “high” oxygen and “low” oxygen atmosphere. In the former, the source of the incorrect atmosphere is likely to be internal to the generator. In the latter, the source is likely to be external to the generator.

The high oxygen system can go out of range if excess hydrogen is leaking into the system, or if makeup air flow into the storage tank is restricted or blocked. Corrective actions must be taken, since high hydrogen leakage is indicative of cracked or leaking pipes, fittings or connections. Inaction may result in severe winding failure. Elimination of the leak will correct the atmosphere of the system. Also there is the concern for excess copper oxide build-up internally to the strands.

Air may enter a low-oxygen system through a leaking return water flange or pipe, leaking pump packing, and other sources. The leak must be corrected to avoid excess copper oxide build-up internally to the strands.

8.3.1.8.2 Flushing and Cleaning

In the event of internal contaminants buildup, e.g., oxidized copper or foreign material, flushing procedures recommended by the OEM should be followed. These procedures will be complicated and must be done carefully. If improperly performed, bar strands may be plugged, the copper build-up may continue, or other serious problems develop.

8.3.1.9 Series Loops

Numerous types of problems have been experienced with liquid-cooled and non-liquid cooled series loops: vibrating strands, cracked strands, leaking connections, broken pipes and leads, poor electrical connection, barrier flashover, shorted strand transposition groups. Corrective actions will vary widely and will be based on failure mode and damage. Consultation with the OEM may be required to establish root cause and correction. Repairs may involve rebrazing, replacing components, replacing bar(s), reinsulation, and adding blocks and ties. Figure 8-22 & 8-23.

Figure 8-22 & Figure 8-23. Insulation Stripped from Direct and Indirect Cooled Series Loops (General Electric)

8.3.1.10 Connection Rings

Primary failure mechanism is vibration, and corrections may involve cleaning, adding blocks, retying, and rebonding.

8.3.1.11 Partial discharge Damage

Partial discharge activity is widespread in high voltage generators. It may range from superficial to moderately damaging, with air-cooled windings considerably more vulnerable than hydrogen-cooled windings. Corrective actions depend on the cause, severity and location of damage. Likelihood of misinterpretation of conditions is high, as is the probability of taking less than optimum corrective actions. This is particularly the case on new types of incidents, since partial discharge activity can take many forms and fundamentally is not well understood.

8.3.1.11.1 Slot

Damage in the slot is difficult to observe and correct. There are two primary causes of arc damage in the slot: vibration sparking and deficient slot partial discharge control.

If the root cause is vibration, and if the damage is not severe (winding passes an adequate high potential test), rewedging may be a sufficient correction. Repair by injection of conductive materials into the ventilation slots has been performed, but this approach may be insufficient for long-time reliable operation and may be intended primarily to prevent bar vibration. Serious damage can only be corrected by partial or complete rewind, and the owner should be careful that the new winding does not have the same incipient weakness as the present winding.

If the root cause is a deficient slot PD control, or a combination of vibration and inadequate grounding, repair may be possible if damage is minor. But more likely, rewind will be required.

8.3.1.11.2 End Winding

Partial discharge damage in the end winding is more accessible to evaluate and may be correctable. Superficial activity is often seen in end windings, even with all systems functioning well. It is commonly evidenced by a whitish color of various shapes on the faces of the bars. Figure 8-24. But it may give the appearance of heavy erosion. If oil is present in the partial discharge field, flowing of a blackened resin-appearing material may be observed, Figure 8-25. Deposits may also be a solid material of a burned-sugar color.

Figure 8-24. Partial discharge Degradation and Deposit in an Air Cooled Stator End Winding

Figure 8-25. Deposit of Oil Decomposition Products in the Partial discharge Field of and Air Cooled Stator End Winding

Evaluation of the evidences of partial discharge activity can be difficult, but it is important that an accurate assessment be accomplished. Correction of superficial conditions may involve simply removal of the deposit and touch up with paint. But more serious conditions may possibly be penetrating into the stator bar ground wall. Skilled and careful examination will be required. It should be kept in mind that damage can be done to the groundwall insulation in the evaluation and correction process.

Partial discharge burning as a result of high potential test has been observed in end windings. These burn areas may be deep and extensive, Figure 8-26 & 8-27.

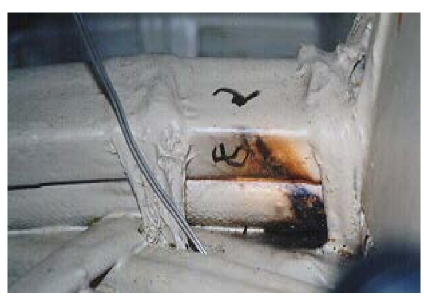


Figure 8-26 & Figure 8-27. High Potential Test Partial discharge Damage to Stator End Winding

There may be no particular pattern to the burn locations resulting from high potential test, although they are more likely to be associated with areas of the end winding that are close to ground. (It is unlikely that serious burning will occur during the relatively low-voltage high potential tests, including 1.5 line-to-line voltage, used for in-service high potential test.) If damage is superficial, repair may be possible simply by scraping off of the surface tracking, followed by repainting. If damage is deep and severe, repair may not be possible.

An infrequent cause of deterioration is deficient connection between slot grounding paint and end arm grading paint. Figure 8-28 & Figure 8-29. (This condition is often referred to as a manifestation of partial discharge, but is actually just s result of the heat generated by the poor connection.) A partial correction may be possible by cleanup and applying of additional conductive paint to accessible locations, but it is unlikely that all locations can be accessed for full repair.

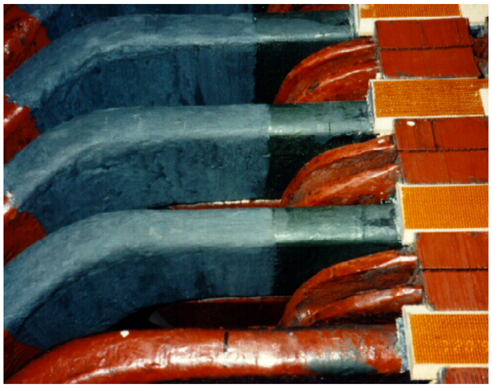


Figure 8-28 & Figure 8-29. **Junction burning and repair**.

8.3.2 Stator Core

Superficial damage and looseness in a core often occurs and if minor is relatively simple to correct, given good procedures and qualified personnel. Correction of more serious core problems can be difficult, costly and time-consuming; in the worst case, a new core and stator winding may be the only solution.

Tightening of a loose core will reestablish pressure on the punching insulation. If the looseness has allowed the punching insulation to wear and otherwise deteriorate, or if the lamination insulation is inherently weak, tightening could lead to increased core iron current flow and core failure.

OEM recommendations on core retightening should be assessed and followed.

8.3.2.1 Loose Core

Local looseness can be corrected by adding tapered shims to the affected tooth areas; this is not an uncommon fix. General looseness often can be corrected by simply retightening the core clamping bolts. But one must keep in mind that if very loose, the flange travel can be sufficiently high to cause stator end winding support displacement problems.

If space blocks have shifted, relocation must generally be accomplished, and in every case travel must be stopped. It may be necessary to further loosen the core before correction can be accomplished, and this brings further risk to end winding support position and other concerns, including failure to accomplish adequate retightening

8.3.2.2 Core Damage

Minor mechanical damage can usually be corrected by etching or by grinding with a sharp cutting tool angled to cut parallel to the laminations so as not to smear iron across the thin insulation, which is only 0.0001 to 0.0003" thick. Figure 8-30. If affected area is more than a few laminations wide, periodic insertion of finely divided mica flake will give added assurance of repair quality. On minor damage where there is indication of no or only localized over-heating, low flux test may be adequate and no high-flux test may be necessary.

Figure 8-30. Repair of Minor Core Damage through Careful Grinding

Where mechanical damage is more widespread and/or deep, or where there is indication of area overheating, repairs will be much more difficult. Figure 8-31. It may still be possible to effect correction by grinding and adding mica, over quite extensive areas if necessary. But in that case, high-flux test would be very important to confirm that the repair has been successful. (Visual inspection alone cannot be generally relied upon.) Combining both low and high flux tests may expedite satisfactory completion of this type repair.

Figure 8-31. Core Damage and Burning of Iron at Bottom of Slot

If an area of overheating is found without accompanying mechanical damage, the problem is most likely lamination insulation failure deep within the core, and restacking may be the only available option. Figure 8-32.

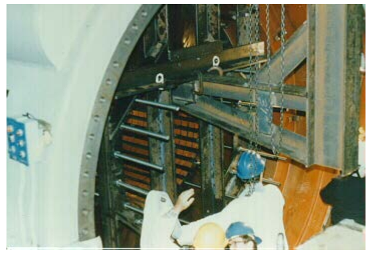


Figure 8-32. Removing Core End-Flange During Restacking of End of Core

In the event of over-fluxing of a core, if iron melting is observed at the end of the core or behind the core, partial or complete restacking will be required. This results from the fact that over-fluxing, by its very nature, tends to cause severe damage deep in the core where access for repair is not possible.

8.3.3 Field

Problems on fields tend to differ fundamentally from those on stators; rewind is more commonly the chosen option on fields, and end of life tends to occur earlier. It is not uncommon for field rewind to be required after 10 to 15 years of operation. Prevalent field damage is from contamination, material yield, material fracture, component migration or shift, and unwanted current flows. Failure modes are typically low resistance to ground, vibration, local over-heating, and current interruption.

8.3.3.1 General Repairs

8.3.3.1.1 Removal and Handling

Field removal from the stator presents numerous opportunities to cause damage to either the field or the stator. Figure 6-4. Personnel who perform this operation should be intimately familiar with proper procedures and have correct equipment in good working order.

8.3.3.1.2 Coupling

The most common repair required on couplings is restoring bolt hole bore galled during bolt removal. If damage is minor, honing may be adequate; otherwise, reboring may be required, along with new, larger bolts.

On some large 4-pole fields, it is necessary to remove the coupling in order to remove the turbine-end retaining ring. This is a major operation involving use of specialized equipment. Figure 8-33 & 8-34.

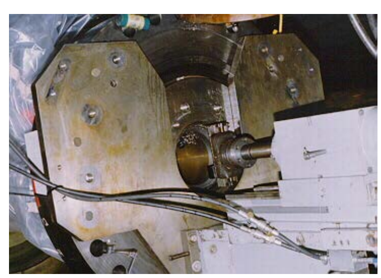


Figure 8-33 & Figure 8-34. Equipment for Removing Large 4-Pole Coupling

8.3.3.1.3 Journals

Journals tend to be a relatively rugged component. Foreign material scoring damage is fairly common on journals, but repair may not be necessary if minor. More significant damage may only require lapping. Serious cutting will require turning of the surfaces.

8.3.3.1.4 Component Locks

All hardware locks should be restored if not fully bent, locked or otherwise proper; this should be done whether or not looseness is observed.

8.3.3.1.5 Fans and Compressors

The OEM should be contacted before attempting to repair these high stress items. If minor nicks are found, grinding may correct the condition. But any serious damage probably will result in component replacement.

8.3.3.1.6 Retaining Rings

Removal of retaining rings should be done by an experienced crew with good equipment. Induction heating, Figure 8-35, is the preferred method, although gas rings were used exclusively until recent years, Figure 8-36. Multiple individual hand-held torches are sometimes used on small fields and shrunk-on rings.

Figure 8-35 & Figure 8-36. Retaining Ring Removal Equipment, Induction and Gas Ring Heating

The ring may be overheated by either method, if care is not exercised. Figure 8-37 & 8-38.

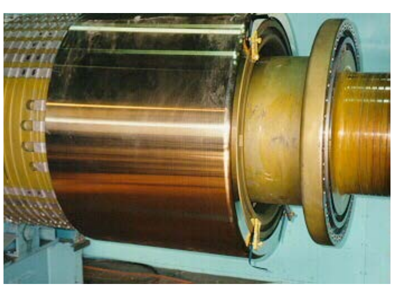


Figure 8-37 & Figure 8-38. Retaining Rings Showing Normal Heating (Left) and Overheating Pattern (Right)

Repair should not be attempted without careful evaluation. It may be permissible to remove rust, minor flaws or even significant flaws by local grinding and polishing, depending on depth, orientation and location of defect. Removal of a small amount of the outside diameter by machining may also be permissible on certain rings. But in general, because of the high operating stresses in these components, repair options are limited, and should be approved by the OEM.

8.3.3.1.7 Wedges

Wedges that have moved, a fairly common condition, should be returned to correct position and staking restored. Figure 8-39. Wedges that have lifted in the dovetail or have been seriously burned during a negative sequence current incident will require replacement.

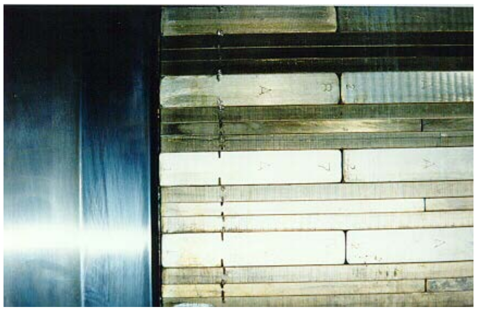


Figure 8-39. Field Slot Wedge Locking Locations

8.3.3.1.8 Cracked or Burned Field Forging

If small cracks are found, it may be possible to grind and remove the defect. A large crack will result in forging replacement. Burning from field winding failure current may also be repairable if not deep, Figure 8-40. Assistance of the OEM should be obtained in reaching any conclusion as to repair of a field-forging crack.

Figure 8-40. Field Forging Damage Due to Broken Field Turn

8.3.3.1.9 Cracks in Winding

Cracked copper turns and connections are a fairly common problem in field windings, and it is not uncommon that the field forging and other components will be damaged by arcing current from a broken conductor. The repair process, then, is likely to involve making a judgment as to how best to repair peripheral damage. Because of the potentially serious nature of such cracks and associated repairs, OEM involvement may be desirable.

Typically OEMs will have issued standing instructions to reduce probability of cracks developing, as well as repair procedures for existing cracks. Cracks tend to develop in locations that are inaccessible, and generally repair will be costly and time-consuming. Because of the inherent difficulty and criticality of these repairs, it is important that the procedures are well understood and performed by a skilled, supervised crew.

Cracking of main leads between field winding and collector connections have tended to be a problem on some designs. Replacement is difficult and should be done by an experienced crew. Figure 8-41 & 8-42.

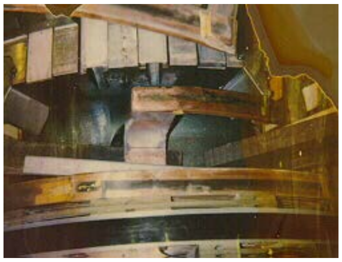


Figure 8-41 & Figure 8-42. Installation of New Main Lead

8.3.3.2 Collectors and Brushes

8.3.3.2.1 Collector and Rotating Rectifier Routine Maintenance

Collectors can normally be satisfactorily cleaned, using good procedures and correct materials. Surface finish may be restorable by strapping the collector. As surfaces wear, turning and reestablishing of outside diameter may be required, adhering to limits set by the OEM. If wear becomes excessive, replacement of rings will be necessary.

Collector connection studs may require removal for leak or other repair. Use of correct tools and assembly procedures is critical. Figure 8-43.

Figure 8-43. Stud Removed from Collector Connections

Rotating rectifiers will require proper cleaning and replacement of defective or deteriorated parts.

8.3.3.2.2 Ring resurfacing

8.3.3.2.3 Corrective action on collectors can include ring resurfacing by stoning or by grinding. In some extreme cases, machining will be required before grinding. There are two acceptable methods for grinding and truing rings:

1. At rated speed, with a rigid stone, or
2. On turning gear, with a rotating grinding wheel.

When grinding on turning gear, Figure 8-44, the objective is to get the collector ring round, and if the shaft is balanced properly, that is how the ring will appear to the brushes at speed.

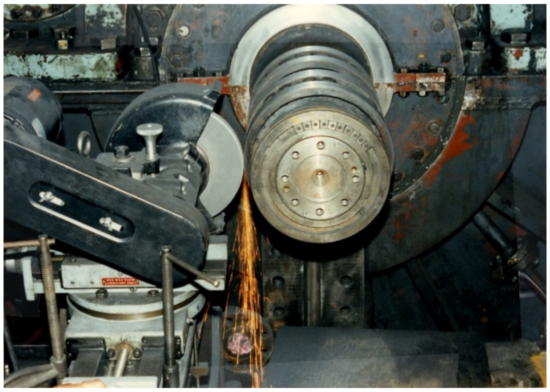


Figure 8-44. Grinding of collector rings on turning gear. (AEP)

When grinding at rated speed, Figure 8-45, the objective is to compensate for shaft vibration to make the ring appear round at speed. In other words, you "grind out" the vibration. However, any later changes in rotor balance also will change the effective ring contour. When properly done, both methods give the brushes a smooth, continuous, polished surface on which to ride.

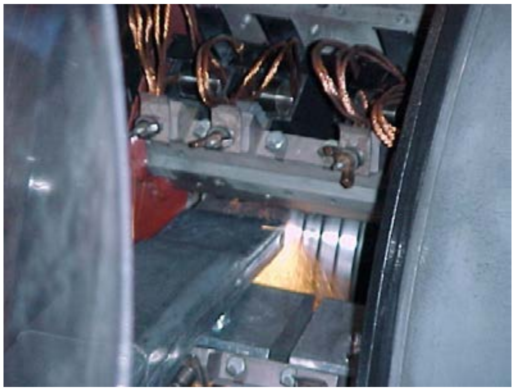


Figure 8-45. Stoning of large collector. (Cutsworth Products/Services)

Periodic collector-ring resurfacing should be considered routine maintenance, and generally collector rings have sufficient stock to last the lifetime of the generator. However, if it has been necessary to resurface a ring more frequently than once every two or three years, the reasons for the ring-surface deterioration should be identified and corrected. Otherwise, excessive maintenance and collector replacement may be necessary. If ring wear reaches a point where the spiral grooving needs to be re-established, this can be done with the field in place. Figure 8-46.

Figure 8-46. Re-grooving collector rings. (Cutsworth Products/Services)

8.3.3.2.2 Brush Holder Retrofit

Industry reliability experience has been much higher on generators equipped with constant-pressure springs and with removable cartridge (magazine) brush holders. Brush holders of this type have been available for 40 years, particularly on very large generators. The removable holders allow close inspection and replacement of brushes with minimal personnel exposure to hazardous conditions.

Retrofit with removable brush holders on existing collectors is possible. One such retrofit has been available for 30 years. More recently, a direct drop-in replacement has become available for individual brush holders.

Retrofit with a well-designed removable brush holders will eliminate the need for direct contact with the collector voltages. Elimination of exposure to this voltage should result in much less reluctance by plant personnel to servicing a collector on an operating generator. In turn, this should significantly reduce the likelihood of collector problems, including flashover, on the generator.

8.3.3.3 Major Field Repairs

Manufacturers have taken broadly differing approaches to field design. Configurations and assembly procedures vary widely. Thus it is difficult to discuss specific details of field repair. However, some general principles do apply, and these will be mentioned in the sections that follow.

As is the case with many of the stator repairs, field repairs tend to be more an art than a science. Because of the potentially serious nature of the results of error, field repairs should be done by an experienced, trained and supervised crew, meticulously adhering to proven procedures. Because cleanliness is vital to successful field rewind, work should be done in a closed area, preferably a “clean room” with controlled atmosphere. Figure 8-47.

Figure 8-47. Closed Room with Controlled Atmosphere for Field Rewind

8.3.3.3.1 Rewedging

Rewedging of generator fields has been a relatively common practice resulting from recommendation to change wedge materials, modify wedge fits, address vibration problems, and to correct other difficulties.

Often with some trial and error, manufacturers have evolved procedures that if closely followed will generally result in a well-running machine. Failure to follow proven techniques can result in radial lifting or yielding of wedges, wedge axial interference, incorrect friction coefficient to slot insulation, axial movement of wedges, and other conditions. Improper rewedging may result in serious operational problems: mechanical unbalance, linear and/or non-linear thermal sensitivity, and in the worst case, wedge or tooth cracking and failure.

8.3.3.3.2 Partial Rewind

Partial rewind of fields is a somewhat common maintenance practice. Figure 8-48. This repair may be required due to cracking of top turns, isolated turn shorts, isolated field ground, thermal sensitivity. Magnitude of repair may range from simply replacing top turns on selected coils, to removal of one or more complete coils. Generally field copper is reusable, unless a material change is required, but annealing and straightening complications may make use of new copper a preferable alternative.

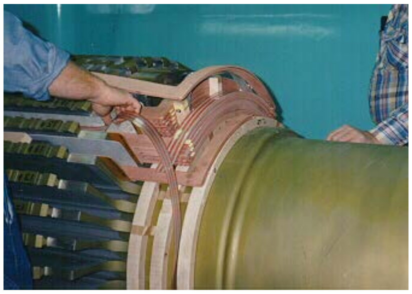
Figure 8-48. Partial Rewind of Field Winding

Rewind procedures are complex and involve many operations. If proven procedures are not used explicitly, results may be unsatisfactory: field grounds, turn shorts, thermal sensitivity, and mechanical unbalance.

Partial or full rewind may be required on windings that are experiencing significant deterioration of the field copper or insulation.

8.3.3.3.3 Full Field Rewind

Because of the high mechanical and electrical duties on field windings, rewinds are rather common. Figure 8-49 & 8-50.



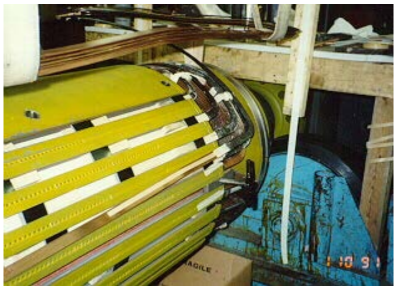


Figure 8-49 & Figure 8-50. Full Field Rewind in Progress

As a result, satisfactory procedures for accomplishing a reliable rewind are generally well evolved. Normally the field copper is reused, since if care is taken in performing the work, rebalance of the field should not be necessary. This is particularly important because fields must be balanced at speed; low speed balance may adversely affect balance at operating speed. (Fields are sufficiently long that they run above first critical, and cannot be balanced with static weight alone. Balancing at low speed may make the field un-operable at rated speed.)

As in the case of partial rewind, full rewind procedures are complex and involve many operations. If proven procedures are not carefully followed, operation of the field is likely to be unsatisfactory: field grounds, turn shorts, thermal sensitivity, and mechanical unbalance.

8.3.4 Other

8.3.4.1 Bearings and Hydrogen Seal Rings

Minor damage to the babbitt may often be repaired by scraping and cleanup. Major damage including significant debonding is likely to require full rebabbitting. Figure 8-51.

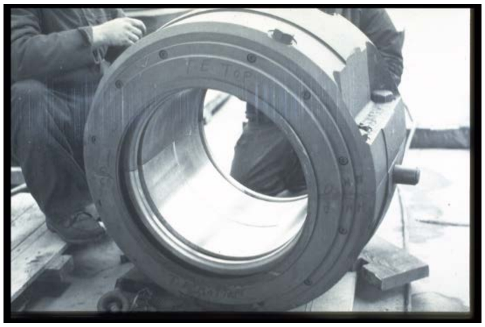


Figure 8-51. Repairs in Progress of Main Bearing

8.3.4.2 Hydrogen seals

Hydrogen seal designs vary considerably among manufacturers, and needed repairs correspondingly vary. Because hydrogen seal performance tends to be sensitive to minor deviations from specification, rework should be carefully performed in accordance with OEM recommendations. Deficient or defective insulation should be replaced using correct materials.

8.3.4.3 Oil Seals

Improperly maintained or assembled oil deflectors are a major source of oil leakage into generators. Corrective actions should be taken to maintain clearances and profiles within OEM and proven requirements. Defective insulation should be replaced. Bearing oil shaft seals (oil deflectors) are shown in Figure 8-52.

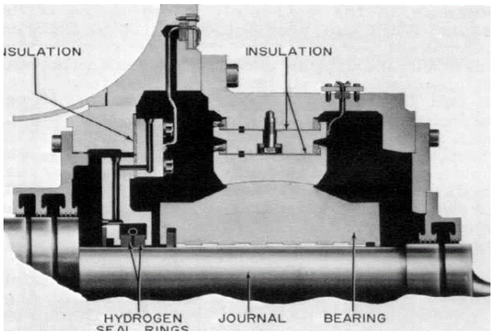


Figure 8-52. Typical Bearing Assembly Showing Components Including Oil Deflectors

8.3.4.4 End shields

On hydrogen cooled generators, end shields are an important source of outward hydrogen leaks and inward oil leaks. All faces should be maintained in good condition and all seal grooves clean. Large generators have experienced persistent oil leakage across the horizontal joint. Correction of this condition may require installation of additional inner bolts in order to have sufficient support to maintain a tight closure of the horizontal joint, Figure 8-53.

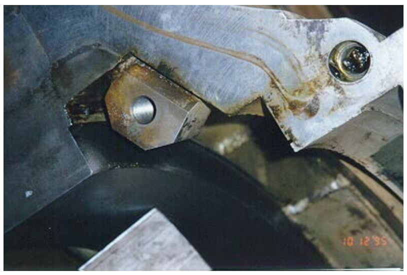


Figure 8-53. Addition Bolting on End Shield Horizontal Joint

Addendum A

A BRIEF HISTORY OF TURBINE-DRIVEN GENERATORS

Abstract

This paper is based on the author's recollections from a 64-year career in turbine-generator design, manufacturing and service – 36 years with General Electric and 28 years as an independent consultant. Having joined GE in 1950, and having worked closely with the "old timers" of that day, the direct knowledge base goes back into the teen years of the early 1900s – a span of almost a century. No guarantee is offered that all the information is exactly correct, but the essence should be acceptably close to give a general understanding of the difficult evolution to the present designs of turbine-generators.

Because the major OEMs of the day kept pretty close (informal) watch on each other, we were pretty well informed on the designs, and troubles, of each other. Thus the information on non-GE OEMs should be fairly accurate.

There has been considerable commonality of materials and designs between OEMs throughout this history. An important example: all forgings for all OEMs come from the same steel mills. But there have been major and important differences in design details. An OEM fortunate enough to have a true genius in their engineering organization was likely to have solved difficult problems with an elegant, simple design. Whereas an OEM with truly excellent engineers (but not genius) may have solved the problem with a complicated, almost Rube Goldberg, design. Examples include field ventilation, stator winding support systems, stator bar strand transition, compensation for non-symmetry of 2-pole circumferential mechanical stiffness, isolation of stator core vibration. Over time, as OEMs have studied competitor generators, there has been convergence on many issues, but there remain to this day, major and fundamental differences.

In writing this "brief history" the focus has been on materials and structural configurations, and the associated service issues. Little detail is provided as to why specific materials were selected or why the configurations were needed.

In the last 15 years, the writer has attempted to pass on the knowledge of his generation of generator engineers to the younger generations of generator design and service engineers. In this effort, the writer has written 25 technical papers and a 240-page text addressing many of these service issues. The interested reader can find these texts at web site: www.generatortechnicalforum.org. On the discussion topic, Inner Water-Cooled Stator Windings, click on any thread, click on the Documents tab at the top, and find downloadable 25 papers and a 240-page text on generator maintenance.

A broader source of information can be found also on this site under: IGTC Resource Center/IGTC Technical Library/Generator Books, Guides, Manuals & Primers.

ELECTRICAL INSULATION SYSTEMS

Stator Windings

Groundwall Insulation

Before the turn into the 20th century, insulating materials were natural products: shellac, cotton, paper. The rudimentary designs were at low voltage and low temperatures, and apparently functioned fairly well as long as duties were kept sufficiently low. With inevitable trends toward higher voltages and higher thermal and mechanical duties, much better materials were required. Somewhere around the turn of the century, 1899 to 1900, mica flake was discovered to have remarkable electrical and thermal properties. But still with shellac, cotton and other relatively primitive materials incorporated in the systems, troubles continued. By the mid-teen years, 1915, it was discovered that by using a vacuum-pressure cycle, mica/cotton tapes could be impregnated with a hot asphalt compound to obtain a major electrical duty improvement.

Asphalt/mica systems served the industry well for 35 years, although by the late 1920s the tape migration phenomenon had surfaced. At General Electric, this occurred on 2 *very* long, very large 4-pole generators. The engineers mis-diagnosed the root cause of condition as cracking of the stator groundwall insulation (girth crack) due to too hard a system and lowered the softening point of the asphalt used in the groundwall. This was exactly the wrong change, since the “cracks” were actually resulting from the groundwall migrating in the slot toward the axial centerline of the core. (At operating temperatures the asphalt was basically a liquid.) Photo1.

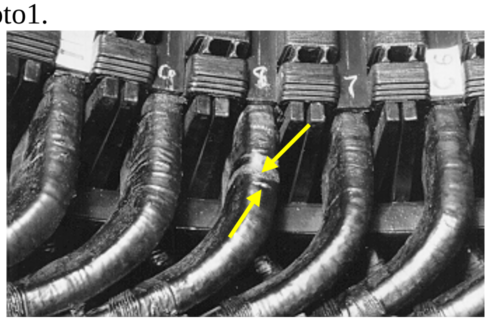


Photo1. Tape separation of ¾” resulting from migration of the groundwall insulation.

In retrospect the better solution would have been a higher softening point temperature. But somewhere around 1935 for reasons not recorded, the GE engineers diluted the asphalt with about 1/3rd linseed oil. Linseed oil has the interesting property of becoming more viscous if held at elevated temperature, thus if a GE generator was not cycled for 3 or 4 years after placing in service, significant migration would not occur.

The net result of these 2 changes (lowering of asphalt flow point and adding linseed oil) was that GE generators over about 40 MW had serious tape migration problems if load was cycled immediately on being placed in service. Otherwise, migration was minor or not at all. Of the ~400 large asphalt-insulated generators built by GE, about 1/3rd were rewound, the remainder is still in service without migration, or have been retired.

Tape migration was difficult to reproduce under laboratory conditions because it was dependent on several variables: load cycling, core length, temperature of the bar copper vs. asphalt softening point, tightness of the bar in the slot, direction of tape application. The GE laboratory efforts were not successful, and GE continued to believe the deficiency was a cracking phenomenon (hence the on-going use of the term “girth crack”).

Westinghouse engineers understood the tape migration phenomenon well, but weren’t sufficiently lucky to have added linseed oil. By the mid-1940s, most of their stator windings on their larger generators were experiencing fatal migration. On a crash basis they developed the Thermalastic (an epoxy-like polyester) groundwall system. This was a remarkable accomplishment, particularly in view of the relatively primitive polyester resins available at that time.

During the ensuing years, all OEMs developed improved groundwall systems: Micapal (a polyester-like epoxy), Micapal II (a true epoxy), Thermalastic-Epoxy (a true epoxy), Micadur, etc.

All these insulations systems rely on mica because of its remarkable partial discharge (PD) resistance properties. (No man-made product begins to have the incredible PD resistance of mica. PD is inevitable in the rectangular configurations of stator bars.) But mica brings with it poor mechanical properties, e.g., brittle, non-extensible, no mechanical strength whatever in cross-grain tension. Thus stator groundwall insulation systems remain with limited mechanical properties, and when subject to bending stress, e.g., short-circuit forces, fracture about like glass. It remains for another generation of engineers to find a way to eliminate the need for mica in stator winding groundwall insulation. Perhaps by use of cable windings or oil submerged stators.

Groundwall Voltage Stress Levels

The stress on the groundwall has a dramatically important impact on electrically-related problems associated with stator windings. The significance of this impact is understood by realizing that duties associated with stress have been found to be in the range of a 7^{th} to 11^{th} power function of the stress level. For example, if the design stress is increased by 20%, the duty increases by about $(1.2)^9$, or about 500%. Recognizing this attribute, stress has been increased relatively slowly over the years by design engineers.

By 1950, the stress level on the asphalt-insulation systems was about 45 volts/mil (mil = .001”). With the advent of hard (polyester-type) systems, the stress level was increased to around 54 vpm. By the mid-1960s, improved (epoxy) systems were being used, and the stress levels increased to the low 60s vpm range. But this range was found very restrictive as designers were under pressure to produce larger and larger indirectly cooled generators, both air and hydrogen cooled. In these machines, where the copper thermal losses had to transmit through the groundwall, thinner groundwall insulation became highly valuable. From this pressure, and in recognition that root-cause electrical failures of the groundwall insulation were rare, evolution toward much higher stress levels occurred. At present, stress levels exceeding 90 vpm are being used. The magnitude of $(90/60)^9$ is too large a number to contemplate (~2500%). Root-cause electrical groundwall failures can be expected to become common.

Problems Associated with Groundwall Voltage Stress

The predominant problem associated with groundwall stress is the phenomenon referred to as partial discharge (PD), sometimes incorrectly called “corona”. The stress gradient within the groundwall results in electrical breakdown in the inevitable tiny voids in the groundwall. These mini-arcs tend to eat through any insulation system that does not rely on the remarkable PD resistance of mica.

If the outside surface of the groundwall is not adequately grounded, there will be discharges of much more energy. This in turn can result in surface PD, indicated in Photos 2 & 3.

Photo 2. Significant surface partial discharge indication in the slot.

Photo 3. Significant surface partial discharge indication in the endwinding.

Both of these photos show conditions that appear very serious, but careful examination and scraping with a thumbnail would find no penetration into the mica groundwall. (Nevertheless, the conditions cannot be ignored as in air-cooled generators, ozone generation will be significant, and there is no assurance that penetration of the mica may not eventually begin.)

Furthermore, the increased capacitive energy increases the duties on endwinding grading systems. For example, the junction between end-arm grading and slot grounding paints. Photo 4.

Photo 4. Burning at the junction of grading/grounding systems.

The damage at this junction is often regarded as PD but is actually burning because of inadequately low interconnection to carry the capacitive current in the end arm grading system.

Where non-mica insulation has been used in endwindings, reliability has sometimes been seriously compromised. One example is shown in Photos 5 & 6, where phase joints were insulated with non-mica potting compound and Nomex.


Photo 5. Indications of PD on the surface of one of the 3 line-to-line voltage phase break locations.

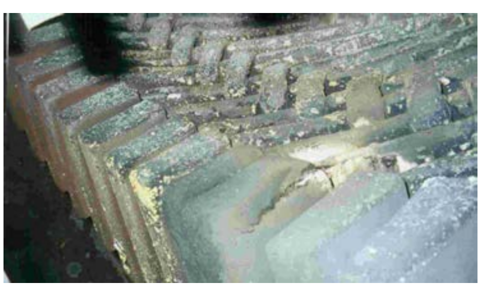


Photo 6. Failure at another of the phase break locations.

A large number of generators rely on physical spacing to hold the voltage stress. So long as the surfaces are clean, operation is satisfactory. But when surface contamination occurs, massive arcing can occur. Photo 7.

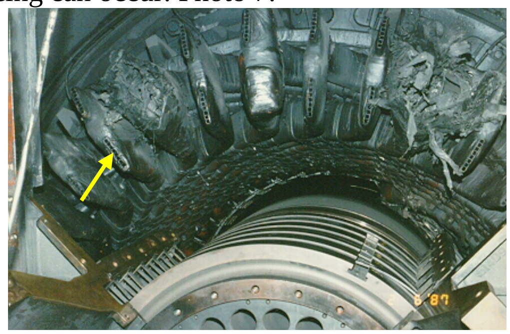


Photo 7. Bare conductor exposed at each series and phase joint. Yellow arrow.

A final observation. Stator winding electrical arc damage normally accompanies stator winding failure, but the actual root cause is usually mechanical, e.g., vibration, fracture, foreign object, contaminants. To this point in time, generator failures due to purely electrical duties are uncommon.

Bare Bar Stranding

Because eddy current losses would immediately melt a stator bar made with sold copper, a stranded design has always been required. On coil windings, no special transposition is needed, i.e., the top and bottom bars of a coil automatically tend to cancel out the voltage difference between the top and bottom strands in the half-coils. (In this document, the term "bar" is used to define a half coil. For convenience the term "bar" will be used almost exclusively.)

On bar windings where it is usual to solidly connect all strands at each end of the bar, this cancelation of radial flux difference in the slots does not occur. Very early (in 1915) a Swiss engineer, Mr. Roebel, invented an elegantly simple way to construct this transposition on bars. His invention was no great scientific discovery, but rather was a remarkably simple way to accomplish a very difficult task – construct the transposition. It is so manufacturing friendly, the Roebel transposition system is universally used by all OEMs, with the exception of those few who have manufactured smaller bar windings without consolidating the strands at the ends of the bars.

The standard Roebel transposition effectively compensates the radial flux density gradient in the slot portion of the winding. But on larger generators of non-coil design, the radial flux gradient in the endwindings becomes sufficiently large to cause problems. (This concern is automatically eliminated in coil windings.) Several approaches have been used here. The simplest is that of a 540^{o} Roebel rotation in the slot. (Mr. Roebel's invention was single 360^{o} rotation.) The somewhat complicated 540 rotation performs a correct compensation in the slot while inverting the strands at the two endwindings beyond the core.

Another approach for endwinding radial flux compensation has been to sub-group the bar strands into bundles of strands; bundles may range from as few as 1 strand to as many as 14 or more. These "bundles" are maintained throughout the entire phase belt. The bundle design greatly complicates the winding manufacturing process and has been accompanied by numerous service problems. Photo 8.

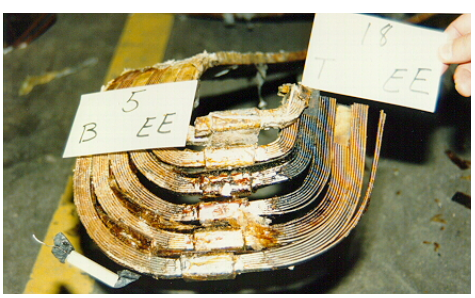


Photo 8. Major winding failure from shorted strand groupings. (See also Photo 7.)

Strand Insulation

A small voltage exists between adjacent strands, probably always less than 1 volt, and the strands must be individually insulated. Originally cotton would have been used, then glass and now commonly Dacron-glass. This material is thin, typically 1 to 3 mils/side.

A larger voltage exists between tiers of strands. Here a "vertical separator" is inserted between tiers. The stress may be as high as 15 volts and the thickness may be in the order of 15 mils. Photo 9.

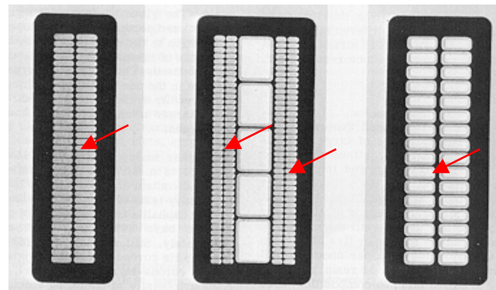


Photo 9. Vertical separator in 3 bar designs. Red arrows. (Strand insulation can be seen as the small separation between strands.)

Voltage Grounding and Grading

If the outside surface of the groundwall is not tied directly to ground, PD will exist between ground and the bar surface. Consequently a semi-conducting paint is applied to the outside surface of the slot portion of the bar (and usually about 2" beyond the slot at each end). If properly applied, and of good quality, this paint will eliminate the PD by periodically grounding the outside surface of the bar insulation to the slot iron.

More complicated is the necessity to "grade" the voltage of the grounding paint at each end of the slot. Photo 10.

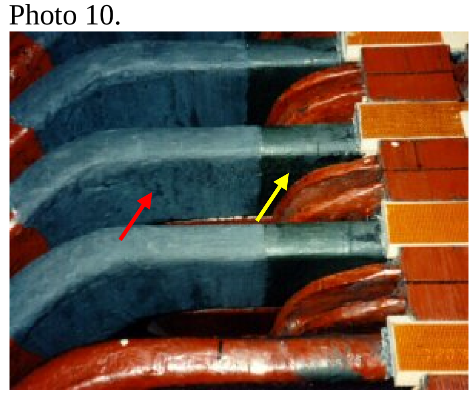


Photo 10. End arm grading, red arrow. Slot grounding, yellow arrow.

The engineering principles here are complex, but the mechanics are relatively simple. Originally asbestos tape was applied for a distance of perhaps 7 to 12" inches beyond the end of the slot grading paint, depending on winding voltage. In the 1960s the industry went universally to silicon-carbide – both to eliminate the hazard of asbestos, but because the silicon-carbide is a more effective approach to grading.

Series/Phase Joint Insulation

Normally these joints were insulated with mica tapes. Beginning about in the 1970s, synthetic resins were used (inside a non-metallic box) to insulate series joints; this is perfectly acceptable because the contained electric stress is low, except during the short-time hipot tests. Mica tape insulation for the phase connections is preferable because the electrical operating stresses are relatively high at the phase locations. Photos 5 & 6.

Physical spacing has also been commonly used by some OEMs. This design approach is safe for hipot test and operational stresses – providing the creepage paths remain uncontaminated, and providing there is not a conductive plasma resulting from arcing of a failing electrical connection. In the event the insulating capacity is violated, a "ring of fire" can result. Photo 7.

<u>Field Windings</u>

The duty differences between stator insulation systems and field insulation systems could hardly be more different. On stator windings, the voltages are high but the mechanical stresses are low. On fields, the voltages are low, less than 700 Vdc, but the mechanical duties very high, in the order of thousands of psi.

Because of the low voltages, and the need for direct contact between cooling gas and winding copper, isolation using electrical creepage surfaces is common. So long as the insulation remains in place and does not become contaminated with conductive materials, the systems tend to perform well. But because the mechanical duties are high, problems occur. Typically problems result from fracture, cut-through and shifting of location of the insulation components. As a result, service problems relating to insulation failure are common on fields.

Slot Liners (Ground Insulation)

Until the about 1960, the ground insulation for the coils consisted of enclosing the coil with cotton or asbestos cloth for mechanical stability and mica flake for insulating properties. Photo 11.

Photo 11. Failed asbestos-mica field slot liner.

This composite structured served adequately because of the low voltage stresses. In more recent years, Nomex, glass/epoxy fabric, and composites of glass/epoxy and Nomex have become popular. Generally this ground insulation is in a U-shape, closed at the top by a creepage block. Photo 12.

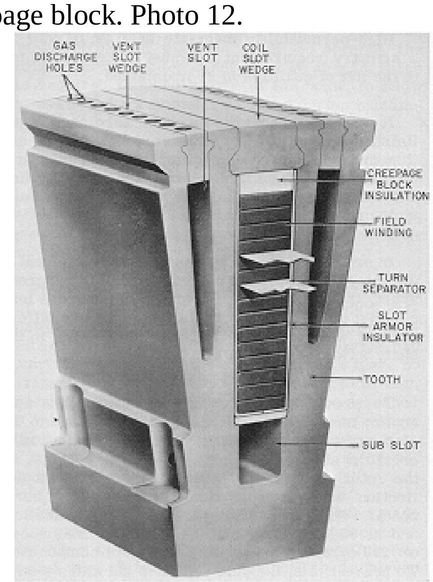


Photo 12. Typical non-direct cooled field slot.

These ground insulation systems have been subject to failure primarily due to contamination, fracture, migration and cut-through. Photo 13.

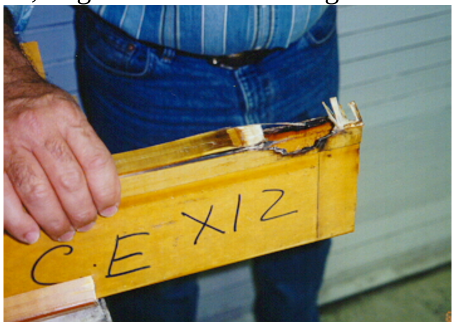


Photo 13. Slot liner with damage from an electrical creepage failure.

Turn Insulation

The voltage between turns is low, typically 1 to 5 volts. Historically mica tape was used, but for the last 50+ years, thin glass/epoxy laminate has been in common use for turn insulation. So long as physical spacing is maintained, turn shorts are unlikely. However, the integrity of the space can be violated by fracture or migration of the material, or by conductive contaminants bridging the spacing. Failure of turn insulation is relatively common.

Endwinding Insulation

Under the retaining rings, sheet laminate of heavy-weave asbestos cloth and mica was the historic insulation system. Again, around 1960 transition was made to a laminate structure of heavy glass cloth and epoxy resin. The laminate is degraded somewhat when the 300C retaining ring shrinks down onto the epoxy glass; however, the materials that are used are sufficiently thick and thermally stable that the electrical strength remains adequate for single use. (New replacement material must be used if the ring is removed.)

Insulating block material is used to hold coil shape and to insulate the axial locations of the endwindings. Photo 14.

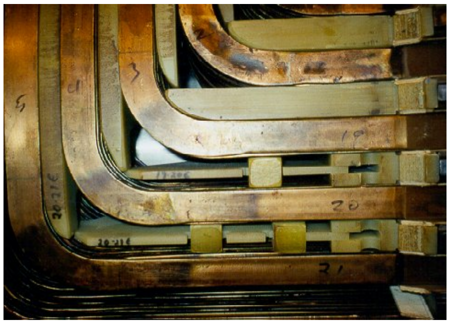


Photo 14. Insulating blocks used to insulate between coils by maintaining physical spacing.

WINDING SUPPORT SYSTEMS

Stator Windings

Slot Support Systems

From the beginning, stator bars were held in the slots by wedges of treated paper or hardwood. The electromagnetic forces were low (almost non-existent), the groundwall insulation was soft, and bars had little cause to vibrate. The wedges held the bars in the slots and kept them from falling out of the slots in service, and maybe kept the bars from being thrown out of the slot in the event of a sudden short circuit.

The wood materials used for 50 years were satisfactory. But wood inevitably shrinks, and the resulting looseness of wedges was a concern. With the advent of man-made resins, in the 1950s transition was made to resin/cotton, resin/asbestos, and then resin/glass materials. (The harder resin/glasses can wear into the core iron if loose, and this can be a concern.) Photo 15.

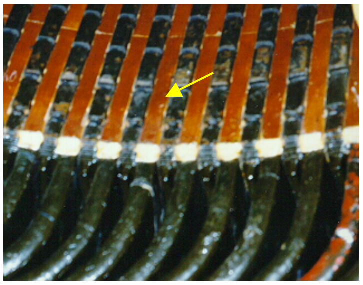


Photo 15. Non-glass wedges in an asphalt-insulated stator winding.

But when hard groundwall systems, i.e., polyesters, were introduced in the 1950s, a shocking condition surfaced – bar vibration. (You could walk by the generator and hear the noise from the impact of the bars in the bottom of the slots.) Needless to say, windings failed very soon, from mechanical wear and impact, and from vibration sparking. An immediate fix was implemented, i.e., wedging with tight downward pressure on the bars.

The electromagnetic force (EMF) is essentially all radially downward in the slot, but if radial clearance existed in the slot, the bars would bounce off the bottom of the slot and vibrate vigorously. Also, if excessive side clearance existed, the bars would rattle in the slot.

These relatively simple wedging systems were satisfactory on indirect-cooled windings, but the slot EMF on the direct-cooled windings was much higher, and vibration recurred. GE solved this situation with the side pressure spring system. Photo 16.

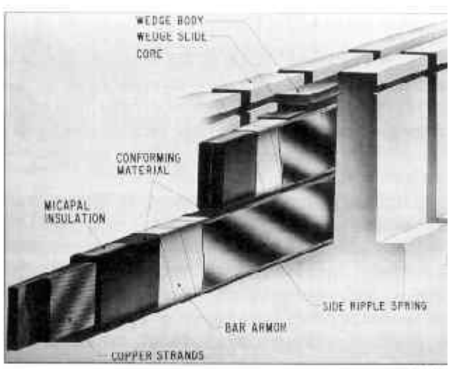


Photo 16. GE wedging system, about 1965.

More recently top ripple springs were added. Others relied on side packing and tighter wedges. Photo 17. Finally the industry added the radial pressure spring almost universally on large generators.

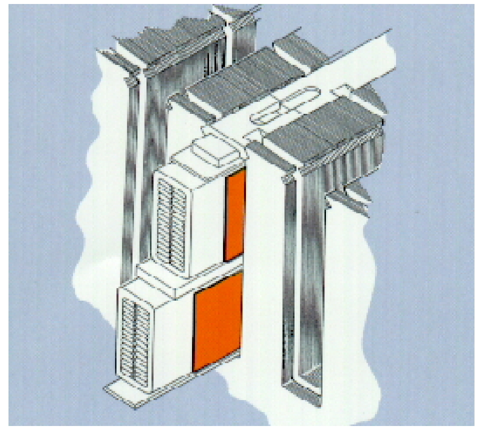


Photo 17. ABB wedge system of about the 1980s. (Side packing in orange.)

Slot bar vibration incidents continue to occur. But in general, if the wedging system remains tight vertically, if clearance does not exist under the bottom bar, and excessive side clearance is not permitted, problems are unlikely.

Endwinding Support Systems

The parameters relative to slot wedging and endwinding support have little in common. The endwinding EMF is lower but still substantial – roughly one-third to one-half that of the slot forces. Because the opportunities for supporting the bars in the endwinding are minimal, endwinding vibration has been much more difficult to successfully address than slot vibration.

Also, until recently there has not been available instrumentation to safely and accurately measure magnitudes of in-service endwinding vibration. Design engineers have not had tools to directly assess the success (or failure) of their new designs. Thus engineers have had to rely on intuition and best judgment in producing new designs, and await accumulation of service experience to determine if the design change was successful.

In the early years, the endwinding EMF was so low that almost anything was going to be alright. The top and bottom bars in the endwinding, if tied together, form a rather strong mechanical structure. It remained primarily only to provide support to the bars (or coils) as they were being initially installed. Photos 18 & 19.

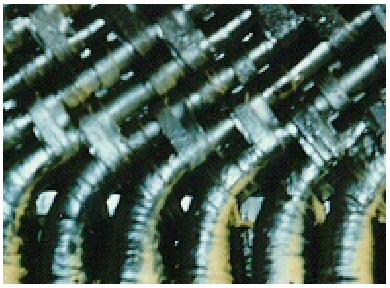


Photo 18. A 1950s vintage string-tied endwinding support system.

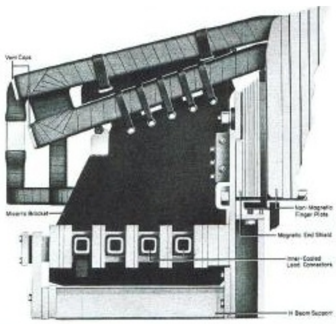


Photo 19. A large, 1960s vintage string-tied system in cross-section.

However, as generators became large, the EMF became so great that endwinding vibration became ubiquitous. Starting about 1960, OEMs went into major development programs, spending millions of dollars developing designs that would hold the extremely high sudden short circuit forces as well as the significant normal operation forces. Photo 20 shows the 4th and last of a series of full-scale models used by GE to develop the system.

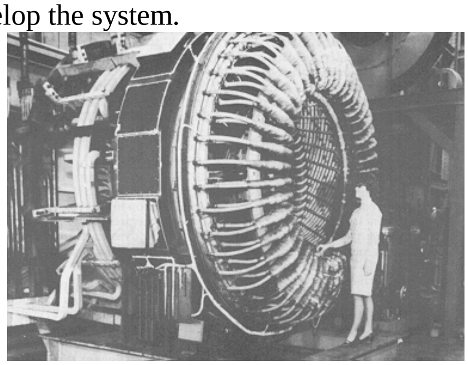


Photo 20. GE model stator IV (model on left), circa 1968.

The resulting GE endwinding system is shown in cross-section in Photo 21.

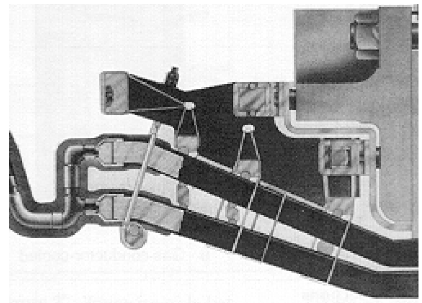


Photo 21. Cross-section of the early high-force GE endwinding support system.

Other OEMs evolved support systems examples of which are shown in Photos 22 &23.

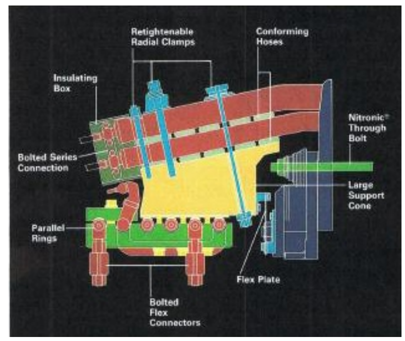


Photo 22. Modern Siemens-Westinghouse support system.

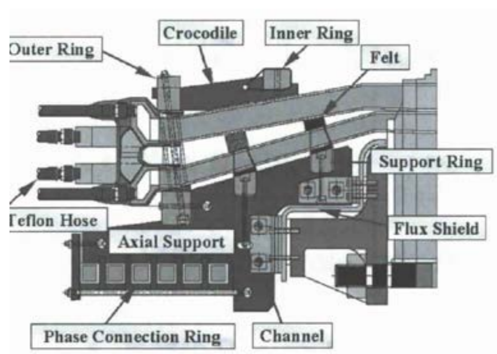


Photo 23. Alstom endwinding support system.

In spite of these huge OEM expenditures, endwinding support remains an ongoing problem. Parts become loose and wear holes in groundwall insulation. Photo 24.

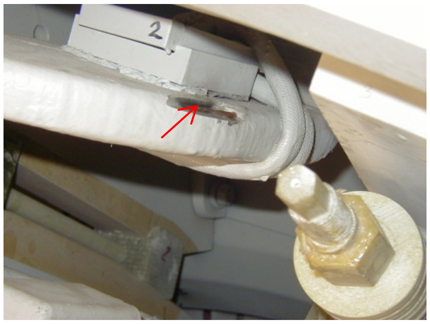


Photo 24. Hole worn through insulation to bare copper by loose support component.

Connections become resonant and break off or fracture the bar. Photo 25.

Photo 25. Series connection broken off and lying under winding.

Sudden short circuit occurs and cracks bars. It is doubtful that any design today can experience a worst-case short circuit without damage to the bars in the endwindings. Photo 26.

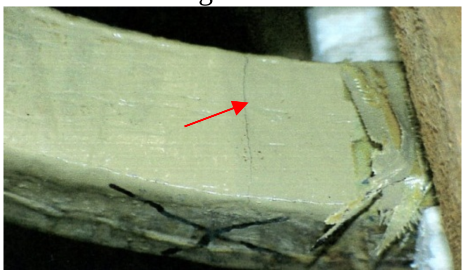


Photo 26. Fractured stator bar. (Crack at arrow.)

Endwinding concerns will remain into the future, particularly from local or general loosening of the systems allowing component wear to occur and resonances to develop. However, it can be expected that with the new capability to safely and accurately measure endwinding vibration, the designs will substantially improve and reliability will substantially increase.

Field Windings

The mechanical forces on field windings are extremely high – resulting from up to 8000 Gs centrifugal force acting radially at the tops of the slots. The metallic wedges can hold copper coils in the slots, and there are stable insulating materials that can generally function acceptably against these steady-state radial forces. It is the cyclic duties resulting from start/stop and load changes that are the primary source of troubles.

The winding copper is a primary source of service problems. Copper has poor mechanical properties, even at room temperature. Yield strength is low, fatigue properties poor. At elevated temperature, above about 130C, these marginal properties begin to fall off. Unlike steel, copper can only be work hardened; it cannot be hardened by quenching. With these low mechanical properties, and the inherent high mechanical duties, designers have had a difficult challenge producing support systems that successfully restrained copper coil dimensions and prevent movement in position.

An indirectly cooled slot support design was shown earlier in Photo 12. In this design, heat losses must pass through insulation and forging iron to be removed by the flow of cooling gas.

These indirect-cooled designs were used until direct cooling was required for higher generator output starting around 1960. A typical direct-cooled shot is shown in Photo 27.

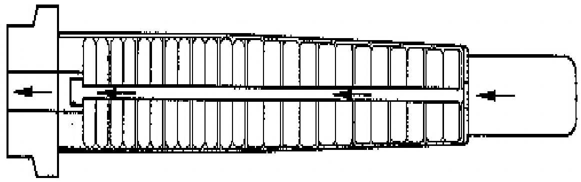


Photo 27. Typical direct-cooled field slot for smaller modern generators.

Electrical isolation in all field designs relies on “creepage” (voltage tracking over an insulated surface) and on “puncture” (voltage penetrating directly through an insulating material). Creepage isolation is used much more on the directly cooled windings, which makes them more vulnerable to contamination.

A typical endwinding blocking scheme is shown in Photo 28.

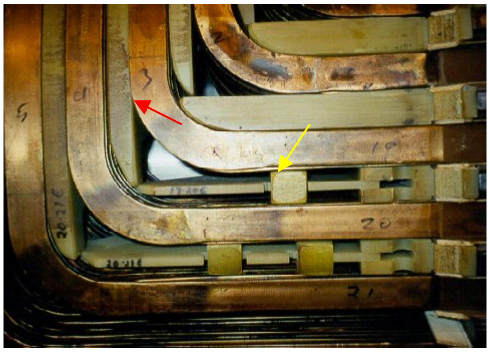


Photo 28. Endwinding blocking under retaining ring.

The radial blocking (red arrow) attempts to hold the coils against distortion and from moving axially. The axial blocking (yellow arrow) primarily attempts to prevent coil distortion. But because the coils are not blocked continuously (to allow for cooling gas flow), and because of the poor mechanical properties of copper, distortion is common. Photo 29.

Photo 29. Badly distorted top turn on smallest coil.

Because of the poor high-temperature properties of copper, significant over-temperature can result in fatal changes in coil dimensions. The result will be an immediate forced outage. Photo 30.

Photo 30. Badly over-temperature and distorted endwinding.

As the windings lose position, the insulating materials tend to wear and crack. Grounds and shorted turns/coils result from damaged and contaminated insulation. Photo 31.

Photo 31. Two largest coils shorted together due to extensive contamination.

Further complicating reliable field operation is the need for uniform cooling of the coils in the rotor body. In Photo 32, the turn insulation and/or top creepage block have shifted axially out of correct location. This partial blockage of some slots and not others will result in bowing of the field (acting as a bi-metallic strip). The resulting bow will cause a “thermal unbalance vector”, and as it grows over time, may force attempts to rebalance the field. If the conditions continue to deteriorate, eventually a field repair or rewind will become necessary.

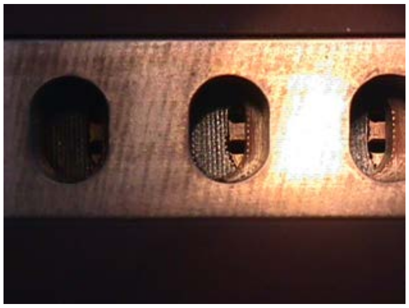


Photo 32. Insulation/copper turn misalignment in the slot.

GENERATOR COOLING METHODS

Originally, generators were cooled by once-through air flow. Contamination problems lead to closed ventilation systems, with water-to-air heat exchangers to remove the thermal losses, i.e., the TEWAC cooling system – Totally Enclosed Water to Air Cooling. This type system is still very popular for smaller size generators.

But by the 1930s ratings were reaching a size where the ability of cooling with air was limiting further increase in rating. It was recognized that use of hydrogen gas as the atmosphere had important advantages: low density, high specific heat, and the high thermal conductivity. In particular, windage losses were reduced to about $1/14^{th}$ that of air. It was also recognized that hydrogen gas was highly explosive, unless hydrogen purity (freedom from oxygen) was kept out of the range between about 4% to 94% oxygen, by volume.

A high-level development program produced the necessary hydrogen shaft seals and system controls to permit the first hydrogen-cooled generator to enter service in the USA in 1937. By coincidence, this was the year of the Hindenburg hydrogen-filled air ship disaster. But there was no OSHA at that time, and hydrogen cooling came into common usage for larger generators.

Over the years there have been a few hydrogen accidents involving serious plant damage and personnel injury and death. The nature of hydrogen fire is such that damage can be dramatic, i.e., hydrogen tends to detonate and produce a high pressure wave. This wave can blow the siding off the entire building and bend a steel door. Photo 33.

Photo 33. Steel door caved by hydrogen detonation wave.

Size limitation came again at around 200 MW in the mid-1950s and manufacturers began development of "direct-cooling" methods, i.e., the cooling media in direct contact with the copper electrical conductors of the stator and rotor.

On the rotor, this involved leaving cooling methods such as Photo 34.

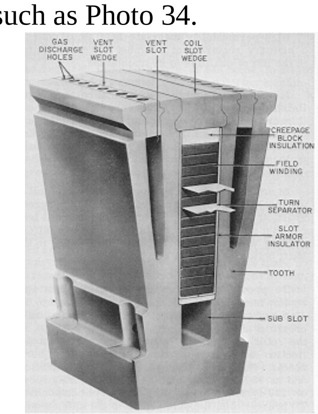


Photo 34. Indirect cooling of a rotor winding.

In rotor winding indirect cooling, gas flows in passages within the forging, thus cooling the forging. The cooled forging then cools the copper by conduction.

With direct cooling, the gas is in direct contact with the copper, Photo 35.

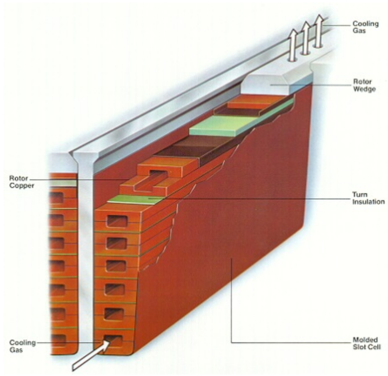


Photo 35. Direct cooling of a rotor winding.

Stator windings until about 1960 were cooled indirectly, left bar in Photo 36. Two types of direct cooling were developed during the late 1950s and are in present usage, center and right bars in Photo 36.

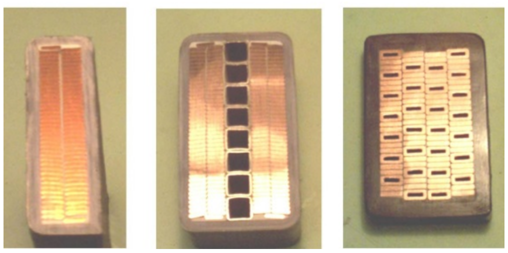


Photo 36. Indirect, direct-gas and direct-liquid stator bar cooling methods.

With indirect cooling, all thermal losses must traverse the thickness of the ground insulation. This electrical insulation is also a quite excellent thermal barrier, thus the incentive to go to direct cooling methods.

With direct-gas cooling, only the strand and tube insulation must be traversed. These barriers are thin and offer little thermal resistance. The bar mechanical structure becomes rather complex in this type of cooling, but a very large number of direct-gas cooled generators are in service and the design has generally performed well.

With direct-liquid cooling, the cooling liquid is in direct contact with the heat-generating copper. Two diverse approaches have been used for the hollow stranding of liquid cooled windings. Most common is hollow copper tubes with all strands, hollow and solid, brazed as a unit into a copper alloy strand header. Photo 37.

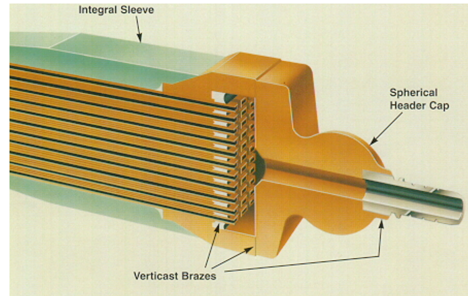


Photo 37. Well designed copper header liquid connection.

Less common is the use of stainless steel tubes individually welded into a stainless header separate from the copper strand connection. Photo 38.

Photo 38. Stainless steel tube header.

The direct-liquid designs have had OEM specific service problems, but in general have performed well.

GENERATOR ROTOR FORGINGS

The mechanical duties on rotor forgings are extremely high on high speed generators, and great effort has gone into development and optimum application of these forgings. Thus a few words on this topic might be in order here.

Rotor Body Forging

The main rotor body forgings reached a crisis point in the mid-1950s. During factory high-speed balance a main field forging failed catastrophically in the OEM balance facility. This rotor was spun in a "pit", with a heavy steel plate cover. When the forging failed, it scattered parts throughout the plant. One 1000 pound piece flew about 1000 feet, more or less axially to the rotor centerline, and crashed down through the engineering offices. Fortunately the failure occurred during night shift and no one was in the office space. But the 2 young test engineers operating the facility were both killed. The rotor was built with a bored shaft centerline of perhaps 6” diameter and the bore opening was filled with 6” diameter magnetic steel plugs. Investigation concluded that the bore plugs were the root cause of failure.

A few months later a field body forging failed in an operating power plant. Damage was considerable, but no one was killed. During manufacture of this rotor a machining error had occurred and a complicated correction was made to compensate this error. The failure was assigned to this correction configuration.

In 1956 a third rotor failed in an operating power plant. (The writer would have been on site at the time of failure had he been home the evening before to answer the phone.) This failure severely injured 3 or 4 personnel and destroyed the turbine-generator. Photos 39-40.

Photo 39. Non-drive end of the generator after forging failure.

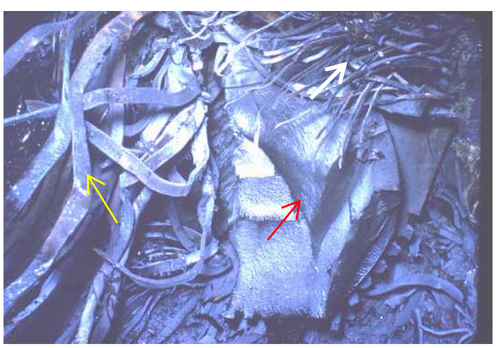


Photo 40. Failed forging (red), field winding (yellow), stator stranding (white).

This field forging had neither of the features of the first 2 failures and the resulting investigation was more thorough. It was found that there were huge inclusions in the basic forging, perhaps greater than 10” in diameter.

At that time, as now, all forgings were coming from the same facilities for all OEMs, and it was concluded that forging material imperfections were the cause of all 3 failures. These inclusions were inherent in the casting processes of that time in that there was heavy contamination in the liquid metal. As the ingot cooled, the impurities percolated toward the ingot center and top. Further contributing to forging vulnerability was that the materials had an FATT (fracture appearance transition temperature) in the range of 40C. This property was totally unacceptable since it means that the material had poor ductility (behaved as a brittle material) below the 40C temperature, and therefore was intolerant to fatigue stress cycles associated with start-stop duty.

The OEMs in conjunction with the steel mills went into a major development program which in a very short time resulted in much better forging quality and NDT procedures for detecting internal material discontinuities. No further failures occurred, partly because of modified operating procedures applied to existing rotors with questionable material properties.

(These modified operating procedures involved operation at higher cooling gas temperatures, which had the unintended consequence of exacerbating the stator winding tape migration problem. See the discussion of stator groundwall insulation, page 2 above.)

<u>Retaining Ring Forgings</u>

Retaining ring materials also went through a complex evolution. Originally rings were magnetic steel, but as size of generators increased a point was reached where rings of non-magnetic material would be highly beneficial. (This need is based on complicated electromagnetic design challenges related to

excess end-of-core heating as load moved toward the leading power factor region.)
The most common of the non-magnetic rings was the 18-5 (18% manganese-5% chrome) material. A few other types of ring material were also used, including Gannalloy. The 18/5 material was found to be subject to stress corrosion cracking, i.e., under high tensile load and in the presence of water, inter-granular cracking occurred. This condition led to several ring failures. One of these 18/5 ring in-service failures was in the mid-1990s. Photos 41-42.

Photo 41. Failed 18/5 ring.

Photo 42. Damage to stator from ring failure.

This ring had been removed and given a full non-destructive test 18 months earlier and was found trouble-free at that time. Oddly, within the same month, at a nearby plant a Ganalloy ring also failed with similar damage.

The problem with 18/5 material was recognized in the 1970s, and in about 1975 an OEM and steel mill went into an intense joint development program. From that effort the 18/18 (18% manganese-18% chrome) alloy was developed. The material acquires an extremely high tensile strength produced in part by a high level of cold expansion during the fabrication process. This involves highly specialized and expensive equipment that is only available at a few facilities in the world.

The 18/18 alloy is not nearly as vulnerable to the stress corrosion phenomenon as the 18/5 alloy, and has been reliable in service since its introduction. It is now the industry standard material for this application.

IN SUMMARY

Clearly this text has been a very general overview, with more left unsaid than said. No doubt there are errors of omission as well as commission. For these included errors and for topics that are unclear or omitted, the writer apologizes to the reader. (With the suggestion that the writer be contacted for clarification.) But hopefully the reader will have a little better understanding, and perhaps appreciation, for the efforts that went into the generator designs of today.

The evolution of large generator winding insulation and support systems has presented many difficult challenges to the engineers who design the generators and to manufacturing personnel who make these machines. Progress will continue, but with continuing increasing sizes and continuing cost pressures, old problems will re-occur, present problems will continue, and new problems will inevitably develop.

But this has been an impressive 100-year development cycle. Those remarkable engineers who have been at the forefront of this effort deserve our grateful appreciation.